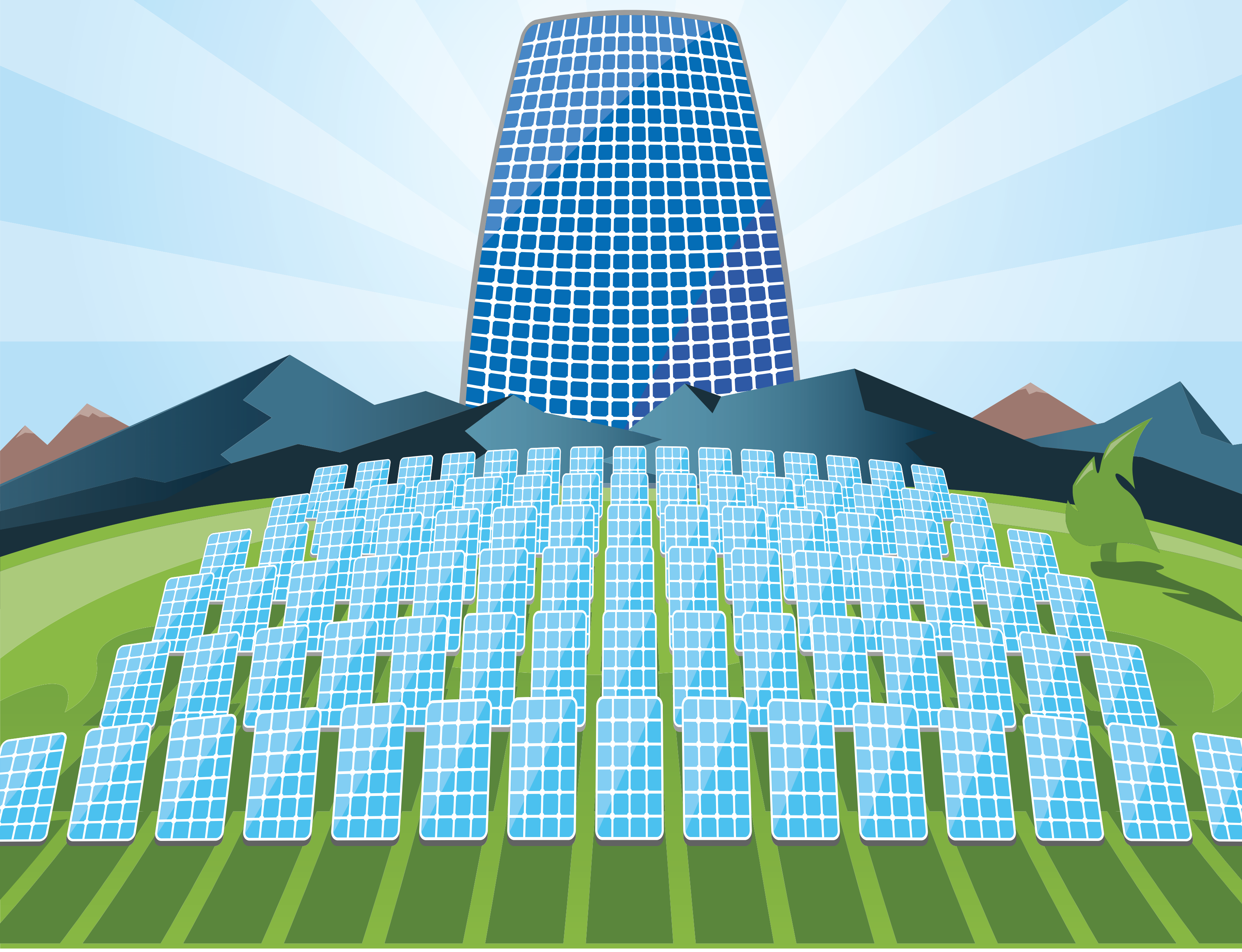
POWER PV TECH

Volume 24 | PV POWER PLANT TECHNOLOGY AND BUSINESS | September 2020

DAWN OF A NEW ERA

550W+ panels are here, but is the industry ready? p.13



MARKET WATCH

Europe's new moment in the sun, p.22

DESIGN & BUILD

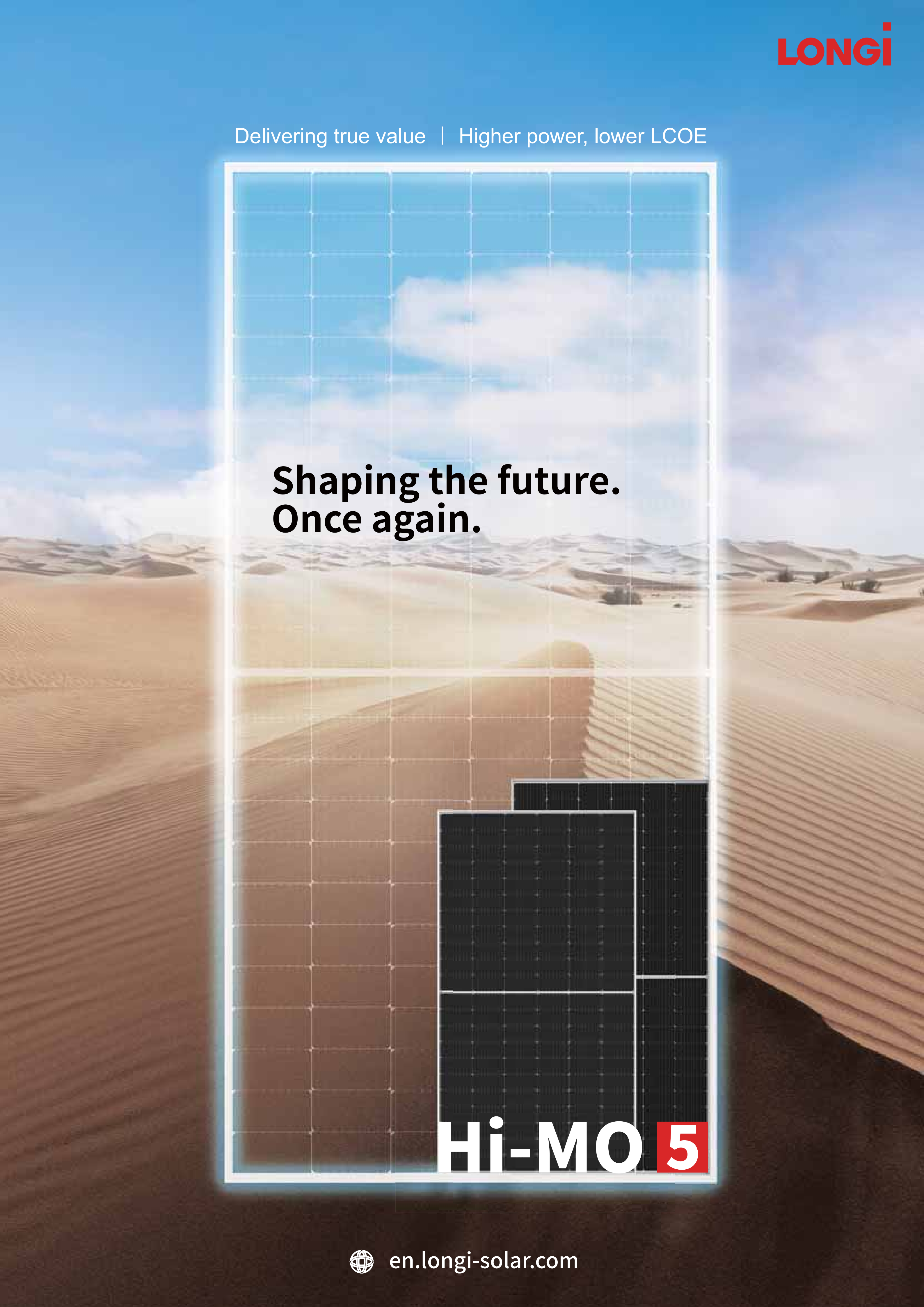
Bifacial yield modelling in Chile's solar hotspot, p.58

FINANCIAL LEGAL PROFESSIONAL

Exclusive bankability insight, p.75

STORAGE & SMART POWER

Everything you need to know about lithium-ion manufacturing, p.86


LONGi
Delivering true value | Higher power, lower LCOE
Shaping the future.
Once again.
Hi-MO 5
en.longi-solar.com

Published by
Solar Media Ltd.
123 Buckingham Palace Road
London, SW1W 9SH, UK
Tel: +44 (0) 207 871 0122
www.pv-tech.org

Publisher
David Owen

Editorial
Editor in chief:
Liam Stoker
Managing editor:
Ben Willis
Senior news editor:
Mark Osborne
Reporters:
Andy Colthorpe, Liam Stoker, Jules Scully, Molly Lempriere

Design & production
Design and production manager:
Sarah-Jane Lee
Production:
Daniel Brown

Advertising
Sales director:
David Evans
Account managers:
Graham Davie, Lili Zhu, Will Swan
Marketing executive:
Carolline Marques

Printed by
Buxton Press Ltd., Derbyshire

PV Tech Power Volume 24, 2020
ISSN: 2057-438X

Cover illustration by Adrian Cartwright, Planet illustration

Introduction

If one facet or trait of the solar PV ecosystem could perhaps define it, then the pace at which it operates would certainly be a popular choice. Costs of manufacturing and deploying the technology continue to fall at near breakneck speed, while tens and hundreds of megawatts can be deployed quicker than any other energy generation technology. It's undoubtedly one of the industry's great strengths.

But could it also leave parts of the sector slightly hamstrung? In what's almost a blink-and-you'll-miss-it evolution, solar modules have moved from last year's 450W to 550W and beyond, with modules boasting outputs as high as 800W on display at this year's SNEC exhibition in China. The premise is simple, more output per panel equals more power per hectare, and this translates to more economical solar for all.

It may not be that simple, as you'll read in this volume's cover feature (p.13). While the new era of larger-sized modules is clearly upon us, they promise to change the sector for good. Challenges right the way through from project design, component procurement to shipping and construction will need to be overcome. There's room for each module class to coexist – BP's 2020 energy outlook states up to 550GW of new renewables capacity could be added each year by 2030 – and developers will make their own independent procurement choices, but collaboration will be key to ensuring the entire ecosystem moves at the same pace as module technology.

This volume of *PV Tech Power* is packed with examples of industry evolution and maturation, indicative of a clean energy sector in rude health and ready to accelerate. Our Market Watch section uncovers how Europe is on the precipice of yet another moment in the sun (p.22), and how in the absence of any federal ambition for clean energy, utilities in the US are taking matters into their own hands (p.18).

Meanwhile we've comprehensive pieces from Enertis on the yield modelling of bifacial panels in Chile's Atacama desert (p.29), widely held as the most ideal location for solar PV in the world, and our coverage of PV Evolution Labs' Module Reliability Scorecard (p.54) provides every inch of detail on module reliability and performance as technological changes gather pace. And if that's not enough to inform and educate your procurement decisions in the months ahead, we've also exclusive insight into the latest PV ModuleTech Bankability Ratings update (p.75), revealing the factors behind our ratings of more than 50 module manufacturers.

As you'll read throughout the pages of *PV Tech Power* volume 24, the solar – and energy storage – ecosystems are evolving and maturing at a rapid and accelerating speed. Modules might be stealing the limelight for now, but the entire ecosystem will be hot on their tails. If the industry can collaborate effectively, with each element of the supply chain helping to lift the other up even further, there is no ceiling to its potential.

Thanks for reading, and we hope you enjoy the journal.

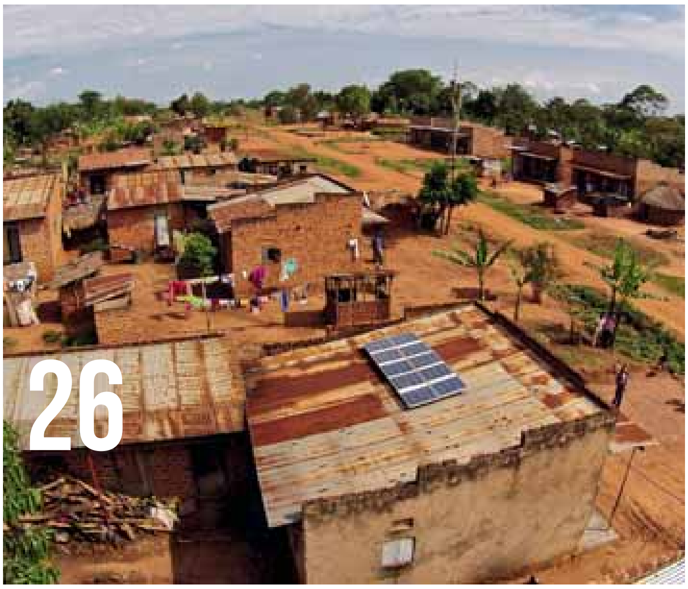
Liam Stoker
Editor in chief
Solar Media

Contents


HUAWEI
FusionSolar
Residential Smart PV Solution
AI BOOST
Optimal Electricity Cost & Active Safety
Active Arcing Protection
2x POWER Battery Ready
One-Fits-All Optimizer
SUN2000-2-6KTL-L1
SUN2000-3-10KTL-M0*/M1
*not support optimizer
SUN2000-450W-P
@ Huawei FusionSolar
solar.huawei.com
community.solar.huawei.com

58-67 DESIGN & BUILD

75-82 FINANCIAL, LEGAL, PROFESSIONAL



86-104 STORAGE & SMART POWER

REGULARS

EUROPE

Generation

New mega-projects help send Europe's solar output soaring to 68TWh in H1 2020

Europe's fleet of solar arrays generated 68TWh of power in the first six months of 2020, a 15% increase on last year's figure as new, larger solar farms came to the fore. New analysis compiled by energy consultancy EnAppSys shows the steep increase has been driven by newly completed projects in the first half of the year, with the advent of significantly larger sites making considerable contributions to total output in the first half of the year. While Europe's solar generating capacity has increased exponentially since 2015, with markets including Germany, Spain, Italy, the UK and France enjoying years wherein multiple gigawatts have been deployed, 2020 has seen the connection of projects significantly larger than before. EnAppSys paid special mention to Iberdrola's 500MW Núñez de Balboa project in northern Spain, which was completed late last year but connected to the country's grid in early Q2 2020.

Credit: Iberdrola

Iberdrola's Nunez de Balboa project in northern Spain has helped send the country's solar output spiralling.

Auctions

'Historic' result as Portugal claims record-low prices in 700MW solar auction

Portugal's second solar auction closed with record-breaking low prices of €11.14/MWh (US$13.12), or US$0.0131/kWh, the country's government announced. Of the 700MW available for auction, 670MW was awarded, with Hanwha Q CELLS winning half of the 12 lots with bids that included battery storage. Other winners included Tag Energy, Iberdrola and Enel, with the majority of the lots including battery storage. The lowest bid falls below the previous industry record tariff of US$0.0135/kWh set by the Al Dhafra project in Abu Dhabi in April. It also comes in around 25% lower than the lowest bid in Portugal's first PV tender last year, which was €14.76/MWh and at the time itself a record.

Solar smashes expectations in 800MW Ireland auction victory

Solar projects have scooped nearly 800MW of contracts from Ireland's first Renewable Energy Support Scheme (RESS), smashing all expectations. The RESS auction had been expected to grant just 10% of its capacity to solar PV, equivalent to somewhere in the region of 100 – 300MW. However the asset class swept aside competing technologies, landing just over a third (34%) of the overall auction volume. A total of 63 projects with a total generating capacity of 796MW were successful, winning at an average strike price of €72.92/MWh (US$86.52/MWh).

Italy

European Energy completes Italy's largest solar farm, readies €800m future investments

Developer European Energy has completed a 103MW solar farm in southern Italy, lauding it as the country's largest to date. And European Energy has claimed the use of cutting-edge solar technologies adopted in its development make it 50% more efficient than it might otherwise have been. Construction of the project, located in Apulia, near Foggia, took one year to complete, and more than 400 people were involved in the construction phase. It is expected to generate some 150 million kWh of electricity each year.

Spain

New laws eye 'massive' deployment of renewables in Spain

Spain's PV industry has welcomed government approval of a package of legislative measures aimed at speeding up the country's transition to 100% renewables. The Spanish cabinet gave the green light to a Royal Decree, signing into law a raft of measures designed to remove barriers to the large-scale deployment of renewables. The move sets renewable energy deployment at the heart of Spain's post-COVID 19 recovery as well as positioning the country to decarbonise its energy system entirely by 2050 through "massive" deployment of clean energy.

Iberdrola pockets €800m to drive renewable growth in Spain

Spanish utility Iberdrola has landed €800 million (US$903 million) in funding from the European Investment Bank (EIB) and Instituto de Crédito Oficial (ICO) to spearhead new renewable energy deployment throughout Spain. The financing package will be put towards the construction of more than 20 solar and wind projects in Spain with a total capacity greater than 2GW. Iberdrola has signed a green energy loan worth €600 million with the EIB, while the financing issued by the ICO – Spain's state-owned bank and lending institution – is the third such loan it has granted to Iberdrola for the development of renewables.

Tech

Q CELLS debuts company's highest power solar module in Europe

Q CELLS has introduced its highest power and highest efficiency solar modules to date into European markets. As part of the Q.PEAK DUO-G9 series, three high-density modules have been launched, all of which feature Q.ANTUM DUO Z Technology, where gaps between the cells are closed to increase module efficiency in relative terms by 4%, delivering an overall efficiency of up to 21.1%, Q CELLS said. The Q.PEAK DUO ML-G9 version has 132 half-cells to deliver a module power output of up to 395Wp.

AMERICAS

M&A

Sunrun to acquire Vivint Solar in US$3.2bn deal

US residential solar installer Sunrun is to acquire rival Vivint Solar as part of a US$3.2 billion all-stock deal that constitutes a major shake-up for the US solar market. The two parties have entered into a definitive agreement which will see Sunrun acquire Vivint, with each share of Vivint's common stock exchanged for 0.55 shares of Sunrun common stock. As a result, Vivint stockholders are expected to hold roughly one-third (36%) of the resultant company, with Sunrun stockholders taking on the remaining 64%. The companies said their combined customer base would make up nearly 500,000 and over 3GW of installs on its balance sheet. It is expected the deal will enable cost synergies to the tune of US$90 million per year post-acquisition. Sunrun chief Lynn Jurich described the venture as a "1 + 1 = 3" situation.

Credit: Sunrun.

The companies' combined customer base will be nearly 500,000.

US

New York issues record-breaking solicitations for renewable energy

New York Governor Andrew Cuomo has announced the largest combined green energy solicitations ever issued in the US, seeking up to 4GW of renewable capacity to combat climate change. While the majority of the solicitations' combined total - 2.5GW - is for offshore wind, two solicitations for land-based, large-scale renewable energy look to procure more than 1.5GW of capacity. The land-based solicitations, combined with a multi-port funding opportunity, are expected to spur approximately US$7 billion in direct investments and to create approximately 4,500 short- and long-term jobs, as Cuomo aims to jumpstart economic growth amid the ongoing COVID-19 pandemic. The Democratic governor said he remains "laser-focused" on implementing a "nation-leading" climate plan and growing the clean energy economy. The solicitations are expected to result in the development of dozens of new large-scale renewable projects over the next decade.

Biden outlines US$2tn climate plan to unleash 'clean energy revolution'

Joe Biden has unveiled a wide-reaching blueprint to transition the US to a carbon-free power sector by 2035 and build a more sustainable economy. The Democratic presidential nominee's plan consists of a US$2 trillion investment over four years in what constitutes a significant ramp-up of ambition for clean energy in the US. Last year, the Biden campaign earmarked US$1.7 trillion for green spending, but spread over ten years. Alongside scaling up best practices from state-level clean energy standards, Biden proposes reforming and extending tax incentives to generate energy efficiency and clean energy jobs. Steps such these will help unleash a "clean energy revolution" and spur the installation of millions of solar panels, including utility-scale, rooftop and community solar systems, the campaign said.

Credit: Gage Skidmore.

Joe Biden aims to transition the US to a carbon pollution-free power sector by 2035.

Brazil

Bolsonaro taps green bonds to deliver 8GW of new solar

Brazil is to turn to green finance to try and deliver a multi-gigawatt boost to renewables, an industry grappling with the COVID-19 chaos that has forced to shelve green energy tenders. President Jair Bolsonaro signed a decree in June that laid the foundations of a green bond programme, meant to channel funding towards solar PV, wind, small hydro installations and energy-from-waste facilities. The so-called green debentures will see debt raised towards these industries, amid hopes by Brazil's government of delivering an 8GW fleet of new solar nationwide, coupled with significant portfolios of new wind (25GW) and small hydro power (3GW). According to estimates from Brazil's Energy Ministry, the three renewable segments could bring Brazil a combined investment of 170 billion Brazilian Real (US$34 billion) by 2029.

Chile

New Chile JV marks start of global green energy drive, says Repsol

Repsol has strengthened its commitment to renewable generation with the creation of a joint venture Chile that will develop more than 1.6GW of green energy projects by 2025, comprising two solar facilities and three wind farms. The energy firm has partnered with Grupo Ibereólica Renovables, with both Spanish companies owning 50% of the new entity. The joint venture will have a diversified portfolio of assets (52% wind and 48% solar) distributed into 78MW of renewable generation capacity already in operation, 110MW under construction, 1.5GW in advanced stages of development which will be operational by 2025 and another 1GW planned for 2030. Repsol said the deal marks the start of an effort to expand its renewable energy activities into new global markets.

Project groundbreaking

World's 'largest behind-the-meter solar project' breaks ground in Nevada

Technology infrastructure company Switch and asset management firm Capital Dynamics have announced the groundbreaking of three developments in Nevada. The projects comprise Switch's Gigawatt 1 initiative, which will soon generate 555MW of solar power and create 800MW hours of battery storage. Work has started on plants in Clark and Storey counties in the state. According to the companies, the Storey County location will be "the largest behind-the-meter solar project in the world", producing 127MW and including a 240MWh battery storage system. Alongside panels made by First Solar, the facilities will feature Tesla Megapacks, which are manufactured at the Tesla Gigafactory in Storey County.

MIDDLE EAST & AFRICA

Tenders

EWEC confirms EDF, JinkoPower, Masdar among winners in Abu Dhabi's world record solar tender

A consortium including Abu Dhabi National Energy Company (TAQA), Masdar, EDF and JinkoSolar development arm JinkoPower have been formally announced as the winning party behind the world record low tender for the 2GW Al Dhafra solar farm. Having won the hotly-contested contract, the parties will now work to bring forward the project following the signing of a contract with Emirates Water and Electric Company (EWEC). At a tariff price of US$0.0135/kWh, Abu Dhabi Power claimed it to be the world's lowest tariff for solar when it was first announced in April 2020.

Saudi Arabia

JV launched to pair 4GW with 'world's largest green hydro project' in Saudi Arabia

A joint venture project has been launched to develop what intends to be the world's largest green hydrogen project, using up to 4GW of solar and other renewables to produce around 650 tons of hydrogen per day as well as 1.2 million tons of green ammonia each year. Renewables developer ACWA Power is among the parties assembled by Air Products under an agreement to assemble a green hydrogen-based ammonia production facility in Saudi Arabia's NEOM with the intent of turning the area into a green hydrogen powerhouse. ACWA, Air Products and NEOM will be equal partners in the project which comes with a US$5 billion investment tag and is expected to come onstream in 2025. A total of 4GW of power from solar, wind and storage sources will be integrated into a facility housing electrolysis units supplied by thyssenkrupp, nitrogen production technology from Air Products and green ammonia production units from Haldor Topsoe.

Dubai

ACWA enlists Shanghai Electric as EPC for fifth phase of Dubai's Mohammed bin Rashid mega-project

ACWA Power has once again turned to Chinese EPC Shanghai Electric to be the engineering, procurement and construction contractor for the fifth phase of the Mohammed bin Rashid Solar Park in Dubai. Saudi Arabian developer ACWA appointed Shanghai Electric as EPC for the latest phase of the mammoth solar project having collaborated with the company a number of times previously. The Mohammed bin Rashid Solar Park comprises both PV and concentrated solar power technologies and will boast a total capacity of around 5GW once complete.

Cedit DEWA

Phase 1 of the Mohammed bin Rashid solar park, completed in 2013. Image: DEWA.

JinkoSolar lands 1GW bifacial module supply deal for Dubai mega-project

JinkoSolar is to supply 1GW of bifacial modules for the fifth phases of Dubai's major Mohammed bin Rashid Solar Park after signing a strategic partnership with engineering, procurement and construction firm Shanghai Electric. The 'Solar Module Super League' member will collaborate with Shanghai Electric on the development, bidding, investment and construction of overseas solar projects by leveraging their respective strengths.

Kuwait

Kuwait cancels 1.5GW Al-Dabdaba solar complex amidst oil crash

Kuwait has cancelled a 1.5GW solar project meant to power the country's state-owned petrol company citing the ongoing COVID-19 pandemic. Having originally tendered for the project in September 2018, the 1.5GW complex was expected to start construction last year prior to commencing operations in early 2021. But delays beset the project and Kuwait's cabinet has confirmed it will not proceed. In a statement issued via Kuwait's news agency, the cabinet confirmed it had elected to cancel all decision on the project due to the onset of novel coronavirus pandemic and its impact on global oil and financial markets.

South Sudan

Solar-plus-storage project completed at UN Humanitarian Hub in South Sudan

A solar and battery storage system will reduce diesel consumption by at least 80% at a base for 300 humanitarian workers in South Sudan, managed by the UN's International Organisation for Migration (IOM). Independent solar power producer Scatec Solar, which is headquartered in Norway, said it has completed work on the project, combining a 700kWp solar PV system with a 1,368kWh battery energy storage system (BESS) and connected to existing diesel generators onsite. The project is sited at the Humanitarian Hub in Malakal, South Sudan.

Israel

Israel's new government plots 15GW-plus solar plan as policy priority

Solar is to become an energy policy axis of the reappointed government of Israeli prime minister Benjamin Netanyahu, with plans now laid out for a decade-long renewable boom. The Energy Ministry released a plan to mobilise 80 billion Israeli Shekel (US$23 billion) in government and private funding to deploy gigawatts of solar by 2030, coinciding with a coal phase-out over the decade. The roadmap by Energy minister Dr Yuval Steinitz is targeting a 16GW solar fleet by 2030, able to cover 30% of the country's power demands. On sunny days, the solar's power mix share could reach peaks of 80%, the document says.

ASIA-PACIFIC

Finance

Asia Pacific renewables could attract US$1tn of investments this decade – WoodMac

Solar and wind power represent a US$1 trillion investment opportunity in Asia Pacific this decade, equivalent to two-thirds of the region's total power generation sector, as countries move away from fossil fuel generation in favour of greener alternatives. That is according to a new Wood Mackenzie report, which reveals the share of wind and solar in the Asia Pacific power generation mix will more than double to 17% by 2030, with more than 51 markets out of 81 modelled exceeding 10% renewable energy. Wood Mackenzie senior analyst Rishah Shrestha said coal investment will fall from its peak of US$57 billion in 2013 to US$18 billion by the end of the decade.

Polysilicon volatility

Daqo expects polysilicon demand to outstrip supply for next 18 months

Major polysilicon producer Daqo New Energy expects polysilicon demand to outstrip supply for at least the next 18 months, due to the lack of new polysilicon capacity and strong demand as a growing number of manufacturers continue to add in-house monocrystalline ingot and wafer production. Longgen Zhang, chief executive officer at Daqo New Energy noted in the company's second quarter 2020 earnings call that some of the major PV module manufacturers, such as JinkoSolar were continuing to invest in in-house mono ingot/wafer production, matching PV module capacity expansion needs. The Daqo executive believes other major players will follow the same vertically integrated path, pushing up demand for high-purity polysilicon when only around 100,000MT of new capacity could be onstream not much sooner than the next 18 months.

New polysilicon blow as flood forces closure of Tongwei facility

Credit: Tongwei Solar

Tongwei's closure of a 20,000 MT facility in China followed a severe flood warning

Severe floods in southeastern China forced the closure of a polysilicon facility owned by Tongwei, dealing yet another blow to the solar industry's supply chain. In mid-August Tongwei confirmed the closure of a 20,000-tonne polysilicon plant in Leshan City, Sichuan, after a Level 1 flood alert was issued by authorities. China's Yangtze River runs through Sichuan, while Leshan itself sits on the interjection of a number of rivers and waterways. It serves as a fresh blow to an upstream solar sector already hit by incidents at facilities belonging to GCL-Poly/JZS and Daqo which have impacted polysilicon supply, increasing price volatility and hitting module manufacturing cost control.

India

Labour shortages and 'restrictive' work practices holding up India solar rebound

Labour shortages and "restrictive" work practices caused by the ongoing COVID-19 pandemic have caused solar deployment to fall by nearly two-thirds (64%) sequentially, with just 351MW having been installed in Q2 2020. That is according to consultancy Bridge to India, whose prediction of 500MW of new PV in Q2 proved too optimistic given the extended lockdown and consequent effect on movement of people and goods. Bridge to India's figure of 351MW is the most optimistic projection issued, with other recent evaluations of India's Q2 performance having reinforced how modest new installations were in the three months to the end of June.

Indian solar association calls for immediate implementation of 50% BCD

India should put in place immediately a basic customs duty (BCD) of at least 50% on solar equipment to safeguard the future of local manufacturers, the chairman of trade body All India Solar Industries Association (AISIA) said. Hitesh Doshi called on policymakers to implement the "much-needed" BCD with immediate effect to protect domestic equipment producers. "The survival of the manufacturers requires the government to look into [the] restructuring of existing policies like [the] implementation of at least 50% basic customs duty," he said. The calls came following a summer of uncertainty as India both extended its safeguard tariffs and mooted a potential BCD rising each year.

Australia

DER and utility-scale renewables can combine to offer cheapest option to Australia's coal retirement

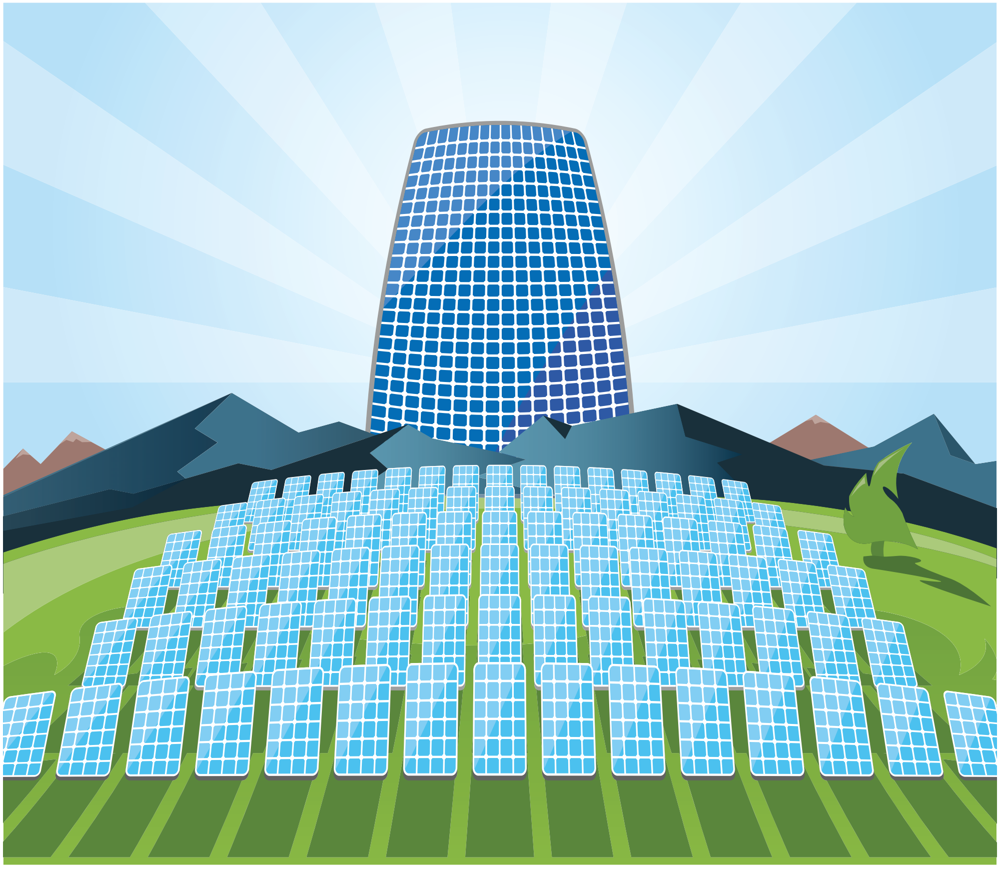
Australia's distributed renewables base could treble and more than 26GW of grid-scale renewables will be needed as the Australian electricity market evolves over the next two decades, a comprehensive review conducted by the country's market operator has concluded. Such an increase in renewables in Australia is the cheapest option on the table as the country's coal fleet retires, but in order to deliver such an overhaul of Australia's power market, up to 19GW of dispatchable resource and a systematic reform of energy policy in the country will be required. The quantity of distributed energy generation connected to Australia's grid is forecast by the AEMO to double or even triple, providing up to 22% of total underlying energy consumption in the country. Meanwhile, more than 26GW of variable renewable energy (VRE) will be needed to replace coal-fired generation in Australia, with nearly two-thirds (63%) set to retire.

NSW to go 'even bigger' with second, 8GW renewable energy zone

Plans to develop an 8GW renewable energy zone (REZ) in New South Wales, the Australian state's second, have been billed as the biggest commitment to clean energy in its history. Located in the New England region, the AU$79 million (US$55 million) project is expected to attract AU$12.7 billion in investment, support 2,000 construction jobs and 1,300 ongoing jobs – all while lowering energy prices. The development marks New South Wales's second of three REZs and came weeks after the first – located in the Central-West and Orana regions – received 113 registrations of interest, totalling 27GW, looking to connect to the 3GW zone in what constituted a significant oversubscription of available connections.

Is solar ready for the high-power era?

Module technology | The rapid evolution of photovoltaic technology has continued, as modules with peak power outputs in excess of 550W are emerging fast. Driven by a thirst for more power and increasingly larger cells, developers and EPCs now face tougher procurement decisions than ever before. But is the industry ready for such a jump? Liam Stoker investigates



Credit: Adrian Cartwright, Planet illustration

There can be no questioning the pace of technological evolution in solar PV, but recent advancements have caught even the most optimistic of industry stakeholders by surprise. Not long ago, solar modules with outputs of up to 450W hit the shelves and left project developers drooling at the prospect of squeezing more power into each hectare of a prospective utility-scale project. And yet, the industry has barely had time to blink and modules with peak outputs in excess of 550W are here, with outputs climbing higher even still.

A new dawn of high-power, ultra-efficient panels has broken. R&D from module manufacturers has produced various series of bigger, better panels, featuring larger, more efficient cells and refined approaches to panel-level technologies. The premise is clear: high output per panels means lower levelised cost of electricity (LCOE), which means more economic solar for all. In a time of contracting subsidies and merchant business models, this stands to be a potentially game-changing development for the entire power sector.

But it's not quite that simple. Bigger does not always equal better, and the introduction of such panels is not as seamless as it may seem. The entire solar supply chain now needs to match the frenetic pace set by module manufacturers.

The industry has quickly leapt from panels with outputs of 450W, to 550W and beyond

Technology driving change

This year's SNEC exhibition in China, rearranged as a result of the COVID-19 pandemic, was perhaps the best example of the industry's rapid advancement. The show floor was littered with modules boasting outputs in excess of 550W, indicating they could quickly become the industry standard. JA Solar even exhibited a module with an output of 810W, alongside Tongwei which had a 780W module on show, even if it is anticipated that it will be a while yet before these particular products hit the shelves.

Exhibitors at the show were quick to describe the next generation of panels on display as falling under 'Solar 5.0', a new era of modules each with an output of 500W and beyond. Journalists from this publication counted 500W+ modules from no fewer than 22 separate manufacturers on the show floor, and analysis of those on display reveals some key technological trends playing a critical role in this evolution.

Most panels on display at SNEC featured mono passivated emitter rear cell (PERC) architecture, while half and triple-cut cells were also prominent. Panels of this kind also boasted multibusbar technologies, the highest-output panels including anything from nine to 12 busbars. The chart (featured) provides a detailed breakdown of the panels, outputs and technologies on display.

But the overwhelming point of discussion when it comes to the technologies behind the new era of panels is wafer size. At the start of 2020 there was much discussion around the emergence of new, larger sizes of wafers and the role they would play in more powerful panels. While this debate almost petered out, with some manufacturers reflecting on it afterwards as a "distraction", it has become clear

Company	Product	Technology	Module Output (W)	Conversion Efficiency (%)	Wafer Size (mm)
Jinko Solar	Tiger Pro N-type 78-cell bifacial module	Tiling ribbon, MBB	610	22.31	182
JA Solar	JumboBlue	1/3 cut, 11MBB, PERC	800	20.50	210
Tongwei	PERC, mono shingled module G12	Shingled module+G12, Large wafer	760-780	21.90	210
Trina Solar	Vertex	MBB, non-destructive cutting, high-density encapsulation	660	21.20	210
LONGi Solar	Hi-MO 5 super-high module	Gallium doped wafer+half-cut+9BB	540	21.1	182
Canadian Solar	HiKu6	Mono PERC	590	21.30	182
Risen	TITAN 600W+	PERC, half-cut, 12BB	615	21.2	210
GCL-SI	GCL-M12/50GDF	1/3 cut, non-destructive cutting+ high-density encapsulation	505	20.8	210
Suntech	Ultra	PERC, MBB, 1/3 cut	605	21.30	210
Yingli Green	Bifacial Panda	1/3 cut, 9BB	550	21.6	210
Seraphim	SII all-black half-cut	Half-cut, MBB, PERC	530	20.30	210
LDK Solar	Mono 210, large size	1/3 cut, PERC+SE, MBB	500	22.40	210
Jinergy	Super-high, mono PERC	Half-cut, MBB, HJT	510	/	166
SPIC	156 cell, half-cut, white backsheet	IBC 6BB half-cut	505	21.6	158.75
ZNshine Solar	150 cell, 10MBB, mono PERC	10MBB, anti-PID degradation	520	21.79	210
DZS Solar	G12-66P bifacial	Shingled module+G12 large wafer	635	22.1	210
Jolywood	Niwa® Super615W high-efficiency bifacial	Topcon, 11BB	615	22.10	210
EGing	Gallium doped MBB SE+PERC high-efficiency module	Gallium doped MBB, SE+PERC, 1/3 cut	545	21.20	210
HT-SAAE	78 cell, half-cut, mono, single glass module	Half cut, 9BB	595	21.3	182
Talesun	BISTAR PRO	Half-cut+10BB	590	21.0	182
HT Solar Group	Mount Tai 6.0	Interconnection, PERC, MBB, high-density encapsulation	600	21.71	182
CECEP	182-cell large size wafer	MBB, half-cut, PERC, non-destructive cutting	540	21	182

A list of all the modules with outputs of 500W and above on display at SNEC this year

that wafer size, and more specifically the emergence of two very distinct camps, looks set to decide the course of the solar industry for the immediate future.

As the chart illustrates, aside from a select few modules still using the existing industry standard-size 158-166mm wafers, most modules belonging to the new class use either the 182mm (M10) or 210mm (M12) wafer size. Most of the upstream solar manufacturing industry has fallen into either of these two class sizes, with the likes of JinkoSolar, LONGi, Canadian Solar and others electing to use M10 wafers, while Trina Solar, JA Solar and a raft of other manufacturers very much walking down the M12 path.

For LONGi, the notion that 'the bigger, the better' does not always ring true, with the manufacturer arguing that module sizes should have a 'sweet spot'. Before throwing its weight behind M10 wafers, Hongbin Fang, director of product marketing at LONGi Solar, says his company analysed conditions relating to not just ingot, cell, wafer and module manufacturing, but system applications, ranging from shipping logistics to electrical parameters that modules operate in. "The natural progression for modules should consider reducing the BOS cost and LCOE instead of only seeking a bigger module size," he says.

Tino Weiss, head of global purchasing at German developer BayWa r.e., concurs, stressing that more power is not always the best course of action, and that balance of system costs should be paramount when it comes to selecting modules for a project. The impact throughout the system of choosing more powerful panels, from both an electrical and physical perspective, can have significant impacts on LCOE. "That's exactly what we need to take into consideration, by what is the right module in the market, what is the impact on production costs of the module and what is the impact on LCOE of the system," Weiss says.

Other industry stakeholders, however, disagree, arguing that increasing outputs per panel can contribute significantly to the LCOE of projects, helping make solar more economical. Pushing boundaries with regards to wafer size and panel output could indeed usher in a new era of ultra-cheap solar developments.

But how much is too much, and at what point do panels become too big or, indeed, too powerful? Technical issues, it would appear, are already arising.

Pushing boundaries, moving goalposts

Technical issues arise as a result of the much larger wafers used in the manufacturing process. The M12 triple-cut and M10 half-cut cells used in some of the next generation of panels operate with a current of somewhere between 11-13A, similar to that of most panels on today's market. This means that they can effectively slot straight into today's system design and be installed alongside other components available today. Voltages of around 50V present in these modules are also something the industry can handle, Weiss says.

The prevalent issue is when panels feature a half-cut M12 cell. The size of the cell, much larger than those featured in modern panels, results in a markedly higher current, around 16-18A depending on the module. This, according to Weiss, is a step too far, causing a ricochet of effects throughout the system design. Furthermore, as Fang says, with wider adoption of bifacial modules and a bifacial gain of 5 - 15%, the working current across such a panel could be more than 20A. "In this case, there is a significantly higher risk of failure due hot-spot or junction box issues," he says.

Not only are thicker cables – up from 6mm to around 10mm – needed to facilitate a current that's 40% up on what's being used today, but system design principles that underpin much of modern utility-scale solar farms also face changes. Combining two strings of panels results in a current higher than 30A, a current which modern inverters cannot handle on a single maximum power point tracker (MPPT).

This is likely to place new strains on the supply chain. Cables of that diameter are not commonly used in the industry and

will be more expensive, while there is a dearth of inverters on the market capable of being used in conjunction with these higher power outputs. Weiss says the introduction of such inverters will almost certainly be at a higher price point, a factor which again must be taken into account when designing the overall system.

Using costlier components throughout the system will obviously increase system prices, impacting the BOS and LCOE of any given project.

But advocates of the M12, 210mm wafer size argue for the benefits of cells using them, professing that their adoption opens the industry up to more significant cost reductions further down the line. Trina Solar's new Vertex range of panels, which boast power outputs of 550W up to 660W, all use M12 wafers and the manufacturer has adopted the mantra of "low voltage, high current" for its marketing. Trina's 550W Vertex panel has a current of 18.39A and a voltage of 38.1V, while the 600W version has a current of 18.42A and a voltage of 41.7V. Dr. Franck Zhang, head of product strategy and value management at Trina Solar, says by opting for a lower voltage than other panels on the market today, more can be connected per string.

Detail provided within a recent webinar co-hosted by Trina Solar and *PV Tech Power's* sister website *PV Tech* showed that in lowering the voltage, as many as 36 Vertex 550W panels could be connected per string, an increase on the 27 pieces of an undisclosed module with a 540W output used as a reference. This meant that the total power per string using Trina's Vertex series equated to 19,800W, an increase of nearly 36% on the 14,580W from the reference string. This, in turn, reduced the number of modules needed to produce each megawatt of installed capacity, the volume of steel needed for racking, the length of cable necessary for each megawatt and savings on other hard costs associated with a completed project. The end result is a saving on BOS costs which, albeit relatively minimal per watt – equivalent to around RMB0.05 (US$0.007) – extrapolated over the course of each megawatt installed, could mean the difference between a project being rendered economical or not.

Selecting any particular panel can evidently have sizeable impacts on not just the components used elsewhere in the project, but on expected returns and the way any project is designed and developed. Weiss says the introduction of 550

Credit: PV Tech.

A selection of the high-power modules on display at this year's SNEC exhibition in China.

and 600W+ panels promises to be a significant change for developers with proven and reliable design methods. "If you look at the last 10 years, project development in regard to system design was quite easy because we didn't have too many changes on the module class. Power class went up, but the size never changed, and the technical specifications never changed like they have now," he says.

But technical issues are not the only elements of a module to change with the evolution of cell technology and sizes. As currents increase, so too do module sizes and weights, yet another modification which poses significant change for the industry.

Size, use and weight

Not withstanding the sizeable challenges in adapting systems to the electrical output of panels, the actual physical differences of these panels compared to previous generations cannot be overlooked. In upsizing to 550W and beyond, the panels themselves are increasing in physical size and weight, resulting in challenges right the way through from shipping and handling to deployment and site management.

While panel sizes and weights vary, those featuring M12 wafers are usually upwards of 2.2 metres long and 1.3 metres wide, some weighing in excess of 35 kilograms, beyond the current industry norm. BayWa r.e.'s Weiss says this is to be felt throughout the supply chain. "Handling, weight, transportation… how will pallets be loaded, how do they fit into the container – these are the questions in regard of the size [of the panels]," he says. LONGi Solar's Fang is equally dubious of shipping constraints caused by increasing module sizes, pointing in particular to the height of standard 40HC shipping containers used in global logistics.

The combined weight of panels during shipping and distribution will also pose questions. As Weiss notes, a standard shipment of some 30 panels each weighing 45 kilograms means a total pallet weight in excess of 1.2 tonnes. "How do you want to drive these through mud on a construction site?" he asks.

Getting the panels to any particular site is one thing; actively deploying panels that weigh upwards of 40 kilograms is another issue entirely. European law states that labourers lifting anything heavier than 25 kilograms cannot do so alone, meaning either lifting equipment or a second – or any other number – of additional workers must help, which in turn has a direct impact on either build times or the number of workers needed on site, adding to labour costs. The same regulations exist in other established solar markets, creating an issue for developers actively pursuing such modules. The matter is, however, further complicated by the absence of such protective legislation in key markets such as China, India or Mexico, prompting a potential split in terms of module adoption.

The combination of size and weight must also be considered in system design and build, especially in relation to the use of mounting structures and trackers, in particular. BayWa r.e. typically installs its solar panels in portrait – with modules typically increasing in width – this minimises the impact from increased weight on mounting structures, Weiss says. Those installing in landscape, however, could see more strain placed upon structures, resulting in a need for a change in design or strength. This is no major problem for the industry to circumvent, with the benefits of increased power/output from each structure providing an impetus to overcome it, but it's a factor of design that must nevertheless be taken into account.

Trackers, however, may be more complicated. As panels get larger and heavier, the notion of clamping a module and tilting it throughout the day becomes more complex, with potentially serious consequences at the panel level. "We're now talking about modules with a length of 2 metres 20 centimetres, and if tracker suppliers want to clamp these kind of modules in the middle with a 400 millimetre clamp, this might cause microcrack issues after five or ten years due to wind or snow pressure," Weiss says.

Tracker manufacturers are answering the call, with the likes of Soltec releasing products specifically geared towards modern 72- and 78-cell modules.

It's not just hard costs associated with components that are at risk of changing significantly with the advent of high-power modules, but soft costs too. And as the cost of solar components continues to decline, it's soft costs which are quickly becoming the focus of developers and EPCs.

What is clear is that while modules have evolved drastically in such a short timeframe, the rest of the industry needs to catch up for the next generation of panels to realise their full potential.

Collaboration is key

"In the last few years the industry has proved that not only increasing efficiency but increasing power by increasing wafer and module size brings tremendous value addition to the customers, especially in reducing the BOS costs," LONGi Solar's Hongbin Fang says, acknowledging that his company had indeed assessed the potential for M12 wafers. "We made a very detailed technology analysis for 210mm wafers all along the value chain – from wafers, cells, modules and PV systems. The 210mm wafer and related module will bring limited benefits to the value chain, but require heavy capital investment throughout the manufacturing process and compromise many aspects of module deployment," he says.

It's evident the entire ecosystem must evolve alongside the modules. Trina Solar's Franck Zhang says that Trina has turned to the likes of NexTracker and Huawei, collaborating with them to help bring forward a new wave of trackers and inverters that can support this new wave of modules. It's been a central cornerstone of and key motivation behind the 600W+ Photovoltaic Open Innovation Ecological Alliance, which Trina Solar unveiled in mid-July. The alliance brings together a total of 39 companies from the solar supply chain with the intent of fostering greater collaboration between them and establishing an ecosystem that can facilitate the introduction and adoption of 600W+ panels.

But, according to Weiss, module manufacturers will need to broaden their horizons even further, and collaborate with those actively deploying modules – the world's developers and EPCs – to determine just what they need from a next-generation panel.

"There have been a lot of discussions in the market beforehand, with EPCs. And, of course, if you ask an EPC 'Do you do you prefer modules with a higher power class?' Then they will say yes. But the question was wrong; they should have asked, 'Would you like to have a module which has a higher power class, and it's definitely much larger than the one before and would have a much higher current?' If they would have raised the question like this, they would have gotten a different answer," he says.

Weiss says BayWa r.e. will, for the time being at least, be sticking with what works for the company's system design principles. Modules featuring half-cut M10 and triple-cut M12 cells will suffice, with Weiss adding that his company "doesn't really need" to go beyond those modules and outputs. He does, however, admit this is not a universal approach. "I know there are other players in the market which don't look into the balance of system. They just look for specific module prices. And of course, the M12 modules will have the highest potential to get the lowest specific module price," he says.

Manufacturing economics and selling prices, set against a race for scale, are set to play a critical role. With production costs per module falling, and module selling prices calculated in price per watt peak, producing more powerful modules at scale makes for much more attractive margins. It's what Weiss describes as an "interesting phenomenon" for the solar market.

Manufacturers are bringing significant scale too. Trina Solar aims to have 10GW of manufacturing capacity for its Vertex series operational by the end of this year, followed by 21GW by 2021 and 31GW by the end of 2022. Others are expected to follow. Meanwhile, manufacturers in the M10 camp – including the likes of LONGi and JinkoSolar – are being equally ambitious with expansion plans.

The solar PV ecosystem would therefore appear somewhat split at what is undeniably a critical juncture. Technology is evolving rapidly and facilitating significant increases in power outputs, but the sector itself cannot – and most likely will not – agree on the best path to take. But there is every opportunity for the two sidest to coexist as project developers worldwide select the module that is best suited to their specific project or pipeline, and design and procure other components accordingly. What is clear, however, is that for the sector to truly embrace panels of 600W+ outputs, it cannot be just the panels themselves that evolve. The entire supply chain must move together, ensuring that each component matures to deliver the kind of LCOE and balance of system benefits that developers are looking for. If that can be achieved, then the next generation of panels will unquestionably usher in a new era of project economics.

Sooner or later though, the industry will have to decide on how large is too large. "Somewhere, the end is reached," Weiss says, commenting that the only way this message will resonate is with improved communication and collaboration throughout the ecosystem. ■

Behind the rise of US utility-driven solar

US utilities | With federal support for renewables having been depleted in recent years, utilities in the US have taken a leading role in the deployment of solar and energy storage. Jules Scully examines how integrated resource plans are driving solar deployment.

Credit: Dominion Energy

As the US tilts towards a presidential election that will very much decide the country's path for the next four years, federal policy towards renewables and, indeed, climate action in general, hangs in the balance.

But in the absence of overarching federal policy, utilities in the US are increasingly taking matters into their own hands. Recent months have witnessed a slew of integrated resource plans (IRPs) published by utilities, each detailing ambitious plans to deploy swathes of solar and other renewables, as well as energy storage, in a bid to wrestle back control of climate action.

In a dramatic policy reassessment, Dominion Energy Virginia is now calling for the development and procurement of approximately 24GW of new renewable energy and storage capacity over the next 15 years – nearly quadruple the targets outlined in its 2019 IRP.

Announced in May, the latest proposal will see Virginia's largest utility look to add nearly 16GW of solar, 5.1GW of offshore wind and 2.7GW of energy storage. The backtrack followed the enactment a month previously of the Virginia Clean Economy Act, which called on Dominion to be carbon-free by 2045 and requires the closure of nearly all coal-fired plants in the state by the end of 2024.

"Solar and storage are going to be absolutely critical elements in order to help us achieve both our company's net-zero commitments as well as our legislative obligations," says Katharine Bond, Dominion vice president of public policy and state affairs, adding that the renewables targets are in part due to increasing requirements as a result of the Clean Economy Act.

Virginia is a "prime example" of the bottom-up climate leadership around the US being demonstrated by cities,

US utilities are making up for lack of federal leadership by procuring large volumes of clean energy generation and storage capacity

states, utilities and other subnational entities, Wendy Jaglom of Rocky Mountain Institute said earlier this year. "While we wait for federal leadership on climate, this is exactly the kind of expanded ambition and commitment needed to build the foundation for a comprehensive, all-in climate strategy that gets us on a path in line with the goals of the Paris Agreement," she added.

The Dominion case is part of a growing trend among US utilities that are decarbonising their power supplies, driven by state policies that support the energy transition, cost declines in solar and battery storage technologies, and corporations looking to procure additional green energy.

In New Mexico, a bill that mandates 100% clean power by 2045 was passed last year; PNM, the state's largest electricity provider, is targeting 100% emissions-free electricity by 2040.

Meanwhile, utilities Avista and Idaho Power are making up for the lack of policy in Idaho by both shifting to 100% clean energy by 2045. Despite the absence of state-wide renewable energy goals, the move will mean most of Idaho is being served by electric utilities intent on reaching 100% renewable energy. Idaho Power has also entered agreements to end participation in two coal plants and is exploring exiting a third — and final — coal plant.

According to the Smart Electric Power Alliance, 68% of all customer accounts in the US are now served by utilities with carbon reduction goals, including 27 utilities with ambitions to be carbon-free or achieve net-zero emissions by 2050.

The 'compelling' case for renewables

US utilities' move away from coal and even natural gas-fired power stations comes as the economic case for renewables becomes undeniable.

Around three-quarters of US coal production is now more expensive than solar and wind energy in providing electricity to American households, a study published last year by renewables analysis firm Energy Innovation revealed.

In Its New Energy Outlook 2019, BloombergNEF found that wind and solar are now cheapest across more than two-thirds of the world and that by 2030, they will "undercut commissioned coal and gas almost everywhere".

Still, reliability issues surrounding solar and wind power mean that some utilities will rely on natural gas and coal in the future. Dominion's latest IRP will see it develop 970MW of natural gas peaking generation to address these reliability concerns.

Alongside proposals to add up to 14GW of new solar capacity by 2038, the Tennessee Valley Authority is also eyeing anywhere from 2GW to 17GW of natural gas generation.

"The biggest concern is that US utilities are continuing to plan for billions of dollars investment in natural gas projects, even as coal plants are being retired in record numbers and renewables become more economical than ever," Devashree Saha, senior associate at the World Resources Institute, tells *PV Tech Power*.

With regards to utilities' reliability issues, Saha highlights the case of Northwestern Energy, which last year bought a 25% stake in a coal plant in Montana, citing reliability concerns. The utility noted the investment would help it meet a winter peak capacity shortfall.

Saha says the already "very compelling" case for utilities to move towards renewables will be consolidated by technological advances that improve the levelised cost of energy for solar, wind and storage. Meanwhile, as clean energy projects increase in size, it will enable utilities to leverage economies of scale to further cut costs associated with equipment, operations and maintenance.

"My guess is that natural gas is going to enter this decade defined by intense competition with renewable energy whose fallen costs and rising deployment will undermine the economic case for gas as a bridge fuel," adds Saha.

This is backed up by a report from Rocky Mountain Institute (RMI) that warns of the "significant risk" of proceeding with planned investment in new gas-fired power plants due to the resulting stranded costs. As of September 2019, there was an estimated US$90 billion of planned investment in new gas-fired power plants and over US$30 billion in proposed gas pipelines.

> "My guess is that natural gas is going to enter this decade defined by intense competition with renewable energy whose fallen costs and rising deployment will undermine the economic case for gas as a bridge fuel"

By the mid-2030s, as clean energy prices continue to fall, building a new portfolio of clean energy resources will become less costly than continuing to pay the operating costs of a combined-cycle gas plant, the report notes, and such a portfolio will provide the same level of energy, capacity and reliability services.

Cost-effective battery storage

US utilities' move towards solar power has been boosted by the technological developments in and declining prices of battery storage, allowing power to be saved for higher demand periods.

PacifiCorp's 2019 IRP identified battery storage as part of a least-cost portfolio for the first time in the company's history. It includes nearly 600MW of battery storage capacity by 2025, all located alongside new solar resources, and more than 2.8GW by 2038.

For Avista, which has a service territory covering parts of Washington, Idaho and Oregon, energy storage "will be key" to removing carbon-emitting resources from its portfolio, according to the utility's senior vice president of energy resources, Jason Thackston. "Our plans for combining long-duration pumped hydro, liquid air energy storage and lithium-ion technology provide the reliable capacity required to meet the demands of long cold winter periods when wind- and sun-dependent renewable resources are not always able to," he says.

Nevertheless, Dominion has cited limitations in existing battery technology as a reason for its natural gas expansion, while Idaho Power has not invested in long-term battery storage to date as a result of "costs and duration constraints".

According to Dennis Wamsted, an energy analyst at the Institute for Energy Economics and Financial Analysis (IEEFA), the development of battery storage technology has been two-pronged: its technical capability and its economic competitiveness. He says that combination is prompting an ever-greater interest in solar within the utility industry as companies "now realise they can shift part/all of the resource to times of the day when it is needed more".

"Contracts along these lines in the Southwest – with utilities signing power purchase agreements for solar-plus-storage projects that pay the provider significantly higher rates during peak demand periods than the rest of the day – give utilities the ability to rely on a given amount to solar power, turning the resource essentially into a dispatchable power source," says Wamsted.

Battery storage developments have not gone unnoticed by state legislators. Seven US states – New York, New Jersey, California, Nevada, Massachusetts, Oregon and Virginia – now have some form of energy storage target.

New York has set an energy storage goal of 3GW by 2030, and the state's six investor-owned utilities are required to conduct competitive solicitations to have a total of 350MW of energy storage resources in service by end of 2022. Thanks to its Clean Economy Act, Virginia goes further than any other state, with an energy storage deployment target of 3.1GW by 2035, 2.7GW of which will be provided by Dominion Energy.

Corporations driving the transition

That 2.7GW figure may well have been influenced by the demands of tech giants such as Apple and Microsoft, which rebuked Dominion last year for the lack of both energy storage and solar energy included in an earlier IRP.

Some 10 companies, all of which operate data centres in Virginia, signed a letter expressing their concern regarding the intention of Dominion to meet their energy demand with "expensive" fossil fuel projects.

"When procured competitively, renewable energy allows us to save money, meet the expectations of our investors and customers and do our part to be more responsible stewards of the environment," they said in the letter. The companies added that Dominion's re-filed 2018 IRP failed to fully take into account the energy preferences of the data centre industry "by limiting the amount of competitively procured solar energy, neglecting to consider energy storage as a cost-effective and beneficial energy resource, and continuing to plan for the development of additional natural gas infrastructure".

Led by the lofty ambitions of tech companies, corporations across the US increasingly have renewables procurement as part of their sustainability objectives. Globally, corporations bought a record amount of clean energy through power purchase agreements in 2019, up more than 40% from the previous year's record, according to BloombergNEF. Most of this purchasing took place in the US.

Facebook topped the Renewable Energy Buyers Alliance's list of largest US energy buyers in 2019 with a procurement of 1,546MW. It was followed by Google with 1,107MW and AT&T with 960MW.

"The rise in corporate interest in renewable energy (both wind and solar) is playing an increasingly important role in the broader transition across the US utility sector," says Dennis Wamsted of IEEFA. "In many cases, companies now will refuse to relocate to a state or expand an existing facility if they are unable to secure green power for that project."

The effect of that corporate demand for green energy has been felt in the small New Mexico town of Los Lunas, where construction of a Facebook data centre has not only lifted the local economy but also accelerated the state's transition toward renewable-powered electricity.

An IEEFA report details how a data complex that broke ground in 2016 – and is now being expanded from 973,000 to 3 million square feet – has increased municipal revenues, created local jobs and driven Public Service Company of New Mexico (PNM) to speed the buildout of utility-scale solar and wind across the state.

According to the report, one condition of the company coming to New Mexico was that it would have ample access to renewable power, and regulators have greenlit power purchase agreements for PNM to allow that to happen.

"While the state of New Mexico gave Facebook ample taxpayer-supported incentives to build at Los Lunas, such incentives are not uncommon, and they don't always work," notes the report. "What sets the Los Lunas example apart are its clearly beneficial local economic impacts and its market-moving renewable energy requirements."

The data centre is driving a "rapid shift" toward renewable energy by PNM, which is projected to source 43% of its power generation from wind and solar by 2023, up from 9.7% in 2013, IEEFA said.

PNM spokeswoman Kelly-Renae Huber tells PV Tech Power that the utility sees its commitment to emissions-free energy as a driver of economic development to New Mexico. "Corporations that share this commitment are attracted to New Mexico because of the state's vision for an energy transition," she says, adding that solar and storage will form a major component in the company's strategy to achieving an emissions-free energy future by 2040.

With the current vacuum of climate leadership at federal level, some US utilities and states are stepping into the void through their commitments to slash fossil fuel generation and transition to zero-carbon production. And as renewable energy prices fall and discerning electricity consumers continue to press for more solar and wind power, further utilities can be expected to join their ranks in the coming years.

'No substitute for federal action' on renewables

While utilities and states continue to implement and progress with their energy transition targets, the picture at federal level tells a different story, with the country a led by a president who once labelled climate change a hoax.

Donald Trump introduced tariffs on imported solar panels and modules in early 2019 to boost the fortunes of domestic manufacturers. While official reviews produced a mixed verdict on their effectiveness, the Solar Energy Industries Association (SEIA) claimed the Section 201 duties have caused "devastating harm" to the US solar sector.

An analysis by SEIA says the trade tariffs have prevented billions of dollars in new private sector investment, cost more than 62,000 jobs and meant that 10.5GW of installations have collapsed. Meanwhile, Wood Mackenzie estimates the duties have made the cost of solar modules in the US 79% higher than in major European countries and 85% higher than in China. The duties are due to phase out in early 2022.

Devashree Saha denies that actions taken by utilities can make up for the lack of support for renewables at national level. "There is no substitute for federal action," she says. "The scale and timeline of the climate change problem requires that the federal government reengage and provide leadership.

"As the United States looks to economic recovery and rebuilding in the shadow of COVID-19, investment in clean energy can be effective in creating jobs, growing the economy and protecting public health, not to mention reducing emissions."

While Congress passed three stimulus packages to combat the effects of the ongoing pandemic earlier in the year, none of them directly addressed the needs of the renewable industry, and Section 201 duties remained in place despite a three-month relief for other US importers, as a result of a Trump executive order.

Recent legislative progress was made in the House of Representatives, where lawmakers in July passed the infrastructure bill, which includes an investment of more than US$70 billion to help modify grids to accommodate more renewable energy sources. Nevertheless, it seems unlikely that the Senate will take up the bill, while Trump indicated he would veto it, saying the legislation "is full of wasteful 'Green New Deal' initiatives".

Attention now shifts to the presidential election. Joe Biden has earmarked US$2 trillion in spending to boost clean energy and rebuild infrastructure as well as help the US achieve a carbon pollution-free power sector by 2035 – a goal that goes beyond many of the most ambitious US utilities. ■

Europe's moment: The green recovery and Europe's solar sector

Europe | The European Union has pinned its hopes for an economic recovery in the wake of the COVID-19 pandemic on green and digital technologies. Molly Lempriere looks at the part solar could play as details are fleshed out

At the end of May 2020, the European Commission announced that this is Europe's moment to repair and prepare for the next generation as it targets support for a major recovery plan to help rebuild following the unprecedented COVID-19 pandemic. A key part of this includes the proposed new mechanism, Next Generation EU, which will look to protect lives and livelihoods, repair the Single Market and build a lasting and prosperous recovery.

Key for the solar industry is that this instrument is not just looking to rebuild the economy as it was, but actively green it, targeting sustainability, climate action and – crucially – renewable energy.

European Commission president Ursula von der Leyen said the recovery plan would turn an "immense challenge" into an opportunity but not just supporting recovery but investing in the future.

"The European Green Deal and digitalisation will boost jobs and growth, the resilience of our societies and the health of our environment," she continued. "This is Europe's moment. Our willingness to act must live up to the challenges we are all facing. With Next Generation EU we are providing an ambitious answer."

Next Generation EU centres around €750 billion in funding, along with targeted reinforcements to the long-term EU budget for 2021-2027. In total this would bring the financial firepower of the EU budget to €1.85 trillion.

While these headline figures have been broadly welcomed by those in the solar sector however, how this money will be targeted remains to be seen and will depend on the applications put forward by member states. The multiannual financial framework will allow funding to be channelled through EU programmes and repaid not before 2028 but not after 2058.

Currently the EU is working on developing the details of how the funding will be used, with more detail expected by the autumn to clarify exactly what it will mean for renewables.

Recovery and resilience: Greening the next steps

From the European Commission's initial proposal we know funding for the renewables sector and other green sectors within Next Generation is split into a number of segments. The largest of these is the Recovery and Resilience Facility, which will consist of €560 billion of financial support for investments and reforms. This includes green and digital transitions, the EU stated, as key priorities.

Miguel Herrero Cangas, policy advisor at trade body SolarPower Europe says that in order for Recovery & Resilience Plans to be approved by the Commission, member states will have to show their actions can "significantly contribute to the green and digital transition". While this is vague, he continues, "this could potentially have a strong impact on the renewable energy sector and the solar sector in particular as a major contributor to the green transition and driver of green jobs".

Beyond this, there is funding available to help kick-start the EU economy by incentivising private investments. This includes upgrading its current investment programme, InvestEU, to a level of €15.3 billion. A new facility will be built into this, to generate investments up to €150 billion in strategic sectors.

In order to address lessons learnt from the COVID-19 crisis, further spending has been set aside for health programmes and civic protection. Additionally, €94.4 billion will go to Horizon Europe, to reinforce vital research into various areas including the green transition.

Credit: Iberdrola

Solar energy looks set to play a central role in Europe's post-coronavirus economic recovery

The lack of clarity as to what will go to each sector currently seems to be partly by design; the exact allocation will be influenced by the responses from member states, allowing them to direct the funding towards the most impactful areas through the consultation period.

According to a leaked document published on website Euractiv a week before the official plan was shared, €91 billion has been earmarked for rooftop solar panels, insulation and renewable heating systems.

As part of this, the document suggests that the EU will tender 15GW of renewable electricity over the next two years. There will be a renewable energy acceleration programme designed to support 25% of the market, with a total capital investment of €25 billion. If this rings true, the EU's green recovery holds a lot of promise for the solar sector.

Green hydrogen at its heart

A key tenet of Europe's green recovery is its commitment to hydrogen, to support the decarbonisation of industry, transport, power generation and buildings. The European Commission has launched its Hydrogen Strategy, to target at least 6GW of renewable hydrogen electrolysers in the EU by 2024, capable of producing up to one million tonnes of renewable hydrogen.

Executive vice-president for the Green Deal, Frans Timmermans, said the strategy would help bolster the Green Deal and the green recovery, ensuring Europe is on the right path for a decarbonised economy by 2050. "The new hydrogen economy can be a growth engine to help overcome the economic damage caused by COVID-19. In developing and deploying a clean hydrogen value chain, Europe will become a global frontrunner and retain its leadership in clean tech."

Beyond 2025, the Commission wants hydrogen to become an central part of the integrated energy system with at least 40GW of renewable hydrogen electrolysers to increase production to ten million tonnes of renewable hydrogen by 2030. At this point, renewable hydrogen technologies are expected have reached maturity, allowing them to be deployed at scale. The Commission argues that with energy system currently accounting for 75% of the EU's greenhouse gas emissions, more than just renewable electricity will be needed to tackle this, and hydrogen appears to be its preferred solution for many hard-to-decarbonise sectors.

Currently, hydrogen provides just a "modest fraction" of the global and EU energy mix. Scaling up to reach the EU's goals will take significant change and investment, with the EU estimating it will need somewhere between 80GW and 120GW of solar and wind capacity. This will likely cost somewhere in the region of €220-340 billion.

Germany: Cutting the cap

While the EU green recovery funding is likely to aid solar and green hydrogen throughout the continent, many countries have been making their own moves to shore up the industry. In Germany, this crucially included the removal of the 52MW cap for solar sites in the middle of June.

According to the Bundesverband Solarwirtschaft (BSW) – the German solar association – the removal of the cap came "just in time."

"The industry's business expectations had gone into free fall in the first quarter of 2020. More and more large solar roof projects burst as it was not clear whether they would be connected to the grid in time. If we had not brought the solar cap down before the political summer break, hundreds of solar companies and over ten thousand jobs would have been at risk," says BSW managing director, Carsten Körnig.

According to a study conducted by the BSW together with the Intersolar Europe trade fair, 96% of market participants think the abolition of the photovoltaic subsidy limit was of great importance. Of those in the study, 31% said that the end of the cap will probably even secure their business existence.

This was one of the biggest barriers to the development of large-scale solar in the country, however others remain. This includes the "sun tax" or EEG levy (the Erneuerbare-Energien-Gesetz or the Renewable Energy Sources Act), which blocks investments by small and medium sized companies, according to BSW. This is particularly concerning as it rose in 2020, up to 6.756 ct/kWh from 6.405 ct/kWh in 2019.

"Germany has a lot of catching up to do when it comes to solarising its energy supply: if only to achieve the climate targets currently in force, we need to double the pace of photovoltaic expansion in 2021 and triple the annual installed PV capacity from 2022 on-wards," continues BSW's Körnig. "The solar power plant capacities envisaged in the German government's climate protection programme for 2030 would have to be built as early as the mid-20s."

While BSW hopes that the EU green recovery will help enforce "most far-reaching and binding agreements possible in Brussels", the willingness of member states to remove barriers such as the subsidy cap will become apparent, it says. For Germany, the necessary acceleration in the rollout of solar technology will depend on reform of the national energy policy framework.

Spain: Moving forwards by Royal Decree

In Spain, there has also been movement from the government to support the solar sector beyond just the EU's targeted green recovery. This will be necessary if it is to hit its ambitious renewables targets, set by the country's Socialist Party Prime Minister Pedro Sánchez and his government earlier this year.

In April, it submitted its national energy and climate plan to the European Commission, with the intention of cutting emissions by 23% by 2030 from 1990 levels. This will require it to grow its solar capacity from 8.4GW at the beginning of 2020, to 22GW by 2025 and 39GW by 2030.

According to EY, these targets are "aggressive but achievable" as Spain became Europe's top market for capacity additions for the first time since 2008 in 2019, adding 4.2GW of solar PV. This is set to continue and will be particularly bolstered by Iberdrola's 500MW Núñez de Balboa solar farm in southwest Spain – Europe's largest solar PV plant – which began generating power in April.

In order to further aid the solar sector and renewables more broadly, the Spanish cabinet approved a Royal Decree in June, which signed into law a raft of measures to remove barriers to large-scale renewables.

These are intended to tackle four key barriers for renewables in the country, including regulation of access and connection – which includes a new auction mechanism designed to create a predictable and stable route to market; new business models that will cover storage and hybrid projects; the promotion of energy efficiency; and numerous mechanisms to boost economic activity and employment as part of the coronavirus recovery.

Arancha Martínez, president of the Unión Española Fotovoltaica (UNEF) welcomed the decree, saying: "This standard responds to requests that we have been making in recent years and we are convinced that, under this new regulatory framework, the photovoltaic sector will be able to reactivate quickly, generating quality employment and strengthening the industrial value chain, elements fundamental in the post-COVID-19 phase."

The Spanish solar sector like all in Europe was hit by the impact of the COVID-19 lockdown, with installations grinding to a halt in many places and planning delayed. Renewable generation surged throughout the period, making up over 70% of the supply according to José Donoso, general director at UNEF, sending electricity prices tumbling and creating a challenging environment for solar producers in relation to marginal costs.

Those companies operating using power purchase agreements (PPAs) have also found this downturn a concern, with prices reduced from €40+/MWh to

Outside the EU green recovery, the UK solar recovery lags behind

While the EU's green recovery has been praised and many countries are seemingly forging ahead, others in Europe have been slower to action. In the UK there has been a lot of talk of a green recovery, but to date little of significance to the solar sector.

According to Jack Dobson-Smith, the UK's Solar Trade Associations (STA) external affairs adviser, the country has "barely begun to scratch the surface" of a comprehensive economic stimulus plan to drive a green recovery.

"With the exception of the £2 billion in funding announced to go towards low carbon technologies, including £1bn for public sector decarbonisation and the Green Homes Grants scheme (solar thermal) there has been little in the way of dedicated support mechanisms for the industry as a direct response to COVID-19. Like many others in the renewable energy sector we are expecting to see further policies announced in the autumn," he says.

Despite the lack of clear support from the government, the STA and the UK's solar sector seemingly remain optimistic. This is largely due to the growth of the subsidy-free solar sector in the country, and the return of the Contracts for Difference (CfD) auctions for solar.

In June 2020, the pipeline of new large-scale solar sites grew beyond 9GW, with more than 600MW added that month alone. Falling module prices and a maturing sector have ensured that the number of projects is continuing to grow, but this could be further supported by clearer policy.

"The UK solar industry is resilient and already returning to pre-COVID-19 levels of activity," continues Dobson-Smith. "It can play an important role in the green recovery. With this in mind, it is at risk of being affected by a fall in investment levels."

Credit: SPP

The UK solar industry's vital signs are strong but government support has been unforthcoming

below €30/MWh according to Donoso. In April, BloombergNEF reported that Spain had become Europe's cheapest market for corporate PPAs with the lowest prices averaging €30.50/MWh.

"The consequence of all these aspects is that we need tenders, as the single tool that can give certainty to the sector," says Donoso. This could help bring calm to the large-scale sector going forwards, regardless of the support from the EU's green recovery.

However, according to Donoso the relaxing of the lockdown has already allowed one area of the sector to boom: the domestic solar sector. Here it is growing fast for two reasons, he explains: "For one we have more devices now that give some physical advantage to the people who invest in self-consumption, and with COVID-19, more people have saved more money from social distancing and staying at home, spending less money, meaning they have now more money in the bank.

"And particularly over those two months they've had more time to think, time to think about projects. Now, the domestic sector is growing even faster than before COVID-19"

Moving forwards

The true impact of the EU's green recovery is up in the air, with the extent of the support for the solar sector unclear until the consultation is complete. However, the inclusion of solar in the conversation from the outset is an encouraging sign as is the clear direction towards building back greener.

Regardless of the amount of support solar will receive though, governments throughout the continent are making steps to ensure that solar is able to contribute to rebuilding their economies. From Germany's removal of its cap and Spain's Royal Decree, to Italy's so-called eco-bonus brought in in June that allows homeowners to claim back as much as 110% of the installation cost of solar, the sector is receiving support.

"Whether as a solar system on the home or upscaled to power plant scale, whether as "fuel" for solar filling stations for the climate-friendly operation of electric cars or temporarily stored in stationary batteries, whether as clean drive energy for heat pumps or for operating electrolysers to produce green hydrogen: the enormous potential of the multi-talent photovoltaic system should now be consistently tapped – to supply homes and even entire residential and industrial districts with a balanced mix and intelligently con-trolled with other renewable energies," finished the BSW.

So, while the solar sector waits in hope for support from the Next Generation EU mechanism and beyond, it seems certain the solar sector will continue to push forwards across Europe regardless. ■

Rural electrification in times of corona

Off grid | Travel restrictions imposed by countries in response to the coronavirus pandemic have contribution to a slowdown in investment in rural electrification projects. Thomas Hillig examines the extent of the investment freeze and possible solutions to get capital flowing into much needed projects again

More than a billion people around the globe do not have access to electricity. The power generation infrastructure in many countries is insufficient. The COVID-19 crisis has revealed the various weaknesses in the power sector while at the same time solar-home systems and mini-grids were used for short-term troubleshooting and for providing a reliable electricity supply to hospitals and health centres.

The solar power revolution could help overcome this unsatisfying situation long-term. Solar allows for a more decentralised approach to power generation. An attractive characteristic of solar power is that scale is less important than for traditional fossil fuel power plants: small generation units can be built in a relatively inexpensive way.

Mixed signals: An insolvency followed by flood of new money

Last year, the sector was shocked when one of the mammoths of the industry, the German solar-home systems (SHS) company Mobisol had to file for insolvency. Many speculations surrounded this insolvency: Were costs out of control? Was it the financing structure that heavily relied on debt? Was Mobisol only the tip of the iceberg? Would other rural electrification players follow soon? Mobisol's insolvency raised concerns for many investors who had already invested in rural electrification companies or considered investments. This is not only true for rural electrification with solar-home systems but also for access-to-energy solutions with mini-grids.

The situation calmed down when Mobisol was rescued and taken over by the French utility ENGIE last September and when BBOX received a US$50m investment from Mitsubishi at around the same time. The sector's doomsday mood quickly flipped over to pure euphoria.

Solar-home systems are the investor's darlings

Solar-home systems (SHS) are micro-power plants with integrated energy storage that provide electricity to individual buildings or households. SHS typically provide DC power that can be used without any problems for lamps and mobile phone charging. For newly electrified households, these are typically the main power needs. The electricity from SHS is not fully comparable to AC power that we are used to in developed countries. More sophisticated appliances such as televisions, fridges or air conditioning units typically require AC power. To overcome these limitations, SHS providers pursue two different solutions:

- Development and provision of DC appliances
- Conversion of DC power to AC power

DC solutions for television, refrigerators, or air conditioning are typically much more costly than standard AC appliances — comparing new to new. Far more importantly, already existing AC appliances cannot be used directly. This is a significant drawback as in many developing countries second-hand appliances play a crucial role. On the other hand, converting from DC to AC adds substantial extra costs.

From an economic point of view the attraction of SHS lays in the fact that they can fish more easily for relatively wealthy customers as they are not bound to the limit of villages. Moreover, the risk is not associated to any centralised assets. This is why solar-home systems have been the investor's darling from the outset.

Certain voices in the international development community insist that developing countries merit the same power quality as western nations and that SHS would not be enough. These voices often advocate mini-grids.

Credit: SunFunder

Smarter due diligence processes could help investment flow into rural electrification projects once again

Mini-grids: autonomous small-scale power plants, storage and distribution on village-level

AC mini-grids resemble a miniature version of the power infrastructure that we know from western countries. Today, on the generation side, mostly solar power plants plus battery energy storage are used, often combined with diesel generators or biomass plants for securing the energy supply during bad weather periods or as a cheaper option during night-time.

In comparison to standard grid infrastructure, mini-grids are much smaller: typical plant sizes are in the range of 10-35kWp solar and less than 100kWh battery energy storage for 150-400 connected households. Mini-grids are typically isolated and completely autonomous. AC mini-grids provide electricity of high quality that can be used by private, commercial and small industrial off-takers. Well-designed mini-grids are considered to provide electricity of a quality that is comparable to sophisticated national grids. The downside is that mini-grids require investments in a rather complex power generation and distribution infrastructure.

Innovation as an enabler: cheap smart meters and mobile money

A new generation of relatively inexpensive smart meters that can be coupled with mobile money solutions allows for remotely controlling the energy sales in an automated way. Pay-as-you-go (PAYGo) systems allow for setting up payment methods for decentral energy sales that imitate pre-paid mobile phone solutions. The end-customer must "top up" his energy account before consuming the electricity. This approach enables SHS- or minigrid-operators to manage the payment behaviour in an automated way and to optimize the money collection process. The approach avoids losses due to failure of payment. The downside is that the solar power output is determined at the moment of the investment when the technical parameters of the plant are specified. If the electricity from a system is not consumed it cannot be sold elsewhere. Forecasting future electricity needs is a key discipline — above all for minigrid developers as minigrids can hardly be removed after construction. SHS companies face more flexibility. In case of non-payment, it is relatively easy — at least from a technical point of view — to dismantle, remove and relocate SHSs.

Are SHS and mini-grids complementing each other?

Both SHS and mini-grid companies have to choose their customers carefully in order to come up with an economically viable business case. SHS providers choose the best customers on a country level or from certain regions in which they operate. Not everyone can afford solar energy. Mini-grid developers make two choices: first, they choose a village, then they choose in a particular village the customers that can pay for electricity and that are easy to access.

As a certain willingness and ability to pay for solar power is required, both approaches have the tendency to address primarily the rural middle class. Subsides that are often incorporated in both approaches do not necessarily reach the poorest of the poor. It becomes obvious that development efforts must be undertaken beyond electrification. Mini-grid developers have to deal with the disadvantage that they cannot fish for the wealthiest clients in target areas

MARKET WATCH

but have to deal with the realities in a particular village. They need to find enough off-takers around a centralised solar-power plant that can actually afford to pay for electricity. Often, within the village they are less demanding than SHS providers regarding the ability to pay for electricity and provide energy access also for poorer households.

Without productive use no rural development

The hope of the international development community was that electrification would trigger economic growth immediately. However, many rural electrification players have realised that the reality is not so easy. Electrification is a necessary precondition for rural development, but it requires much more than just electricity. And this is a problem – at least for the mini-grid developers. They typically oversize the solar power plant in regard of initial consumption to be prepared for their customers "climbing up" the energy ladder. If the development process does not kick in, their market is not sufficiently large to operate the mini-grids efficiently.

COVID-19: Full throttle or full brake for rural electrification?

The COVID-19 pandemic is highlighting the importance of critical infrastructure and could potentially speed up the development of both mini-grids and solar home systems. Mini-grids, with their ability to provide resilience, seem to be a perfect fit for hospitals and larger health centres while SHS would rather be used for small health centres. International development organisations could see in rural electrification a proven solution for providing first aid during a local outbreak in the pandemic.

Though these advantages clearly exist there are also numerous new hurdles, which could slow down the development. The pandemic and associated lockdowns have left their marks on the solvency of the off-takers. Payment losses from both SHS and mini-grid customers are so far rather topics that are discussed behind closed doors. However, it is obvious that business cases that were hardly favourable before require during the pandemic significant support form the international community. In times when the domestic economy is struggling it is questionable how reliable this support will remain or if it will be rather be expenditures that will be cancelled first if national budgets are under pressure due to recessions.

The corona pandemic will also interfere with the processes of rural electrification players. A possible second wave in Asia could create issues regarding the supply chain. Lockdowns in rural areas have already caused some delay because sales activities and installation that require physical presences were postponed. The pandemic also put pure survival into focus of many remote and rather poor households. Down-payments that are required for new solar assets lose importance.

We have also observed a similar phenomenon in some parts of the administration of the target countries for rural electrification investments; sometimes civil servants from rural electrification agencies have been for fighting the pandemic and cannot fulfil their tasks to drive forward SHS or mini-grid projects. Long-term investments in these critical power infrastructure projects require a strong backing from the local administration.

Due diligence as bottlenecks for investments and virtual approaches to move forward

Though the first wave of the pandemic did not affect Africa as much as feared in the beginning, lockdowns slowed down investment from international development organisations – even if the funding was not withdrawn, travel bans hindered due diligence activity by mini-grid and SHS developers. Typically, a sample of existing installations is checked on-site, end customers are interviewed and thorough discussions are conducted with the SHS or mini-grid players before investing substantial sums. For months, these on-site activities have been almost impossible to conduct by potential investors from Europe or the US. This is why investments into SHS and mini-grid players have receded during the pandemic.

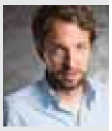
Already in the past we have seen that due diligence was rather expensive and timely for investments in rural electrification. We proposed streamlined approaches to save money and time for investors and rural electrification players. In the pandemic, the situation has exacerbated substantially. Given that travel restrictions still exist we see the absolute need for virtual due diligences. With our experience of two very thorough due diligence processes in Africa and India, we see ideally prepared to shortcut entrenched habits and have developed a remote due diligence approach that will come up with comparable results. Our approach would contribute to overcome the current investment bottleneck.

Already in the past we have seen that due diligence was rather expensive and timely for investments in rural electrification. We proposed streamlined approaches to save money and time for investors and rural electrification players. In the pandemic, the situation has been exacerbated substantially. Given that travel restrictions still exist we see the absolute need for virtual due diligence. With our experience of two very thorough due diligence processes in Africa and India, we are ideally prepared to shortcut entrenched habits and have developed a remote due diligence approach that will come up with comparable results. We have set up specific protocols for conducting these remote due diligence process including to ensure that investors have the same confidence that they obtain from on-site due diligence visits. Our approach would contribute to overcome the current investment bottleneck and to unlock capital that has not been removed but is simply held up by current restrictions.

Investments are rather postponed than cancelled

The good news from the rural electrification side is that so far only very few funds have been withdrawn, the process is rather slowed down due to technical reasons – throughout the value chain of rural electrification players such as customer acquisition or installation of the systems and also on the investors side. It does not take a crystal ball to see that this might change for the worst if the pandemic continues longer than expected. ■

Author



Thomas Hillig founded THEnergy in 2013 as a specialised consultancy focusing on energy generation for industrial and commercial consumers. The main areas covered are renewable energy microgrids and remote hybrid power plants for sectors such as mining, tourism, telecommunication, or agriculture. THEnergy combines Hillig's previous experiences working at Alstom Power in conventional energy generation and at Innotech Solar. At the beginning of his career, Hillig consulted leading companies from the transport, telecommunication and construction sectors.

Tackling inconsistencies in bifacial PV technology

Bifacial technology | A comprehensive understanding of the global performance and extra gain offered by a bifacial module remains an elusive goal for PV owners and EPCs due to variations arising from different design, manufacturing and testing methods. Vicente Parra, Ruperto J. Gómez, José C. Vázquez and Francisco Álvarez of Enertis review the main sources of variability and outstanding uncertainties that must be addressed as the industry seeks to define standard rules for reliably selecting, purchasing and deploying bifacial PV modules

Credit: Enertis

Nowadays, considering bifacial modules as a first option for a new solar plant is becoming mainstream in the PV market, thanks to their rapidly growing trend as a standard PV device worldwide.

In September 2018, the 9th edition of the International Technology Roadmap for Photovoltaic (ITRPV) report forecasted a market share for bifacial cells close to 15% by 2020 [1]. In fact, bifacial module deliveries exceeded 25% in 2019 and are expected to reach 40% this year and 60% in 2021, with no indications of a market slowdown in the short term.

Not long ago, the idea of using higher performance, double-faced PV modules was still considered a sort of double edge-sword versus the traditional monofacial-based PV technology. The main reasons behind this were its higher price and the somewhat limited project bankability, due to the additional uncertainties to deal with, subsequently guaranteeing the theoretical energy gain from the modelling of many new site and PV system variables [2, 3].

Notwithstanding this, it was implicitly understood – and, today, better modelled – that increased energy yield per module area was beneficial. The development was also favoured by the rapidly narrowing price gap versus traditional monofacial devices (basically the same, as of today), eventually leading to a remarkably minimised levelised cost of electricity (LCOE), as the key economic metric of a solar PV plant [4]. However, despite the fact that optimisation of the front side power output of a solar panel will prevail as a key factor to consider in a project development, the race for a comprehensive understanding of the performance gain offered by the back side of a bifacial module continues to be a test for any PV asset owner and EPC player. Therefore, a close and multidisciplinary cooperation framework with PV equipment manufacturers, technical advisors, modelling software developers, etc. is needed to rise to the challenge.

Testing and factory inspections are key measures in controlling the uncertainties and variabilities in bifacial PV technology

Even so, these uncertainties associated with the design of a bifacial PV system in turn take for granted that the

Tier-1 Supplier	Nameplate Power/W	Cell type	BOM's key parameters
A	380/385	Half-cell 9BB	POE/Dual glass 2.5mm, transparent rear side glass. Wire cell connector Φ 0.35 mm Aluminium frame 30x28 mm[a]
B	400/405	Half-cell 9BB	POE and EVA+POE/Dual glass 2.0mm white ceramic glaze on rear side glass Wire cell connector Φ 0.35mm Aluminium frame 30x35 mm
C	370/375	Full cell 5BB/12BB	POE/Dual glass 2.5 mm white ceramic glaze on rear side glass. Cell connector 0.23x1 mm (5BB) and wire Φ 0.40mm (12BB) Aluminium frame 30x28 mm
D	400	Half-cell 9BB	POE/Dual glass 2.0 mm white ceramic glaze on rear side glass Wire cell connector Φ 0.35mm Aluminium frame 30x28mm
E	370/375	Full cell 5BB	POE/dual glass 2.5mm, white ceramic glaze on rear side glass Cell connector 0.25x0.9mm Frameless

Table 1. Manufacturing cases, suppliers, PV modules and related features cited in the present article; [a] *BxC* sides (C: coplanar to glass substrate, potentially leading to cell shading)

bifacial module's datasheet and international standards are perfectly determined, understood and experimentally validated when facing the purchase of thousands of panels for a utility-scale PV project; nothing could be further from the truth as of yet.

Therefore, and specifically concerning the design and power performance of a bifacial PV module, this article reviews some of the main sources of variability and outstanding uncertainties that need to be addressed by the industry to grasp and define a series of standard rules for a reliable selection, purchase and use of bifacial panels in high-performance PV projects, as a new technological paradigm in the solar market worldwide.

For this purpose, examples of real cases devoted to the advisory, manufacturing inspection and testing activities performed in the last year by Enertis in several Asia-based module factories are reviewed (Table 1). All of them refer to bifacial modules' manufacturing for large-scale projects worldwide, which in turn were dictated by specific Module Supply Agreements (MSA), designs and Bill of Materials features, many of which are barely known in detail by the buyers prior to and even after production completion. It is here that the role of independent third-party inspectors as Enertis monitoring the processes is key.

The present article will cover four key subjects, as follows:

- Lack of international standards adopted by the industry;
- Inhomogeneous bifaciality values, within and amongst manufacturers;
- Effect of module design and Bill of Materials (BOM) on bifaciality;
- Front versus rear-side performance asymmetries.

To conclude, a quick overview vis-à-vis the influence of bifaciality on the PV plant's economics will be reported, so that the interest in controlling the bifacial properties of the modules at the early stages of development of a PV project is highlighted.

As a matter of fact, guaranteeing the bifacial values during the production of hundreds of thousands of PV modules for a large-scale plant is certainly not a straightforward task. Thus, this article is not a criticism of the activities currently performed by the module manufacturing industry, but a review of the actual picture that a module purchaser should consider when dealing with bifacial devices.

Lack of standardisation

The purchase of a bifacial PV module is currently equivalent to that of monofacial. In a bifacial module, despite the inherent two active faces, the purchased power output is delimited by the front side, which is suitably stated in the corresponding nameplate label. Nonetheless, flashing the front side of a bifacial module with the solar simulator setup typically used for monofacial technology leads to potential imprecisions in the panel's maximum power values (*Pmax*), owing to the residual light absorption by the rear side during the measuring process.

Also, a quick review of the commercial datasheets available in the market evidences that the definition of the extra power gain coming from the rear side is somewhat conservative and imprecise, hitherto based on diverse concepts such as 'integrated power', 'synthetic power' or just 'bifacial gain', depending on the supplier. The bifacial performance is basically defined by a series of simplistic power additions (5%, 10%, 20%, etc.) to the front-side, Standard Test Conditions (STC) Pmax value, including general disclaimers regarding the dependency on the eventual site conditions. A similar situation occurs with the PV performance files characterising the module, e.g. the acquainted, but usually not experimentally validated .pan files used by PVSyst modelling software, despite its direct influence on energy yield and derived financial metrics. In terms of warranties, tentative attempts related to bifacial performance are currently being proposed, even though there is still work to be done in this sense as well.

Therefore, the implementation of internationally accepted standards ruling the reliable and accurate description and determination of both power output and bifacial performance of a PV module now becomes a requirement.

In early 2019, the *IEC TS 60904-1-2:2019 - Photovoltaic devices - Part 1-2: Measurement of current-voltage characteristics of bifacial photovoltaic (PV) devices* draft document was launched [5], as a first official trial to describe the best practices and protocols to measure the current-voltage (I-V) characteristics of bifacial photovoltaic cells and modules, using either natural or simulated sunlight. Unfortunately, to date, this technical specification (TS) still seems far from being adopted as a mainstream guideline by, principally, module manufacturers. This means that PV modules are not being rated in a consistent and standardised manner.

In short, this IEC guideline addresses the two main aspects indicated previously or namely i) the use of well-controlled and consistent flash testing setup and measurement procedures and ii) the determination of a series of parameters characterising the bifacial properties of a PV module, such as the so-called $Pmax_{bifi100}$ and $Pmax_{bifi200}$, which stand for the Pmax values at rear side irradiances of 100W/m^2 and 200W/m^2, respectively, based on module's bifaciality or bifacial coefficient (expressed, for Pmax, as $\varphi_{Pmax} = Pmax_{rear}/Pmax_{front}$). This document also introduces concepts such as equivalent irradiance (G_E) and BIFI coefficient, this one based on Wp/Wm^{-2} units, being quite conveni-

Supplier	Sun simulator	Pulse length	Calibration method	Calibration frequency	Control of rear-side irradiance during flash	Rear-side measurement frequency	Rear-side calibrated values	Pmax Bifacial Coefficient (inline)
A	Tower simulator/ Xenon lamp	10ms	**Isc and Pmax** Front side reference values @ STC for both front and rear side maximum power	Every 2h	[a]DL: 5.95m [b]GD: 1m [c]Full dark conditions: No Baffles: No. [d]Non-reflective back material: Yes	10 pcs/day	No	[e]73.15 ± 1.23 *(75.64, 68.26)* *N = 1,000*
B	[f]**Wks 1** Flatbed Simulator/LED Flatbed Simulator/Xenon lamp	**Wks 1** 100ms 100ms	**Pmax** Front and rear side reference values @ STC for front and rear side maximum power respectively.	**Wks 1** Every 6h Every 4h	**Wks 1** DL: 50 cm GD: N/A. Full dark conditions: No Baffles: No. Non-reflective back material: No	0.5% of daily Wks production (minimum 10 pcs/day).	Yes	67.11 ± 1.24 *(70.50, 65.02)* *N = 1,120*
	Wks 2 Tower simulator/ Xenon lamp	**Wks 2** 10ms		**Wks 2** Every 6h	**Wks 2** DL: 5.80m D: 1m Testing area is covered simulating a dark room. Full dark conditions: No Baffles: No. Non-reflective back material: No			
C	Flatbed simulator/Xenon lamp	10ms	**Pmax** Front side reference values @ STC for both front and rear side maximum power	Every 2h	DL: 50cm GD: N/A. Full dark conditions: No Baffles: No. Non-reflective back material: No	10 pcs/day	No	76.40 ± 2.52 *(82.41, 71.07)* *N = 110*
	Tower simulator/ Xenon lamp	100ms			**Wks 2** DL: 5.50m GD: 1m D: 1m Full dark conditions: No Baffles: No. Non-reflective back material: No			
D	**Wks 1** Tower simulator/ Xenon lamp	**Wks 1** 50ms	**Isc** Front side reference values @ STC for both front and rear side maximum power	Every 4h	DL: 5.95m GD: 1m Full dark conditions: No Baffles: No. Non-reflective back material: Yes	10 pcs/day	No	71.59 ± 1.33 *(77.29, 70.00)* *N = 155*
	Wks 2 Tower simulator/ Xenon lamp	**Wks 2** 50ms						
E	**Wks 1** Tower simulator/ Xenon lamp	10ms	**Isc and Pmax** Front side reference values @ STC for both front and rear side maximum power	Every 2h	DL: 5.50m GD: 0.97m Full dark conditions: No Baffles: No. Non-reflective back material: Yes	3 pcs/4h	No	71.54 ± 0.91 *(74.82, 68.43)* *N = 4,120*
	Wks 2 Tower simulator/ Xenon lamp							

[a] DL: Distance between module and light source; [b] GD: Ground-to-rear side distance; [c] in general, testing area was covered by curtains simulating a dark room. Still, open areas or windows to allow staff operation were evidenced; [d] If included, it did not comply with IEC TS 60904-1-2 recommendations; [e] Mean ± Std. Dev. (maximum value; minimum value), N: number of samples; [f] Wks: Production Workshop

Table 2. Experimental variables regarding flash test setups and protocols used by the suppliers herein reported, including Pmax bifacial coefficients

ent to correlate bifacial extra power with rear irradiance conditions. The $Pmax_{bifi100}$, $Pmax_{bifi200}$ parameters could be included in a module's datasheet, as a prelude for the implementation of a standard bifacial power value ($Pmax_{bifi\text{-}STC}$). In this way, the acknowledged game rules historically used for monofacial panels could also be applied to bifacial.

As empirical proof of this, quite a few aspects revealing a lack of standardisation and subsequent heterogeneity when performing flash tests during inline manufacturing were noticed (Table 2), from daily inspection works conducted by Enertis in the workshops. As a result of it, and despite the equivalent datasheet's bifacial coefficients declared by the suppliers, significant differences were found in the average Pmax bifacial coefficients recorded during inline production (e.g. six points variation between Supplier A and B). Further comments to this outcome will be mentioned in sections below. Besides, unlike the 100% measurement of front side Pmax values performed in the workshops, those from the rear are limited to just a few units per production day.

For instance, the use of optical baffles around the module sample, plus non-reflective surfaces behind the module are highly recommended [5] to limit the rear side irradiance absorption during the flash tests, as it is also proposed in the abovementioned IEC specification. However, there was no clear harmony among suppliers in this regard, exemplified by the use of different solar simulator systems and setups, such as LED-based flatbed or Xenon lamp-based tower simulators, even by the same supplier in different workshops. Likewise, divergencies related to a flash tester's calibration procedure were found, namely the use of Isc, Pmax or both Isc and Pmax values of the reference modules to set the correct parameters of the solar simulator for the inline Pmax module rating. Also, there was a tendency to consider front's side I-V values during flash testing calibration to determine the rear side Pmax values, and thus bifaciality, introducing additional uncertainties in the measurement. In this sense, internal studies showed a ca. 1% absolute overestimation of Pmax bifaciality could be observed when testing rear side Pmax using rear side calibrated values, instead of front side parameters for both front and rear values.

It has been also reported that high-efficiency PV modules, such as bifacial ones, may have a significant internal capacitance, resulting in I-V measurement artefacts due to transient effects when measured with short pulse durations using common pulsed flash testers [7], leading to inaccurate output power values. Also, as indicated in Table 2, no uniformity among suppliers was found, not even within workshops from a same brand, in some cases.

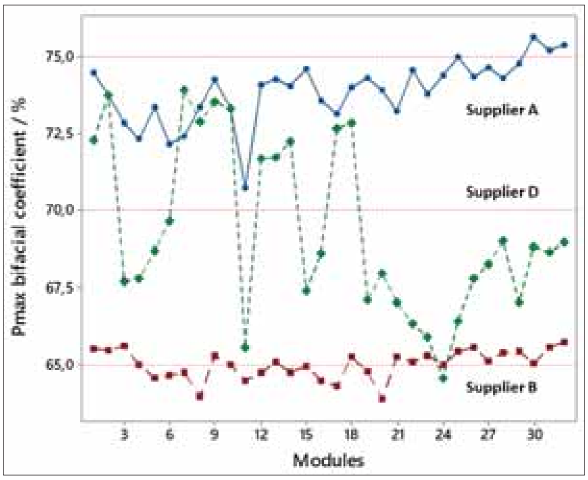


Figure 1. Pmax bifaciality values registered by Enertis laboratory from random samples taken during manufacturing of the first batch of modules. The dashed lines represent bifaciality thresholds from the 70±5% market standard

In summary, all these inconsistencies involve further sources of uncertainty, potentially leading to non-negligible power rating deviations from basic metrology issues reasonably easy to standardize and control during inline processing. In this regard, special care will need to be taken with the incoming era of large size, high performing solar panels [8], expected to beat the barrier of 600W shortly.

Regarding the quality and reliability of bifacial panels, it is not usual that a purchaser receives commercial proposals including extended certification tests for bifacial modules. These devices have higher current values outdoors, on account of the extra rear irradiance gain onsite. Therefore, BOM certifications should be adjusted to this new experimental reality. For instance, the common IEC 61215-based bypass diode and thermal cycling tests should now be performed at no less than 20% additional maximum currents versus a module's datasheet short circuit values.

Bifacial inhomogeneity during inline production. Module design and BOM

The bifaciality of an e.g. 144-half-cells, >2.0m^2 area PV module is a macroscopic variable difficult to be set in a fully consistent and replicable way even by the most sophisticated module manufacturer today. Proof of this is the declared, somewhat tolerant, industry standard in this regard: 70±5% bifacial coefficient. Consequently, up to 10 points' variation is virtually accepted by the PV market at present.

So, in this section, the patent non-uniformity of bifacial properties of the modules witnessed by Enertis during in-factory inspection activities for different large-scale module supplies, is reported.

As plotted in Figure 1, and, again, despite the use of equivalent datasheet bifacial coefficients, Enertis laboratory data revealed noticeable differences amongst manufacturers, in terms of absolute Pmax bifaciality (e.g. Supplier A vs. Supplier B) and large fluctuations during production, as occurred with the first production batches of Supplier D, with more than eight points deviation in several samples.

In case of Supplier B, several values below the minimum accepted 65% threshold were also reported. This was considered a major non-conformity, and so an investigation process was triggered, aiming at improving this low bifaciality value in real time during production, without incurring delays with deliveries. For this purpose, several BOM/design features were analysed: module frame, ceramic glazed glass pattern and the solar cells, particularly their metallisation grid.

Regarding the impact of a module's frame, Table 3 collects I-V flash data for the same module serial number, with and without frame. In the framed module, the rear side's current values were markedly influenced by shading effects, resulting in more than 7% lower rear side power output and then a ca. five-point loss of bifaciality. This outcome should not lead per se to conclusions about the preference of bifacial frameless modules, but to understand the effect of frame dimensions – especially the C side – on the rear-side performance. In this case, the 30x35 mm aluminium frame could not

	Front side						Rear side						
PV Module	Pmax/ Wp	Voc/V	Isc/A	Vmpp/V	Impp/A	FF/%	Pmax/ Wp	Voc/V	Isc/A	Vmpp/V	Impp/A	FF/%	Bifacial coefficient (%)
Frameless	406.62	48.98	10.49	40.49	10.04	79.13	285.29	48.29	7.24	41.11	6.94	81.64	70.16
Framed	406.18	48.99	10.43	40.63	9.99	79.51	264.71	48.44	6.94	42.28	6.26	78.76	65.17

Table 3. Effect of frame on the bifacial I-V flash characteristics for a same PV module

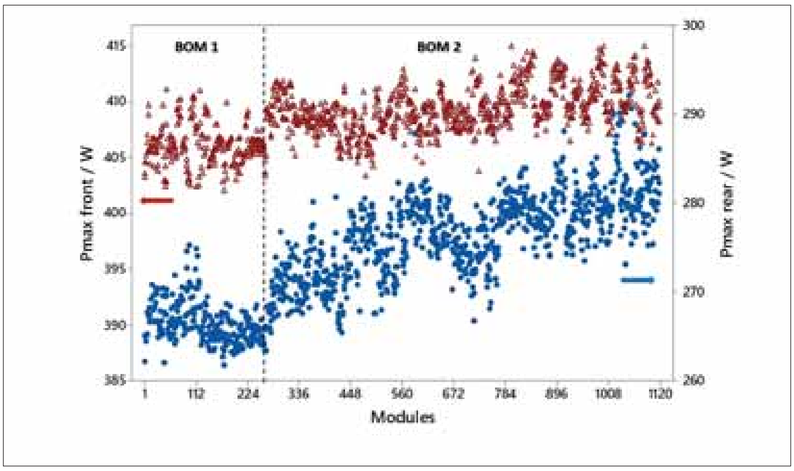


Figure 2. Pmax bifacial coefficients registered during inline production by Supplier B (400/405W modules are random and equivalently plotted). The dashed lines represent change of module's BOM/ design, leading to bifaciality and frontal Pmax enhancement

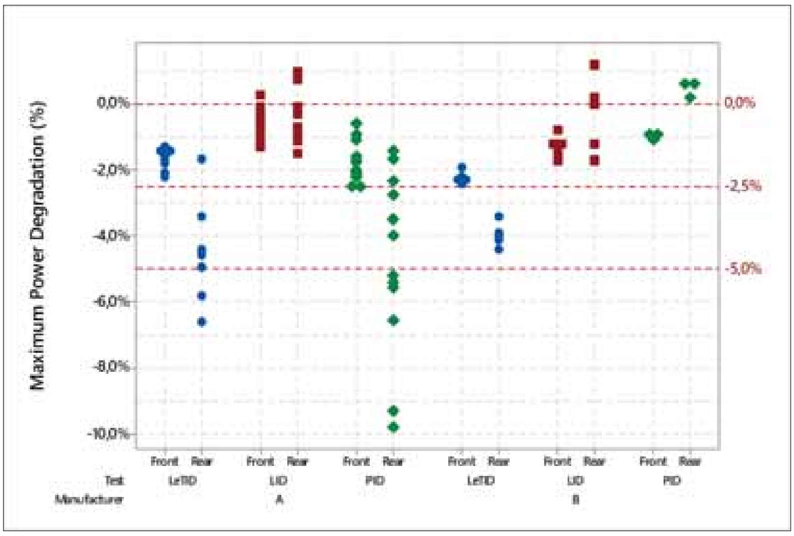


Figure 3. Pmax degradation results of modules' front and rear sides after LeTID (168h, 75° at Isc-Impp current injection), LID (outdoor, 25KWh/m² at Impp conditions) and PID (-1,500V, 85%RH, 85°C) controlled stresses for Supplier A and B

Location	Bifaciality (%)	Yield (MWh/MWp)	Bifacial gain (%)	LCOE (%)
Chile, North (Albedo: 0.30) 150MWp	Monofacial	*3.058*	N/A	N/A
	65	*3.154*	*+3.15*	*-2.54*
	70	*3.160*	*+3.36*	*-2.78*
	75	*3.167*	*+3.56*	*-3.02*
USA, Arizona (Albedo: 0.30) 150 MWp	Monofacial	*2.375*	N/A	N/A
	65	*2.487*	*+4.73*	*-3.43*
	70	*2.496*	*+5.10*	*-3.76*
	75	*2.504*	*+5.46*	*-4.09*
Spain, South (Albedo: 0.20) 150MWp	Monofacial	*2.028*	N/A	N/A
	65	*2.108*	*+3.95*	*-2.70*
	70	*2.114*	*+4.25*	*-2.98*
	75	*2.120*	*+4.56*	*-3.26*
UK, South (Albedo: 0.25) 50MWp	Monofacial	*1.124*	N/A	N/A
	65	*1.197*	*+6.45*	*-4.98*
	70	*1.202*	*+6.94*	*-5.42*
	75	*1.208*	*+7.44*	*-5.86*

Table 4. Yield, bifacial gain and LCOE analysis of the effect of bifaciality over three PV plants in various locations worldwide. General assumptions: 400W module; 2V-tracking; 2.2m height; 35% GCR; central inverter 4MW; CAPEX, OPEX and discount rate as per Enertis internal data

be eventually modified, even though it was considered a key factor reducing the global Pmax bifaciality of the module.

In collaboration with the supplier, further modifications related to BOM were implemented. The first one involved a minor reduction of the ceramic glazed pattern of the rear glass (3mm adjustment; 'BOM 2' in Figure 2), plus the use of narrow rear-side soldering pads in the PV cells was carried out. These material-based tunings led to a manifest rise (up to three points) of bifacial coefficient through the increase of rear-side Pmax power output. In parallel, the front side's Pmax was, in turn, improved, at no extra cost for the buyer.

From this descriptive example, it can be concluded that there is room for optimisations of bifacial modules, just considering relatively affordable PV device design and BOM adjustment actions.

Bifacial asymmetries: performance

Any stakeholder involved in the development of a PV project is aware of power degradation phenomena such as light-induced degradation (LID), potential-induced degradation (PID) and the last guest at the PV party, light and elevated temperature-induced degradation (LeTID), characteristic of modules using the currently mainstream Passivated Emitter Rear Cells (PERC).

The bifacial coefficients of the I-V parameters are not the only variables featuring the non-symmetrical behaviour of a bifacial panel. Figure 3 illustrates this in a revealing way.

The graph evidences how the asymmetrical nature of a bifacial PV module can lead to significatively different degradation rates towards LeTID and PID-induced stresses. For instance, in the case of Supplier A, Pmax rear-side values after just 168 hours of LeTID processing reached an outstanding 7% absolute degradation. For PID, this effect was even more pronounced, surpassing 9% rear-side degradation in the case of Supplier A. Discussing these exciting effects in detail goes beyond the scope of the present article. However, in a few words, it is known that both LeTID and PID phenomena are ascribed to solar cells' architecture and manufacturing processing. Regarding PID, additional influences at module level, specifically from the encapsulant's volume resistivity and glass chemical composition [9] are also expect-able. So, PID is a markedly BOM-related effect, so that additional materials requirements are to be considered in advance to mitigate PID-based risks in the modules. Therefore, from these results, it can be claimed that that PID and LeTID are understood as surface-like degradation phenomena, whereas LID, typically associated to wafer substrate's Boron-doping and oxygen contamination, is rather considered a bulk-like degradation mechanism. In agreement with this statement, Figure 3 shows how front- and rear-side LID-based underperformances were nearly equivalent.

PV plant performance and economics

As mentioned before, optimising the modules' front-side power output remains a key task to address for the design of a high-performance bifacial PV plant. Therefore, to this end, ensuring the accurate measurement of the Pmax value of a bifacial panel, including bifaciality, is mandatory.

Table 4 includes a quick sensibility analysis of the influence of module bifaciality in significant PV project metrics as energy yield, bifacial gain and LCOE. Three PV project cases are considered, namely Chile (Atacama zone, 150MWp), USA (Arizona, 150MWp), Spain (Andalusia region, 150MWp) and the southern UK (50MWp). For a global comparison purpose, the monofacial case is set as reference for bifacial gains and LCOE reductions. A properly measured 400W front-side power output module was considered.

It is well known that bifacial gain will depend mostly on geographical location (direct/diffuse irradiances), ground albedo conditions and system configuration. These variables will impact directly on the irradiance reaching the modules from the rear side.

Nonetheless, non-negligible differences associated to the intrinsic module bifaciality will also be expected. As observed in the table, increasing a module's bifaciality from the formally accepted 65% to 75% values would result in an increase of annual yield of 0.4-1.0% depending on project location. Likewise, LCOE can be reduced by 0.5-0.9%. Such reduction in the cost of the energy, even if apparently minor, could fairly determine the feasibility of a solar PV project in current competitive markets such as those based on energy auctions. It should not be forgotten that, in all these cases, the PV modules being purchased would be based on equal price, regardless the resulting bifacial coefficients eventually delivered, from the rough, but virtually official 70±5% standard thresholds. Thus, it seems more than reasonable for a project developer to pay attention to the Pmax rating and bifaciality determination of a bifacial PV module during its manufacturing.

In conclusion, bifacial technology is here to stay. At present, there are no major technical or economic reasons not to consider bifacial modules when starting a new PV project development. Although the front-side power output will keep ruling the performance of a solar panel, several sources of variation and vis-à-vis the right rating of a module's front output and the extra power and energy potentially harvested by the rear side remain unresolved. This happens not only at the PV site, but also from the device design or BOM used, and throughout the inline I-V testing activities.

These uncertainties, summarised as follows, still need further assessment and an improved control, so that reliable PV plant energy yields and LCOE figures can be optimised and warranted at early phases of the project development:

- Even after the appearance of the IEC TS 60904-1-2 document early in 2019, the adoption of international standards for an appropriate measurement of the electrical parameters of both the front and rear side of bifacial modules is yet to come. This applies to both the I-V curve testing method and solar simulator setups. Improving this is a question of time and market education, so that the best controlled and standard practices can be assumed by the industry in short order.
- Patent inhomogeneity of the bifacial coefficients during production, in part associated with non-optimised module designs and BOM, but also the still non-uniform flash test procedures already mentioned.
- Asymmetric rear versus front-side degradation behaviour of modules towards well-known effects as PID, LID or LeTID, potentially leading to unexpected performance losses in the first years of operation.

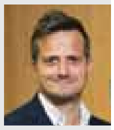
Hence, and probably more than ever, with prices per watt-peak reaching historical minimum values with big sized and high output modules arriving, the investment in technical revisions of bifacial modules specifications and performance control activities during production would be rationally encouraged [10]. ■

Turn to p.58 for insights into the latest developments in bifacial yield modelling

References

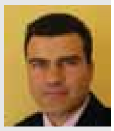
[1] https://itrpv.vdma.org/
[2] R. Kopecek, J. Libal (2018) Towards large-scale deployment of bifacial photovoltaics, Nature Energy, 3(6) 443–446;
[3] T. S. Liang, M. Pravettoni, C. Deline, J. S. Stein, R. Kopecek, J. P. Singh, W. Luo, Y. Wang, A. G. Aberle, Y. S. Khoo (2019) A review of crystalline silicon bifacial photovoltaic performance characterisation and simulation, Energy Environ. Sci., 12(1):116–148.
[4] P. Tillmann, K. Jäger, C. Becker (2020) Minimising the levelised cost of electricity for bifacial solar panel arrays using Bayesian optimisation, Sustainable Energy Fuels, 4, 254-264
[5] https://webstore.iec.ch/publication/34357
[6] J. López-García, D. Pavanello, T. Sample (2018) Transient Effects and Internal Series Resistance Calculation on Bifacial Silicon PV Modules, 35th EUPVSEC, 1363-1367
[7] J. López-García, D. Pavanello, T. Sample (2018) Transient Effects and Internal Series Resistance Calculation on Bifacial Silicon PV Modules, 35th EUPVSEC, 1363-1367
[8] https://www.pv-tech.org/editors-blog/when-will-large-area-m10-wafers-be-used-in-high-performance-solar-modules
[9] W. Luo, Y. S. Khoo, P. Hacke, V. Naumann, D. Lausch, S. P. Harvey, J. P. Singh, J. C., Y. Wang, A. G. Aberle, S. Ramakrishna (2017) Potential-induced degradation in photovoltaic modules: a critical review, Energy Environ. Sci., 10, 43-68
[10] V. Parra. R. Gómez (2018) Implementing risk mitigation strategies through module factory and production inspections, PV Tech Power 16, 25-28.

Authors

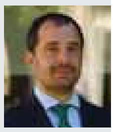


Dr Vicente Parra is the head of quality and technology at Enertis Solar. He has a 12-year track record in the PV industry as technology manager in solar companies devoted to silicon ingots, wafers, cells and modules manufacturing. For Enertis, he has led numerous PV plant troubleshooting activities, factory/production inspections (modules and BOS equipment) and supply agreement advisory activities, covering 15GWp+ experience so far.

Dr Ruperto J. Gómez is a process, manufacturing and technology senior engineer with 16 years' experience in the PV and semiconductor industries. Ruperto has led several projects with international partnerships related to turnkey projects of new PV module manufacturing lines in China, India, Mexico and Poland. He is currently working as quality operations manager in Enertis Solar.



Dr José C. Vázquez is a senior project manager at Enertis Solar. With more than 16 years' experience in the aerospace and PV industries, he has worked in different positions covering the entire value chain of the solar PV, as quality and R&D manager of solar cell/modules factories and senior technologist in EPC companies.



Francisco Álvarez, as a senior consultant of eight years' experience, is specialised in the evaluation of the solar resource and energy production for PV plants worldwide. Since 2016, his experience has focused on Latin America market. Currently, Francisco is the consultancy manager at Enertis Chile Spa, focusing on technical due diligence activities of solar PV projects for developers and financial entities.

Challenges and solutions for ensuring the long-term health of solar power plants

EPC best practice | Later this year, a new set of industry guidelines will for the first time codify a set of best practices for EPC contractors. Ahead of publication, members of Solar Power Europe's O&M task force look at some of the critical areas of PV system integration where high-quality EPC work can most effectively influence a project's lifetime performance

Solar PV is a reliable and stable technology, with innovation in modules only increasing its life expectancy. While PV modules generally receive most of the attention in the solar sector, there are a variety of technologies and services that are essential to the success of any PV installation; many of these come under the umbrella of EPC – engineering, procurement and construction – encompassing end-to-end solar services, from system design and procuring components to installing the project.

After the success of SolarPower Europe's Operations and Maintenance (O&M) Best Practice Guidelines – now in its fourth version – and its first edition of guidelines related to Asset Management (published in December 2019), the task force behind the two documents is now developing its first-ever EPC Best Practice Guidelines, which will aim to help the industry standardise and optimise the EPC segment. The document, which will be published later this year, is not only targeted towards EPC providers, but all relevant stakeholders, including investors, financiers, monitoring solution providers, asset managers and even O&M contractors. An important element of the EPC guidelines will be to benefit from the long-term experience that the European solar industry has in the operational phase and create a feedback loop and dialogue with all providers.

This article aims to introduce some of the core elements of EPC: inverters, trackers, junction boxes, and monitoring technology. These are the technologies that ensure the long-term success and efficiency of solar installations, and, if appropriate attention is given to them, can end up saving developers significant resources over the course of the solar PV system's lifecycle.

Inverters: the heart of PV plants

Inverters and their associated technologies are central components in all solar PV systems. Inverters ensure downstream that the power generated by the PV array can be fed into the grid, used by connected AC consumers or temporarily stored in conjunction with storage systems.

EPC contractors have a key role to play in ensuring the long-term health of PV power plants

Upstream, they perform important safety functions, such as earth fault detection, arc detection and anti-islanding. Due to the continuously increasing share of PV in the energy mix, inverters must perform more and more tasks, also related to grid stabilisation; as grids become smarter, inverters must also take over more grid-related services. In order to perform these services at all times, an increasing number of PV power plants will be combined with energy storage systems. The inverter can thus be described as the heart of any PV power plant – its failure therefore leads to serious problems with the larger system components.

Topology

The topology of a PV power plant usually follows three different concepts: (1) large parts of the plant can operate via a central inverter; (2) the inverter can be used at string level, combining single or multiple strings; or (3) it can be operated on a module level, via module-level power electronics (MLPE). With regard to ease of

www.pv-tech.org | September 2020 | 36

maintenance and availability of the plant, it should be noted that central inverters are easy to maintain, and in the best-case scenario can be repaired on site, therefore offering a high overall lifetime of 20 years or more. However, in the event of a problem, large parts of the power plant are separated from the feed-in. MLPEs as well as string inverters cannot usually be repaired on site and should not be touched until environmental influences have been eliminated. In the event of their failure, only smaller system parts or even only one PV module is affected. Such inverters usually have a lifetime that is shorter than the plant's operation time, so they need to be replaced during the life of the system.

In addition, the specific number of failures for less accessible components increases with the number of electronic components used in the system. Market analyses in relation to the frequency of the use of different topologies in industrial and utility plants show an even distribution of string inverter and central inverter designs, and a growing number of MLPE-based plants (although on a much lower level). Availability also plays a major role in the selection of the appropriate design or provider. In the event of a defect, short-term availability of replacements is crucial to keep yield losses to a minimum.

Inverters play a central role in the overall reliability of a PV system

Credit: SMA Solar

Planning and commissioning

The importance of planning when it comes to PV installations cannot be emphasised enough. In addition to the quality and reliability of the components used, it is at this stage that the quality of the system's subsequent performance is determined. Besides standard-compliant planning, the environmental conditions and working windows recommended by the manufacturer must be observed. Non-observance of these requirements usually leads to increased failure rates during operation. It is therefore recommended to have each system of relevant size inspected by an independent party before and after commissioning, and to have any deviations corrected. The documents of the IEC 62446 series, for example, provide guidance on the appropriate procedures.

Downtimes of PV systems are often caused by inverters [1]. However, many of the interruptions underlying these evaluations are ultimately due to problems with other system components. Here, ground-fault problems and, if a corresponding detection is available, actual or incorrectly detected arc-faults play a role. In addition to the plant design, the quality of the components used is of decisive importance. However, a plant designer or installer has only limited possibilities to comprehensively assess quality without being able to rely on field data and other empirical values. The conformity of the inverters to qualifying standards is mandatory but does not allow a detailed statement about their durability in the field. This can only be determined by a long lifetime test, in connection with simulations based on inverter lifetime models.

Maintenance

According to the data available, the error rate for inverters is 300–500 times higher than for PV modules [1]. Even if one considers that the number of installed modules is similarly higher than the number of inverters, this value shows the importance of inverters for reliably high yield values of PV systems. The reliability of inverters depends largely on the reliability of the components installed in them, such as IGBT power bridges, capacitors and others. The lifespan of each of these components can be assessed accurately on the basis of extensive modelling. The inverter, however, consists of a large number of such components which are complexly interwoven and where a reduced function of most of these components results in a standstill of the entire inverter. Because of this, the prognosis of the lifetime of such systems is complex and not always accurate.

A decisive factor that determines the lifespan of inverters, besides the design, is their maintenance during operation. While not all the topologies described above can be maintained in the same way – MLPEs are maintenance-free in principle and string inverters can hardly be maintained – it is often sufficient to protect against environmental influences and contamination during maintenance. In addition, especially for large plants, the creation of a maintenance concept consisting of the three most important components – preventive maintenance, corrective maintenance and predictive maintenance – is a good idea. Details on the creation of such comprehensive concepts are described elsewhere [2, 3]. It is expected that future innovations to inverters will improve their lifespan; however, early research indicates that an extended provision of grid-related services, such as reactive power supply, will have a negative effect on the lifespan of inverters [1].

Ensuring the structural integrity of trackers involves multiple stakeholders

Credit: Array Technologies

Energy storage

Large-scale energy storage systems are still a relatively new technology, and there is only limited data as to performance and lifespan. It can be assumed that energy storage systems, at least with regard to electronic components such as semiconductors and capacitors, exhibit similar failure rate behaviour to those in classic system configurations. The core of the energy storage devices – the battery cells – exhibit a different behaviour. In addition to so-called 'calendar ageing', they exhibit load-dependent ageing. Depending on the application – rare grid support or daily complete cycling – they have to be replaced at a certain point, but usually before the inverter has reached the end of its lifespan. Further topology-dependent considerations are described elsewhere [4].

The reliable and continuous operation of inverters is of central importance for long-term high energy yields of PV power plants. A good system design that allows for standard-compliant operation under the conditions specified by the manufacturer is of central importance. However, this should be checked in the course of a detailed plant acceptance test in order to be able to address deviations. A plant-specific maintenance concept helps to detect and eliminate early failures in time. It also ensures that many environmental influences are reduced over the years to the level envisaged in the plant design.

Trackers

As it stands, there is no specific standard for the structural calculation of trackers in a solar PV fixed structure. Therefore, the calculation is based on civil codes for building like ASCE or Eurocode. There is a deficit in standardisation, which could lead to problems. Moreover, applicable tracker certification for IEC 62817 or UL 3703/UL2703 do not cover structural issues but rather potential failures or health and safety issues. With that said, civil construction codes have typically been applied to trackers with insufficient attention to the structural dynamics. Structural dynamics refers to a type of structural analysis that relates to the behaviour of structures subjected to dynamic loading (i.e. wind, wave, traffic, earthquakes, impacts, etc).

Dynamic behaviour is a concern for both fixed solar structures and solar trackers, however, the latter are generally more flexible and thus more susceptible to aerodynamics. The type of dynamic load of concern in solar trackers is therefore wind. Aeroelasticity is the study of the interaction between the deformation of an elastic structure in an airflow and the resulting aerodynamic force (fluid-structure interaction). This is an interdisciplinary problem: aerodynamics (a bluff body in an airflow), dynamics (effects of inertial forces), and elasticity (material behaviour of the structure).

Solar PV tracker failures are often caused by insufficient consideration to the aeroelastic effects during the design and testing phase. Often components directly attached to the torque tube have been deformed or even completely broken or ruptured, including U connections, bolts, nuts, brackets, slew drives, torque couplers, bearings, or even torque tube extensions. This demonstrates that the components receive dynamic energy when excitation happens; this phenomenon is called dynamic amplification or instability and can be mitigated by designing the structure to withstand them.

There needs to be a minimum level of study and testing required to properly address the potential aeroelastic effects of PV trackers. In addition to the mean and background components of the wind loads, which form part of a static structural analysis, the self-induced structural response of the tracker creates additional inertial loading, particularly in the modes with the lowest frequencies. How to make sure that the stiffness force is equal or above the self-excited forces plus the buffeting force, less the inertial and damping forces? One reasonable approach is looking at the instabilities to characterise them properly.

Conventional single-axis trackers rely on a central torque tube driven from a single location in the middle and are free to rotate at the ends of the row. This makes them particularly susceptible to various types of aerodynamic instabilities depending on their chord length, natural frequency, and damping ratio. These instabilities can be driven by five identified mechanisms:

1) **Torsional flutter and galloping.** Flutter is related to aerodynamic forces depending on the rotation and angular velocity of the structure itself and can lead to large amplitudes that can cause a catastrophic failure, such as the famous Tacoma Narrows Bridge in the USA. This mechanism characterises high-tilt angle behaviour. Galloping also depends on the rotation of the structure but due to variations in the aerodynamic pitching moment. The pitching moment reduces the overall structural stiffness, resulting in either unidirectional twisting or oscillatory motion. This mechanism characterises low-tilt angle behaviour.
2) **Torsional divergence.** The flexible axis of rotation can result in significant deflections at the outside edges of the row, which could result in a snowball effect of increased loads. This mechanism is most likely to occur in extreme wind events. Trackers are typically protected with a stow position protecting the structure from torsional divergence. According to UNE-EN 1991-1-4, some simplified formulae can help to determine if divergence can be a significant problem for the tracker under consideration.
3) **Buffeting.** Buffeting is the result of turbulent flow and wakes generated by windward objects. It is recommended to review EN1991-1-4 (Spanish annex) to see if this is applicable to the tracker under analysis. Wind tunnel testing – using small-scale tracker models in a simulation of the natural wind – is being used by the industry to determine the aerodynamic properties of a proposed tracker and the critical wind speeds for the onset of the unstable behaviour. This can be accomplished in at least two ways:
   a) **Sectional wind tunnel and Computer Fluid Dynamics** (CFD) for buffeting. The key advantage is that it can be inexpensively and quickly produced and can be easily

modified to investigate the changes to the structure layout. Sectional wind tunnels typically use mean values and some instabilities are triggered by gusts. In this case, low turbulence intensity tested does not necessarily mean a conservative approach.

b) **Full aeroelastic model testing** (3D buffeting). This is the more expensive way if the multi-row option is selected. The tested scale is smaller than the sectional wind tunnel but still representative for a tracker. The whole tracker does not twist the same (as is the case in the section model), only the free end has the full twist. Moreover, an instability in one row can trigger instability in neighbouring rows.

4) **Vortex-induced vibrations.** Vortex-shedding takes place when vortexes shed alternatively at two opposite sides. This produces an oscillating force perpendicular to the wind direction. Resonance shall occur if natural frequency match shedding frequency and deflection would be amplified on this case. It is recommended to review EN1991-1-4 (Spanish annex) to see if this is applicable to the tracker under analysis.

5) **Aeroelastic deflection.** If under a design wind event, the tracker deflects significantly, it is likely that the tracker is susceptible to dynamic effects, such as aeroelastic deflection. This means that the wind loads will change because of the varying shape of the tracker. Aeroelastic deflection closely relates to torsional divergence, but the difference may be that they are associated to non-stationary and stationary causes and consequences, harmonic loading, and instability, respectively. This instability can be estimated with iterative methodology.

The aforementioned instabilities are studied in different ways in the industry. A consensus has yet to be reached on the corresponding uncertainties associated with the methodologies used. However, any common approach should consider the three main disciplines working on the study of the above issues: (1) rigid-body dynamics, (2) fluid mechanics, and (3) structural mechanics.

The lack of consensus is also explained by the variety of results reported by the wind tunnel experts. It appears that there is not a single curve fitting all trackers because damping ratios, modal frequencies, stiffness, mass, and geometry are slightly different from one manufacturer to the other; full-scale testing on trackers to quantify the natural frequencies and damping ratios for each mode should be conducted with several site-specific factors that are typically experienced in the field, such as different soil conditions, pile spacing, pile dimensions, or torque tube thickness.

Several tracker failures that have occurred in the last few years have made it clear that construction, installation and commissioning issues may be involved in the tracker failures, not only the presence of any of the aeroelastic instabilities above mentioned. In a PV plant in Spain, a torqueing check revealed that almost two-thirds of the checking points showed torques below the minimum requirement by the manufacturer in their installation guideline. A wind event caused damages in the trackers, but who is responsible for those damages? It is true that the lack of torque was one issue, but the wind conditions did not justify the level of damage unless the aeroelastic effects were behind the failures.

Today's market is dynamic, and the tracker industry is moving fast. Therefore, situations where the civil work constructor, the installer and the tracker manufacturer are not willing to accept any responsibility on the tracker damages should be avoided in the future for the sake of the reputation of the solar industry. Any standardisation in the tracker industry regarding structural calculations and aeroelasticity should also consider the impact of the design, manufacturing, construction, installation, and commissioning on the final stability of the trackers for the site conditions.

Monitoring

The general trend in the solar industry is a reduction of on-site monitoring, leading to a situation where monitoring involves too much data and too little information. Solar PV plants show 5-10 incidents per year on average; this includes a number of false positives and issues with the communication infrastructure. Incidents may result in unnecessary engineer visits to PV plants to rectify the various issues. Reducing the number of unnecessary visits from engineers can reduce overall O&M costs for a plant.

Monitoring is often seen as an avoidable cost, as it does not contribute to the money-earning part of PV system operation, thus there is a lot of value engineering. This leads to a number of problems. First, there is no redundancy planned into monitoring systems, resulting in unnecessary call-outs from engineers. Further, monitoring is critical in identifying potential warranty cases, so saving too much on monitoring means that critical trends may be missed, and faults may develop in a way that the remedy ends up being more expensive than it would have been otherwise. Not monitoring appropriately means that optimisation potential is missed. There are diverging views, but on average, well-monitored and optimised systems have an increased yield of 3-5%. In case of selling or purchasing a system, the data is critical in establishing the value of the asset. Issues in the monitoring can devalue the asset significantly.

Typical faults in monitoring include:

- **Communication errors:** To remedy this potential error, use two independent methods of communication;
- **Sensor issues:** This refers to device failures, idiosyncratic measurements, or even birds sitting on top of an irradiance sensor. Here redundancy helps as well as automatic failure detection algorithms in the database;
- **Incorrect mounting:** Here, module temperature sensors can drop off and measure ambient temperature. Module temperature is often not done, but is actually critical if one encounters issues in the field and seeks to investigate them based on monitoring data;
- **Incorrect calibration or units:** This can involve mixing Fahrenheit or Celsius, using different standards when defining UV irradiance, or simply having value engineered the costs of calibration by using non-accredited suppliers or extending the stability date being set;
- **Soiling of irradiance sensors:** This can also mask issues relevant for potential quality issues.

Often, monitoring may appear superfluous but is in fact an essential performance assurance method. Monitoring should not be treated as an expense but instead more like an insurance policy that pays for itself. Generally speaking, the savings from reducing monitoring quality are small compared to the damage that can occur by missing issues or incorrect readings.

Junction boxes

Solar module junction box for crystalline solar modules

In general, a solar module junction box for crystalline PV modules consists of the housing cover, cover seal, housing body, terminal blocks for receiving the bypass diodes, the bypass diodes and a cable pair with plugs. For fully automated assembly the cable pair is rolled up.

TwinBox for crystalline and thin-film PV modules

A TwinBox for crystalline and thin-film PV modules is designed for fully automated assembly. It has a high dependability due to matching of components, potting compound, silicone, and adhesive foil; and it includes a compartment for electrical connection between box and panel hermetically sealed with potting compound. Further, it has a compact design due to integration of a connection technology directly into the junction box. The connection of the TwinBox is achieved by using a connector system. Depending on the choice of cables and connectors various voltage systems may be realised: IEC 1,000V-1,500V as well as UL 600V-1,000V.

Bypass diodes

During the construction of solar modules, single cells are switched in series to so-called 'strings' to achieve higher system voltages (see Figure 1, left). If one or more cells are shaded (for instance, by branches of trees or antennas), the affected solar cells no longer act like a current source, but as power consumers. Non-shaded cells deliver further current through them, generating high power losses; hot spots may occur and even cell breakdowns. To overcome this problem, bypass diodes are switched parallel to every single or some combined cells, bypassing current flow across the darkened strings (see Figure 1, right).

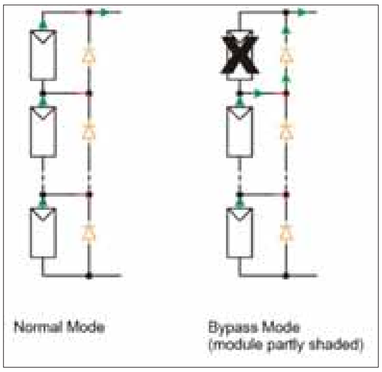


Figure 1. Function of bypass diodes (Stäubli)

Like every semiconductor device, bypass diodes have a certain leakage current, which in the normal mode of operation reduces the current supplied by the cells and therefore decreases efficiency of the solar module. Therefore, the leakage current especially at higher temperatures, should be as low as possible. Compared to this, partly shading modules is only an extreme operation mode that should be completely avoided, or at least only used during short time periods. For this mode of operation, low forward losses are desirable. Finally, the bypass diode must be protected against overvoltage spikes – such spikes may occur during assembly of the system, if current conducting cables are interrupted, or during operation, due to lightning, or other natural hazards.

Cables

Solar PV cables are halogen free and can match with most PV components, such as PV junction boxes and PV connectors, which have a rated voltage up to 1,500V DC. A fine stranded wire of tinned electrolyte copper (IEC 60228/cl.5) as well as robust materials provide a low-loss transfer even after many years. When used in accordance with instructions, the expected lifetime of this product is at least 25 years. In addition, insulating and sheath material designs provide greater resistance to abrasion and moisture. The double insulated, electron beam cross-linked cable with special compound is certified to all current standards and meets all fire safety regulations. Durable and robust materials provide increased water-repellent properties.

Conclusion

The potential of a solar PV plant is defined in the planning and design stages, by appropriate quality assurance. This article provided an overview of the main components and challenges related to EPC and is a kind of 'teaser' for SolarPower Europe's EPC Best Practice Guidelines. The guidelines will give an overview of all aspects of EPC, including handover from project developer to EPC, handover from EPC to O&M contractor, contractual recommendations, risk analysis, and mitigation recommendations. The guidelines will be launched in November at SolarPower Europe's annual event, "Solar Quality 2020". Interested companies are invited to get in touch with SolarPower Europe if they would like to be part of this initiative. ■

References

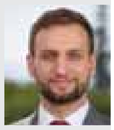
[1] Nagarajan, Adarsh, Ramanathan Thiagarajan, Ingrid Repins, and Peter Hacke. 2019. Photovoltaic Inverter Reliability Assessment. Golden, CO: National Renewable Energy Laboratory. NREL/TP-5D00-74462. https://www.nrel.gov/docs/fy20osti/74462.pdf.

[2] National Renewable Energy Laboratory, Sandia National Laboratory, SunSpec Alliance, and the SunShot National Laboratory Multiyear Partnership (SuNLaMP) PV O&M Best Practices Working Group. 2018. Best Practices for Operation and Maintenance of Photovoltaic and Energy Storage Systems; 3rd Edition. Golden, CO: National Renewable Energy Laboratory. NREL/TP-7A40-73822. https://www.nrel.gov/docs/fy19osti/73822.pdf.

[3] 2018, "Operation & Maintenance, Best Practices Guidelines / Version 3.0", Solar Power Europe.

[4] Efstratios Chatzinikolaou et al., 2016, "A Comparison of Grid-connected Battery Energy Storage System Designs", IEEE Transactions on Power Electronics 1-1.

Authors



Máté Heisz, head of international cooperation, SolarPower Europe
Máté Heisz is the Head of International Cooperation at SolarPower Europe, and Coordinator of the association's Lifecycle Quality Workstream and Emerging Markets Workstream. Prior to joining SolarPower Europe in 2017, Máté spent four years in Tunisia working as a Renewable Energy Advisor at the Tunisian Ministry of Energy on behalf of the German Development Cooperation (GIZ). Máté holds a Master's degree in International Relations from the Free University of Berlin, and a Master's degree in Economics from the Corvinus University of Budapest.

Ralph Gottschalg, director Fraunhofer CSP, Department Reliability and Technology for Grid Parity
Prof. Dr. Gottschalg has been Director at Fraunhofer Centre for Silicon Photovoltaics, Department Reliability and Technology for Grid Parity since 2018. He is also Professor of Photovoltaic Energy Systems at Anhalt University of Applied Sciences in Köthen, Germany. Before this he was Professor of Applied Photovoltaics at the Centre for Renewable Energy Systems Technology (CREST) at Loughborough University, UK.

Martin Lütgens, senior project manager solar international, ABO Wind AG
Martin Lütgens is Senior Project Manager Solar International at ABO Wind AG in Germany. Before this he was Head of Purchasing and Project Management at CTF Solar in Germany. He has also held positions at Günther Spelsberg Photovoltaic and BP Solar.

Nicolas Bogdanski, global head of energy storage systems, TÜV Rheinland AG
Dr. Bogdanski studied Electrical Engineering at Wuppertal University, Germany. He has been working as a scientist in the field of semiconductor science and polymer mechanics for several years. At TÜV Rheinland he is part of the solar energy R&D group where he is responsible for PV reliability projects.

César Hidalgo, Principal Engineer Solar, DNV GL
César is a Principal Engineer at DNV GL, and has led an international solar team from 2007 until 2015. His previous roles within DNV GL have included Senior Independent Engineer in Spain and Latin America, representative for DNV GL's WindFarmer software in Spain, Latin America and the Balkans, and responsibility for training courses in Spanish, among other marketing positions. César worked for Haskoning International Consultants in renewable energy consulting in the period 1995-2000, and was also the director of a cogeneration plant based on gas and fuel-oil engines of 15MW during the commissioning and first months of operation.

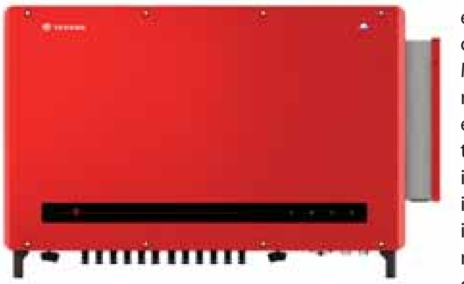
Product reviews

Inverter | GoodWe launches its most powerful 'HT Series' string inverters in the 100-136kW range

Product Outline: GoodWe has launched its new HT series string inverters – 100kW to 136kW – which are the company's most powerful and intelligent devices to date for the commercial & industrial as well as the utility-scale PV markets.

Problem: The new 'HT-Series' incorporates different sets of technical strengths, in order to achieve higher savings in installation, while enhancing productivity and diversifying the monitoring options available, thus taking safety to the maximum possible level in accordance with the most demanding national standards.

Solution: The HT series inverter is compatible with bifacial modules, ensuring maximum utilisation of available solar



energy. It offers 12 MPPT for maximum energy yield, together with inter-operability with tracking systems, making it compatible with larger-area, high-performance modules. The HT series offers a high efficiency of 99%, minimising mismatch losses, while maintaining and maximising intelligent energy generation with a 50% DC oversizing capability along with 15% AC overloading to fulfill energy generation demands. Furthermore, the HT Series can help maximise generation across the entire PV system with its capability of low voltage start-up and full output in harsh environments of up to 50º.

Applications: C&I and utility-scale PV power plants.

Platform: The HT series offers a No Fuse No LCD design with Full Film capacitor. The lifespan of the film capacitor is more than four times that of an aluminium electrolytic capacitor in environments above 70º. It comes with AC connector temperature detection, and is capable of conducting string and plant level health diagnosis, IV curve diagnosis.

Availability: July 2020 onwards, globally.

Inverter | Huayu's 'HY 2000 Plus' microinverter compatible with new era of 500W+ solar panels

Product Outline: PV inverter specialist, Huayu New Energy has launched its 'HY 2000 Plus' microinverter that has the highest recorded power density on the market and has four (4) MPPT (Maximum Power Point Tracking) and quad-module-level monitoring as standard.

Problem: Although traditional microinverters have gained market acceptance, the biggest barrier for market growth has been the high per watt cost compared with traditional string inverters used in residential, C&I and utility-scale PV power plants.

Solution: HY-2000-Plus microinverter is a cutting-edge design by Huayu for quad-module applications with a 4 MPPT design. Its power density reaches 554.05W/kg

with maximum continuous output power of 2,050W with only a net weight of 3.7kg. The HY-2000-Plus microinverter has a maximum DC input voltage of 60V DC, compared to conventional string inverters with a rated DC input voltage around 200V DC, to prevent possible arc incidents. The HY-2000-Plus microinverter also has a start-up voltage of only 22V DC, which means greater electricity yield in low-light conditions at dawn and dusk.

Applications: Residential and C&I rooftops as well as utility-scale PV power plants with solar panel size from 315Wp to 580Wp (VOC less than 60V).

Platform: The Huayu 4 in 1 microinverter series (2000/1600/1300/1200/1000W) is a combination of high performance and cost-effective design. With four MPPT and module-level monitoring, comparing with some "4 in 1" microinverters with only 2 MPPT, Huayu microinverter is one of the few real microinverters which can work based on four module-level power point trackers. A 25-year warranty is available.

Availability: Mass production began on 1 July 2020.

Module | JA Solar's DEEPBLUE 3.0 panels drive PV power plant LCOE down to new levels

Product Outline: JA Solar's highest performing large-area PV panel series, DEEPBLUE 3.0, provides outputs of over 525Wp, designed for an era of grid parity and intensive electricity price competition to reduce the levelised cost of energy (LCOE) and maximise the economic value of PV systems.

Problem: The PV industry is undergoing rapid technological development at wafer, cell and module level that is driving an unprecedented wave of new solar panel products onto the market. The

rapid shift is being driven by the need to continue to reduce the LCOE, supported by solar panels enabling in quick succession 400Wp, 500Wp and soon 600Wp performance in the field.

Solution: The DEEPBLUE 3.0 module utilises 180mm x 180mm large-area solar cells, and combines Ultra-T glass, innovative 11 busbar and PERCIUM+ technologies to achieve its ultra-high conversion efficiency of 21%. Under standard testing conditions, power output of the 6 ×12, 72-cell DEEPBLUE 3.0 ultra-high efficiency module was able to reach 525Wp-plus. Compared to current mainstream 400W modules, the adoption of 525W+ modules can provide a 7-9% decrease in LCOE to the consume, according to the company.

Applications: Commercial and industrial, and utility-scale PV power plants.

Platform: The elimination of cell gaps on the DEEPBLUE 3.0 raises the panel's conversion efficiency by 0.4%, while the use of lightweight framing brings its weight down 10% to 28.5kg. Single 72-cell glass panel dimensions are 2,267mm x 1,123mm. JA Solar has additionally become the first PV manufacturer to mass-produce high-efficiency Mono PERC MBB cells and modules using Ga-doped wafers. The application of Ga-doped silicon wafers to solar cells can mitigate the initial light-induced degradation (LID) issue.

Availability: Mass production slated to begin in Q3 of 2020.

Module | JinkoSolar's 'Tiger PRO' modules designed to lead LCOE reductions with max 580-watt peak performance

Product Outline: JinkoSolar has recently launched its 2020 flagship utility-scale module series, 'Tiger PRO', which includes three new modules, 72 TR, 72 HC and 78 TR versions and bifacial options.

Problem: The global PV market is rapidly moving towards high-performance modules to reduce system costs and initial upfront capital investment as the drive to lowest continues. This has required a shift to increasingly larger wafer sizes and new cell interconnect technologies to push module power outputs above 500Wp and approaching 600Wp.

Solution: The new Tiger PRO module combines the half-cut cell design to reduce cell current mismatch and ribbon

power losses. In addition, 9-Busbar and Tiling Ribbon (TR) technologies reduce the distance between the main busbar and finger grid lines, which decreases the resistance loss and increases power output and efficiency of the module while maintaining a low (Voc) open circuit voltage. As a result, utility-scale plants can reduce the amount of DC cabling, PV mounting and combiner boxes required, lowering the balance of system costs.

Applications: Utility-scale PV power plants.

Platform: The Tiger PRO module series comprises of two monofacial and two bifacial products in 72-cell (2,230mm x 1,134mm) and 78-cell (2,411mm x 1,134mm) configurations. The (182mm wafer) 72-cell TR half-cut monofacial-PERC module reaches 535Wp performance, with the larger 78-TR version tops out at 580Wp. The Tiger PRO bifacial module in 72-TR form is available with up to 530Wp in dual glass and glass/transparent backsheet configuration with up to 30-year lifetime for bifacial modules with Dupont Tedlar based transparent backsheet, while the 78-TR from achieves 575Wp in a dual glass configuration.

Availability: Mass production in the third quarter of 2020.

Storage | KSTAR offers all-in-one CATL energy storage system for improved safety and reliability

Product Outline: KSTAR has introduced its new 'All-In-One' single-phase storage solution', the BluE-S-5000D SERIES, which combines KSTAR inverters with a CATL battery solution. The latest KSTAR hybrid solar system provides power continuously, without any interruption, as the CATL powerful batteries connected to them store the energy.

Problem: The traditional hybrid electricity generators typically use diesel or petrol for fuel. To protect the environment and make the best of energy, hybrid inverter systems offer the best solution. However, for hybrid inverter systems the battery quality is very important to guarantee safety and reliability.

Solution: KSTAR's BluE-S-5000D SERIES is the most up-to date all-in-one single-phase storage solution, which provides safe, smart and high efficiency and for residential applications, according to the company. To offer optimal performance and a long lifespan, the BluE-S-5000D series is an AC coupled all-in-one CATL battery module with KSTAR inverter, low maintenance and easy to install. TheBluE-S-5000D series includes a five-year product warranty and 10-year performance warranty with 24/7 monitoring via the 'KSTAR Cloud' app.

Applications: PV self-consumption, back-up power, fuel saving solutions, battery expansion, load shifting and off-grid solutions.

Platform: The TheBluE-S-5000D series is IP 65 design, optimized for its working environment, so that the hybrid system can work under harsh conditions, such as storage temperature range–20º~ +60º, salty air and humid conditions. optimized for its working environment, so that the hybrid system can work under harsh conditions, such as Storage temperature range–20º~ +60º, salty air and humid conditions.

Availability: June 2020, onwards.

Module | LONGi Solar's 'Hi-MO 5' Series module offers 540Wp performance for PV power plants

Product Outline: LONGi Solar has introduced its next-generation series of large-area high-performance modules for the utility-scale PV power plant markets globally. The new Hi-MO 5 Series offers up to 540Wp performance with gallium-doped, newly defined M10 (182mm x 182mm wafers) half-cut monocrystalline PERC cells and nine-busbar 'Smart Soldering' cell interconnect technology.

Problem: In the era of grid parity and project bidding, PV module performance is rapidly improving to provide significant LCOE and balance of system cost reductions. As a result, large-area wafers, coupled to innovations at the cell and module level need to be compatible with PV inverters and tracker systems, notably for bifacial systems.

Solution: Hi-MO 5 modules deploy gallium-doped M10 (182mm2) wafers, which provide better security to light-induced degradation with stable, long-term power generation. LONGi's proprietary 'Smart Soldering" technology uses integrated segmented ribbons. The triangular ribbon design maximises light trapping, while the flat section reliably connects cells with reduced spacing. As a result, the Smart Soldering technology reduces the tensile stress of the cell by around 20% as the cell interconnect gap is reduced to approximately 0.6mm, compared to standard spacing of around 2.0mm.

Applications: Hi-MO 5 (72-cell) offer the lowest LCOE for utility-scale PV power plants.

Platform: The Hi-MO 5 Series modules are constructed in a double glass with frame format and maintains the traditional six-row design in the 72C layout. The height of the shipping container limits the module width to about 1.13m. The length of the 72-cell Hi-MO 5, at about 2.25m, is also compatible with many racking systems available on the market from 1P to 2P designs.

Availability: Hi-MO 5 will be produced in volume and receive IEC/UL certification in September 2020.

Product reviews

Module | Q CELLS offering first AC Modules with Enphase IQ 7+ microinverters

Product Outline: Q CELLS has launched its 'Q.PEAK DUO BLK-G6+/AC 340-345' PV module, which is the first AC Module from Q CELLS to come to market using the Enphase 'IQ 7+' microinverter. The first Enphase and Q CELLS-developed ACMs will be available from major distributors in the US starting July 15th.

Problem: AC modules can reduce labour costs, improved SKU management with accelerated design, and faster installation times.

Solution: The Q.PEAK DUO BLK-G6+/AC produces high yields, due to power classes of up to 345Wp and efficiencies of up to 19.5%, using its Q.ANTUM DUO monocrystalline half-cell technology, combined

with state-of-the-art circuitry and six-busbar cell design. The Q.PEAK DUO BLK-G6+/AC Enphase Energized ACM allows installers to be more competitive through improved capital management, reduced labor costs, improved SKU management with accelerated design, and faster installation times. The AC modules are assembled in the USA at Q CELLS' manufacturing facility in Dalton, GA.

Applications: Residential PV systems.

Platform: The Q.PEAK DUO BLK-G6+/AC offers long-term reliability with a 25-year product warranty and one of the lowest degradation rates in the industry, which guarantees 85% initial performance in the 25th year. The seventh-generation Enphase IQ microinverter system dramatically simplifies solar installations and provides a complete AC solution that produces no high-voltage DC, providing a safe solar solution for homeowners. Enphase Energized AC modules from CELLS work seamlessly with the full suite of Enphase IQ accessory products: the lighter two-wire Enphase 'Q Cable', the Enphase 'IQ Combiner 3' with pre-installed Enphase 'IQ Envoy' gateway, as well as the Enphase 'Encharge' energy storage system.

Availability: The first Enphase and Q CELLS-developed ACMs will be available from major distributors in the U.S. starting July 15th.

Module | Seraphim offers all-black 'S2' solar panel without performance sacrifice for residential and commercial rooftops

Product Outline: Seraphim Solar has introduced its S2 full-black half-cell series module, specifically for residential and commercial rooftop installations. This new iteration of the present S2 module series offers an all-black facade for superior aesthetics, while providing high-performance power output of up to 330Wp.

Problem: The rooftop PV market is rapidly transitioning to higher-performance modules to reduce installation costs, while owners are becoming increasingly knowledgeable and discerning regarding the overall PV system aesthetics with preference for greater visual integration into the roof.

Solution: Seraphim's S2 full-black half-cell module series has been designed to meet the need for superior aesthetics without sacrificing power output for residential and commercial rooftop installations. The full-black module utilises a range of large-area wafers, as well as half-cut cells, offering a power output of up to 330Wp with a module conversion efficiency rate of 19.5%. Half-cut monocrystalline PERC technology reduces current and sheet resistance, minimises mismatch losses and reduces cell to module losses.

Applications: A wide range of rooftop installations requiring superior aesthetics and improved shading performance.

Platform: Seraphim's S2 full-black half-cell module series is available in three different formats to meet the specific needs of the wide range of residential and commercial rooftop requirements. The smallest module is a 60-cell half-cut (120-cell) format using 158.75mm x 158.75mm large-area wafers with dimensions of 1,690mm x 1,002mm, weighing 19kg. The medium sized module uses 166mm x 166mm large-area wafers in a 60-cell half-cut (120-cell) format with module dimensions of 1,776mm x 1,052mm, weighing 20kg. The largest sized module in the S2 full-black series has a 66-half-cut (132-cell) format with 158.75mm x 158.75mm large-area wafers and dimensions of 1,852mm x 1,002mm, weighing 20kg.

Availability: July 2020, onwards.

Inverter | SolarEdge's new 'Energy Hub Inverter' provides flexibility in home storage backup

Product Outline: SolarEdge Technologies has introduced its new 'Energy Hub Inverter' with Prism Technology that combines the performance of HD-Wave technology and the functionality of 'StorEdge' to achieve higher levels of flexibility in home backup while simplifying installation..

Problem: Currently, most residential PV systems are grid-tied, which provides only a fragmented energy environment that is inefficient and costly to consumers. Creating a centralised platform that coordinates energy production, storage and consumption at a local level is a critical step in turning residential houses into smart energy homes and traditional grids into smart grids.

Solution: When DC coupled with power-

stacked batteries and the new backup interface, the Energy Hub Inverter supports up to 200% DC oversizing and can power part of or the entire home, up to 200A, during grid outages. While also enabling fast and simple installation, the solution eliminates the requirement for a main panel upgrade or generation panel, even when connected to multiple inverters, batteries, or generators. The Energy Hub Inverter has a high weighted efficiency of 99% and when DC coupled with batteries, the combined efficiency reaches 90.8%.

Applications: Residential PV and energy storage systems.

Platform: With up to 200% oversizing, Energy Hub DC-coupled solution can generate and store more energy than AC-coupled solutions - enabling larger systems and more power. Energy that would normally be lost in AC-coupled solutions can now be stored in a battery and used by the homeowner to maximize self-consumption

Availability: July 2020, onwards.

Product reviews

Inverter | Ginlong's new 'Solis Hybrid' inverter equips EU residential market with maximum storage benefits

Product Outline: Ginlong Technologies has introduced its latest hybrid energy storage inverter across EU markets, the three-phase Solis-HVES (High Voltage Energy Storage). Solis is intended to maximise residential solar-plus-storage systems with an intelligent, reliable, and secure Smart Home Solution.

Problem: As the energy supply market shifts at pace in how energy is supplied, costed, and consumed, homeowners need to be able to adapt to how, when and what electricity they are drawing on. Residential energy consumers across the EU need to maximise their energy self-consumption, safely and reliably.

Solution: The new 5G hybrid inverter brings a high conversion efficiency of 98.4% to solar-plus-storage systems. Its 1.6 PV-to-battery ratio supports load and battery supply, improves system utilisation and boosts generation – increasing ROI for the residential market. With dynamic MPPT (2 MPPTs with 4 DC inputs), and a maximum 26A DC input current, it is compatible with various applications, including bifacial modules. With 10kW in charging and discharging power, the customer will need less time to ensure a healthy battery state-of-charge value and can also carry more critical loads. Customers can maximise their self-consumption with flexible operating modes such as time-of-use and off-grid backup, enabling smart time shifting to leverage time-of-use schedules and optimise energy use.

Applications: PV energy storage system.

Platform: This new high voltage hybrid inverter also carries the latest fifth-generation Solis inverter technology making it one of the most technically advanced hybrid inverters available, according to the company.

Availability: July 2020, onwards.

Tracker | Soltec's 'Dy-WIND' technology tackles dangerous dynamic effects of wind on PV power plants

Product Outline: Wind consultancy firm, RWDI in collaboration with tracker systems specialist, Soltec have developed a new method for comprehensive dynamic analysis in tracker wind-design to give the stability needed to a PV power plant installed at an extreme location or exposed to high winds.

Problem: Extreme winds can damage the tracker structure and produce extra structural costs of PV power plant. Several studies have shown that the current regulations applied to solar trackers are not sufficient to size these structures since they do not consider the second order effects produced by the action of the wind when it impacts onto the in-situ tracker.

Solution: Using computational calculations and CFD simulation models, it is possible to create 3D numerical models that with great precision, reproduce the structural behavior of solar trackers when subjected to wind loads as would be encountered in the field. The Dy-WIND methodology is a code-challenging analysis method applied to solar tracker wind-design, based on accurate wind-loading analysis. Dy-WIND is a combination of DAF (Dynamic Amplification Factors) + FAM (Fluttering Analysis Method) + BAM (Buffeting Analysis Method) as a new standard in tracker multi-array design analysis.

Applications: Soltec single-axis trackers for utility-scale PV power plants.

Platform: The Dy-WIND design counts on robust piles and robust mounting rails for modules. The tracker system contains a reinforced slewing drive with specialised features and stronger torque-tubes to improve stiffness. The section coupler assembly increases tube stiffness with optimised specifications of material, cross-section, and fastening. Soltec has incorporated Dy-WIND in the design of Soltec tracker systems such as the SF7 and SF7 Tandem single-axis trackers.

Availability: Currently available.

Module | Trina Solar's Vertex' panel series has 550/600W performance classes for PV power plants

Product Outline: Trina Solar has launched its latest 'Vertex' solar panel series, designed with a new platform of technology innovations to provide ultra-high performance for utility-scale PV power plant applications with a path to 600W panels in 2021. Bifacial modules are also included in the new Vertex series.

Problem: Since the beginning of 2020, the photovoltaic industry has leapfrogged into the era of 500W-plus high-power output. By choosing a monocrystalline wafer size of 210mm x 210mm, Trina Solar has locked in the largest possible wafer size that will be in volume production over the coming years as it is the largest size from 300mm diameter ingots, while other size options face upgrading challenges and higher production costs.

Solution: The Vertex 550W and 600W panels are optimised solutions in terms of product design, manufacturing, transportation and system compatibility for utility-scale and C&I applications. Optical performance power improvements of between 1% and 1.5% have been achieved by adopting a circular MBB string ribbon, reducing cell surface shading and creating a light-trapping effect. The MBB current path has been reduced by up to 60%, compared to a 5BB layout, enabling an electrical performance power improvement of 1% and 1.5% and an overall module efficiency improvement of 0.4-0.6%.

Applications: Utility-scale PV power plants.

Platform: The Vertex 550W panel layout is 5 x 11 cells with dimensions of 2,384mm x 1,096mm, weight 29kg. The 600W version will be a 6 x 10 cell layout with dimensions of 2,172mm x 1,303mm. The dual glass option weight is expected to be around 35.3kg.

Availability: Volume production in the fourth quarter of 2020.

PV reliability lessons from 100,000 systems

Performance | Despite the importance of reliability to the cost competitiveness of PV, large data sets enabling high-level investigation of the technology's performance in the field are relatively scarce. Dirk C. Jordan, Chris Deline, Bill Marion and Teresa Barnes of the National Renewable Energy Laboratory, and Mark Bolinger of the Lawrence Berkeley National Laboratory study a unique data set of 100,000 PV systems in the US, drawing out tips for better reliability that have relevance to other parts of the world

Credit: First Solar

Reliability plays a critical role in PV's cost competitiveness with traditional energy sources. Many research groups and institutions around the world pursue to quantify PV field performance, degradation and failures. However, data sets studying a large number of systems that provide a high-level overview of issues occurring in the field are still difficult to find [1]. In response to the global financial crisis of 2008, US Congress enacted the American Recovery and Reinvestment Act in 2009 (ARRA). Section 1603 of ARRA gave qualified renewable energy projects the option to elect a cash payment in lieu of the federal investment tax credit (ITC). The award stipulated that annual PV production and comments relating to the performance needed to be reported. The data set comprised about 100,000 PV systems totaling to over 7 gigawatts (GW) direct current (DC) capacity or roughly 7% of the US fleet at the end of 2019. The insights gained from this data set provide valuable information of the performance and the state of reliability of the PV fleet in the USA.

The interrogation of data from 100,000 PV systems in the US provides fruitful insights into performance and reliability

While the dataset is limited to systems in the USA the same lessons are more generic and may be applicable to other parts of the world.

Fleet performance

The data set consisted of annual production data for five years for each of the systems, the nameplate rating, an estimated production value and the location. The ratio of measured over predicted production could be calculated for all systems to assess system perfor-

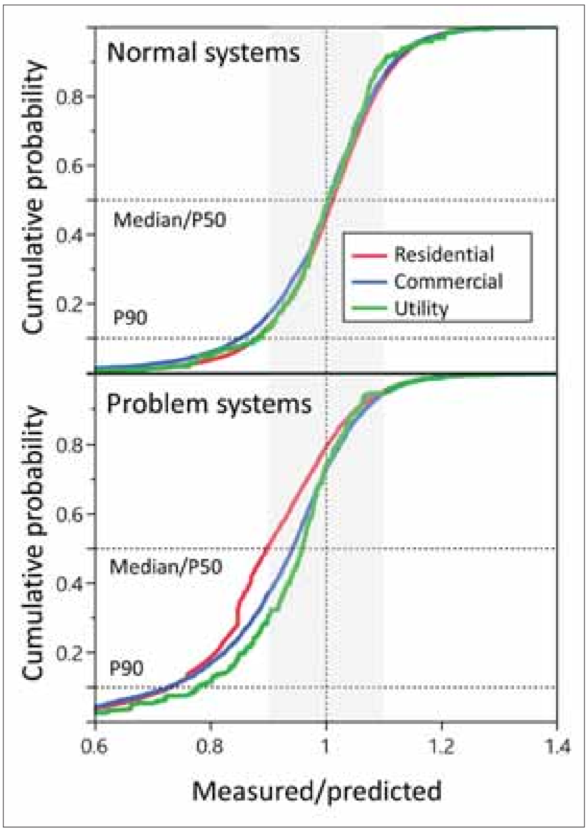


Figure 1. Cumulative distribution function of the five-year mean of the measured/predicted production ratio for normal systems not impacted by specific performance issues (top), and systems impacted by specific issues (bottom) discussed in the following sections. Different system sizes are indicated by different colour; the median (P50), the P90, and the unity ratio are indicated by dashed horizontal and vertical lines, respectively. A 10% band around the unity values is indicated in grey

mance health. The data set is approximately divided into residential (1–25kW), commercial (25kW–1MW) and utility-scale systems (>1MW). The division between groups is somewhat arbitrary but reflects the general trend between different types of systems, although individual systems at the respective limits may have been incorrectly classified. For systems over 5MW, in addition to the 1603 data, we generated our own production estimates using a separate data set acquired by the Lawrence Berkeley National Lab, which also included greater levels of detail on system specifics such as mounting configuration than was presented in the 1603 data. In general, we found good agreement between our own and the 1603 estimates, lending some credibility to the production numbers contained in the 1603 data set.

The five-year mean of the measured over predicted production ratio is displayed in Figure 1 as a cumulative distribution function (CDF). The advantage of a CDF compared to a histogram is that it more easily allows comparison of multiple large distributions.

The top graph shows all "normal" systems, i.e. systems that were not knowingly impacted by some issue. The data are colour-coded by the size of the systems and the median or the P50 is indicated by a black horizontal dashed line, as is the P90 that is often used in financial models.

The unity value, i.e. systems performing as expected, is indicated by a vertical dashed line together with a grey 10% band around it. At the median, the CDFs of the "normally" operating systems show slightly higher production than expected. In addition, the utility-scale category exhibits a tighter distribution, indicated by a steeper curve, is most likely aided by closer supervision in the planning and operation phase and/or more accurate predicted values. The P90 value falls between 0.8 to 0.9; in other words, 90% of all systems produce approximately within 10% of the expected production. The general asymmetry of the CDFs indicates the limited upside of the production ratio, but the much greater risk for energy loss. A minority of systems greatly underperform and overperform, clearly indicating a problem with the system, production estimate, or reporting. However, because no comments regarding the performance were entered, these systems had to be treated as "normally performing" systems and are included. An additional source of uncertainty might be the difference in accuracy of revenue grade meters typically used in utility-scale systems compared to standard meters more commonly used in residential applications.

"Installation quality was found to play an important role in PV reliability and emphasises the importance of installation best practices"

The bottom graph of Figure 1 shows similar CDFs of systems that were impacted by specific issues in any of the five-year reporting period. Similar to the "normally" operating systems, some systems greatly under- and overperform because of the different impact of certain issues on performance. However, some general observations can be made: utility systems show a reduced performance at the median compared to "normal" systems, but they perform substantially higher than residential systems. This is a difference that we will explore in more detail below. Commercial systems fall between the utility systems (similar performance at the median) and the residential systems (similar performance at the P90).

Hardware reliability lessons

The performance-related comments were mined by a combination of automatic and manual routines, such as keyword searches, sorting, classification and lastly reading. If multiple performance-impacting entries were recorded in a single year, each issue was counted in its respective subcategory, although the great majority of performance comments were single-entry issues. The number of occurrences is then obtained by simply integrating the number of issues for each subcategory and dividing by the total number of systems reporting for each year. Because it is not always known if all systems were operating for the full 12 months for each year the five-year mean values for each subcategory is shown in Figure 2.

The lost production for each subcategory is obtained by examining the subsequent, or preceding, years of the affected year and determining the normality of operation by the performance comments. The performance of such normally producing years is then averaged for each affected system, allowing a rudimentary estimation of the performance-impacting issue. Because of the uncertainty in reporting and confounding effects of multiple entries, these numbers should be regarded as estimates.

As has been reported before, inverters are the most common hardware problem for PV systems [2]. The occurrences for residential systems are slightly lower than commercial- and utility-scale systems, possibly indicating more reliable inverters (microinverter or string inverters) or underreporting. However, it can be seen from the graph that the lost production for utility systems is substantially lower than commercial and residential systems. This trend is observable not only for inverters but for many hardware issues, most likely because of the closer monitoring and supervision of larger systems. Meters are a somewhat surprisingly high-occurrence hardware issue, three-quarters of which constituted replacement. "Unspecified repairs" are failure events that occurred,

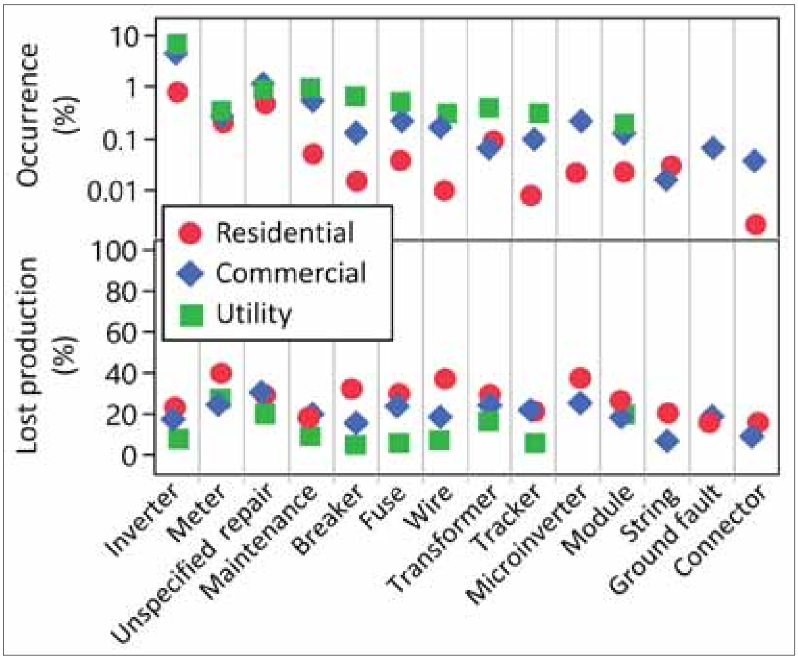


Figure 2. Hardware issue occurrences (top) and lost production (bottom) for each hardware subcategory. The different size of the systems is indicated by different-coloured symbols

All issues	Residential	Commercial	Utility
Mean lost (days)	44.5	27.3	8.8
Median lost (days)	38.5	21	5
Mean lost capacity (%)	9.4	6.1	2.3
Median lost capacity (%)	8.4	4.8	1.3

Table 1. Mean and median of lost production days and estimated lost capacity by system size for all hardware issues combined.

but from the comments it could not be deduced what item failed and what was fixed. It is interesting to note that maintenance events (a proactive approach) typically have lower occurrence than repairs (a reactive approach), yet they have lower impact on lost production, a general trend that is not limited to the PV industry. The next three subcategories are breakers, fuses, and wires, which may be somewhat unexpected and may indicate installation improvement possibilities. It is also conceivable that pressure to reduce installation costs leads to procurement and acceptance of nonconforming items, e.g. breakers have been found to be one of the most commonly counterfeited electrical products in the United States [3].

Also included here are transformer problems, although these hardware problems are on the utility side of PV systems, about half of which consisted of replacements. The occurrence appears fairly high because of three lightning strikes to substation transformers that led to outages of PV systems in the vicinity. The next two subcategories are tracker and microinverter or DC optimiser issues; the latter two are grouped together. However, both subcategories have in common that fact the occurrence numbers extracted from this dataset are most likely underestimated. The reason is that mounting configuration was only available for a few hundred systems greater than 5MW but not for systems below 5MW. Therefore, to calculate the occurrence, we had to use the total number of available systems. It is likely that not every commercial and utility system below 5MW employs trackers, just as not every residential system employs microinverters; thus, we can conclude that we most likely underestimated the numbers for these two subcategories. Tracker systems in the residential category are most likely an artifact of the division line between the residential and commercial category because residential systems are typically deployed in fixed-tilt configuration. Next are module-related issues that appear to be relatively low and in the historical range of 0.02% to 0.2%, however, the effect of underperforming modules may not have been fully captured here. String problems were typically caused by reverse connections—a problem that occurs most often at the residential level. The final two subcategories are ground faults and connector issues. Connectors are specifically related to module connectors that were incorrectly crimped and/or starting to separate under load. Both of these subcategories do not occur very often but could have serious safety implications by causing fires; thus, they deserve our full attention.

Additional insights into hardware issues may be gained by examining the time it takes to resolve specific issues. Some, but not all comments, recorded the start and end time of a specific repair issue. Unfortunately, that reduced the number of data points available for each subcategory markedly, as seen in Figure 3.

Only the inverter and breaker subcategory allowed an estimation of resolution time for all three PV system size categories. Boxplots with the median indicated by a crossbar are also shown for each subcategory. Similar to lost production, utility systems show the quickest resolution at a median of six days for inverter problems, followed by commercial and

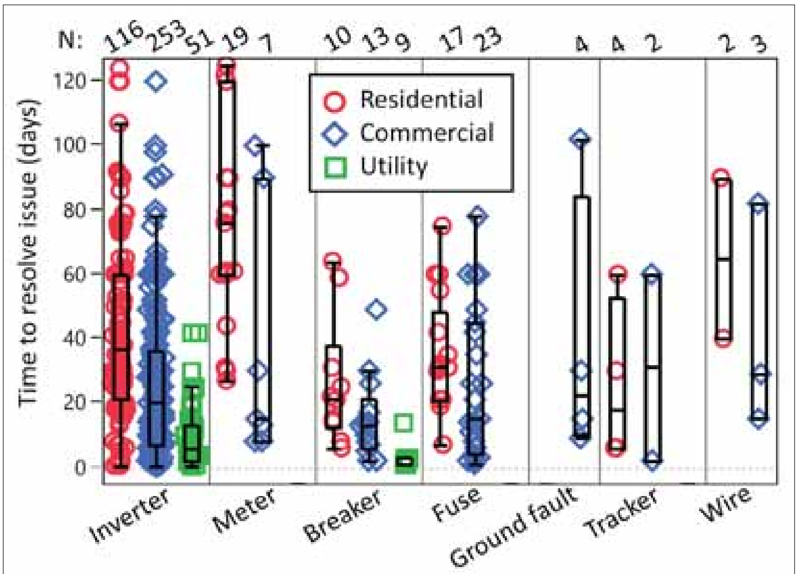


Figure 3. Days to resolve specific hardware issues partitioned by size of the installation category

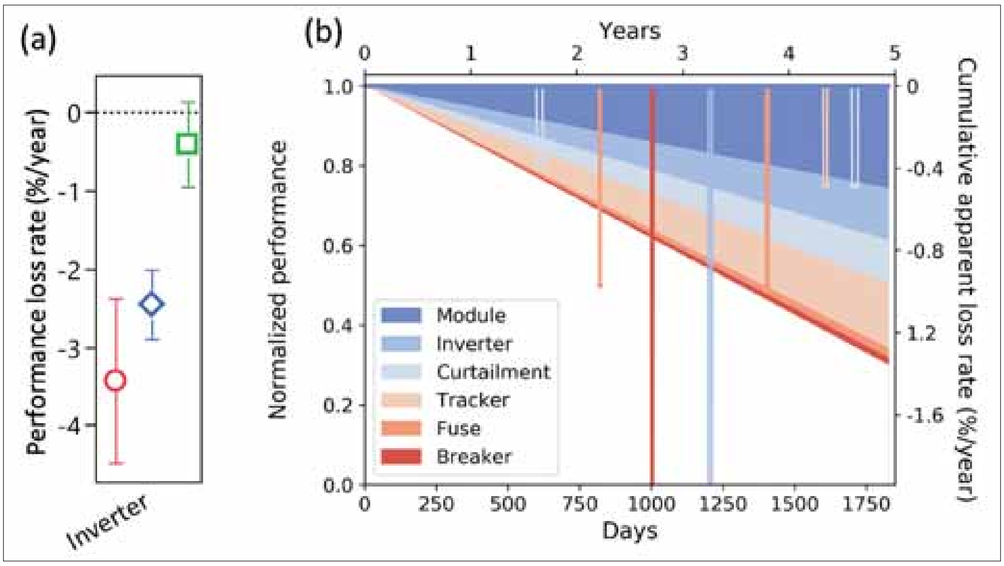


Figure 4. Apparent performance loss rates caused by inverter downtimes (a) and illustrating of module versus systems performance loss

residential systems at the median of 20 days and 37 days, respectively. A comparable trend, but with slightly shorter resolution times, can be seen for breaker problems. Meter issues took considerably longer to resolve for residential systems than for commercial systems although a large variability exists because of the relatively low number available. Fuses show a similar trend but also similar resolution times as inverters. It is interesting to note that other hardware issues such as ground faults, trackers and wires can take considerably longer to resolve, probably because of a combination of the complexities in detection and repair.

Median and mean values of lost production days are given in Table 1 when all hardware issues are combined. In addition, an approximate value of the lost capacity by system size can be estimated. At the utility scale, only days of production are typically lost representing 1-2 % of capacity. For commercial systems typically weeks of production are lost and residential systems more than a month.

Recoverable and nonrecoverable performance loss

Long-term unrecoverable performance decline or performance loss rates have a great impact on the economics of PV projects. With only five years of data and limited weather correction, the resulting performance loss rates obtained from this data set would have high uncertainties. However, the inverter subcategory contained sufficient data points to calculate an apparent performance loss rate from the P50 values of each year with a standard least-squares regression approach and for each system size category and correlate it with the downtime of the system, as shown in Figure 4 (a).

Because interruptions caused by inverters were in the order of a few days for utility systems, no apparent "degradation" was visible for this category. However, commercial and residential system interruptions caused by inverters were in the order of several weeks to more than a month. These apparent "performance loss rates" due to the inverter outages outside the uncertainty are clearly visible and may be recoverable. This clearly emphasises that operations and maintenance (O&M) records must be carefully considered in evaluating performance loss at the system level. Figure 4 (b) illuminates the difference between module and system performance loss more clearly, although a different performance loss method, such as the year-on-year method incorporated in RdTools for example may lead to a different system performance loss rate [4]. Nevertheless, it can be seen that downtime from specific balance-of-system (BOS) components aggregate from an average module to a much greater system performance loss [5].

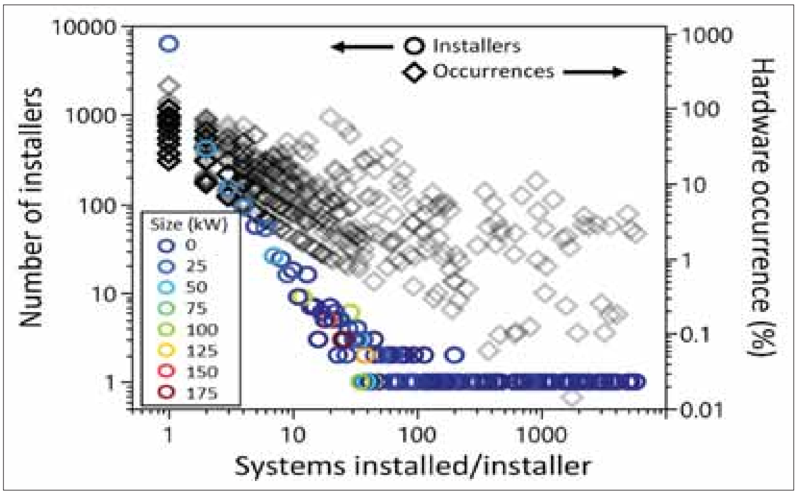
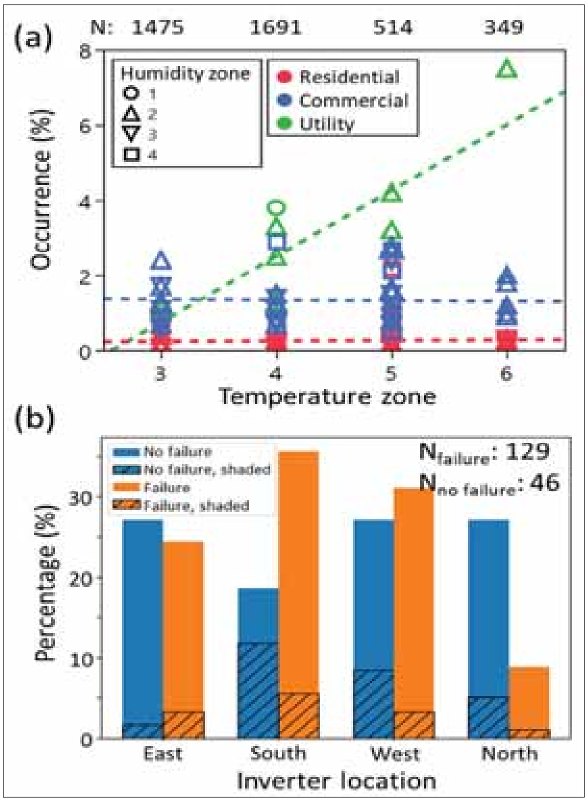


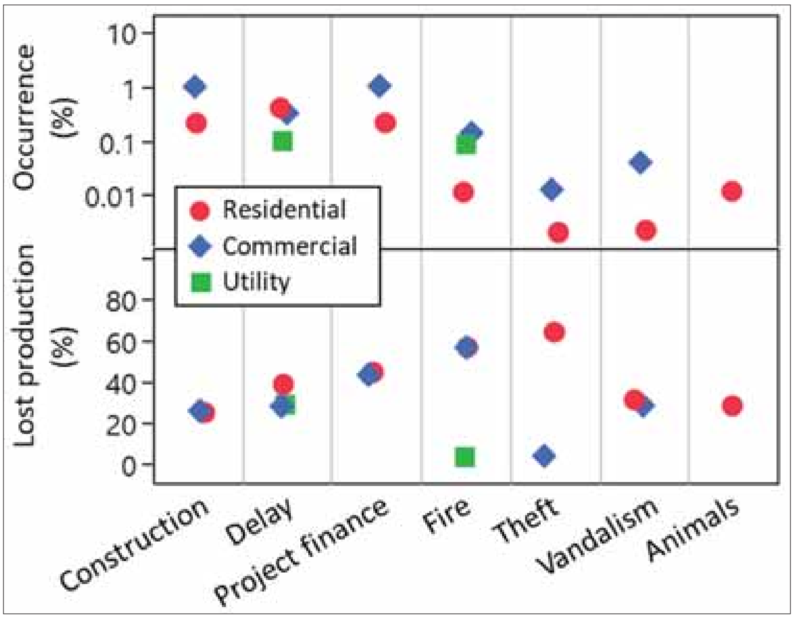
Figure 5. Number of installers versus systems installed per installer colour-coded by the median size of the installation (left axis). Occurrence of hardware issues for each installer as percentage (right axis)

Installation quality

Some of the BOS component failures raise questions about installation quality and its impact on reliability. Figure 5 displays the number of installers vs. the number of systems installed per installer as open circles colour-coded by the median size of the installed system. Large commercial installers can be found on the right side of the graph. In contrast, the left-hand side shows a large number of installers who installed only one or two systems. Hardware occurrence issues for the same installers are graphed as open diamonds on the right-hand axis. One hardware incidence per year would result in 100% occurrence; because more than one issue can occur per year, occurrence numbers greater than 100% are possible. Despite the imperfect metric, installers that install fewer systems have a higher occurrence of hardware issues than installers that install a great number of systems. This emphasises the benefits of installation experience, standards and certifications such as those provided through the IECRE, the IEC's system for certification to standards relating to equipment for use in renewable energy applications. Furthermore, training and certifications for installers could have a positive impact on long-term reliability.



▲ **Figure 6. Inverter failures occurrences (a) as a function of PV-specific temperature zones (model based on rack-mounting). The system size is colour coded and the humidity PV climate zone is indicated by different symbols. Regression lines are indicated by dashed lines. The number of data points for each zone is indicated on top of the graph. Inverter orientation for systems that experienced failures (orange) and without failures (blue) is shown in (b). Inverters that received some shading through adjacent buildings or vegetation are indicated by the cross-hatch pattern**

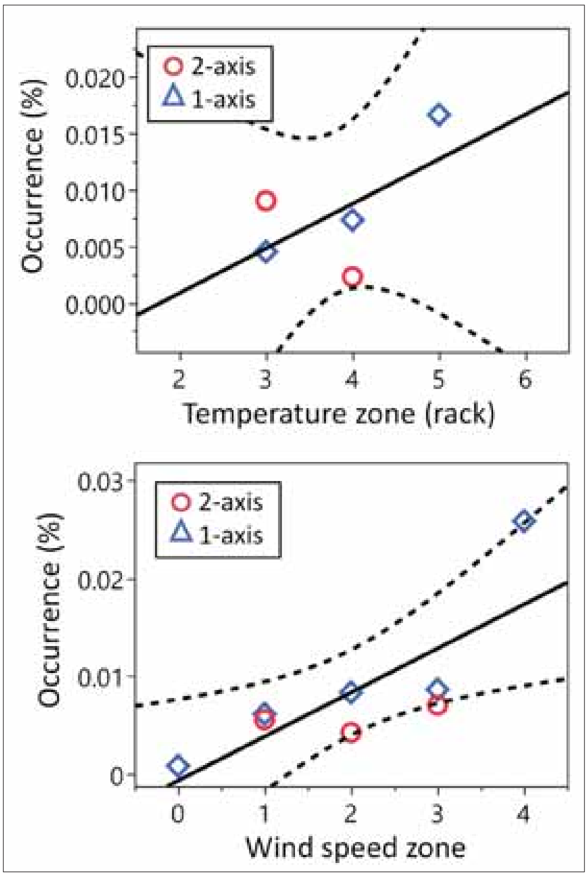


▲ **Figure 8. Hardware issue occurrences (top) and lost production (bottom) for each project subcategory. The different size of the systems is indicated by different-coloured symbols**

Climate trends and installation best practices – shade BOS components

An often-asked question is if certain failures are related to climatic conditions such as temperature, humidity and wind speed. To investigate this question, we adopt the PV-specific climate zones instead of the commonly used but insufficient Köppen-Geiger climate classification [6]. An increased number of inverter failures can be seen in hotter climate zones for utility-scale systems, as shown in Figure 6 (a). Yet, commercial and residential systems do not follow the same trend.

The explanation for this discrepancy may be that utility projects are typically large, ground-mounted systems where inverters are exposed in the field and may not always be shaded. In contrast, many commercial systems (but not all) and residential systems are rooftop installations where the inverter can be found facing different directions depending on the building orientation or located inside the building. The systems that experienced inverter failures were sampled, orientation recorded using Google maps and displayed in orange in Figure 6 (b).



◀ **Figure 7. (a) Tracker issues as a function of PV-specific temperature zone (rack-mounting); (b) PV-specific wind speed zone. The tracker type is indicated by different colours and symbols. Standard least square regression fits are shown by black solid lines. 95% confidence intervals are indicated by dashed lines. The number of data points for each zone is indicated on top of the graph**

Disproportionally, more inverters were facing south and west than east, with very few facing north. In addition, inverters that could experience some shading because of adjacent structures or vegetation are indicated by cross-hatching. In contrast, systems without inverter failures were randomly sampled because of the large number and are shown as blue bars for comparison. Orientation of these inverters is almost evenly divided between the four directions, with south-facing inverter having the lowest percentage. Furthermore, these inverters were also more likely to be shaded, which is again indicated by cross-hatching. Unshaded inverters facing south in the northern hemisphere are exposed directly to the sun and experience higher temperatures for longer periods than shaded inverters. West-facing inverters experience sun exposure coinciding with daily maximum ambient temperatures, possibly explaining the high failure percentage. Certainly, inverter manufacturer and type may have an impact on the number of failures too and may contribute to some data noise.

Trackers are often used in utility-scale systems and ground-mounted commercial installations and are similarly exposed to various weather conditions. We test the possibility of tracker failures in different climate zones, as shown in Figure 7. More data is required to confirm a tenuous trend of higher failures in hotter climate zones although hotter climate zones also often consist of more sandy climates that could be correlated to increased failure risk. In contrast, a much clearer trend of higher failures in higher wind speed locations can be seen in Figure 7 (b).

PV project issues

Hardware issues are not the only category that can have a substantial impact on PV production. In this section we discuss some project- or site-related problems. The most common of these losses, as shown in Figure 8, is post-installation construction at the PV site. Roof repairs or renovations during which the PV system must be turned off and removed are common causes of power loss in residential and commercial systems. The lost production averages in the 20% range. Utility systems are typically ground-mounted and experience most of their construction prior to commercial operation date (COD); thus, these systems are typically unaffected by construction. Delays in COD can occur for a variety of reasons and commonly occur in the first year. The causes range from delayed permitting, grid connection, monitoring, or other equipment installation. Furthermore, if the target COD falls into the winter, the weather often causes delays depending on the exact location. In this subcategory, commercial and residential systems are more affected by delays than utility systems. In contrast, project finance is a subcategory mainly affecting residential and smaller commercial systems and is characterised by larger impacts with increasing years. The project finance subcategory is any type of nonpayment that resulted in the shutdown of the site or the physical relocation of the system, which can have a tremendous impact on the annual production. Fire, or thermal events, is an alarming subcategory because of its widespread visibility and ramifications for the entire industry. However, most events reported in this subcategory were not caused by the PV system. The two events in the utility group were caused by forest fires near the PV system but were not caused by the PV system. Two incidents involved the inverter rather than the modules, indicating additional potential risks downstream of modules such as inverter and combiner boxes. The remaining subcategories are characterised as primarily affecting only residential and commercial systems. Theft affects mainly modules in residential systems whereas commercial systems are more impacted by the theft of copper wires. Vandalism and damage caused by animals may not occur often, but they can have a substantial impact on annual production. Finally, force majeure events (not shown here)—events where a site was completely destroyed by fire or wind without hope of recovering at least parts of the system—average one to two events per 100,000 sites per year.

Conclusion

The 1603 data set consisting of 100,000 PV systems and totalling more than 7GW of capacity provided some fruitful insights into PV system performance and reliability. The majority of systems—80-90%—performed within 10% of expected production, which is a positive finding for the entire industry. In addition, module-related failures were found to be very low, ca. 0.2%/year, although the full effect of underperforming modules may not have been fully captured in this data set. These positive aspects were balanced with some findings of areas of concern, specifically some balance-of-system problems. For example, inverter failures were found to be high but were also found to be influenced by installation best practices. Installations where the inverter was exposed to less direct sun exposure showed significant lower failures.

Installation quality in general was found to play an important role in long-term PV reliability and emphasises the importance of installation best practices, training, certifications and standards, not only at the manufacturing level but also at the installation level. Moreover, general hardware issues at the utility level were resolved much more quickly than at the commercial and residential level, emphasising that a proactive approach to operations and maintenance and rapid detection of issues has room for improvement. Finally, further research is required to better estimate lost production for specific causes, as confounding factors could not always be clearly separated in this study.

Acknowledgement

The authors would like to thank E. Settle, J. Coughlin, D. Gagne, D. Peterson, and Katherine Jordan. This work was authored in part by Alliance for Sustainable Energy, LLC, the manager and operator of the National Renewable Energy Laboratory for the U.S. Department of Energy (DOE) under Contract No. DE-AC36-08GO28308. Funding provided by the U.S. Department of Energy's Office of Energy Efficiency and Renewable Energy (EERE) under Solar Energy Technologies Office (SETO) Agreement Number 30295. The views expressed in the article do not necessarily represent the views of the DOE or the U.S. Government. The U.S. Government retains and the publisher, by accepting the article for publication, acknowledges that the U.S. Government retains a nonexclusive, paid-up, irrevocable, worldwide license to publish or reproduce the published form of this work, or allow others to do so, for U.S. Government purposes.

References

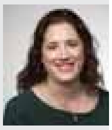
[1] J. Leloux, L. Narvarte, D. Trebosc, "Performance Analysis of 10,000 Residential PV Systems in France and Belgium", 26th European Photovoltaic Solar Energy, Hamburg, Germany, 2011.
[2] A. Golnas, PV system reliability: An operator's perspective, IEEE Journal of Photovoltaics, Vol. 3, No. 1, pp. 416–421, 2013.
[3] Electrical Safety Foundation, International, Results: ESFI Counterfeit Baseline Survey – 2014, May 2014.
[4] https://github.com/NREL/rdtools
[5] M. Bolinger, W. Gorman, D. Millstein, D. Jordan, "System-level performance and degradation of 21 GWDC of utility-scale PV plants in the United States", Journal of Renewable and Sustainable Energy, Vol. 12, No. 4, 2020.
[6] T. Karin C. B. Jones, and A. Jain, "Photovoltaic degradation climate zones", 46th IEEE Photovoltaic Specialists Conference, Chicago, IL, USA, 687 – 694, 2019.

Authors

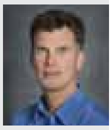
Dr Dirk Jordan has been a senior reliability at the National Renewable Energy Laboratory since 2009. He received a PhD in physics from Arizona State University in 1999 and a BS in physics from the University of Heidelberg in Germany. He specialises in the performance and degradation of PV modules and systems.

Dr Chris Deline is a research engineer at NREL investigating PV system degradation rates and bifacial performance modelling. He also manages the PV Fleet Performance Data Initiative, which aggregates and analyses third-party field performance data, and manages the PV Proving Grounds programme at NREL for field assessment of novel PV technologies

Bill Marion is a principal engineer at the National Renewable Energy Laboratory. He has a MS in energy systems and is a registered professional engineer. Bill has more than 35 years' experience working in the area of PV module and system testing and evaluation, modelling and solar resource assessment.



Teresa Barnes manages the Photovoltaic (PV) Reliability and System Performance Group at NREL. She is also the principal investigator and director of the DuraMAT Consortium for module materials research. Dr Barnes' group focuses on PV module and system reliability, including accelerated test development, outdoor field testing, energy yield assessment, degradation rate analysis, field performance benchmarking and materials science. She is a Chemical Engineer with a PhD from the Colorado School of Mines and a BS from the University of Maryland.



Mark Bolinger is a Research Scientist in the Electricity Markets and Policy Department at Lawrence Berkeley National Laboratory, where he conducts research and analysis on renewable energy—primarily utility-scale wind and solar power—with a focus on cost, benefit, and market analysis."

PV Tech's analysis of the 'Top Performers' in PVEL's '2020 PV Module Reliability Scorecard'

Modules | Mark Osborne analyses the sixth instalment of PV Evolution Labs' annual module rankings and the insights it offers into the state of PV reliability and performance as technological change continues apace

Credit: PVEL

The PV Module Reliability Scorecard, now in its sixth edition, ranks commercially available PV modules by their performance in PV Evolution Labs' Product Qualification Programme (PQP). The PQP is a comprehensive, rigorous test regime that assesses reliability and performance of PV modules.

The '2020 PV Module Reliability Scorecard' report, undertaken each year by PV Evolution Labs (PVEL) in partnership with DNV GL, has continued to raise questions over key aspects of module reliability.

This is not just because of the accelerated development and introduction of new modules that drive the levelised cost of electricity (LCOE) down but because well-known and proven reliability testing sequences still catch out products that fail to meet the required degradation rates of less than 2% to become a recognised 'Top Performer' according to PVEL's scoring system.

Granted, PVEL's testing sequence criteria have evolved over the years, primarily to increase cycle-times that further push the ability of modules to meet the Top Performer requirements as part of the lessons learnt during the evolution in module reliability testing.

A good example of this would be the PVEL damp heat (DH) test, where it has become well known that under the IEC 61215 electrical safety test, a DH duration of only 1,000 hours is required, which led to relatively few modules experiencing electrical safety issues regardless of the Bill of Materials (BOM) used meeting IEC test conditions.

PVEL subjects modules to rigorous testing to assess their reliability and performance

However, PVEL doubles the number of cycles to 2,000, which has uncovered number of degradation issues that reduce module performance well past the 2% PVEL degradation rule. As such the DH test remains a benchmark for module reliability as the number of BOM variations continue to increase in the pursuit of lower LCOE metrics.

Importantly, in the 2020 report, PVEL has also added a boron-oxygen (BO) stabilisation step to the tough damp heat testing regime as the test's high temperature and no current environment can also lead to destabilisation of the passivated BO complexes within some PERC cells, according to PVEL. To further explore this problem, PVEL added a post-DH2000 boron-oxygen stabilisation process to its PQP sequence.

The more recent introduction of potential-induced degradation (PID) testing is another development in line with the mass introduction of Passivated Emitter Rear Cell (PERC) technology that can suffer this type of performance degradation, undermining the performance benefits of the cell technology and therefore the claimed lower LCOE.

Although PVEL is also introducing a light and elevated temperature-induced degradation (LeTID) test, this was only announced in mid-2019 and so more time is required for this new test to be introduced, primarily for mono-PERC cells. As a result, the LeTID susceptibility test highlighting Top Performers did not appear in the current report. This was also true for the new backsheet durability sequence.

In keeping with previous analysis of PVEL's report we will first look at the four historical reliability tests and the developments noted in the latest report.

Thermal cycling

In PVEL's thermal cycling test sequence, modules are placed in an environmental chamber where the temperature is lowered to -40°C, dwelled, then increased to 85°C and dwelled again. Maximum power current is applied to the modules while the temperature is increased and decreased.

A total of 600 cycles, repeated 200 times over three periods is said to equate to about 84 days in the climate chamber. However, PVEL previously ran the TC test with 600 cycles but had increased this to 800 cycles in recent years. DNV GL had noted in the PV Tech-hosted TechTalk webinar and in the report that the lowered number of cycles was due to its analysis that the TC600 test was actually a sufficient test duration with few reliability excursions being meaningful or could introduce non-representative failure mechanisms when undertaking the extended test. It should be noted that IEC 61215 testing requires only 200 cycles, which has proven insufficient.

PVEL had previously noted that thermal cycling performance improved 42% in the 2019 scorecard, even though it used TC800 sequence.

In the 2020 report, PVEL noted strong results from a host of wafer, cell and module varieties such as standard and half-cut cell module types, as well as thin film, shingled cells, multi-bus bar and heterojunction (HJT) modules.

There were nine PV module manufacturers that achieved Top Performer status in the thermal cycling tests in 2019, compared to 17 manufacturers in the 2020 TC tests.

It should be noted that both glass-glass and glass-backsheet bifacial modules achieved Top Performer status in the 2020 TC tests and that a total of 54 different modules were recognised as Top Performers. In 2019 the number of Top Performer modules was 24.

PV Module Manufacturer	Module Thermal Cycling
Adani/Mundra	ASP-7-AAA
	ASP-6-AAA
Astronergy	CHSM72P-HC-xxx
	CHSM60P-HC-xxx
	CHSM72M-HC-xxx
	CHSM60-HC-xxx
	CHSM72M(DG)-B-xxx
	CHSM60M (DG)-B-xxx
Canadian Solar	CS1H-MS
First Solar	FS-6xxxA
GCL-SI	GCL-M3/72H
	CL-M3/60H
	GCL-M6/72H
	GCL-M6/60H
	GCL-M3/72GDF
	GCL-M6/72GDF
	GCL-M3/72DH
	GCL-M6/72DH
Hanwha Q CELLS	Q.PEAK DUO G5
	Q.PEAK DUO L-G5.2
	Q.PEAK DUO G6
	Q.PEAK DUO G7
Hellene	72M-xxx
	60MBLK HOME PV
HT-SAAE	HT72-156M (V)
	HT60-156M (V)
	HT72-156M (PDV)-BF
	HT60-156M (PDV)-BF
JinkoSolar	JKMxxxM-72HL-V
	JKMxxxM-60HL-V
LONGi Solar	LR4-72HPH-xxxM / LR4-60HPB-xxxM
	LR4-72HPH-xxxM / LR4-60HPB-xxxM
	LR6-72PH-xxxM / LR6-60PB-xxxM
	LR4-72HIH-xxxM / LR4-60HIB-xxxM
	LR4-72HIBD-xxxM / LR4-60HIBD-xxxM
Panasonic	VBHNxxxSA17
REC Group	RECxxxTP2M
Silfab	SLGxxxM
	SLAxxxM
Suntech	STPxxxS-24/Vfh
	STPxxxS-20/Wfh
Trina Solar	TSM-xxxPE14H
	TSM-xxxPE05H
ZNShine	ZXP6-72-xxx/P

Figure 1. There were nine PV module manufacturers that achieved Top Performer status in the thermal cycling tests in 2019, compared to 17 manufacturers in the 2020 TC tests

Damp heat

In PVEL's damp heat tests, PV modules are placed in an environmental chamber and held at a constant temperature of 85°C and 85% relative humidity for 2,000 hours (about 84 days in total). The heat and moisture ingress stress the layers of the PV module. In comparison, IEC testing has a duration of only 1,000 hours.

There were six Top Performers in the 2019 damp heat tests, compared to 13 in the 2020 scorecard, a significant increase from previous years.

PVEL noted that this was mainly due to newer bifacial glass-glass and glass-backsheet module BOM shifting from EVA to POE in glass-glass modules, having performed poorly in previous DH tests. A significant number of tested modules in 2018 and 2019 had exhibited greater than 4% degradation, according to previous PVEL reports.

As a result, the number of different modules achieving Top Performer status also increased to 32 in the 2020 scorecard, compared to 16 in the 2019 report.

PV Module Manufacturer	Module Thermal Heat Cycling
Astronergy	CHSM72P-HC-xxx
	CHSM60P-HC-xxx
	CHSM72M-HC-xxx
	CHSM60-HC-xxx
	CHSM72M(DG)-B-xxx
	CHSM60M (DG)-B-xxx
Canadian Solar	CS1H-MS
First Solar	FS-6xxxA
GCL-SI	GCL-M6/72H
	GCL-M6/60H
	GCL-M6/72H
	GCL-M6/60H
Hanwha Q CELLS	Q.PEAK DUO L-G5.2
	Q.PEAK DUO G6
	Q.PEAK DUO G7
Hellene	72M-xxx
	60MBLK HOME PV
HT-SAAE	HT72-156M (V)
	HT60-156M (V)
	HT72-156M (PDV)-BF
	HT60-156M (PDV)-BF
JinkoSolar	JKMxxxM-72HL-V
	JKMxxxM-60HL-V
LONGi Solar	LR4-60HPB-xxxM
	LR6-72PH-xxxM
Panasonic	VBHNxxxSA17
REC Group	RECxxxTP2M
Silfab	SLGxxxM
	SLAxxxM
Sunergy California (CSUN)	CSUNxxx-72MH5
	CSUNxxx-60MH5
Trina Solar	TSM-xxxPE14H
	TSM-xxxPE05H
Vikram Solar	Eldora VSP.72.AAA.05
	VSP.60.AAA.05
	Somera VSM.72.AAA.05
	VSM.60.AAA.05
ZNShine	ZXP6-60-xxx/P

Figure 2. There were six Top Performers in the 2019 damp heat tests, compared to 13 in the 2020 scorecard

Dynamic mechanical load

In the dynamic mechanical load (DML) testing, PVEL installs a module according to the manufacturer's recommended mounting configuration, then subjects it to 1,000 cycles of alternating loading at 1,000 Pa. The module is then placed in an environmental chamber and subjected to 50 thermal cycles (-40°C to 85°C) to cause microcrack propagation, then three sets of 10 humidity freeze cycles (85°C temperature and 85% relative humidity for 20 hours followed by a rapid decrease to -40°C) are used to stimulate potential corrosion.

The modules are then characterised and inspected visually to evaluate the status of the module's frame, edge seal and cell interconnections. The dynamic mechanical loading can induce microcracks that do not necessarily result in significant power loss, according to PVEL, yet only after thermal cycling and humidity freeze testing that metal conductors affected by cell cracks can break, which leads to black inactive areas and increased power degradation.

The DML testing sequence was tweaked in the 2019 Scorecard to include 30 humidity freeze cycles. About 80% of the historical test data included only 10 humidity freeze cycles, according to PVEL.

As a result, the percentage of dynamic mechanical load sequence Top Performers fell by 37% in the 2019 results, versus historical results, according to PVEL. There had been nine PV module manufacturers that had achieved Top Performer status in the 2019 DML tests; in the 2020 scorecard

PV Module Manufacturer	Module Dynamic Mechanical Load (DML)
Adani/Mundra	ASP-7-AAA
	ASP-6-AAA
Astronergy	CHSM72P-HC-xxx
	CHSM60P-HC-xxx
	CHSM72M(DG)-B-xxx
	CHSM60M (DG)-B-xxx
Canadian Solar	CS1H-MS
LONGi Solar	LR6-72PH-xxxM
	LR6-72HPH-xxxM
	LR6-60HPH-xxxM;
	LR6-60HPB-xxxM
REC Group	RECxxxTP2M
Silfab	SLGxxxM
	SLAxxxM
Vikram Solar	Eldora VSP.72.AAA.05
ZNShine	ZXP6-72-xxx/P
	ZXP6-60-xxx/P

Figure 3. A total of 16 different modules had achieved DML Top Performer status in the 2019 scorecard, compared to 19 in the 2020 report

PV Module Manufacturer	Module PID
Adani/Mundra	ASP-7-AAA
	ASP-6-AAA
Astronergy	CHSM72P-HC-xxx
	CHSM60P-HC-xxx
	CHSM72M-HC-xxx
	CHSM60-HC-xxx
	CHSM72M(DG)-B-xxx
	CHSM60M (DG)-B-xxx
Boviet Solar	BVM6612M-xxx-H
	BVM6610M-xxx-H
First Solar	FS-6xxxA
JA Solar	JAM72S09-xxx/PR
	AM60S09-xxx/PR
JinkoSolar	JKMxxxM-72HL-V
	JKMxxxM-60HL-V
	JKMxxxM-72H-TV
	JKMxxxM-72HL-TV
LONGi Solar	LR6-72PH-xxxM
	LR4-72HIBD-xxxM
	LR4-60HIBD-xxxM
Panasonic	VBHNxxxSA17
SunPower	SPR-Axxx-G-AC
Suntech	STPxxxS-24/Vfh
	STPxxxS-20/Wfh
Trina Solar	TSM-xxxPE14H
	TSM-xxxPE05H
	TSM-xxxPE14A
	TSM-xxxPE05A
	TSM-xxxDE14A(II)
	TSM-xxxDE05A(II)
Vikram Solar	Somera VSM.72.AAA.05
	VSM.60.AAA.05
ZNShine	ZXP6-72-xxx/P
	ZXP6-60-xxx/P

Figure 4. A total of 47 different modules achieved Top Performer status in the PID tests in 2020 scorecard, compared to 34 different modules in the 2019 report

PV Module Manufacturer	Module PAN File
Astronergy	CHSM72M(DG)-B-xxx
	CHSM60M (DG)-B-xxx
GCL-SI	GCL-M3/72GDF
	GCL-M6/72GDF
HT-SAAE	HT72-156M (PDV)-BF
JA Solar	JAM72S09-xxx/PR
JinkoSolar	JKMxxxM-72H-TV /
	JKMxxxM-72HL-TV
Panasonic	VBHNxxxSA17
Trina Solar	TSM-xxxDE14A(II)

Figure 5. Seven PV module manufacturers that achieved Top Performer recognition in the first PAN file test, which included 10 different modules

that number declined to eight, proving the DML test is proving more difficult to pass year-on-year. PVEL put this down to several reasons, including BO destabilisation in PERC cells because of the damp heat conditions during humidity freeze testing.

PVEL also noted that module performance was susceptible to power loss caused by cell cracking and rapid temperature changes, as part of the new mechanical stress sequence (MSS). PVEL plans to release a separate publication featuring MSS results in the coming months. PVEL also reported that both glass-glass and glass-backsheet bifacial modules had shown similar performance results following the DML sequence.

A total of 16 different modules had achieved DML Top Performer status in the 2019 scorecard, compared to 19 in the 2020 report.

Potential-induced degradation

PVEL's PID test is carried out in an environmental chamber with voltage bias equal to the maximum system voltage (MSV) rating of the module (-1,000 V or -1,500V) being applied under 85°C and 85% relative humidity for two cycles of 96 hours. These temperature, moisture, and voltage bias conditions allow PVEL to evaluate degradation related to increased leakage currents.

Results from the 2019 Scorecard showed 15 PV module manufacturers have PID under control, which was lower than the 20 companies achieving Top Performer status in the 2018 test report.

The number of PID Top Performers in the 2020 report stood at 20 out of 22 companies reported to have been in the tests that received at least one Top Performer award from the four historical reliability testing regimes.

Importantly, a total of 47 different modules achieved Top Performer status in the PID tests in 2020 scorecard, compared to 34 different modules in the 2019 report.

However, PVEL noted in the latest report that the median PID degradation results had been higher than at any time in its 10 years of testing.

In reference to PID testing of bifacial modules, PVEL noted that there was both a wide range of front-side and rear-side cell degradation, with bias towards higher degradation on the rear side cell. In one case, PVEL reported power loss of over 30%.

Some of the rear-side degradation was said to be due to a reversible polarisation effect that could occur in bifacial modules during PID testing, but not all p-type bifacial modules suffered this issue.

PAN files

New to the Top Performer rankings test is PAN files. This is analysis PVEL has used in its PQP work but is the first time included in benchmarking module energy yields with PVsyst software.

The procedure is to have three identical PV modules tested across a matrix of operating conditions per IEC 61853-1, ranging in irradiance from 100W/m^2 to 1,100W/m^2 and ranging in temperature from 15°C to 75°C. Two 1MW PV plant site simulations are undertaken with one site in a temperate climate at a 0° tilt (in Boston, USA), and a 1MW site in a desert climate at 20° tilt (in Las Vegas, USA). A custom PAN file is then created with PVsyst's modelling software that enables PVEL to measure the highest kWh/kWp energy generation based on its measurements of details such as temperature losses and low-light conditions.

PVEL noted that its historical PAN file data from all PQPs since 2016 meant that only 4% of modules tested would receive a 2020 Scorecard Top Performer designation.

There are a lot of moving parts in this testing, not least in relation to bifacial modules. The lack of real-world data on operating bifacial plus tracker PV power plants has challenged PVsyst modelling accuracy, especially in low-light conditions, according to presentations at the last BiFi workshop in Amsterdam, in September 2019.

PVEL noted that that bifacial modules showed a step-function performance improvement as two thirds of the Top Performers were bifacial modules. The exclusion of inverter clipping at the simulated PV power plant in Las Vegas led to mono-bifacial modules generating 7.7% higher median output higher than monofacial modules. At the simulated horizontal tilt site in Boston the median bifacial energy yield was 3.3% higher than the monofacial median.

Other differentiated yield performances simulated included a heterojunction module, which obviously offered high temperature performance gains, due to having some of the lowest temperature coefficients.

It should be noted that the data

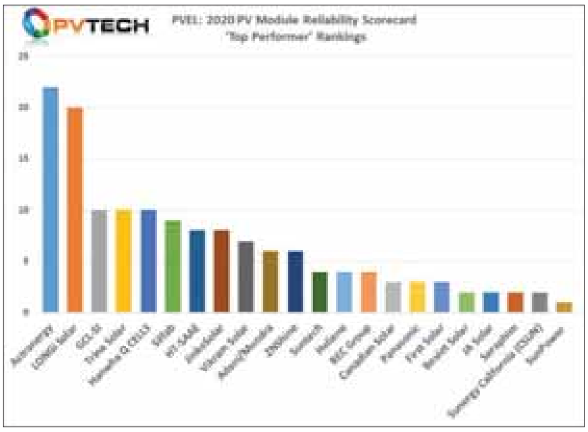


Figure 6. The total number of Top Performer rankings a company achieved in the 2020 scorecard, regardless of the number of modules entered for testing by any given module manufacturer

PV Module Manufacturer	Top Performer Status Total	Top Performer Status Different Modules
Astronergy	22	6
LONGi Solar	20	13
GCL-SI	10	8
Trina Solar	10	6
Hanwha Q CELLS	10	4
Silfab	9	3
HT-SAAE	8	4
JinkoSolar	8	4
Vikram Solar	7	4
Adani/Mundra	6	2
Suntech	6	2
ZNShine	6	2
Heliene	4	2
REC Group	4	1
Canadian Solar	3	1
Panasonic	3	1
First Solar	3	1
Boviet Solar	2	2
JA Solar	2	2
Seraphim	2	2
Sunergy (CSUN)	2	2
SunPower	1	1

Figure 7. Top Performers including the number of PV modules tested

presented below is only from PVEL's PAN testing as part of a PQP where the samples are factory witnessed.

As a result, there were seven PV module manufacturers that achieved Top Performer recognition in the first PAN file test, which included 10 different modules.

PVEL's 2020 Top Performers

We should make it clear that in compiling PVEL's 2020 Top Performer rankings analysis from the historical four key module reliability testing regimes, PVEL has reiterated that not all PV module manufacturers undertaking the scorecard are required to make the testing results public.

Also, it is important to clarify that several PV module manufacturers that achieved Top Performer ratings in some categories were listed in the 2020 report, yet PVEL had not completed full tests on some of these manufacturers' modules at the time of the report's publication, which could include some manufacturers' modules only achieving a few Top Performer rankings but when full testing is completed could have achieved more Top Performer rankings.

The chart in Figure 6 is a compilation of the 22 PV module manufacturers that successfully achieved Top Performer status for any number of modules in the 2020 Module Reliability Scorecard that have been made public but may also have not completed all test when PVEL published the report. Basically, this chart is just the total number of Top Performer rankings a company achieved in the 2020 scorecard, regardless of the number of modules entered for testing by any given manufacturer.

Figure 7 also ranks manufacturers by the total number of Top Performer awards, but also breaks out the number of different modules tested from these manufacturers that contributed to each manufacturer's total.

We can note that the first two manufacturers listed, Astroenergy and LONGi Solar achieved the highest number of Top Performer awards with a contrasting number of modules tested.

However, further down the rankings PV manufacturers' Top Performer awards coupled to the number of different modules receiving awards is more uniform. This indicates that some companies are outperforming others from the perspective of having achieved Top Performer status in all four historical testing regimes, sometimes for just one module but also for several different modules.

One example of a PV manufacturer achieving Top Performer status in all four historical testing regimes with only one module is REC Group. An example of a PV manufacturer achieving Top Performer status in all four historical testing regimes with more than one module is Silfab.

Although this is hard to detect in the Figure 7 table, breaking out all the PV manufacturers that achieved Top Performer status in all four historical testing regimes, regardless of the number of different modules tested, provides the elite group (see Figure 8) of Top Performers from the 2020 scorecard.

As noted previously, REC Group is represented in this elite group with its monocrystalline PERC-cell based 'TWIN PEAKS 2' module, in case people are not familiar with its module part numbering system.

LONGi Solar's HiMO 1 module, which is a mono PERC-based module, is also listed as it achieved Top Performer status in all four historical testing regimes.

North America-based PV manufacturer, Silfab, punched well above its manufacturing weight (capacity) with two mono PERC-based modules achieving Top Performer status in all four historical testing regimes.

Finally, we have China-based Astronergy that had four modules out of six different product offerings receive Top Performer status in all four historical testing regimes. These elite Top Performer modules include Astronergy's Astro Twins half-cut mono PERC, half module designed product offering.

The company was also amongst the few manufacturers to achieve Top Performer status in the new PAN file performance analysis. As such, Astronergy has set the bar very high for next year.

Indeed, PVEL indicated that in the 2020 scorecard testing, several tests, notably DML may have been the toughest test to achieve Top Performer status but there were a number of PV manufacturers modules that were very close to the 2% deviation rule. Therefore, the number of manufacturers with a clean sweep of the historical testing regimes could have been much higher than in previous years.

That said, the 2021 scorecard should include the planned new testing categories and so in many respects will be a new class of Top Performers from that point onwards. ■

PV Module Manufacturer	1.Thermal Cycling	2.Damp Heat	3.Dynamic Mechanical Load (DML)	4.Potential-Induced Degradation (PID)	5.PAN File
Astronergy	CHSM72P-HC-xxx	CHSM72P-HC-xxx	CHSM72P-HC-xxx	CHSM72P-HC-xxx	
Astronergy	CHSM60P-HC-xxx	CHSM60P-HC-xxx	CHSM60P-HC-xxx	CHSM60P-HC-xxx	
Astronergy	CHSM72M(DG)-B-xxx	CHSM72M(DG)-B-xxx	CHSM72M(DG)-B-xxx	CHSM72M(DG)-B-xxx	CHSM72M(DG)-B-xxx
Astronergy	CHSM60M (DG)-B-xxx	CHSM60M (DG)-B-xxx	CHSM60M (DG)-B-xxx	CHSM60M (DG)-B-xxx	CHSM60M (DG)-B-xxx
Silfab	SLGxxxM	SLGxxxM	SLGxxxM	SLGxxxM	
Silfab	SLAxxxM	SLAxxxM	SLAxxxM	SLAxxxM	
LONGi Solar	LR6-72PH-xxxM	LR6-72PH-xxxM	LR6-72PH-xxxM	LR6-72PH-xxxM	
REC Group	RECxxxTP2M	RECxxxTP2M	RECxxxTP2M	RECxxxTP2M	

Figure 8. There were four manufacturers that achieved this position in the 2020 Scorecard, one more than last year

The Atacama desert in Chile as a bifacial hotspot: yield modelling within the ATAMOSTEC project

Modelling | Alongside the recent rapid boom in bifacial solar deployment, extensive work has been underway to fine-tune the yield modelling of bifacial systems. Drawing on case studies from the ATAMOSTEC test site in Chile, researchers involved in the collaborative venture describe how it is helping improve understanding of bifacial yield and laying the foundations for a set of new rules to inform system design and installation

Figure 1. The ATAMOSTEC and UA test site in the Atacama desert in Chile

Bifacial solar technology was first developed back in the 1960s. Initially considered too costly, over some decades it remained dormant while the overall PV market boomed. However, with bifacial cells now becoming more or less a commodity within various cell technologies, the sleeping beauty of bifacial PV has finally awakened.

To accompany the rapid uptake of bifacial installations it is essential to provide practical guidelines for their configuration to optimise LCOE. Compared to monofacial installations the bifacial configuration concerns more parameters with complex interrelations and different geographical response. The ultimate goal of modelling is to turn the complexity of so many system parameters and with varying constraints into a manageable simplicity, offering reliable and simplifying solutions using straightforward input. This article summarises how the rapid progress made over recent years has improved understanding of design rules for bifacial PV. It also examines some case studies from within the ATAMOSTEC consortium operating in the Atacama Desert in Chile, as a collaborative effort between several institutional and industrial partners.

With the improved understanding of bifacial yield and the resulting best practices, bifacial PV shows strong signs of bloom in emerging markets such as Latin America, where companies such as Enel Green Power are turning to bifacial PV in order to power large-scale (200-600MW) solar projects in Chile, Brazil and Mexico. In addition, due to the recent exemption of bifacial panels from Section 201 import tariffs, US bifacial installations are expected to reach 2GW in 2020. [1]

Looking back: bifacial manufacturing, measurement and modelling

While the first bifacial cell patent was granted in 1960 and bifacial solar technology further developed in the late 1960s, it took surprisingly long – until the early 1980s – before the simple yet effective energy gain of the module backside was even considered for effective exploitation by collecting the ground albedo. Researchers at UPM Madrid reported bifacial energy gains of 35% in summer and over 50% in winter by using white painted walls and ground surfaces. [2] In 1986, the same group at UPM Madrid came up with a bifacial model based on a View-Factor approach that again estimated very high bifacial gains of up to

Five rules of thumb for bifacial installation design as found by modelling and as discussed in this article

A) 2D models give correct relative trends but underestimate absolute rear irradiance
B) The impact of the mounting structure cannot be neglected for bifacial gain diagnoses, forecast and yield.
C) The optimal tilt angle for bifacial systems is larger than for monofacial systems. This difference increases with ground albedo and latitude.
D) For vertical bifacial configurations, the bifaciality of the module (back-to-front ratio) strongly affects the energy yield and the LCOE of the system. This effect is independent of ground reflectivity.
E) The gain obtained by tracking is additive to the bifacial gain of a fixed-tilt system

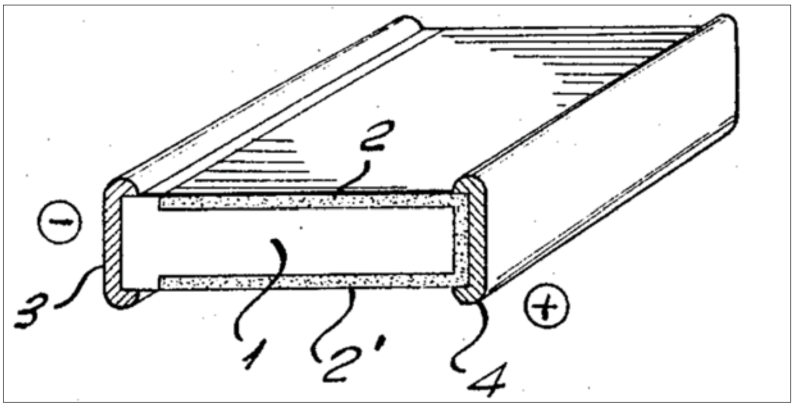


Figure 2. Double junction bifacial cell from a 1960 patent by H. Mori from Sharp (Japan). 1: n-type silicon, 2 and 2′: p-type emitter regions

Credit: NASA

Figure 3. The International Space Station powered by bifacial PV

60% in winter. [3] Much more modest gains of around 20-25% were reported in 1993 by Martin Green at UNSW Sydney. [4]

The earliest appearance of bifacial PV in real-world applications, although somewhat out of this world, happened in Russian spacecrafts in the 1970s [5] and later on in the International Space Station, launched in 2000, where bifaciality offered increased sunlight collection from the Earth's albedo, which could avoid sun-tracking as required for monofacial modules. On the space station the module backside was found to produce about one third of the power of the module frontside. This in-orbit performance validated the results of a bifacial performance model that had been developed by NASA [6].

Whereas bifacial modules were deployed at the ISS because their doubled-sided light capture allowed the system to avoid sun tracking, recent years have seen a growing awareness of the benefits of using tracking on ground based bifacial systems. ENEL Green Power is operating such an innovative bifacial plant with horizontal single-axis tracking (HSAT) [7] at the site of La Silla in Northern Chile. Tracking of the modules and the resulting increase of tilt angles appears effective in reducing the effect of soiling in sandy climates like a desert [8,9]. Some modelling results on the La Silla plant will be discussed in the section on case studies.

Another bifacial configuration of increasing interest is illustrated in Figure 4. The use of vertical systems allows combined use of land for PV and agriculture ('agri-voltaics') [10]. Such a vertical configuration reduces soiling losses and saves on cleaning costs. It is also reported to give significantly lower operating temperatures due to optimised convection [11]. This not only gives a better performance ratio but may also lead to improved long-term reliability. When snow is involved a vertical bifacial installation even benefits due to the increased ground reflection (figure 4b).

Modelling and measuring: intimate partners

The choices to be made for the design and financing of a bifacial installation are the result of a complex multi-criteria assessment where modelling can help to minimise lengthy trials and costly errors.

However, yield modelling is more than just predicting the exact value for the energy production of a bifacial PV plant. It can also help in the project definition by determining the most and least critical design parameters, related to the geometric configuration and geographical location. This can be done by a sensitivity analysis with varying parameter settings. In addition, measurements in the field do not have control over many of the 'intangible' parameters involved, such as meteorological events. This kind of 'noise' can only be filtered out by statistical methods which require lengthy data acquisition sequences, whereas modelling offers strict control over parameters and can pinpoint noise by taking it into account separately. The fact that modelling allows separation of the front and rear contributions enables identification of the most significant contributions to the energy yield and their design origin. Finally, modelling can help to build a common 'language' to define comparative test and measurement standards.

In general, the set of parameters taken into account for bifacial yield modelling consists of:

- Geographical location;

Credit: Next2Sun GmbH

(a) (b)

Figure 4. (a) vertical bifacial configuration for agri-voltaics (left); (b) vertical test bench with bifacial heterojunction modules during winter at CEA-INES (Bourget-du-Lac, France)

- Local ground reflectivity;
- Local weather dataset (direct, diffuse irradiance, ambient temperature, wind speed, etc.);
- PV module specs, like efficiency, dimension, bifaciality, temperature coefficient, etc.;
- PV field design parameters: module tilt, module elevation above ground, row spacing, number of modules in a row, number of rows, module installation format (portrait/landscape), ground cover ratio (GCR).

Modelling challenges – opportunities and obstacles

Simulation of bifacial module performance involves the integration of optical, electrical and thermal models. Climatic parameters such as irradiance, ambient temperature and wind speed serve as input to the thermal and optical models that on their turn delver the input for the electrical model to obtain the projected energy output from the system. The main difference between monofacial and bifacial simulation is of course in the optical model. Currently, the most important available bifacial irradiance models are based on ray-tracing (RT) or view-factor (VF) methodologies.

A third, empirical, approach is based on fitting formula derived from simulations and measurements using geometrical system configuration and albedo as input parameters. These types of models vary a lot since the coefficients can be computed based on theoretical models, measurements, etc.

The main difference between 2D and 3D View-Factor models is the complexity of the equations. The 2D-VF approach assumes the PV module rows to be of infinite length, with PV arrays described as a two-dimensional cross-section of the rows. Consequently, analytical formulas can be used and calculations can be made within the order of seconds. This approximation is well suited for long regular rows such as in large-scale ground-mounted PV installations, or on flat rooftop commercial installations. However, it cannot be directly applied to smaller bifacial systems where the backside irradiance may vary drastically from the centre to the edge of the array. These edge effects can well be taken into account by 3D View-Factor models. But for these models there are no simple analytical formulas: integrals need to be solved and simulations can take from minutes to several hours, like for the simulation of a tracker system.

Ray-Tracing algorithms simulate the path of light rays and are capable of reproducing a highly detailed interaction between geometries of the modules and their supporting structure but at the expense of computational cost, typically days on a standard laptop. One of the best-known ray-tracing tools is 'bifacial_radiance' [12]. Table 2 lists some other open-source tools and commercial products, as well as some academic simulation tools [13].

Modelling case studies – modelling versus measurements

A - The discrepancy between bifacial gain as modeled by 2D-VF and ray-tracing methods

2D view-factor modelling may give the correct tendencies for parameter sensitivities but users need to be aware that they may underestimate the absolute value of the bifacial gain by a few percent compared to ray-tracing methods. Modelling of the front-side irradiance is nowadays fairly straightforward using commercial packages like PVsyst, which is a 2D view-factor model.

To compare the accuracy of rear-side irradiance of the different modelling approaches ISC Konstanz evaluated two open-source tools from NREL: 'Bifacial VF' (2D-VF) and 'Bifacial Radiance' (ray tracing) were applied for rear-side simulation whereas the front side was modelled using 2D view-factors [14]. For comparison, the same simulations were run using PVSyst for both front and rear side. As a case study the 1.7MW La Silla PV system in Chile was used, the first large PV system combining horizontal single-axis tracking (HSAT) and bifacial modules. In order to identify trends, a sensitivity study on the elevation of the modules above ground was made. Results are presented in Figure 5. Since this is a tracked system, module elevation is relatively high.

We can see that 'PVSyst' and the equivalent '2D-VF' approach from NREL give very similar results and trends, as expected. However, when comparing with the Ray-Tracing results, the rear-side results appear largely different. Both approaches give a similar trend, but the ray-tracing approach predicts a significantly (2-3%) larger bifacial gain (defined as the ratio of backside irradiance to total irradiance).

These modelling results were then compared to measurements from the La Silla site, as given in Table 3, which shows

	View-factor (VF)		Ray-tracing (RT)
Origin	From heat transfer studies		Rendering image method
PV System definition (the modules)	2D (infinite row hypothesis)	3D	3D
Modelling rear side inhomogeneity (edge effect)	No	Yes	Yes
Precise structure shading (racking)?	No (at best a global shading factor)		Yes
Reflection nature (scattering)	Isotropic only		All types of reflection (isotropic, specular, etc.)
Unconventional configurations: BIPV, curved surfaces etc.	No		Yes
Computation time to simulate yearly irradiance on a standard laptop	Seconds to minutes	Hours	Days
When to use?	Rules of thumb trends yield calculation	Yield calculation diagnostic and prevision	Diagnostic and prevision

Table 1. Comparison of ray-tracing (RT) and view-factor (VF) methods

**available in Python as open-source software*	2D view-factor	3D view-factor	Ray-tracing	Empirical
Open source	pvfactors* PUB model bifacial_vf*		bifacial_ radiance*	Prism Solar
Commercial	PVSyst Polysun		PVCase	Polysun
Research/academic		BIGEYE MoBiDiG TriFactors	MoBiDiG	

Table 2. Overview of most used bifacial simulation tools

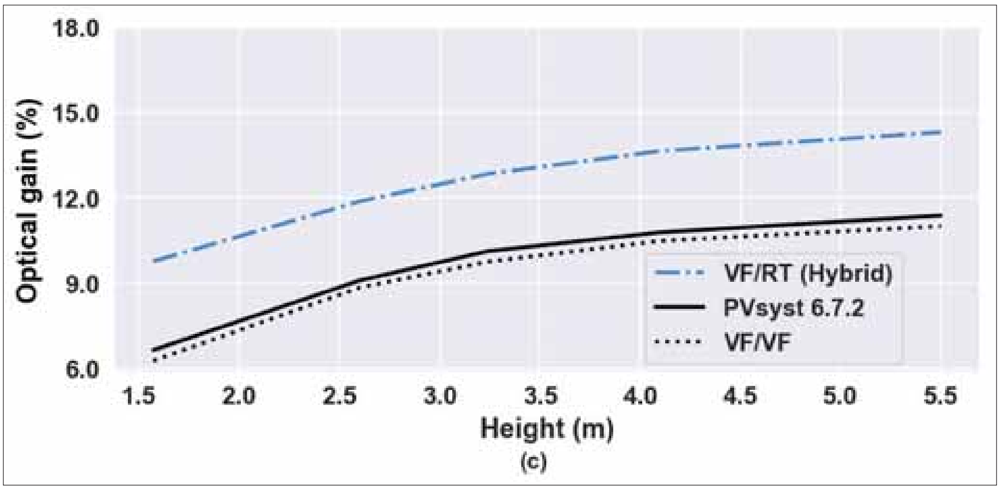


Figure 5. Simulated bifacial gain of the La Silla tracked bifacial plant in Chile, using PVSyst (with a 2D-VF approach) and MoBiDiG models. MoBiDiG is evaluated using two different approaches: 2D-VF for both front and rear side (dashed black) or 2D VF for the front side and RT for the rear side (dashed blue)

	Bifacial electrical gain (%)
Measured data	10.4 – 12.4
MoBiDig with RayTracing for rearside	9.3
MoBiDig with 2D-VF for rearside	6.5
PVSyst 6.7.2	6.8

Table 3. Measured data over four months on the HSAT bifacial PV System at La Silla (compared to their monofacial HSAT system) and simulation results using three approaches. Adapted from [8]

that MoBiDiG with ray tracing gives a bifacial gain close to the one measured in the La Silla PV plant. However, all the three simulation models (PVSyst, MoBiDiG with 2D-VF and MoBiDiG with ray tracing) underestimate the measured bifacial gain. This raises the question whether the measured value for the bifacial gain might be affected by an artefact such as a faster field degradation of the STC power for the monofacial (p-type) modules compared to the bifacial (n-type) modules.

Of course, it can be questioned if this 2-3% higher precision of the ray-tracing approach justifies a simulation time that explodes from minutes to days. However, it has to be kept in mind that other types of simulation, like for the loss diagnosis discussed in the next section, require smaller simulation time steps that will lead to discrepancies between 2D-VF and RT approaches that can go up to 10%.

B – The impact of the mounting structure on bifacial yield diagnosis and forecast.

To forecast bifacial energy production profiles over the day, accurate values of rear irradiance are necessary at a minute-wise resolution. The precision depends on the capability to reproduce the exact configuration of the PV system, including the mounting structure. The mounting structure (racking) will influence rear irradiance and its uniformity over the entire rear surface of the bifacial PV array. Non-uniformity of the rear irradiance can be a significant loss factor and has been found to increase with higher ground albedo, direct radiation from the sky and with lower tilt angle of the PV array [15].

The impact of racking was evaluated at the test bench of CEA-INES by comparing measured and simulated rear irradiance. As indicated in Figure 6 it was measured by reference cells facing ground at the plane of the array (POA) in positions E (edge) and C (centre). Using ray tracing, the test bench is simulated with the mounting structure as it is (Figure 6, bottom left) and without any structure, assuming free-floating panels (Figure 6, bottom right).

The mean absolute error (MAE= $1/n\Sigma\Delta_i$) was used as an indicator of precision for the simulation. It was found that the influence of the mounting structure was largest at the edge position E and this position was evaluated in more detail to gain a better insight into the capability of the various simulation tools to deal with the effects of the mounting structure under either sunny or cloudy weather in both winter and summer. Figure 7 compares measurement with simulations using 2D-VF (pvfactors), 3D-VF (TriFactors) and RT models (bifacial_radiance, without and with racking).

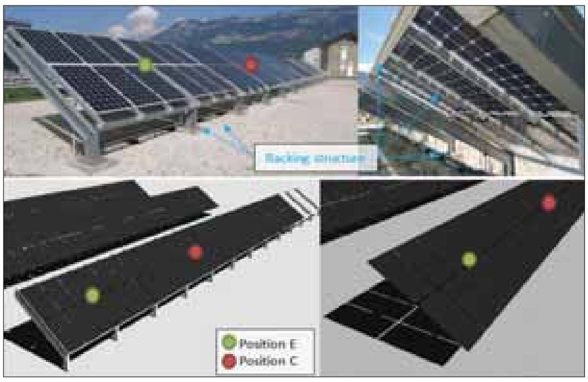


Figure 6. Bifacial PV test bench at CEA-INES, Le Bourget-du-Lac, France (top). 'Bifacial radiance' simulation with racking (bottom left) and without (bottom right)

From the numbers for the MAE between simulation and measurement it is concluded that:

- The VF models have a 50% higher error than the RT models (MAE of 15.1 versus 10.3)
- The error averaged over all four models is 50% higher in winter than in summer (10.5 vs. 14.9)
- On cloudy days this error is lower than on clear days: 26% in winter (12.6/17.1) and 13% in summer (9.8/11.2)
- Lowest error over the four sky conditions is obtained by the 'Radiance' model with racking (6.3)
- Highest error over all four sky conditions is obtained by the 'pvfactors' model (15.5)

C - Optimal tilt angle for bifacial systems is larger than for monofacial systems

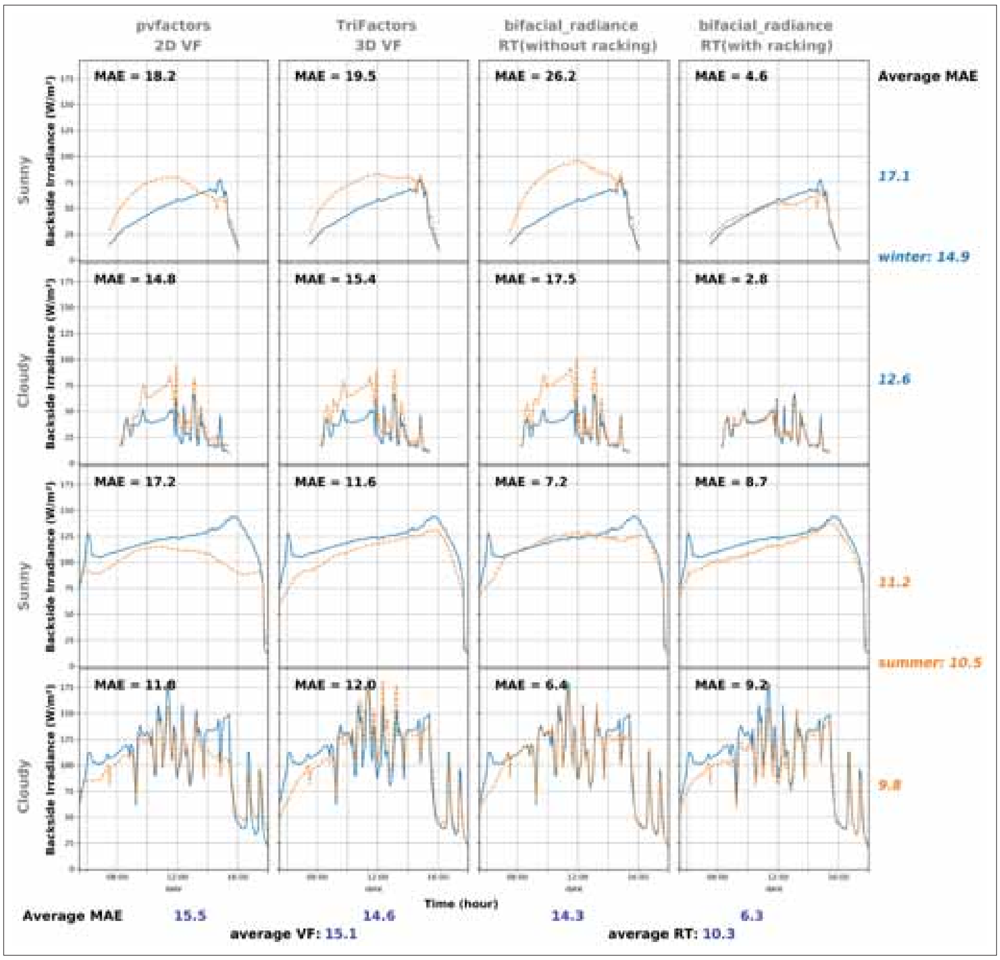
As can be intuitively anticipated the optimal tilt angle for bifacial systems will be slightly larger compared to that for monofacial systems, because higher angles favour the rear-side irradiance. Figure 8 illustrates this effect for two locations at 24.5° latitude (Atacama Desert, Chile) and 45° latitude (Chambéry, France) for two albedo values (0.3 and 0.6).

D – Vertical bifacial installation: the importance of the back-to-front ratio for energy yield and LCOE

The bifaciality of a module, also referred to as back-to-front ratio (BTFR), is crucial when calculating the LCOE of bifacial systems or when comparing monofacial to bifacial systems. It usually varies from 65% to 95%, depending on the cell technology. The rear-side energy production increases linearly with bifaciality.

Vertical installations with east-west orientation offer a production profile that is interesting because it has peaks in morning and afternoon and can help to tailor energy production over the day when mixed with equator-oriented modules. In addition, such a configuration helps to avoid soiling with associated losses that can easily reach 20%.

As stated before, 2D-VF models are well suited to indicate trends. Figure 9 indicates the trend of bifacial gain with increasing



◀ Figure 7. Measured (blue) and simulated (brown) rear irradiance over the day (6am to 6pm) for four different sky conditions (winter and summer, cloudy and clear) by four different simulation approaches (2 VF and 2 RT, of which one without (nr) and one with racking taken into account) at edge position E of Figure 6. The numbers indicated are the mean absolute error (MAE) between measurement and simulation for the 16 different combinations

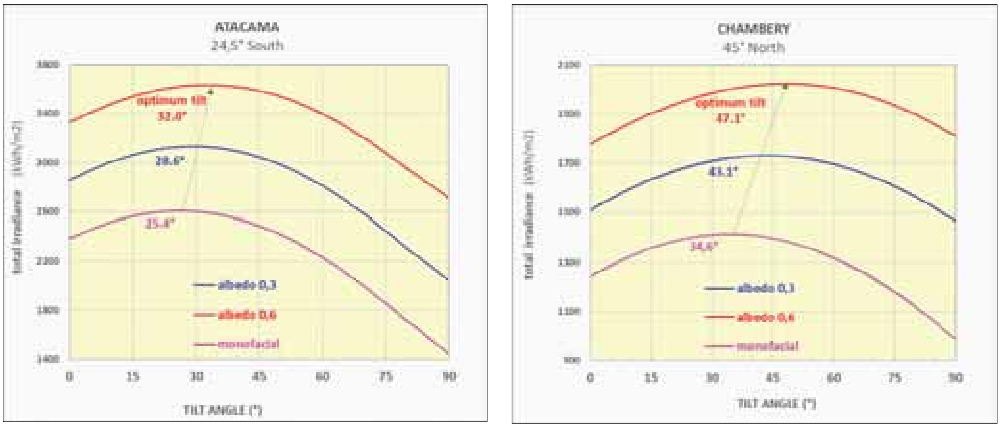


Figure 8: Simulated annual bifacial irradiance as a function of tilt angle and albedo for the Atacama Desert (Chile) and Bourget-du-Lac (France). The optimal bifacial tilt angle is seen to increase with albedo and latitude and is always higher that the optimal tilt angle for monofacial systems

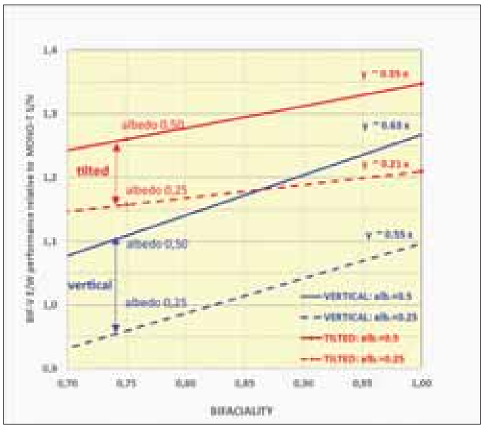


Figure 9. Annual performance, relative to south-oriented tilted monofacial, of bifacial modules in EW-vertical (in blue) and south-tilted configuration (in red) as function of their back-to-front ratio (module bifaciality), for albedo values of 0.25 (dotted line) and 0.50 (solid line). Simulated for the test site at CEA-INES, Le Bourget-du-Lac (France) using the PUB 2D-VF model from Purdue University

bifaciality, for equator tilted and vertically mounted bifacial modules. Compared to the tilted bifacial installation, the BTFR sensitivity is 2-3 times stronger for the vertical installation.

Another way to present this sensitivity of vertical installations to module bifaciality in a geographic perspective is shown in Figure 10, which compares vertical EW-oriented modules to equator-tilted monofacial modules, taking into account satellite-based data for the ground albedo [16]. The green regions, where the vertical bifacial installation outperforms the monofacial installation by over 5% reduces rapidly when decreasing bifaciality from 100% to 90% and 80%. The overall benefit of vertical bifacial installations is expected to be larger than that depicted in Figure 10 as it does not consider soiling losses that can be severe (10-20%) for tilted modules and are largely reduced for vertical installation.

The bifaciality of a module is determined by the cell technology, with PERC cells at a typical value of 80% bifaciality whereas SHJ heterojunction cells achieve up to 95%. A study by Fraunhofer ISE [17] on the economic value of optimised bifaciality has shown that the higher bifaciality of heterojunction modules will give them a price margin of €0.1/Wp higher than PERC modules to still deliver the same LCOE (of €0.06/kWh). In other words, a higher modules price of up to €0.1/Wp still comes down to the same LCOE due to the increased bifaciality. This economically acceptable price margin for higher bifaciality scales with the target value of the LCOE.

E - The gain obtained by tracking is additive to the bifacial gain of fixed tilt systems

Similar monofacial, bifacial, fixed tilt and tracked systems have been compared with results summarised in Figure 11.

First, we can see (Figure 11a) that the bifacial gain is lower for the tracking system than for the static one. In addition, the tracking gain is lower for bifacial than for monofacial systems (Figure 11b). This is

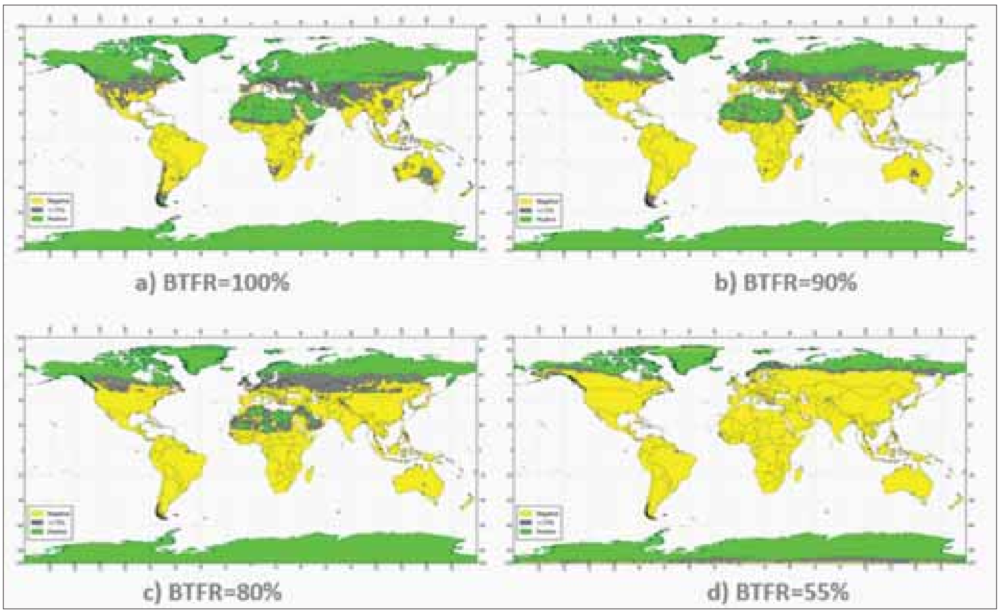


Figure 10. Effect of back-to-front ratio (BTFR) on the yield of vertical bifacial E/W oriented panels compared to monofacial equator-oriented tilted panels. The color is green when the gain is higher than 5%, yellow when the loss superior to -5% and grey otherwise

because tracking optimises the front-side irradiance and the relative contribution of the rear side is lower compared to the static case. A closer look on the different contributions to the energy gain, and the relation between them, is given in Table 4 that considers the case of a ground cover ratio (GCR) of 0.35 in Figure 11. It also gives the gain relative to the fixed tilt monofacial system.

There is no direct relation between the bifacial tracking gain (32.6%, in red) on one side, and the tracking gain of monofacial (23.5% in orange) and the bifacial gain on fixed tilt configuration (10.1% in green) on the other side. Nevertheless, it appears that the sum of the tracking gain of monofacial and the bifacial gain on fixed-tilt configuration gives a good approximation of the observed bifacial tracking gain. This observation has been verified for all GCR values and it has been confirmed by measurements performed at the ATAMOSTEC platform (see Figure 1), as shown in Table 5 for a tracked system with 44 modules. The tracking bifacial gain (44%) is almost equal to the gain of tilted bifacial (11%) plus the gain of the tracked monofacial (31%), both relative to tilted monofacial.

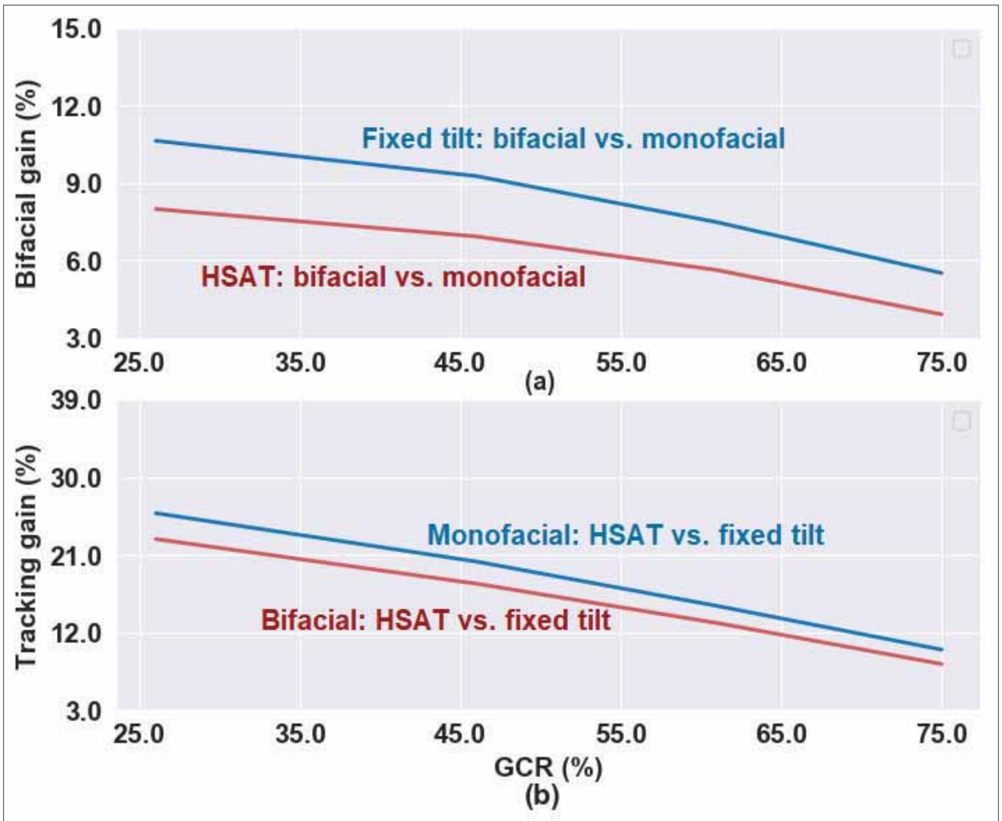


Figure 11. (a) Simulated bifacial gain of fixed-tilt and HSAT system as a function of ground cover ratio (GCR); (b) tracking gain for monofacial and bifacial systems. Gains obtained for a full year simulation with MoBiDig (2D-VF for the frontside and RT for the rearside)

Looking forward – what is next?

LCOE calculations

Coupling opto-electrical and LCOE models is quite a challenge. As a good example, SERIS Singapore used a Monte-Carlo approach on weather, module and cost parameters to compare the LCOE of fixed tilt, single-axis and dual-axis installations with either monofacial or bifacial modules. For single-axis tracking they considered both standard horizontal single-axis tracking (HAST) and tilted single-axis tracking (TSAT). For TSAT, the axis of rotation is tilted (usually at 30°) offering a better angle of incidence, mainly during winters, at higher geographical latitudes. SERIS' study showed that the lowest LCOE for 90% of all locations around the world is offered by bifacial-1T installations, as summarised in Table 6.

The table shows an LCOE reduction of 3% when using bifacial systems with respect to their monofacial counterparts. One-axis tracker systems achieve an average reduction on LCOE of about 14% compared with fixed-tilt systems, while double-axis systems suffer an increase of LCOE by 8%. The table also shows that yield gains from bifacial and tracking are cumulative. No soiling was considered in these simulations, nor in the vertical bifacial configuration that is a straightforward way to strongly reduce soiling.

Evolution of existing simulation tools

It is common practice in comparing PV test and measurement methods to do round-robin comparisons between different laboratories and different equipment and methodologies. This concept is currently applied, by comparing the numerous bifacial simulation models that have been developed within institutes and industries, within the IEA-PVPS-task 13: Bifacial PV Modeling Comparison. Some of these tools are already available as open source ('bifacial_radiance', 'bifacial_vf', 'pvfactors', 'PUB' model).

A common framework would facilitate the combined use of these tools by the PV community. The PV-LIB library [20] offers a

Table 4. Simulated comparison of normalised energy production of different configurations and the corresponding gains. Normalisation has been made (in grey) relative to the fixed tilt monofacial system from figure 11 with GCR = 0.35 (in colours)

Compared to equator-tilted monofacial	Gain
Equator tilted bifacial	11%
Tracking monofacial	30-31%
Tracking bifacial	44%

Table 5: Comparison of bifacial gain, tracking gain and bifacial tracking gain based on measurement data at the ATAMOSTEC platform [18]. The tracked system is a stand-alone tracker with 44 modules

Energy *LCOE*	Monofacial fixed-tilt	Bifacial Fixed-tilt	Monofacial 1-T	Bifacial 1-T	Monofacial 2-T	Bifacial 2-T
Monofacial Fixed-tilt	1 *1*	1.07 *0.97*	1.26 *0.86*	1.35 *0.84*	1.31 *1.08*	1.40 *1.04*
Bifacial Fixed-tilt	0.94 *1.03*	1 *1*	1.18 *0.89*	1.26 *0.87*	1.23 *1.11*	1.31 *1.08*
Monofacial 1-T	0.79 *1.16*	0.85 *1.12*	1 *1*	1.07 *0.97*	1.04 *1.25*	1.11 *1.21*
Bifacial 1-T	0.74 *1.19*	0.79 *1.16*	0.94 *1.03*	1 *1*	0.98 *1.28*	1.04 *1.24*
Monofacial 2-T	0.76 *0.93*	0.82 *0.91*	0.96 *0.81*	1.03 *0.78*	1 *1*	1.07 *0.97*
Bifacial 2-T	0.71 *0.96*	0.76 *0.93*	0.90 *0.83*	0.96 *0.81*	0.94 *1.03*	1 *1*

Table 6. Modelled comparison of energy yield (in blue) and LCOE (in red) of monofacial and bifacial systems at fixed-tilt, single-axis and double-axis tracking. The ratios compare the system in the column to the system in the row. Results for single-axis tracker installations refer to either horizontal (HSAT) or tilted (TSAT) configuration depending on which configuration gives highest energy yield in each particular location (adapted from [19])

set of functions and classes for simulating the performance of photovoltaic energy systems, including bifacial ones, and could be a solid basis for such initiative. Together with the standardisation of the variable names [21], initiated by SANDIA Labs, the convergence of existing bifacial tools would help accelerate bifacial installations by reducing yield prediction uncertainties. Finally, whereas VF and RT models have so far been the two main methods to model rear irradiance, new approaches are appearing that could become game changers for bifacial modelling. An example is the 'ray-casting' approach [22] that could offer both the precision of ray tracing and the short computation time of view factor-based modelling.

The future of bifacial PV systems

The majority of existing bifacial tools are not capable of simulating tilted single-axis tracker systems. TSAT systems produce more energy and may have a better LCOE than horizontal single-axis trackers at higher latitudes. Therefore, models predicting the behaviour of such systems are necessary to justify the acceptance of TSAT system configurations.

Module bifaciality is important, even more so for vertical installation. As SHJ modules (95%) and nPERT/TopCon modules (90%) offer significantly higher bifaciality than current PERC modules (80%) the higher €/Wp of SHJ and nPERT/TopCon modules in the end leads to a lower LCOE for vertical installation. Bifacial modelling tools are essential to determine what technology fits best to a certain location and system configuration.

Finally, some physical phenomena such as soiling, ageing due to UV, etc. still need to be investigated, both experimentally and numerically (using machine learning). Because energy yield modelling does not take into account soiling, the comparison with real data will give an indication of the relative losses induced by soiling and compare these losses to associated cleaning costs. The same holds true for other degradation mechanisms such as UV ageing along the years.

All these aspects are studied within the ATAMOSTEC project. The Atacama Desert presents some very specific conditions and is a perfect test field for soiling and UV degradation of bifacial systems of various configuration (vertical E/W, fixed tilt, tracking) and cell technologies (including SHJ). The outdoor facilities located in the Atacama Desert have already given promising results, with a 44% production gain with a tracking bifacial system compared to a fixed tilt monofacial one. This also allows validating bifacial modelling in a wide diversity of climatic conditions.

Conclusions

Bifacial technology and the estimation of its energy gain are rapidly evolving through improved modelling and measurement methodologies. The latter include the accurate measurement of site conditions, notably ground albedo. Ultimately modelling strategies will also allow staying on the same page with respect to measurement and test protocols as well as to reduce or understand uncertainties that affect bifacial project financing risks, in order to assure that these are at the same level as for monofacial projects.

Acknowledgements

The work described here is part of the ATAMOSTEC project. We recognise the support provided by the Chilean Economic Development Agency (CORFO) with contract No 17PTECES-75830 (AtaMoS TeC). Special thanks to Hervé Colin for managing the outdoor monitoring site at CEA-INES. ■

Turn to p.29 for insights into how inconsistencies in bifacial module technology are being tackled

References

[1] Wood Mackenzie Power and Renewables, "Global bifacial module market report 2019", cited in https://analysis.newenergyupdate.com/pv-insider/first-solar-exit-epc-market-us-bifacial-installs-hike-four-fold-2020

[2] A. Cuevas et al., "50% more output power from an albedo-collecting flat panel using bifacial solar cells", Solar Energy, Vol.l9, pp.419-420, (1982).

[3] A.Krenzinger et al., Estimation of Radiation Incident on Bifacial Albedo-Collecting Panels, International Journal of Solar Energy, Vol.4 (5), 1986

[4] M.Green et al., Computer simulation of enhanced output from bifacial photovoltaic modules, Progress in Photovoltaics, Vol.1, 293-299 (1993)

[5] G.A. Baltyanskii, N.M. Bordina, et al. "Test of experimental bifacial solar array on spacecraft Salut-5", Cosmic Research 18, 812-814 (1980)

[6] A. Delleur et al., "Electrical Performance from Bifacial Illumination International Space Station Photovoltaic Array", J. of Spacecraft and rockets Vol.42 (1), Jan.–Feb.2005

[7] A. Di Stefano et al., "La Silla PV plant as a utility-scale side-by-side test for innovative modules technologies". In Proc. 33th EUPVSEC 1978–1982 (2017).

[8] E. Grau Luque et al., "Effect of soiling in bifacial PV modules and cleaning schedule optimization, Energy Conversion and Management", Vol.174, October 2018, Pages 615-625

[9] M. Garcia et al., "Soiling and other optical losses in solar-tracking PV plants in Navarra", Progress in Photovoltaics, Vo.19 (2), March 2011, pages 211-217

[10] M. Ito et al., "Geographical mapping of the performance of vertically installed bifacial modules", proceedings EUPVSEC June 2016, Munich

[11] S. Bhaduri et al., Mitigation of Soiling by Vertical Mounting of Bifacial Modules, IEEE J. of Photovoltaics, Vol. 9(1), January, pages 240-244

[12] See https://www.osti.gov/biblio/1574140

[13] Example : Purdue University Bifacial Module Calculator (PUB): https://nanohub.org/tools/pub

[14] D. Berrian et al, November 2019. "Performance of Bifacial PV Arrays With Fixed Tilt and Horizontal Single-Axis Tracking: Comparison of Simulated and Measured Data", in IEEE J. of Photovoltaics, vol. 9, no. 6, pp. 1583-1589.

[15] Djaber Berrian et al, September 2019. "Rear irradiance inhomogeneity of bifacial PV modules: Modelling and quantification by MoBiDiG", 6th Bifacial Workshop, Amsterdam.

[16] M. Ito et al., "Geographical mapping of the performance of vertically installed bifacial modules", proceedings EUPVSEC conference, Munich, 2016

[17] L. Bodlak et al., "Price-bifaciality relationship of modules in vertical east-west oriented PV systems", proceedings EUPVSEC conference, Amsterdam, 2018

[18] The Atamo Bifacial Module Developed in Chile, specially adapted to high radiation and desert conditions, see first success, AtamosTec website, published April 23, 2020. See http://www.atamostec.cl/

[19] Rodrıguez-Gallegos et al., Global Techno-Economic Performance of Bifacial and Tracking Photovoltaic Systems, Joule Vol. 4, Issue 7, pages 1514-1541, 15 July 2020.

[20] Pvlib-python GitHub main page, see https://github.com/pvlib/pvlib-python

[21] PV modeling glossary, within the Duramat framework, see https://duramat.github.io/pv-terms/

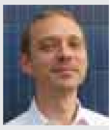
[22] F.Sönmez et al, "Fast and accurate ray-casting-based view factor estimation method for complex geometries", Solar Energy Materials and Solar Cells Vol. 200, Sept.2019

Authors

Florent Haffner studied general engineering at Ecole Centrale de Lyon (France), with a focus on the challenges of energy transition. After various internships on renewable energies, he joined CEA-INES in 2018, working on bifacial modelling and PV integration into the electric grid.

Djaber Berrian earned his BSc in physics in 2013 at the University of Science and Technology Houari Boumediene in Algeria, where he also received his MSc in renewable energy in 2015 with a thesis on mathematical modelling for defective photovoltaic generators. Throughout his study he participated in different activities in the field of renewable energy. His passion for renewable energy brought him to ISC Konstanz in February 2017, where he is working as a PhD candidate on energy yield modelling of PV systems using the MoBiDiG software tool. He is also involved in the European project BiFaLo that has a focus on bifacial modules.

Francisco Araya Rojas studied electronic engineering at Universidad de Antofagasta where he received the MSc degree after he joined the Centro de Desarrollo Energético de la Universidad de Antofagasta (CDEA). He worked as a research engineer with focus on PV system performance. He is currently working on modelling of bifacial PV systems at CEA-INES toward a PhD degree in electrical engineering.

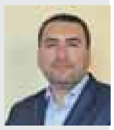


Andreas Halm obtained a degree in physics at Konstanz University in 2006 and joined ISC in 2008 working on industrial solar cells made of SoG-silicon. In 2010 he got engaged in the development of high efficiency n-type back contact solar cells. In 2015 he moved his focus to new interconnection approaches and joined the module department. In 2016 he became group leader of the module development group and since 2017 has headed module department.

Elías Urrejola Davanzo is CTO of ATAMOSTEC and has worked in the entire PV value chain, from the production of industrial solar cells, design of pilot plants, testing of disruptive technologies in the desert and development of large-scale plants. He has been senior solar researcher and head of the bifacial PV project at Engie Laborelec Chile, director of the solar line and senior researcher at Fraunhofer Chile, specialist engineer at Air Liquide (France) and at Sunways AG (Germany) and researcher at ISC-Konstanz (Germany). He holds a PhD in physics from the University of Konstanz (Germany) and a civil electrical engineering degree from the University of Santiago, Chile.

Delfina Muñoz graduated as industrial engineer and obtained a PhD in photovoltaics from the Universitat Politècnica de Catalunya in Barcelona (Spain). She joined CEA-INES in France in 2008 as a postdoctoral researcher, where she became head of the heterojunction solar cells lab in 2010. She is a member of the steering committee of the nPV and tandemPV workshops and combines project work with laboratory activities, directing PhD students and developing next-generation heterojunction solar cells based on tandem technology.

Joris Libal is R&D project manager at ISC Konstanz, overseeing technology transfer and cost calculations in the areas of high-efficiency n-type solar cells and innovative module technology as well as energy yield simulations. He received a degree in physics from the University of Tübingen and a PhD in the field of n-type crystalline silicon solar cells from the University of Konstanz. He has been involved in the entire value chain of crystalline silicon PV, with various positions at the Universities of Konstanz and Milano-Bicocca and, prior to joining ISC Konstanz in 2012, as R&D manager at the Italian PV module manufacturer Silfab SpA.



Edward Fuentealba Vidal received his degree in civil engineering at Antofagasta University, Chile, in 1999 and obtained his masters (2005) and doctorate (2008) degrees in electrical engineering from the Power Electronics Institute at the University of Santa Catarina, Brazil. He has been executive director of the Antofagasta Development Energy Center since 2010. His interests include solar energy (PV and thermal) and power electronics applied to solar energy and industrial processes.

Eric Gerritsen studied engineering physics at Twente University (The Netherlands) before joining Philips Research Laboratories (Eindhoven, NL) in 1985 to work on ion implantation, for which he received his PhD from Groningen University in 1990. He then held various positions within Philips Lighting and Philips Semiconductors in Germany, Netherlands and France. In 2008 he joined CEA-INES where he has been active on development and technology brokering of PV module materials, processes, equipment and applications.

Technical considerations to ensuring bankable floating PV projects

Design | As larger floating solar projects become a more common sight around the world, bankability is increasingly coming to the fore to satisfy the demands of financiers. Jeremy Ong, Ken Tay and Harald Hammer look at some of the areas where careful due diligence is vital to managing and mitigating technical risks for lenders

Bankability is the key to unlocking new sources of finance for floating solar projects

Credit: Lightsource

The growth of floating PV gloablly and the increase in project sizes has led to the need for lenders to provide financing to support these projects. In such instances, experienced advisors are requested to provide due diligence and to ensure technical risks for the project are highlighted and can be mitigated.

FPV market evolution

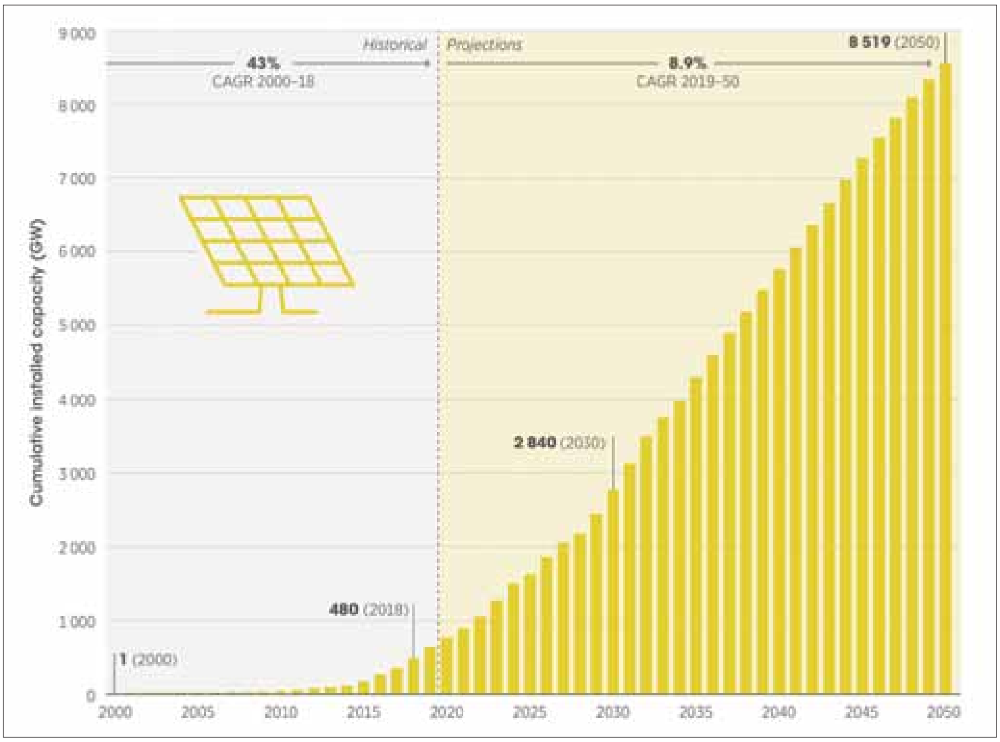
Floating PV as a nascent segment in solar has been gaining momentum globally in the last few years, particulalry in the APAC markets since 2014, and will satisfy just under 1% of annual global solar demand by the end of 2019, and 2% of global solar demand by 2022 [1].

This follows the huge growth in the overall global solar PV market, which grew at a compound annual growth rate (CAGR) or 43% from 2000 to 2018 and will continue to increase at 8.9% CAGR to 2050 [2].

The world's first floating PV project was a 20kWp system started in Achi, Japan in 2007. From there most FPV projects were small test prototypes of less than 100kWp until mid 2014. The Fukushima Tsunami disaster in 2011 resulted in the Japanese governement shutting down the country's nuclear plants and creating a new policy and generous feed-in tariff of JPY42 for PV systems [3], and also stimulated the growth of floating PV in Japan [4]. The majority of these projects were smaller in scale at less than 2MWp, enabling

Credit: Wood Mackenzie

Figure 1. Annual global solar demand (GWdc), annual floating PV demand (GWdc), and FPV share of global demand %.



Credit: IRENA

Figure 2. Compared to 2018 levels, cumulative solar PV capacity is expected to grow sixfold by 2030, with a CAGR of nearly 9% up to 2050

developers to build them on equity and without requiring non-recourse project financing. Therefore, many of these early floating PV projects built in Japan at that time will not have undergone a very rigorous due diligence. The other large market taking off was China, nearly at the same time in a parallel trajectory. In China, the projects were not small but much larger in size of up to 40MW, and these were developed and built mostly by the local floating system suppliers and then sold to the local utilities after construction and when operating. These projects were also built not with non-recourse project financing but fully on equity.

Interest in floating PV grew because the traditional areas where PV was built on land became more difficult and challenging; increasing land pricing, complexity of multiple land ownership, permitting and regulations on land use changes made floating PV on water bodies a more viable option to consider.

Growing need for project financing

With a growth of larger projects in the APAC region there becomes a need for developers to look at lenders to provide financing; with that, proper technical due diligence also becomes a neccessity from the lenders to help assess the technical risks associated in the technology, design, construction and operational aspects of the floating PV project.

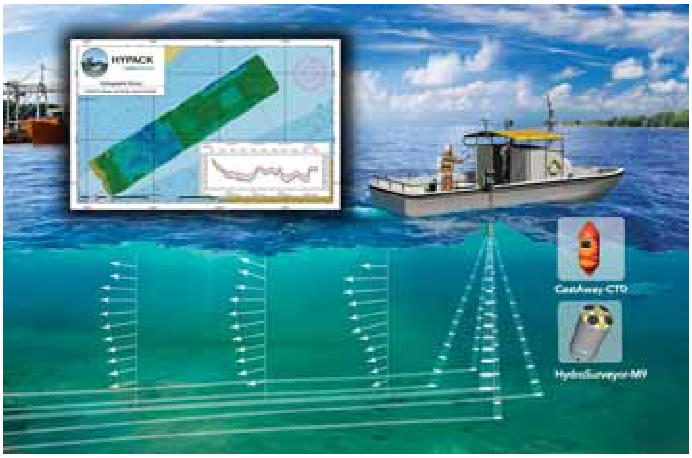
Site assessment

An on-site assessment is critical to gain an appreciation of the actual site conditions. Having such in-situ measurements during the plant design phase will provide a more accurate forecast of the energy resource, good understanding of terrain conditions and identify key potential issues that can be mitigated early on. For a large floating PV project, where the majority of the PV plant will be on the water, one of the main challenges is to identify the conditions below the water surface, which is not possible with just a visual inspection.

Bathymetry and topography surveys

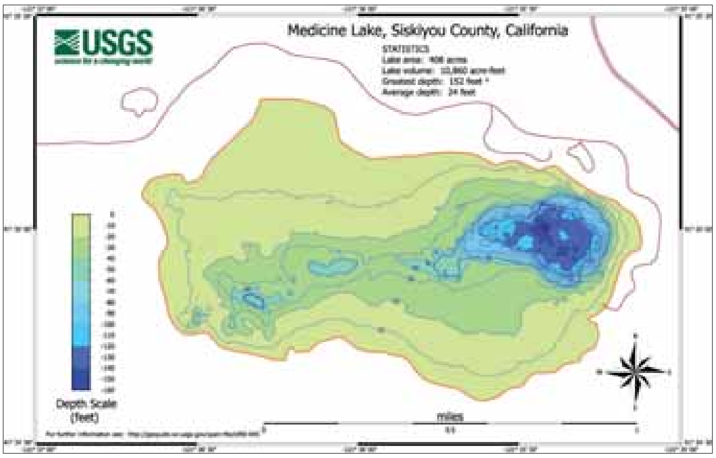
A bathymetry survey is performed to map out water depth variations across a project site and provide a perspective of the underwater terrain of the water bed. For a bathymetry survey at inland water bodies, a portable single beam echo sounder may be mounted over the side of a boat. For large water depths and extensive survey areas or nearshore/offshore, multi-beam echo sounders operated from a dedicated vessel are most suited. The bathymetry survey is complemented by a topography survey of the land area to cover locations for transmission facilities and any anchoring at the banks.

A bathymetry map is a critical input to define usable areas for placing floating PV islands as well as to identify suitable mooring and anchoring solutions. The bathymetry data is also useful to assess whether an anticipated fluctuation of water level due to seasonality may result in some floats resting on the water bed. In addition, any potential clash between the floating PV islands and nearby banks can be prevented with accurate topographical information above and below water.



Credit: SonTek

Figure 3. Bathymetry survey



Credit: USGS

Figure 4. Bathymetric map showing contourlines

Geotechnical survey

A geotechnical survey is carried out to identify soil conditions and potential lateral variability of the water bed, particularly at anchoring areas for the floating PV installation. In the survey, information on soil properties at shallow depths, e.g. up to 6m, is obtained from either borehole sampling or continuous probing tests, such as CPT or a combination of both. Shear strength of the sub-bottom soils is used for the anchor sizing for a given design mooring load. The type of suitable anchors is also dependent on the soil condition at the water bed. While concrete blocks are generally applicable for a "hard" bed, other types of anchor, such as pile or plate anchors may be more suitable for relatively soft soils.

For inland water bodies or neashore areas, the survey may be conducted from a floating pontoon or a temporary platform using the conventional soil boring technique. It is important to ensure that the scope of geotechnical survey for floating PV installation is adequate. In order to overcome inherent uncertainties or information gaps in available soil data, field tests on selected anchors may be performed to proof load the design tension force.

Meteorological survey

Design load for a floating PV installation is highly dependent on the anticipated environmental extremes [5] at the site, such as wind speed and any waves and current. For installations at inland water bodies, wind force is typically the predominant loading condition while for nearshore more complex loading conditions induced by wind, wave and current are envisaged.

Design wind speed extremes may be available from a local code but more detailed information including wind directionality may be obtained from a site measurement for at least one-year duration. Extreme value analyses can be performed from the site measurement data and other long-term data from any nearby weather stations to derive extreme wind speeds for various return periods. In the absence of design codes for floating PV, usually a 50-year return period wind speed (3-sec gust at 10m) is recommended for the ultimate limit state design.

Wind-induced waves and surface current may be estimated from established theories. When design optimisation is desired, a detailed measurement of waves and currents together with long-term stillwater level changes at the site can be performed using various remote-sensing techniques such as Acoustic Doppler Current Profilers.

Investment in obtaining accurate site parameters at the early stage of a project should be able not only to optimise the design and its cost but also minimise risks of damage/failure, which might lead to higher costs for remedial measures or even a total loss of the asset. More reliance on updated information should also be emphasised in view of the change in global weather patterns, which show increased frequency of extreme weather events occuring over the last several years.

Site	A	B	C	D
Water Body	**Reservoir**	**Hydro dam**	**Reservoir**	**Hydro dam**
Area of Water body [Ha]	450	6,200	91,500	32,300
Elevation [AMSL]	0.40	215	1	56
Wind Speed[1]				
Maximum wind speed [m/s]	**40.00**	**22.00**	**57.60**	**20.50**
Maximum average five min [m/s]	5.86	6.00	15.44	5.80
Daily Average [m/s]	1.13	1.60	3.44	2.60
Water Level				
Yearly Average variation [m]	**0.40**	**11.80**	**2.20**	**12.00**
Maximum water level [m]	1.10	220.00	13.50	62.00
Min water level [m]	0.10	207.00	10.60	50.00
Maximum water depth [m]	6.50	94.00	20.10	25.00
Average water depth [m]	2.30	34.90	2.80	4.30

Table 1. Comparisions of four sites a) water body type b) wind conditions and c) water level variation

Site comparisions

Appreciation of a site is important and comparing some aspects of these four sites in Asia shows that they can be very different in each individual aspect, which can affect design requirements in a fairly major way. Table 1 gives a high level overview of the site-specific wind and water level parameters on these four different inland water bodies in Southeast Asia and how they vary. The three parameters to highlight are: a) water level variation on a yearly basis, b) maxmium water depth, c) maximum five-minute wind gust. The maximum wind speed can be seen in Site C at 57.6m/s and it is also has the largest area of water, but the second highest wind speed is Site A with a much smaller water area of 450ha. Site B and D are both hydro dams with relatively simiar yearly water level variation of nearly 12m, but their maximum water depths are very different at 94m at Site B and 25m at Site D; the average water depth is 34.9m at Site B versus only 4.3m at Site D. Also, the daily average windspeed of the four sites vary from 1.13m/s to 3.44m/s, which is three times more than the lowest; this can have a significant effect on the energy yield overall and a significant contribution to long-term future revenues of the project. This highlights how good quality, accurate site and historical data is crucial to both the mechanical design solution, but also to the accuracy in modelling the energy yield of the project (more will be discussed in the section on resource data and energy assessments).

One unique challenge on Site D is that due to changing weather patterns over recent years, in the dry season 30% of the water body will be left dry. This becomes a potential challenge for the type of floating system technology used as currently no float system is designed to ensure safe operation on dry land, as it may be undulating terrain and debris left on the lake bed.

Siting of grid interconnection facilities

In the case of a potential large greenfield floating PV site greater than 50MW, there will potentially be a need to locate and identify a suitable HV substation on land nearby the site to connect and dispatch power. Locating the best technically viable option can be a challenge if the land needs to be converted in line with

local land use regulations. Negotiations of leasing or buying of the land may also often become long drawn and complicated, more so with a tight timeline to achieve the commercial operations date (COD). So with this, it is very helpful to have quick assessments on the technical side in calculating the infrastructure cost with an optimal and safe optimised design.

Anchoring and mooring

Actual behaviour of floating solar PV under design environmental conditions is expected to involve interactions of fluid, structure and soil. Although design input parameters for the environmental extremes can be reliably obtained, derivation of the environmental loadings for design purposes is non-trivial in the absence of detailed technical guidelines for the structural aspects of solar PV and floating solar PV in particular.

Several failure cases of floating solar PV plants under typhoon conditions in Japan were reported. Recently a 13.7MWp floating solar PV plant was significantly damaged and caught fire after Typhoon Faxai at Yamakura Dam in Japan (see Figure 8). The storm reportedly came in at an average wind speed of 41m/s, which is apparently higher than the local code required. During the same typhoon, a smaller floating solar PV plant in Ariake Reservoir experienced a different failure mode in which the interior floats were detached from the outer ones and pushed to the shore. Such failures imply that the current engineering practice can be deemed insufficient to safeguard failure of the system or the critical components in the event that design extreme loading occurs within the system's expected lifetime.

Good engineering design takes experience and appreciation of the interactions between the different design desicplines to ensure robust and yet cost-effective design. Solar PV has been a mainly electrically led field and less focused on detailed mechanical, structural and geotechnical aspects of design. With the growing deployments of floating PV at a larger and larger scale, due consideration should be given to the critical elements of floating PV systems, such as float joints as well as the mooring and anchoring system including its connections.

Unlike offshore structures for oil and gas activities, where high redundancies are inherent system requirements to prevent structural failures and loss of lives, mooring systems for floating solar PV pose unique challenges. In view of the typically large quantity of mooring lines and anchors involved in a floating solar array, cost optimisation of the mooring system including the installation and maintenance aspects is of paramount interest. Presently, the number of mooring lines are often determined by a simple distribution of the total design horizontal load according to the strength of the mooring-float interface. No mooring design optimisation has been sought through detailed modelling, such as hydrodynamic simulations, in order to lower the mooring system cost and ease the maintenance without compromising its reliability.

Furthermore, robustness of the current typical mooring system for large floating PV arrays and in more challenging environments such as deep water, highly varying water-bed elevations and coastal area needs to be further investigated. The use of elastic mooring lines or connections has been adopted in several projects to overcome extreme water level fluctuations or anticipated high peak load with the conventional mooring system. Cost-effective key enabling technologies for futureproof large-scale floating PV installations, including at nearshore areas, need to be urgently identified.

Credit: RTS Corporation

Figure 5 Typhoon caused fire on Japan's largest floating PV site on Yamakura Dam in 2019

Technology specification

The appropriate specification of technology for a particular project site needs to look into not just international codes and standards but also consider the local environmental conditions. The emphasis should be on correctly specified PV modules, inverters, combiner boxes and electrical balance of system (BoS) equipment, as well as PV float systems and anchoring and mooring equipment, some of which may not have immediate, but rather mid- to long-term impacts on the performance of the plant.

The majority of all floating PV systems available on the market today are made from HDPE plastic material. It is important for any large bankable project to consider the following tests to show resistance and durability for their design life of 25 years and beyond in their material tensile strength. As there are currently already industry standards for UV testing on extruded and blow-molded plastics to simulate accelerated environmental test conditions under UV light, high temperature and humid conditions, the HDPE samples should undergo UV testing according to ISO 4892-3:2016(E) Method A cycle no.1 for 3,000 hours,


Credit: DNV GL-PVEL

Figure 6. PV module inspection and PV Inverter testing

where these test samples are then tested for tensile strength according to ISO 527-2:2012 plastics determination of tensile properties. The float material should also comply with fire safety requirements and fire hazard tests according to IEC 60692-2 -11 - Glow-wire flammability test method for end-products (GWEPT).

Manufacturing audits and quality inspections

To ensure equipment conforms to the quality stated in the supply contract terms, there should be a manufacturinng audit report by an independent third party, while a manufacturing inspection of the production of the modules and inverters should be a mandatory requirement for developers who are concerned with good quality control for equipment procured for their projects. They should have expereinced and credible independent QAQC inpectors do this on their behalf. This really helps to ensure the manufacturing quality assurance of the products, be they PV modules, floats systems or inverters, is done during the entire process to ensure quality and performance.

Energy production assessment

Weather resource

Compared to a traditional ground-mount PV plant, it is even more critical to accurately assess the on-site wind condition for a floating PV plant for structural loading and foundation design. However, good and long-term on-site measurements of surface winds over water bodies (both inland and offshore) [6] are not always readily available. Due to the localised behaviour of wind patterns, even ground station measurements a few kilometers away from the actual site can be quite different.

An alternative has been to use satellite or reanalysis data sets to assess the on-site wind conditions. These datasets, while useful to provide a general idea of the site conditions, are subjected to higher uncertainty due to inherent modelling assumptions and coarse spatial resolution. Moreover, not all global datasets are created equal. These datasets tend to be validated and tuned using regional ground measurements [7]. The implication being that regions such as Continental United States and Western Europe, with a long tradition of meteorological measurements, are well validated while regions such as the Maritime Continent tend to behave poorly [8].

Site-measured data

For site-measured data it essential to measure the following parameters with sensors of the correct specification: irradiation, wind speed and wind direction, ambient temperature and module temperature, humidity and precipitation. For large utility-scale projects the pyranometers specification should comply to ISO 9060-2018 Class A (secondary standard) and IEC 61724 Class A, with an understanding of the site location requirements on precipitation and temperature range. For the anemometer specification it is important for the sensors to be suitable to meet the historical maximum windspeeds. This is to ensure good accurate site data is collected, not just for the measurement campaign, but also during the operational phase in case of extreme weather events in potential hurricane and typhoon-prone areas. The duration of the measurement campaign should ideally be minimum one year to fully capture the seasonality of the site in a full year cycle, which again will help to reduce the uncertainty of the energy yield estimate. This, in tandem with other long-term historical data, either from other ground measurements or satellite data, helps to provide better correlation and more accurate long term energy forecasts.

As part of the measurement campaign, a soiling station to measure accurate site soiling conditions becomes much more helpful than having guidance estimates, which is good for more mature segements such ground-mounted and commercial and industrial projects.

Loss assumptions for the energy model

An important part of the energy assessment are the loss assumptions being input into the energy model. These losses may seem very small and insignificant at first glance but will all have a compound effect in the long-term energy yield forecast. The emphasis is not on being conservative but rather accuracy with the modelling approach. The following factors are some that are not always included: accurate creation of PV module PAN and PV inverter OND files, thermal loss factors, DC and AC system losses, accurate soiling loss estimates, module specific losses such as temperature coefficients, module qualify factor (MQF), PV module degradation, mismatch losses and light-induced degradation (LID) .

Grid connection review and system studies

There are a few reasons for conducting grid system impact studies for a grid-intergated PV project.

One key point is compliance with the local grid code requirements for licensing, but for the lenders it is to help understand the potential of curtailment and unavailability, and to be able to find mitigation strategies to limit if possible.

The following are system studies that should be done:

Steady-state analysis:

- Power flow analysis (PV generation for peak and light loads).
  - o It is important to have load flow results for peak load and light load systems. However, PV loading can be different (20%, 30%, 50%, 60%, 100% etc.).
  - o Certain countries require steady-state results for different years as well (e.g. for the next 10 years with five years interval).

Short circuit analysis:

- Power system component loadings to assess the thermal capacity;
- Component rating calculation;
- Operation power factor study;
- A complete contingency study (N-1) for the plant network. (N-1-1 and N-2 might be required);

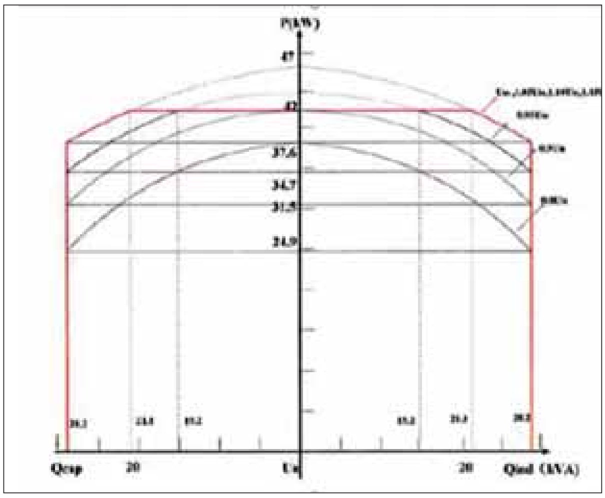


Figure 7. Power quality analysis

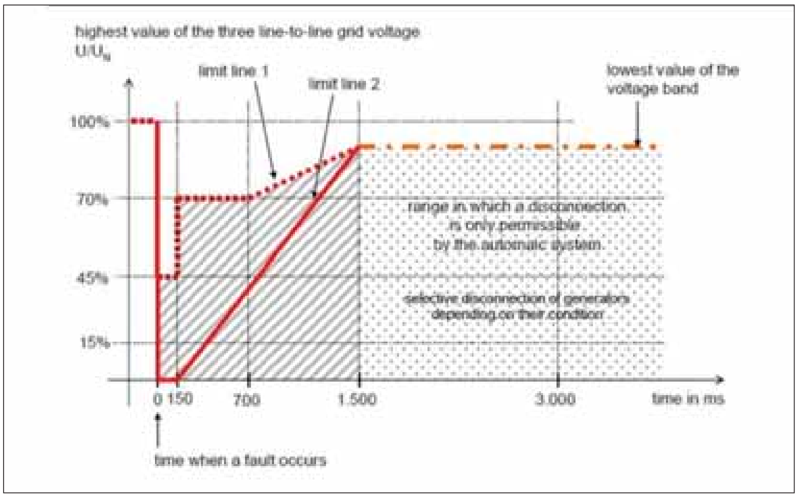


Figure 8. Low voltage ride through

- Reactive power compensation analysis

Power quality analysis (EMT):

- Harmonic study;
- Flicker study.

Dynamic studies (EMT, RMS):

- Transient study;
- Oscillatory stability (eigenvalue) analysis;
- Medium and long-term dynamic studies (30s to 10min);
- Sub-synchronous resonance studies;
- Fault ride through capability study;
- Over frequency analysis study;
- Model validation study (plant modelling methodology).

Grid curtailment

Curtailment risk is a recurring issue that is seen in markets where there is a huge growth in solar being developed in resource-favourable locations and provinces, such as in the early days in China, Japan and more recently in Vietnam. The difficulty is getting good network data and modelling it accurately, something that is not always available. Often in the due diligence process for greenfield projects there is not enough available data to establish the curtailment risks, and there are no easy answers on how this is to be accurately estimated. Every project poses its own challenge so it is ideal to have good local experience and knowledge of the specific grid models where possible.

Conclusion

The emphasis when embarking on a floating solar project is to understand what the major risks are for the particular site, based on a sound knowledge of its specific conditions, and to ensure the energy yield assessments have captured good site-measured inputs to provide accurate long term forecasts. Such analysis will help ensure proper designs that are both electrically and structurally sound and comply not just to local codes but good international best practices. Engaging good and experienced technical advisors with the due diligence process will help reduce and mitigate the major technical risks.

References

[1] Cox, M., 2019. *Floating Solar landscape 2019*, s.l.: Wood Makenzie Power and Renewables & Cox, M., 2019. *The State of Floating Solar: Bigger Projects, Climbing Capacity, New Markets*. Available at: https://www.greentechmedia.com/articles/read/the-state-of-floating-solar-bigger-projects-and-climbing-capacity

[2] International Renewable Energy Agency, 2019. F*uture of Solar Photovoltaic: Deployment, investment, technology, grid integration and socio-economic*, Abu Dhabi: International Renewable Energy Agency.

[3] Anon., 2012. *Japan Approves Feed-in Tariffs*. Available at https://www.renewableenergyworld.com/2012/06/22/japan-approves-feed-in-tariffs/ [Accessed July 2020].

[4] Laboratory., D. R. E., 2019. Great potential for floating solar photovoltaics systems. *Environmental Science & Technology*, 8 January.

[5] European Academies' Science Advisory Council, L. -. N. A. d. W., 2018. New data confirm increased frequency of extreme weather events. *ScienceDaily*.

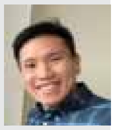
[6] Kameda, S. K. K., 2017. Validation of gridded data set of global surface wind/wind-stress vector field. *J Oceanogr*, pp. 585-601.

[7] Alexandre Boiley, L. W., 2015. Comparison between meteorological re-analyses from ERA-Interim and MERRA and measurements of daily solar irradiation at surface. *Renewable Energy,* Volume 75, pp. 135-143.

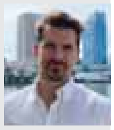
[8] Fonseca, R. K. T. &. T. C., 2019. Multi-scale interactions in a high-resolution tropical-belt experiment and observations. *Clim Dyn*, 15 March, Volume 52, p. 3503–3532.

Authors

Jeremy Ong is DNV GL's regional solar segment leader for APAC. He graduated with a B.Eng (Hons) in civil and environmental engineering from the University of Edinburgh, Scotland. He has worked in the solar industry since the start of 2008 and has >6.5GWp of utility-scale PV and >2GW of FPV project experience, covering technology qualification, FPV supplier benchmarking, technical due diligence, preliminary designs, bankability reports and factory audits. He has strong technical and operational experience building the project execution and O&M teams in APAC in Singapore, China, Korea, India, Taiwan, Philippines, Thailand and Australia.



Ken Tay is a senior renewables analyst for DNV GL. He has been working in wind energy research for more than seven years, focusing on mesoscale and LES modelling of wind climate for offshore wind applications. He has received a Bachelor degree in aerospace engineering and a PhD in sustainable earth from Nanyang Technological University (NTU), Singapore. He has worked on a number projects in onshore/offshore wind, including technical due diligence, energy yield assessments and monitoring campaigns.



Harald Hammer is a solar consultant for DNV GL Renewables Advisory. He has been working in the solar industry for six years focusing on energy assessments, engineering and technical due diligence. He has received a Bachelor degree in renewable energy from the Norwegian University of Life Sciences and a MSc in renewable energy from Murdoch University in Perth, Australia. He has worked on several floating PV projects including technical due diligence, site conditions assessment, energy yield assessments, supplier benchmarking and monitoring campaigns.

PV ModuleTech Bankability analysis extended to show module suppliers' strengths and weaknesses

Bankability | Finlay Colville, head of market research at PV Tech Power publisher Solar Media, discusses what's inside the Q3 2020 update of the PV ModuleTech Bankability Ratings report and how it details a module supplier's strengths and weaknesses

The latest findings from PV Tech's unique bankability analysis – the PV ModuleTech Bankability Ratings report – have now been completed, forming the basis of the Q3 2020 rankings for leading global module suppliers. This article discusses the main findings of the new report.

In addition, I will show for the first time, extended bankability analysis undertaken that allows detailed benchmarking of all A and B grade module suppliers, across a range of financial and manufacturing metrics, and how real-time 'report-cards' can be generated on module suppliers revealing their relative strengths and weaknesses.

Credit: LONGi Solar

LONGi Solar remains the only Triple-A rated module supplier.

Number of A and B grade module suppliers now exceeds twenty

The overall company rankings, based on their individual Bankability scores, for Q3 2020 are shown in figure one.

LONGi Solar continues to be the only AAA-Rated module supplier, largely because the company's finances remain in a different league to all other companies shipping GW-plus product annually today. This is coming in part from gross/operating margins – even through 2020 – well above others, but almost regardless of the financial ratio/metric compared, LONGi Solar is either best-in-class or in the upper quartile.

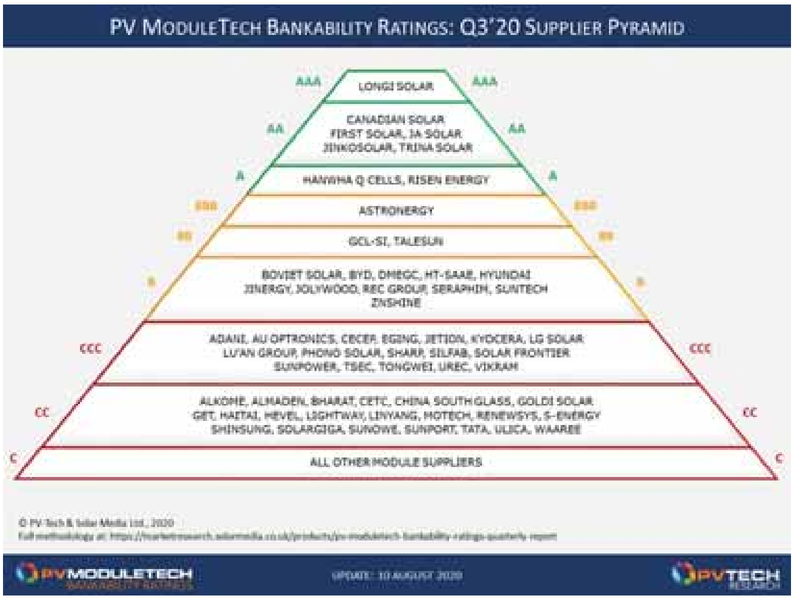


Figure 1: The latest release of the PV-Tech PV ModuleTech Bankability Ratings report shows eight module suppliers with A-Grade ratings, and LONGi Solar again the only AAA-Rated company.

The AA-Rated company grouping is now looking more stable, with Trina Solar and JA Solar re-listed (or back-door listed) in China. While JA's private-status hiatus was rather short-lived (two years) it took Trina about four years and overlapped with a reset in the company's positioning during 2017 and 2018 in particular.

China-listing clearly makes sense when seeking to invest in expanding in-house capacity needed to stay in control of manufacturing/production and costs. It should be remembered also that, aside from the US, there is really no strong motivation to add any new capacity outside China.

Of the eight A-Grade (AAA, AA and A-Rated) module suppliers, it is not inconceivable that 18 months from now, JinkoSolar will be the only Chinese-run/US-listed company. This assumes that Canadian Solar's plans to carve out its manufacturing (upstream) business as a separate Chinese-listed entity come to fruition.

How things have changed for Chinese companies seeking to list in the US, compared to just five years ago.

Peer-group variance should dominate corporate KPI's & success evaluation

For the last 15 years, one of the biggest challenges for the PV industry has been in benchmarking module suppliers; a situation made all the more difficult with 100-150 module suppliers generally in the mix at any given time. Not to mention a bunch of suppliers that don't actually make any product, don't exactly explain this to the outside world very well, and try sell a brand name to the market sometimes in competition with their OEM supply source!

It is definitely time for the PV industry to reclassify these companies as resellers, not module suppliers, in the same way that distributors don't make products and just act as middle men. Or even just classify companies like Sharp and others as end-users of products. Perhaps, I will return to this in coming months, possibly in light of where the new SunPower/Maxeon entity may decide to position itself strategically.

Returning to simple benchmarking, it would be fair to say that peer-group benchmarking of leading module suppliers has been extremely limited, with capacity and shipment levels often forming the only comparisons.

During 2019, when we gathered all the manufacturing and financial data together (to allow the PV ModuleTech Bankability Ratings analysis to be done), it was clear that the ability to do benchmarking and rankings in an altogether new and enhanced way was possible.

Peer-group benchmarking is everything. Almost nothing else matters, when looking at company shipments, revenues, profits, earnings, debt, capex, R&D spending, assets, liabilities, technology roadmap, etc., etc.

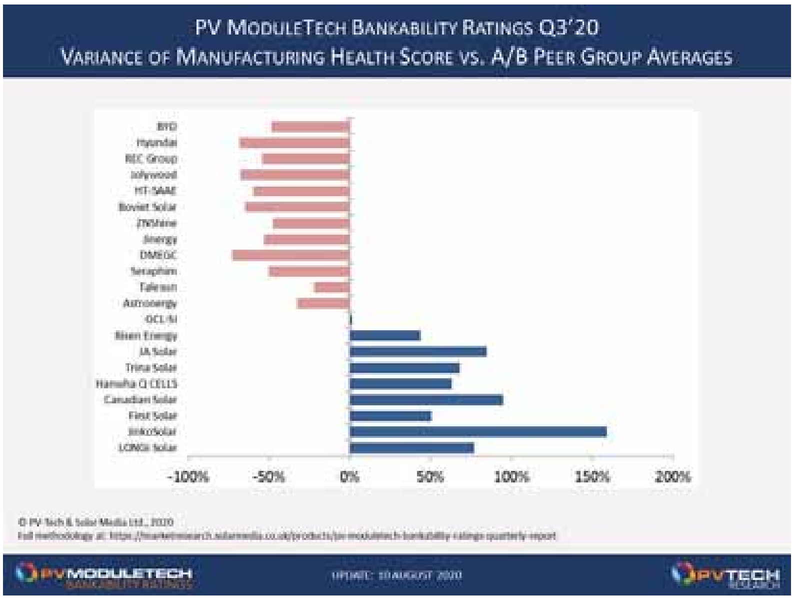


Figure 2: A-Grade rated PV module suppliers are clearly differentiated from the top-20 module suppliers to the industry today, when looking at the PV ModuleTech Bankability Ratings scores for Manufacturing (a combination of supply/shipment, capacity and technology).

It sounds incredibly simple and obvious, and indeed it should do. But the devil is in the detail. First, you need to know what constitutes a peer-group and which companies are members of this exclusive listing. Then you need to know a great deal about each company's quarterly operations (financial, manufacturing), updated at least quarterly. And finally, you need a good command of statistics and analytical tools, coupled with the ability to understand and explain related graphical output.

The entire process that involved creating the PV ModuleTech Bankability Ratings was by default a peer-group allocation tool in its own right. Simply setting up boundary conditions between A, B and C-Graded scores, and further across the grade rating categories (e.g. AAA, AA, A for A-Grade), puts companies into levels occupied by their peers.

There are two clear options for doing peer-group benchmarking across PV module suppliers. One is to isolate the A and B-Grade module suppliers; a total of 22 companies. The second would be to reduce the number of module suppliers, comparing only A-Grade companies (a total of eight).

Essentially, this is done (whether for A/B or A only peer-group benchmarking) by taking the average of the peer group for any specific metric or ratio (e.g. US utility shipments, return-on-equity, manufacturing capex, US AD/CVD-free cell/module Southeast Asia capacity, etc.) and show the difference in each company's value (the 'variance') from the average of the peer-group.

This variance is best expressed in percentage terms (how much over/under the peer-group average). For example, if the average utility shipment volume over a trailing three quarter period into Europe is 50MW, then a company shipping 150MW within this period has a variance score of (positive) 200%: conversely, a company shipping just 25MW has a variance score of -50% (i.e. negative).

This allows a couple of important things to be considered now. First, at any given point in time (end of last quarter, Q/Q, Y/Y or any quarter in the past), any module supplier company can be benchmarked against the average of the peer-group. This shows very quickly the areas where the company is performing better or worse than its main competitors.

It is effectively a quarterly-trending, external/third-party derived, corporate performance indicator, as it relates to manufacturing and shipping PV modules to commercial, industrial and utility segments globally.

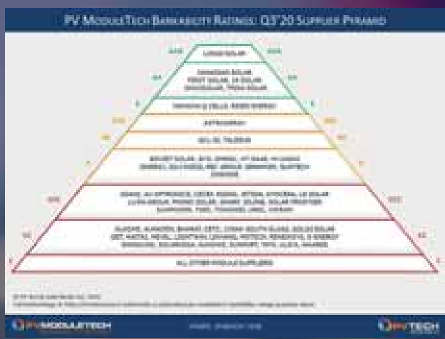
Having developed the PV ModuleTech Bankability Ratings to allow ranking all PV module suppliers for non-residential (commercial, industrial and utility) deployment globally, it is now time to expand the ratings feature with extensive benchmarking analysis.

PVMODULETECH
BANKABILITY RATINGS

Ranking the most bankable PV module suppliers - new data from PV-Tech Research released August 2020

The report provides everything you need to benchmark all your existing and potential suppliers against each other in terms of bankability, refine your supplier short-lists so that only the most financially stable companies remain that enhance your sites' performance, risk profile and long term returns.

- Unparalleled company data, analysis and forecasting for more than 50 of the major global module suppliers to the industry, refreshed each quarter
- Financial operations of each company - both public-listed and privately-held - in a clear, understandable format, all benchmarked to PV industry operating norms
- Technology and module shipment trends, updated quarterly, forecast to the end of current calendar years, including company in-house production by region, technology and capex/R&D



We are offering **free introduction webinars** to companies interested in accessing the full range of services available – email **marketresearch@solarmedia.co.uk** to find out more

https://bit.ly/2zdtrKf

SOLAR MEDIA
MARKET RESEARCH

Put very simply, we have now created a tool to visualise the strengths and weaknesses of PV module suppliers, and how these change over time. The next section illustrates a couple of examples now.

Why AAA, AA & A-Ratings remain the gold standard of module supply

The entire methodology of the PV ModuleTech Bankability Ratings was underpinned by qualification as A-Grade rated being above 50% in a 0-to-10 scoring mechanism. Entry to this elite grouping by default demanded both multi-GW of shipments to non-residential PV segments, coupled with financial health that was in the 'safe' zones for PV sector longevity.

Companies that were shipping all product to residential segments score low (regardless of financial performance). Companies that are close-to or beyond technical bankruptcy score low also (regardless of their shipment volumes). Ultimately, the highest scoring (Bankable) suppliers should be the ones we see getting the lion's share of the megasolar sized global utility-scale business.

To illustrate this now, we can look at one of the variance-derived peer-grouping graphics. Here, we isolate the PV ModuleTech Bankability score for Manufacturing. (Recall that the Bankability Score combines Financial Score/health and Manufacturing Score/health.)

The peer-group for this analysis consists of all A and B-Graded module suppliers (a list of 22 companies for Q3'20). Most of the peer-group variance studies are performed on a trailing three-quarter average basis, including the one shown in figure two for Manufacturing Score (health).

Figure two is incredibly useful when looking at peer groups (in this case all A and B-Rated module suppliers). However, if you want to look at one company only and see how they compare to peers across a range of other parameters (not simply Manufacturing health), then a slightly different presentation is required.

To illustrate this, we have chosen Canadian Solar as a topical example. I will return to why Canadian is 'topical' in nature later in the feature: for now, let's look at Canadian Solar's Q3'20 'report-card'. Some of these metrics are shown in figure three.

To understand the graphic best, consider negative/red-coloured bars (to the left of the y-axis) to be 'weaknesses' in relation to the A/B peer grouping. Conversely, positive/blue-coloured bars (to the right) are 'strengths'. The higher the variation percentage score, the greater the strength or weakness.

In figure three, we have separated some of variance scores into groupings. The lower three are top-level Bankability and its constituent factors (Manufacturing, Financial health). Then, working upwards, the next grouping shows market-share globally (commercial, industrial, utility) and within six countries/regions. (RoW has fleetingly been referred to by some as 'emerging'.)

Above the market-share variances are a selection of financial terms/ratios. Much more will be communicated on these in coming months, as this continues to be one of the biggest challenges; pulling out ratios that allow differentiation and are meaningful from the perspective of a module buyer (as opposed to a stock-market investor/trader).

The final category at the top are brand-new metrics we have created to best understand what capex and R&D really means in the PV industry. Again, we will explain these more later. Essentially, companies score high if they are able to spend low on capex and R&D. Our ratios of capex and R&D turnover are key ones today, in a different way to a few years back; being frugal on spending here is a major plus, not a sign of caution.

Let's try quickly to explain Canadian Solar's play in the industry today, with reference to figure three. From bottom-to-top.

Manufacturing health is well above peer-average today, aided by capacity expansions/upgrades recently (in particular in Southeast Asia for US shipments less AD/CVD). Financial health is below-average (slightly), not because Canadian Solar is anywhere close to losing money or in trouble, but because various group entities controlling members of the peer-grouping (LONGi, First Solar, Chint Group, Hengdian Group, Boway Alloy, Hyundai Energy Solutions) have financial scores well above those of Canadian Solar today.

The market-share analysis in figure three is a great way to see where the company has been successful in deploying resources recently. The focus has been the US, Japan, Europe and various RoW/'emerging' regions. Japan has been the big winner for Canadian over the past couple of years, all the more interesting when considering the company's somewhat reluctance to embrace the mono-mantra in terms of technology offerings.

The high score for US shipment market-share is somewhat a validation of the investments into Thailand over the past couple of years also.

Interestingly, the 'negatives' or 'weaknesses' in terms of market-share

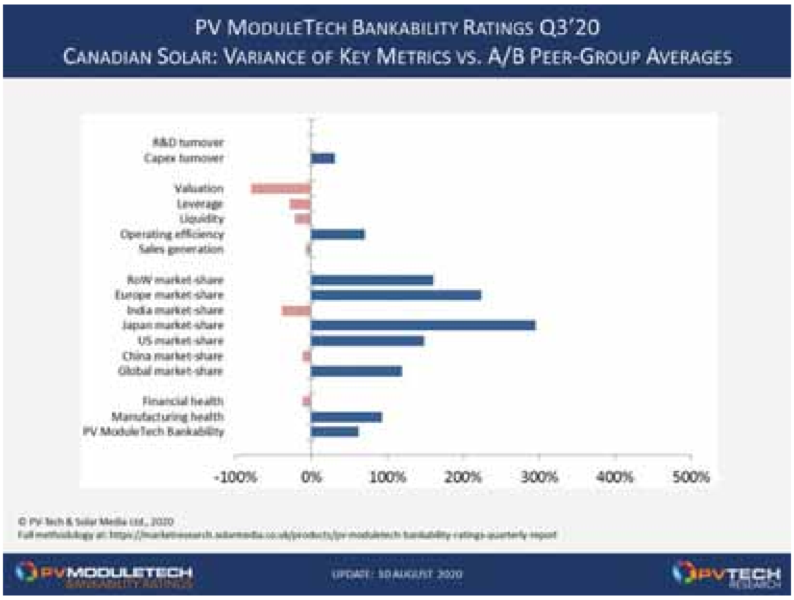


Figure 3: As one of the most bankable PV module suppliers today, Canadian Solar performs well above the average of its peer-group competitors across many financial and manufacturing levels/ratios.

today are confined to China and India. To many, having minimal dependence on these two end-markets may in fact be seen as a positive. Collectively, China/India today are fraught with risks in terms of module supply.

Ideally, a Chinese-run module supplier should be aiming for fill order books with overseas shipments with the exception of India. Then, if need-be, domestic China shipments can be filled if needed. And if things are really bad, serving the Indian market is probably a last resort. Therefore, Canadian's market-share scoring is extremely good compared to its competitors.

The next group of metrics are finance-specific, covering a range of ratios capturing revenue generation, profitability, short-term cash solvency, long-term debt and valuation. The choice of metrics or ratios here is much more complex, compared to simply comparing module supply market share, or indeed the overall financial health ranking that uses a prescriptive Altman-Z analysis as the basis. The key to choosing ratios here is driven by looking at variances in the operations across the peer-group chosen, rather than for example some of the metrics used to assess whether companies represent a good or bad short-term investment. A full explanation, including additional ratio benchmarking, is contained in the full quarterly PV ModuleTech Bankability report.

Across the peer-group here, it is clear that Canadian Solar's operating efficiency (net profitability) is well above most of its competitors. For Canadian, this is actually coming from strong gross margins for its two main revenue streams; selling modules and selling short-term owned downstream assets. The company is almost unique today in the industry in this regard, and this is captured below also in regard to plans to carve-out the upstream part of its business.

The last two metrics compared are new ones created by our in-house analysis, and are based on capex and R&D spending. While there is often a belief that greater capex and R&D spending is something that shows leadership, within the PV industry this is far from the case. Let me explain this more before looking at Canadian Solar's variance with respect to the peer-group.

R&D spending varies hugely across module suppliers, and has done for many years. Many companies have survived just fine by largely following technology trends introduced/developed by others, without having to prioritise in-house R&D spend. China is the perfect case-study in this regard. Others – most notably First Solar – have a necessity to invest in R&D as a result of being technology-differentiated. Over the past 10 years, there is a clear correlation between fleet panel average efficiencies and investment levels into R&D.

Our Capex Turnover metric compares module-specific revenues to capex invested into cell and module lines, and it a more granular method compared to looking at group revenues and overall capex across different parts of the PV value-chain or indeed capex into non-PV business units.

Minimising capex now while adding 10-20 GW of new cell/module capacity over the next 2-3 years is key. Today, this is exemplified by JinkoSolar and Canadian Solar.

The goal is surely to maximise module revenues while minimising capex levels. Right now, this is a massive deal for PV companies, in particular in China. Essentially a bang-for-your-buck, minimising capex now while adding 10-20 GW of new cell/module capacity over the next 2-3 years is key. Today, this is exemplified by JinkoSolar and Canadian, and the fact that Canadian has a net-positive Capex Turnover ratio compared to the peer-grouping should not come as a surprise. Indeed, when we look at some of the peer-group players, some have far less ambitious capacity growth plans, making their Capex Turnover very high in the near-to-mid term.

R&D spending is more of a misnomer in PV, and this certainly includes also how companies define and report R&D spending per se. This is limited correlation between R&D investment figures when looking at, for example, US companies listed in the US and Chinese companies listed in China. The R&D Turnover metric is calculated in a similar manner to the Capex Turnover ratio. Canadian Solar's return on R&D is aligned with the peer-group.

One of the reasons also for choosing Canadian Solar as the case-study for the new enhanced peer-group variance analysis is not just to see where the company has strengths and weaknesses today versus the other 20 A/B peer-group of suppliers, but to get a feel for what a 'new' China-listed manufacturing-specific Canadian Solar might look like.

While Canadian Solar's module revenues (as a percentage of group turnover) are lower than the likes of JinkoSolar or JA Solar today, the company's business is still heavily weighted to producing modules at low cost, and maximising margins when selling modules. As such, many of the metrics underpinning Canadian Solar (as listed on NASDAQ) will be similar to those reported by the proposed China-listed entity.

However, the three areas where the company is below-par above (liquidity, leverage, valuation) are almost certain to be reset upon Chinese-listing. As such, we would expect to see an instant improvement upon listing, very similar to what was seen with Trina and JA Solar in the past 12 months.

The need for detailed Bankability analysis continues

Our decision to expand the PV ModuleTech Bankability Ratings analysis at PV-Tech was driven by the many requests from report users that have been starved of company-to-company benchmarking for many years. We are in the process of adding more features here. Ultimately, anything qualified and data-driven that can help developers, investors and EPCs understand the difference between module suppliers is gold dust.

Top of list now is doing the peer-group variance analysis, confined only to the A-Grade companies (top eight module suppliers today). This is perhaps a far more valued comparison, as these companies are the ones mostly dominating GW-scale contract supply business today. Expect to see the headline results in the next volume of *PV Tech Power*. ■

How cybersecurity is becoming crucial in the digital age

Credit: Neoen

Cybersecurity | A string of high-profile cyberattacks on energy infrastructure highlights the vulnerability of solar farms as they become increasingly reliant on digital systems. Alice Grundy looks at the rising threat of cyberattacks and the measures asset owners can take to mitigate the risks

Cybersecurity can easily fly under the radar, just as a hacker weaves through systems and sifts through files undetected. The documented cases of cyberattacks on the energy system are hardly a page-spanning list, and the number of cases on solar assets even fewer. But that doesn't mean the risk is as slight. What is largely considered to be the first cyberattack on a power grid took place in Ukraine in 2015. It is also considered to be one of the most dramatic cyberattacks in the energy sector; in a scene that should be straight out of a spy movie, an operator in the Prykarpattyaoblenergo control centre was locked out of their computer, watching as their curser moved independently from any of their own actions. The attack took out 30 substations and caused a blackout that took six hours to fully resolve.

The knowledge that a cyberattack could – and has – caused blackouts seeped into other events. When the UK had a major blackout on 9 August 2019, initial suggestions seen on social media were that it was a result of a cyberattack, although within hours these rumours were squashed. It was, in fact, a result of a lightning strike that triggered faults in an offshore wind farm and gas-fired power station, and not a result of a cyberattack.

Whilst cyberattacks on solar farms specifically are not commonly reported, this could well change. Digitalisation is creeping into the solar industry, automating processes and making components smarter. And where there are increases in digital technology, the threat of cyberattacks is never far behind.

The trend of digitilisation in solar raises the threat of cyberattacks

Digitalisation and the effect of lockdowns

The solar sector is embracing digitalisation little by little. The lockdowns that were put in place due to the COVID-19 pandemic have resulted in a speeding up of digitalisation efforts. Companies both in and out of the energy sector have become more reliant on digital tools for their day to day running, with many employees working from home. Significantly more business is therefore being conducted via calls and emails over a face-to-face conversation between colleagues. Whilst this may have affected the awareness of the importance of digital services, it has also increased the risk of a cyberattack.

"The threats and dangers have grown during the lockdown period because of that increased reliance," according to Geoff Taunton-Collins, senior analyst at renewables insurer GCube. Taunton-Collins says that when compared with other risks solar assets see, the cybersecurity threat level is "reasonable but growing".

This is echoed by Marek Seeger, information security manager at SMA, who says that solar is "becoming a more interesting target for hackers" as the technology takes a larger role in power supply as a result of decarbonisation and decentralisation efforts.

In particular, small and medium-sized solar systems are in danger, he says, with >1MWp plants usually integrated, connected and maintained "in a professional way that includes all relevant safety measures".

One way hackers can artificially create a malfunction in a PV system is to launch cyberattacks to the inverter controls and monitoring system, according to Ali Mehrizi-Sani, associate professor at Virginia Polytechnic Institute and State University and co-author of a 2018 paper assessing the cybersecurity risk of solar PV units with reactive power capabilities.

"This is a vulnerability that can be, and has been, exploited to attack the power system," he says, pointing to how the large number of PV units in the power system – including rooftop solar – means that there are "lots of attack points", underscoring the importance of cybersecurity at the inverter level.

Keeping cybersecurity measures up to date is therefore incredibly important for solar installers and operators, particularly due to the 15-20 year lifetime of a solar farm, meaning that cybersecurity will need to continue to develop as the farms age, with up to date measures allowing operators to stay ahead of hackers.

This can, however, be made difficult by a lack of awareness over cybersecurity. Cyberattacks on renewables assets are underreported, according to GCube's Taunton-Collins, occurring because it's "easier to keep quiet than other industries".

Most cyberattacks result in data breaches, such as the cyberattack on EDP in April 2019. The Portuguese energy firm was hit with a Ragnar Locker ransomware, with over 10TB of sensitive company files stolen. When third-party data is leaked, it has to be reported to the authorities of the country it occurred in, as well as an alert sent to the people whose data has been stolen.

However, attacks on renewables assets are more likely to be business disruption attacks, which are private and internal, due to many not holding third-party data. Asset owners therefore often have no reason to publicise that an attack has taken place. Furthermore, releasing information on this sort of attack can hurt the reputation of both the company and potentially of the industry itself, leading to some asset owners keeping quiet.


Credit: BayWa r.e.

As a potential weak spot, inverters are the focus of a research project in the US looking to develop new measures for protecting PV systems

One cyberattack on a solar farm that did end up hitting headlines, however, was on US solar operator sPower, which occurred in 2019. It didn't result in any blackouts, and sPower – which owns and operates over 150 renewable generators in the US and recently concluded financing for the 620MWdc Spotsylvania Solar Energy Center, its biggest ever project – has been unsurprisingly tightlipped about the incident.

Pay out or lose out

There is a wide variety of outcomes when a solar asset owner is targeted by hackers. When hit with a ransomware attack, the figures demanded by hackers can climb to astronomical heights. The asset owner is then left with two choices: pay up to resolve the situation or replace its computer systems completely and start afresh. However, this itself is not a perfect solution. Replacing computer systems is a costly and time-consuming endeavour. Everything must be migrated over to the new system, a disruption which can often be underestimated by asset owners.

In 2016, a SABELLA tidal project in France was rendered inoperable for two weeks as a result of a ransomware cyberattack. Similarly, Norsk Hydro was attacked by ransomware in 2019. The company – which deals in both renewable energy and the manufacture of aluminium – didn't pay the ransom, a decision that left it recovering for many months after and cost it over £45 million.

"These things can really quite cost you when they hit, as Norsk Hydro found," Taunton-Collins says.

It's not just the costs of replacing systems; fines can be levied by the grid operators of the country affected. If a particular asset has an agreement in place to provide a certain amount of energy but is unable to due to a cyberattack, then fines or penalties may be imposed due to the failure to meet targets, resulting in a shortfall or, in extreme cases, a blackout.

With the stakes – and resulting costs – so high, measures which can mitigate the risk and protect asset owners from cyberattacks are crucial. Daily backups of data are a start, particularly of important or pertinent data. Staff training, as well an access of least privilege system – meaning that workers only have access to systems required for their jobs rather than everyone having access to everything – are also measures that can help boost security. Alongside this, multifactorial identification and changing passwords from the default – which are often available online and therefore easy for a hacker to get a hold of – can help.

SMA's Seeger suggests that to help solar assets improve their security across the board, there needs to be "central and uniform directives on an EU level". Manufacturers also need to ensure that their devices adhere to the highest standards of cybersecurity while installers and operators must provide for secure integration, he continues.

Seeger points to how the inverter manufacturer is a part of SolarPower Europe's Digitalisation and Solar Workstream. In May 2017, SolarPower Europe's Digitalisation and Solar Taskforce published its 'Seven Commitments on Digitalisation', with an aim of helping the solar industry fully transition to digitalised solar.

Among these were commitments to data protection and cybersecurity, with the document stating that "we will champion data protection", and recommending that all active parties in the solar industry implement "state-of-the-art" data protection alongside committing to putting "stringent cybersecurity measures" in place.

The taskforce then called for policy changes to help guarantee these high standards. Mercè Labordena, senior policy advisor for digitalisation at SolarPower Europe, says that due to new threats being created and those already existing evolving, the European solar industry needs to "constantly adapt its response".

This requires a holistic approach to be adopted, Labordena continues, helping to "increase the cyber-resilience of the solar industry and working together on all levels, from citizens and companies, to member states".

Innovating to keep up

However well protected an asset is, it is still possible for it to be hacked. New solutions are, however, being developed to help to keep up with the evolving threats.

A research project is underway in the US, led by the University of Arkansas, with an aim of developing systems to protect solar technologies from cyberattacks. The project – dubbed Multilevel Cybersecurity for Photovoltaic Systems – was awarded US$3.6 million from the US Department of Energy (DOE) Solar Energy Technologies Office, and is to focus specifically on inverters with a plan of addressing issues such as supply-chain security and real-time intrusion detection methods. Researchers are also looking into identifying and mitigating vulnerable spots, control system security and safety protocols.

Commenting at the time of the original project announcement in April 2020, principle investigator, professor Alan Mantooth, said that the DOE was aware of the "critical importance" of protecting solar systems, with the new research group "nicely qualified" to help address the problems around cybersecurity.

On that note, a new US solar cybersecurity initiative was created in June 2020. The Cybersecurity Advisory Team for State Solar (CATSS) was created by the National Association of State Energy Officials and the National Association of Regulatory Utility Commissioners, with additional support provided by the US Department of Energy Solar Energy Technologies Office.

The CATSS is to identify model solar-cybersecurity programmes and actions for states to take in partnership with utilities and the solar industry, creating actionable solar cybersecurity strategies and roadmaps.

It is hoping to work with both federal and private-sector stakeholders to mitigate cyber risks, using a state-led advisory group and dialogue with solar and cybersecurity experts to advance education, tools and access to technical assistance.

The question remains, however, as to whether the onus should be on the industry to put in place the innovations and high levels of cybersecurity measures needed to protect their own systems and assets, or if governments should be legislating to ensure a standardised, high level of security is met.

"Since Europe has an interconnected power transmission system, uniform European specifications should play the leading role here," SMA's Seeger suggests when asked about the topic. However, he continues to argue that aside from that, manufacturers should be putting the highest priority on the cybersecurity of their products, stating that these high levels of security standards can only be achieved if all the parties involved, including manufacturers, plant owners and operators, "make constant efforts to ensure adequate cybersecurity".

Whilst it isn't the most common problem for a solar farm to run into, the threat of a cyberattack is still present. Not only that, it is ever-evolving and becoming more prevalent as solar transforms into an increasingly digital-reliant industry.

Energy infrastructure is "one of the most critical assets of a modern society and a backbone for its economic activities", SolarPower Europe's Labordena says, with cybersecurity and data protection no longer isolated issues, due to the "ever-increasing integration of all sectors of the economy via electrification" and the adoption of digital technologies. As more devices become digital, smart and connected to the power system, the risk of cyberattacks will only continue to grow with them.

As Labordena puts it: "For this reason, cybersecurity needs to be at the top of the agenda of Europe and the European solar industry".

The same could no doubt be said for solar markets around the world.

ROADMAPS AND POLICY DECISIONS: How cybersecurity factors into policymakers' agendas

Cybersecurity for the energy system – and solar PV in particular – has not necessarily been overlooked by policymakers across either the EU or the US. In the EU, a report from the Energy Expert Cybersecurity Platform (EECSP) was published in 2017, making several recommendations to the European Commission on cybersecurity in the energy sector.

Four priorities were outlined, including setting up an effective threat and risk management system, an effective cyber response framework, continuously improving cyber resilience and building up the required capacity and competences in cybersecurity for the energy sector.

Following this, in 2019 the European Commission published its recommendation on cybersecurity in the energy sector. It highlighted how the main issues relating to cybersecurity in the energy sector are namely real-time requirements – with some elements of the sector finding it difficult to implement cybersecurity due to having to work in real-time - cascading effects due to the interconnection of electricity grids and gas pipelines across Europe and the combination of legacy and state-of-the-art technology.

Several measures to solve these issues were outlined, including – but not limited to – recommendations for energy network operators to apply the most recent security standards for new installations wherever adequate, as well as formulating tenders with cybersecurity in mind. This would include demanding information about security features and compliance with existing cybersecurity standards.

Meanwhile in the US in 2017, Sandia National Laboratories was given funding by the US Department of Energy (DOE) Energy Efficiency and Renewable Energy Solar Energy Technologies Office to create a five-year roadmap for photovoltaic cybersecurity.

This roadmap identified several existing barriers – the unpredictability of cyber threats, the regulatory uncertainty of PV cybersecurity and the insufficient sharing of threat, vulnerability, incident and mitigation information among the government and industry – and set out six clear goals to achieve in the following five years.

The DOE stated in March 2019 that the roadmap was helping to create "a path for improving cybersecurity" where there are "clear roles and responsibilities for government, standards development organizations, vendors and grid operators".

Then in June 2020, the DOE released a cybersecurity roadmap for wind, stating that whilst it was wind-specific, the roadmap's strategies were "likely to be applicable to other forms of energy".

Presented to you by:

STORAGE & SMART POWER

Energy Storage NEWS

Introduction

Welcome to another edition of 'Storage & Smart Power', brought to you by Energy-Storage.news.

Well, the global COVID-19 pandemic is still with us and on top of that much of the US' West Coast is being ravaged by fire as we speak. Somehow we will get through this year, but it's been a difficult one for many and by now a lot of us are wondering what on earth can happen next.

On the one hand we've seen a reduction in global emissions that may have given us a minor 'silver lining' and on the other we realise that that temporary slowdown means almost nothing when there's still so much to be done. It isn't good enough to remain inert or even obstructive on solving the climate crisis. Even those that have a hard time accepting the scientific reality of climate change are being confronted with the truth of air pollution and the limited resources of a planet - and a global population - under extreme pressure.

As you've probably already seen from the main PV Tech Power journal this quarter, the clean energy industries are responding not only to that call, but are also scaling up and progressing rapidly, because that's what smart industries full of smart people do.

In this section of the journal, we hope to give you a lot to think about and perhaps even embolden you - the industry - towards finding some solutions to the big questions, whether those are technical, environmental, economical or even policy-driven.

I've been lucky enough to speak with some real industry thought-leaders for my feature article, 'For lithium to still lead the way…'. EIT InnoEnergy's Bo Normark, Cadenza Innovation's Christina Lampe-Onnerud and Aceleron's Amrit Chandan all had fascinating and particular takes on whether lithium-ion can maintain its market leadership and what needs to happen for lithium batteries to continue improving. Safety, sustainability, transparency and more come under the spotlight.

On a closely related note, the experts at Photovoltaik Institute Berlin (PI Berlin), have contributed 'What you should know about manufacturing lithium-ion batteries'. The authors look not only at the complex process of cell manufacturing, but also what it takes to then put those cells into a full-on battery energy storage system and crucially, what the quality control measures are that are essential to put in place.

Further downstream, Naim El-Chaimi of consultancy Clean Horizon has offered up an in-depth take on the present and (likely) future market opportunities for energy storage in Europe, with 'Europe's energy storage transformation'. From the collective frequency control reserves procurement shared by six European nations, to individual deep dives into opportunities - and challenges - in France, Italy, Spain and Portugal, this detailed article offers up many insights.

Last, but certainly not least, Janice Lin, founder and president of the Green Hydrogen Coalition discusses 'Green hydrogen: the zero-carbon seasonal energy storage solution'. Many of you will know Janice Lin not only from her role as CEO of consultancy Strategen but also as the long-time leader of the influential California Energy Storage Alliance. In her article, Lin explains how discovering the potential of green hydrogen was a 'Eureka!' moment for her and explains why you should think about it too.

We're in difficult times, but I'm confident that we've got some great people working on this. As Christina Lampe-Onnerud of Cadenza Innovation, puts it: "Everybody has a responsibility to get involved, we don't have a lot of time and we have an enormous opportunity".

Andy Colthorpe, Solar Media

NEC crashes out of the industry

NEC's Energy Solutions division, which has been responsible for NEC Corporation's activities in battery energy storage, is leaving the industry.

The Massachusetts-headquartered division was previously known as A123 Energy Solutions and has been a subsidiary of the Japanese electronics major since its acquisition in 2014 for US$100 million, when it was the energy storage systems business of lithium battery maker A123 Systems, owned by Chinese automotive components company Wanxiang.

The company has since delivered 986MW across 141 battery energy storage projects in the grid-scale and commercial sectors. A report by Bloomberg said that despite this, the subsidiary has never turned a profit, while a plan to sell the division off had been "thwarted" by the COVID-19 pandemic and an "orderly winding down" has been announced to customers.

Despite nearly a gigawatt of projects since 2014 including New York's first 20MW grid-scale system (pictured), NEC struggled to turn a profit in its battery storage business.

Siemens Energy to develop thermal energy storage with startup EnergyNest

Siemens Energy has formed a partnership aimed at sustainably decarbonising the industrial sector with Norway-headquartered thermal energy storage company EnergyNest.

EnergyNest makes what it calls Thermal Batteries, where a specially formulated concrete (which the company has trademarked Heatcrete) is heated using high temperature heat transfer fluid (HTF) that passes through steel pipes inside the units. Siemens has already worked with EnergyNest including a 1MWh project begun in 2015 to verify the technology at Masdar City in Abu Dhabi.

51MWh vanadium flow battery system ordered for wind farm in northern Japan

Transmission and distribution network operator Hokkaido Electric Power has contracted Sumitomo Electric Industries to supply a grid-scale flow battery energy storage system for a wind farm in northern Japan.

Sumitomo Electric will begin constructing the 17MW / 51MWh vanadium redox flow battery (VRFB) system on the island of Hokkaido during this Japanese financial year (JFY), capable of storing energy for three hours and connected to the wind farm. The project will be completed by the end of March 2022.

Sumitomo Electric has already deployed the world's biggest flow battery system so far, in the same region. Completed in 2015, that demonstration project was 60MWh total capacity. The company has also done smaller projects in territories including the US and Europe.

Li-ion cell prices predicted to almost halve in price by 2029

Lithium-ion cell prices will fall by around 46% between now and 2029, according to new analysis from Guidehouse Insights, reaching US$66.6 per kWh by that time.

A report published by Guidehouse in May predicts that the most substantial price declines are expected to be seen in the next five years, "before decline rates gradually reduce". Today, cell prices are in a range of between US$98.6 per kWh for the lowest and around US$192.3 per kWh, averaging out at US$122.9 per kWh. By 2024, this average base price will drop to US$86.2 per kWh.

Tesla in Battery Day teaser

Tesla CEO Elon Musk and fellow executives talked up the potential for Tesla Energy to reach "roughly the same size" as the company's automotive business in an earnings call with analysts in July.

Musk trailed the forthcoming Battery Day planned for September when a 'big reveal' of developments in battery tech and supply chains for the company is expected, while also shedding light on some strategy and dynamics of that side of the business.

The CEO said that the "real limitation on Tesla growth is cell production at affordable price," and that this "fundamental scaling constraint" would be addressed on Battery Day, referring to pricing and logistics in every step of the supply chain as potential factors "that will set the growth rate".

US regulator FERC takes 'most important' step towards clean energy transition

What has been described by the head of its federal regulator as the "single most important act" the US could take in smoothly transitioning to a "clean energy future" will become reality, with distributed energy storage set to join wholesale markets and compete to provide services on a "level playing field" with fossil fuel resources.

The United States Court of Appeal in the District of Columbia (DC) ruled in early July to deny petitioning from the National Association of Regulatory Utility Commissioners (NARUC) as well as the American Public Power Association and others, to prevent the passing of the Federal Energy Regulatory Commission (FERC) ruling FERC Order 841.Order 841 states that barriers to distributed and behind-the-meter energy storage participating in wholesale electricity markets should be removed.

'Largest standalone battery project' in Texas' ERCOT market under construction

Construction on a 100MW battery energy storage project in Texas has begun through partners Able Grid Energy Solutions, MAP Energy, Astral Electricity and Mortenson.

Developer Able Grid announced that full notice to proceed has been issued on the Chisholm Grid battery energy storage system, which will have an initial rated capacity of 100MWac and is scheduled to begin operations in mid-2021.

Like several other large-scale battery storage systems already built or under development in Texas the plant, located in the city of Fort Worth, will play into the Electricity Reliability Council of Texas (ERCOT) market.

Serving between around 75% to 85% of the US state's electricity demand through operating the electric grid and managing the deregulated electricity market, ERCOT performs financial settlements for sellers and buyers of power as well as planning the power generation mix on its grid.

What you should know about manufacturing lithium-ion batteries

Quality | Ensuring high quality levels in the manufacturing of lithium-ion batteries is critical to preventing underperformance and even safety risks. Benjamin Sternkopf, Ian Greory and David Prince of PI Berlin examine the prerequisites for finding the 'sweet spot' between a battery's cost, performance and lifetime

The proliferation of rechargeable lithium-ion batteries used in a wide range of applications has moved the technology clearly into the public eye. Debate about various battery types, their properties, cost and performance have become popular topics in private and professional discussions.

However, most of these discussions tend to put an excessive emphasis on the chemistry of the cells in the batteries. For example, whether a lithium iron phosphate battery is safer than a lithium-nickel-manganese-cobalt battery. In truth, battery performance is affected by not just one, but up to five primary factors: cell chemistry, cell geometry, manufacturing quality, matching technology to application, and system integration.

Cell chemistry is considered to be the "tip of the iceberg". It is the most visible characteristic, but the actual performance of battery systems in real-world applications seldom depends to a large degree on the cell chemistry. More often it is one of the other five factors.

Manufacturing quality is one of the most critical factors, but also least discussed. The cause for this is likely that cell chemistry and geometry can easily be discussed based on the multitude of information available in the public domain. Matching of the most suitable battery chemistry to the application is a topic that can be simulated and discussed with modern computing tools. Manufacturing and manufacturing quality, however, is typically an in-house secret of each manufacturer – and often exposes clear differences between manufacturers even when using the same chemistries. There is little incentive for manufacturers to have details about their manufacturing processes published in any form.

The manufacturing quality of lithium-ion batteries is a key determinant of lifetime performance

What is a "battery energy storage system"?

The term BESS, or battery energy storage system, refers to a system that is more than just a battery. For a battery to function efficiently it needs additional components. A BESS typically includes a power conversion system, otherwise known as an inverter, which includes bi-directional power electronics used to charge and discharge the battery simultaneously. A power control system informs the inverter when to charge and discharge batteries. Additional cooling and fire-fighting systems are installed to prevent and contain any thermal related events. And finally, auxiliary power supplies as well as a storage container are needed to support and house the overall system.

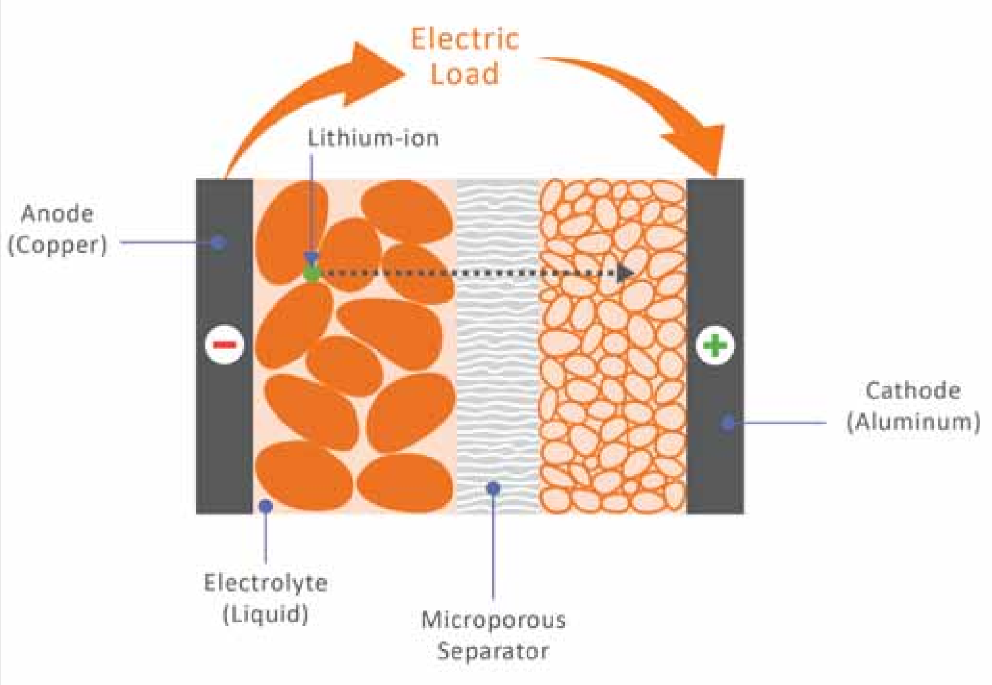
Due to the complexity of a complete BESS, this article focuses on the batteries and their manufacturing only. For real-world projects, it is advised to keep in mind that the battery is only one part of the overall system. The other components and the interactions between them need to be evaluated with the same care to achieve high levels of BESS performance and safety.

Structure of a battery rack

Before examining how battery cells are manufactured, it is good to understand how a battery rack is organised. Battery cells are similar in design to cell phone or laptop computer batteries, except that they are much larger. Cells are combined into a cell block using either a serial or parallel connection. Cell blocks are assembled into modules with communication ports to measure temperature and voltage. These modules are then connected within a rack, which provides the serial connection for battery modules. The battery rack will also include an upstream control system known as switchgear, which provides current sensors and communication protocols. It is important to note that this arrangement is based on IEC standard terminology and some may use different terminology.

Design of a battery cell

The purpose of a battery is to move electrons from the anode to the cathode while discharging the battery. This is accomplished by having lithium-ions, positively charged particles, moving through a microporous separator that is filled with an electrolyte, which prevents the passage of electrons. This process is sandwiched between a negatively charged copper collector and a positively charged aluminum collector. It is important to have homogenous surfaces to allow the lithium-ions to pass through easily.



Cell manufacturing is a complex process requiring careful quality control

Manufacturing of a battery

At first glance, a battery has cells, modules and strings – which makes it similar to a PV panel. However, major differences become obvious when comparing the individual cells. A PV cell operates according to the quantum photovoltaic effect; a battery cell relies on chemical reactions. The operating principle of a battery is more like a chemical process engineering plant, and as a result the manufacturing processes differ significantly.

Unlike PV cells, lithium-ion battery cells need to be monitored individually for voltage, current and temperature for safety and performance reasons. The quality and accuracy of the battery management system plays an equally important role in the performance and safety of the overall battery system. That means all processes related to the manufacturing of the corresponding electronics need to be managed similarly to the production of a PV inverter.

Making a high performance, safe battery system is not rocket science, but it does require extensive diligence. The main challenge is in creating a three-dimensional structure (a round or prismatic cell) out of a largely two-dimensional structure (layers of foil).

As an example, a common 50MWh BESS will have a surface area in the magnitude of 500,000 square meters (i.e. approximately 5,000,000 square feet) of electrode pairs. That's equivalent to the area of 70 soccer fields. If the BESS were coupled to a 50MWp PV power plant, the surface area of the battery cells would be larger than the surface area of the PV panels charging them.

To manufacture these cells, it is critical to create this surface with extreme precision. A common benchmark is that the maximum deviation of surface thickness should not exceed 1% to 2%. If a manufacturer exceeds this, the battery runs a higher risk of becoming a safety hazard and suffering accelerated performance degradation.

The manufacturing of a battery can generally be separated into four major steps:

1. Initial quality control and electrode production
2. Cell stack assembly
3. Drying, electrolyte filling, formatting, ageing, and sorting
4. Assembling cells into a battery

Step 1: Initial quality control and electrode production

As with any manufacturing process, it is crucial to verify that the materials and processes meet product quality requirements, such as:

- Are the raw materials of the required purity?
- Does the residual humidity within the electrolyte meet the set limits?
- Are the critical operations and process checks fully automated or do they depend on the attention and qualification of individual personnel?
- Is the machinery calibrated and cleaned in order to avoid cross-contamination between different production processes?

To manufacture cells, there are two required electrodes: the anode and the cathode. There needs to be an aluminum foil associated with the cathode material, and a copper foil plated with the anode material.

Step one is to produce active materials through mixing. Dry materials are added into the mix for the storage of lithium ions, but also for electrical conductivity. Then a solvent is added to the mix for the application of the active material onto the foils. The goal is to coat the foil with larger particles of the active material and smaller particles for the electrical conductivity. A binder is also added to help the material stick to the foil.

The mixture, also referred to as "slurry", needs to be evenly distributed so that it will lead to good conductivity both electrically for electrons to reach the foil and ionically for the lithium ions to pass through the material itself. This is one of the most critical parts of the cell manufacturing process.

The mixture needs to be homogenous, which can be very tricky because large and small particles don't like to mix together, nor stay that way. An example would be adding large and small stones to a box. When shaking the box, the different stone sizes will have a tendency to separate from one another. In order to achieve a homogenous mixture it is critical that this step be managed carefully.

Once the homogenous active materials are created, they need to be coated onto the substrate foils. Coating foils is a critical step. It's important that the foils be coated in a consistent way and with minimal defects. This process requires creating a continuous, defect-free foil. If one section of the foil is defective, the entire length is discarded. This is a step where a manufacturer can decide to cut corners and allow defective rolls to be used, otherwise they would be throwing away valuable material. The continuous nature of some of these processes makes it very important that they are monitored closely by appropriate sensors and qualified personnel.

Once the foil has been coated it is checked for thickness. If the coated foil meets the specifications, it is processed through a drying machine because the foil itself is wet. There is solvent in the foil, which needs to evaporate to ensure a solid coating on the surface. Running the next batch of foil is critical at this time because as foils are stacked there needs to be coating on both sides.

Calendering is the compression stage for the active materials on the foil. The foil coating will have shrunk slightly during the drying process. Without compression the ions will pass easily but will have difficulty passing electrons due to internal resistance. Furthermore, calendering increases the energy density of the coating. After calendering there is a cutting process for the foils. The result will be stacks of anode and cathode sheets that can now be used for the production of the actual cells.

Step 2: Cell stack assembly

With the cathode and anode sheets separated, the next step is to stack the copper foils and aluminum foils with a separator in between. The separator serves to keep an electrical separation between the active materials, but to allow lithium ions to pass through the electrolyte. When stacked they become battery cell stacks. There are several different methods to create the stacks, such as rolling, stacking or z-folding. The possibilities are constrained by the desired cell geometry.

The completed stacks are inserted into a case and the external terminals are connected. The cell is then sealed shut through vacuum sealing or welding.

Step 3: Drying, electrolyte filling, formatting, ageing and sorting

Residual humidity inside the lithium-ion cells is a critical factor that affects the ageing and degradation characteristics of the cell. To reduce it, the assembled cells are left in a drying oven for hours to days. Longer drying periods improve the durability but increase production cost.

The separator foil between the cathode and the anode is not conductive to the lithium ions. For the cell to function, an electrolyte needs to be introduced into the dried cell. An opening in the case allows humidity to evaporate and provides the manufacturer an access point for adding electrolyte filling. The electrolyte is usually a lithium salt mixed into a solvent. This step is followed by the final sealing of the cell.

Lithium ion cells have one important chemical difference to other cells – they come in a discharged state. To make the cells operational they must first be charged and discharged through a series of cycles. During the first charging something very important happens. The formatting creates a protective layer on one of the electrodes, which is excellent for the lifespan of the battery cell. For this to be effective it must be produced correctly, or the cell will quickly degrade. Similar to the drying process, slow formatting improves the durability of the cell, but increases the production cost.

Ultimately, the cells are inserted into a hot ageing chamber for several days to identify any defective cells. Afterwards, they are graded and sorted into different qualities in accordance with the customer's requirements.

Step 4: Assembling cells into a battery

Cells need to be assembled to make a complete battery. There may be the option of adding a cooling system before the module is sealed. Voltage sensor wires and temperature sensors are added to the module. Other options include installing fuses, fans or sealant depending on the application. The battery is run through a series of tests including high voltage testing, internal resistance testing, load testing and capacity testing.

Adding a cooling system is an option before cells are assembled into a module


2-4 December | The NEC, Birmingham
SOLAR & STORAGE
LIVE UK 2020
BOOK NOW
Bringing together the solar, storage & EV industries to power the energy system of the future.
4000+ Attendees
250+ Speakers
150+ Exhibitors
120+ Start-Ups
Co-located with:
CHARGE UK 2020
terrapinn.com/SSL/SolarMedia

Managing manufacturing quality

Battery manufacturing is a complex production process featuring over 170 individual steps between quality control and production. Some of the most critical quality parameters include residual humidity and surface homogeneity. The impact of poor manufacturing can cause the cell to degrade very quickly. Cell capacity can be reduced after only a few cycles, or if cells remain inactive, they will be more prone to self-discharge. If the production process is managed poorly safety hazards can also be produced. For example, poor surface homogeneity can generate small spikes that can punch through the separator and generate a short circuit inside the cell.

Making good quality batteries is complex and needs high levels of control and precision. Quality management in manufacturing is therefore key to delivering a performing and safe battery. Quality management often comes down to practical and financial questions – specifically:

1. Making the "perfect" battery is expensive. The main cost factors are production time and raw material costs. It is possible to make batteries that last 15,000 cycles and 20 years. However, the cost would be prohibitive and, in reality, 3,500 to 4,000 cycles and 10 years are good enough for most applications. The recipe for making such a battery is not about making a "perfect" battery, but about finding the sweet spot between cost, performance and lifetime.
2. Mistakes happen. Just as in any other production facility, quality management depends a lot on the culture and processes in a company. The question is not if errors happen in the factory, but whether the manufacturer has the right processes and skilled personnel in place to identify and rectify them promptly and appropriately.
3. Being a critical customer. Most cell manufacturers provide cells of the same type at different quality levels. By default, it's likely that buyers will be sold the most basic grade that only just pass the quality requirements. To get a consistent, high-quality battery, buyers need know how to specify what they want and are able to check during and after production.

It is not always possible to check the most important qualities of a battery when you have the final product in your hand. So as a buyer, what are the practical options to manage quality and safety?

Value of an energy capacity warranty

A practical measure is to obtain a warranty covering the energy capacity of the BESS or battery system being purchased. The warranty may also be called a battery performance warranty. It is a robust legal tool to secure against improper sizing or accelerated degradation. However, this warranty has some limitations similar to those of any product warranty:

- A warranty is reactive, not proactive. It only becomes active once the energy capacity of the battery system has been proven to be insufficient. It does not address the problem of manufacturing quality at its root cause, nor does it prevent failures or underperformance from occurring in the first place.
- The bankability of a warranty depends on the warrantor. If relying on an energy capacity warranty, the warrantor must still exist at the time a case of warranty is identified.
- A warranty claim always bears additional costs for the buyer or owner. For a BESS, these are typically legal costs and any costs for balance of plant extensions required to fit the additional battery systems that the warrantor provides to remedy the lack of energy capacity. There may also be other costs incurred by the BESS owner during the process of making and establishing a claim for which there will be no reimbursement from the manufacturer.

Therefore, it is good business practice to accompany the energy capacity warranty by the following proactive measures to manage quality.

Type testing

Cells and the battery system can be type tested. This type testing can cover both safety and performance characteristics. Type testing usually provides a good insight about the general quality of a battery system. However, it also has the following limitations:

- Cells for type testing are usually manually selected by the manufacture. This bears the risk of "cherry picking" the best cells for testing.
- As mentioned above, most manufacturers have different grades of the same cell. There is no certainty that the sample cells provided will be manufactured using the same raw materials, production line and grading criteria as will production cells.
- Performance type testing is time consuming. When testing whether the cyclic ageing of a cell is in compliance with the requirements, a test for 4,000 cycles takes approximately one year. That amount of lead time is usually not available in real-world projects and the products being manufactured could well have changed during that time.

Therefore, type testing addresses some of the concerns about proactively managing battery quality, but it needs to be accompanied by other processes.

Manufacturer auditing

Let's assume a battery manufacturer has the right product at the right price, with a sound energy capacity warranty and a battery type that has passed all the performance and safety tests an advisor or engineer has recommended – what quality

Warranties offer some protection against underperformance but do not prevent this happening in the first place

related risks should still be considered and how should they be managed?

The first is to review the factory of the manufacturer in person and in detail. The best time to do this is before closing the supply contract. This review is called manufacturer (factory) auditing and usually covers the following:

- Are the incoming materials used for production checked appropriately?
- Is the battery production process managed and supervised appropriately?
- Does the manufacturer comply with an appropriate level of production care to meet the economical "sweet spot" or does the manufacturer take impermissible shortcuts?
- Are the required and appropriate quality checks carried out after each step to verify the product is suitable for the next steps?
- How are errors and rejected materials handled? Are the conclusions fed back into the production process?
- How is the final product checked, tested and graded?
- Does the manufacturer respect the compliance requirements of the customer? Does the manufacturer comply with the applicable environmental and occupational hazard requirements?

The manufacturer audit provides insights on these questions and gives a much higher degree of confidence that not only is the battery design sound, but that the manufacturing process to build it is also of a high, consistent quality.

Production witnessing

Ultimately, once the supply contract is signed and the battery for a project is in production, it is imperative to verify that the manufacturer maintains a high level of quality during the actual build of batteries that will be installed – especially if corrective action was undertaken to address weaknesses after the manufacturer audit was conducted. This method of 'live' quality assurance is called production witnessing and typically consists of a third party supervising all the key process, testing and inspection steps in making the finished batteries. After production witnessing has given the green light, the battery is ready for integration and shipping to site – to hopefully enjoy a long reliable, safe life delivering dependable, electric power. ■

Authors

Benjamin Sternkopf has the degree of Dipl.-Ing. (German equivalent to MSc) in electrical power engineering from RWTH Aachen University, Germany. He has worked exclusively in energy storage with a strong focus on battery energy storage systems since 2011. His track record includes milestone projects such as the first commercial large-scale BESS in Europe (WEMAG Schwerin, 10 MW / 10 MWh, 2012), the first multi-purpose BESS in the UK (Leighton Buzzard, 6 MW / 10 MWh, 2014) and the first large-scale BESS in Mexico (Aura Solar, 10 MW / 5 MWh, 2018).

Ian Gregory began his solar career in 1998 working for the Royal Dutch/Shell Group Companies as new technology manager within the solar division in Europe. He became Global Product of the Shell PV panel manufacturing business after it was acquired from Siemens in 2001, working both in the European headquarters in Amsterdam and the North American headquarters in Camarillo, CA. Ian became director of product marketing at Evergreen Solar in 2006 and left in 2011 to form SolarBuyer with a former colleague. In 2018, SolarBuyer was acquired by PI Berlin. Ian now runs the US division of PI Berlin. Ian has a master's in mechanical engineering from the University of London (UK).

An accomplished digital content producer and marketing professional, David Prince has long been interested in contributing to environmental sustainability. He has an extensive background in cable television, information storage and higher education. As a content producer, he has served small enterprises to large corporations. David holds degrees from the University of Rhode Island and Fairfield University.

Europe's energy storage transformation

Storage applications | Energy storage systems were historically used for grid balancing purposes within Europe, limiting their use to such applications or to be considered as "auxiliaries" to renewable generation assets. However, as market prices evolve and new revenue streams emerge, stakeholders must discover the diverse applications that such systems can tap into, writes Naim El Chami

Credit: Alfen

Opportunities for energy storage in Europe are gradually scaling up from early pilots and one-offs

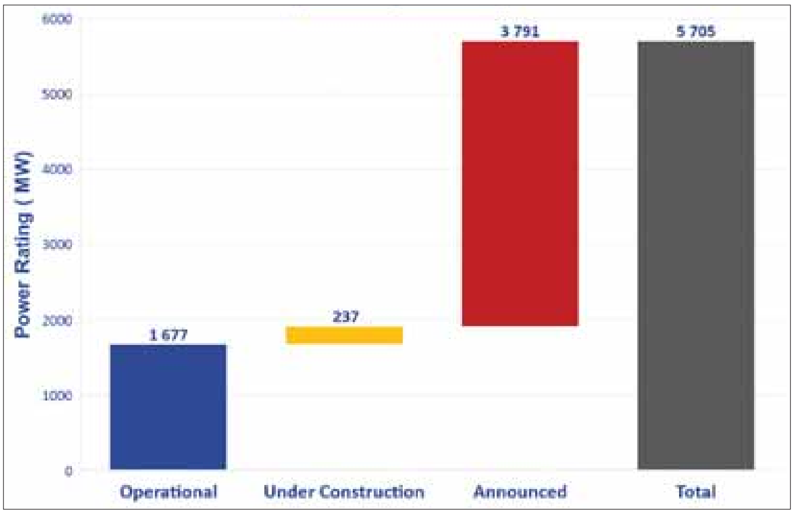


Figure 1. European large-scale energy storage projects by status as of August 2020

The European energy storage industry has witnessed remarkable growth over the last decade, going from 9MW of project announcements in 2010 up to a total of 5,700MW in 2020 (year to date). Out of these projects, around 1.7GW are operational while the remaining 4GW are either announced or under construction (Figure 1) [1].

Such uptake has been predominantly led by frequency control applications. However, things are changing as new revenue streams emerge and market prices tend to decrease.

The rise and fall of the frequency control bonanza

European frequency control markets played a major role in energy storage uptake thanks to lucrative revenues and accessibility to new technologies such as batteries. In fact, batteries are well suited for primary reserve provisioning thanks to their fast response and the assets get remunerated by the grid operator for each MW available (payments in €/MW/h) to ensure system resiliency.

In Western Europe, 3GW of frequency control reserves (denominated Frequency Containment Reserves, or FCR) are jointly procured by six countries on a common platform. The current FCR auction takes place daily and involves Germany (603MW), France (561MW), the Netherlands (74MW), Switzerland (68MW), Austria (62MW) and Belgium (47MW) with Denmark (DK1, 30MW) expected to join soon, as well as Spain (275MW) and Poland (168MW) in the years to come. Currently, 477MW of battery storage systems are already delivering this service (out of which 87% are located in Germany) with an additional 209MW on the way.

For each country, the frequency containment reserve requirement is based on the ratio of the yearly national production (in MWh) to the yearly total production over the synchronous

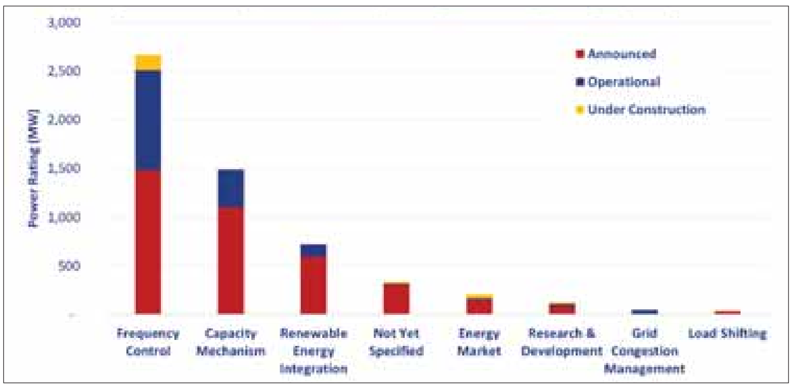


Figure 2. Most common applications for European large-scale energy storage systems

European area. Procurement targets slightly vary every week based on TSO (Transmission System Operator) requirements and past years' production. In fact, 30% of each country's reserve must be nationally sourced and the exports to other FCR Cooperation members are limited to the maximum between 100MW and 30% of each capacity block.

However, this market's revenues fell from an average of €26/MW/h in 2015 and €18/MW/h in 2017 to as low as €5/MW/h in early 2020. Henceforth, this market could no longer justify project viability by itself, requiring new and additional revenue streams.

The fall in FCR prices and the impact of energy storage systems

Frequency Containment Reserve auctions take place over the Regelleistung platform. Until July 2019, these auctions used to occur on a weekly basis before shifting to a daily one as products were procured on a day-ahead term. The older auction model incentivised bidders to "guess" bidding prices, rendering them unrepresentative of the actual merit order of FCR resources.

Another change took place on 1 July 2020 as the FCR auction timeline was once again changed: instead of bidding for 24-hour products, market participants are now able to bid daily for six four-hour delivery periods. This evolution offers more flexibility to market participants, allowing them to participate in other markets and diversify revenue streams within the same day. Thus, a better market transparency is expected since FCR prices will probably reflect market conditions (higher prices in the day, lower in the night).

This evolution can be seen in Figure 4 that represents marginal FCR prices over the last three years. The most significant event is the sharp decrease of market revenues as prices fell from an average of €18/MW/h in 2017 to as low as €5/MW/h in early 2020. Such price fall renders the new market evolution even more crucial to ensure project viability through multiple revenue streams that will be discussed in the next part of this article.

One of the price fall causes is the high volume of battery storage uptake: there's about 477MW of storage providing FCR services, which lowers prices as batteries are inherently more competitive than any other participant in this

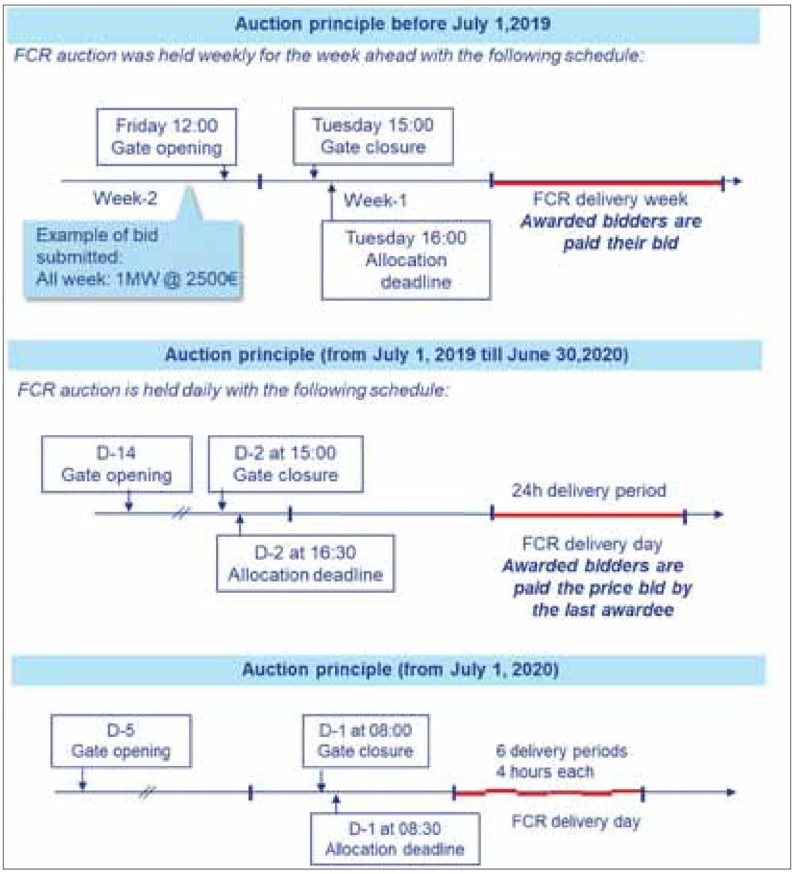


Figure 3. FCR auction timeline

market since the marginal price for FCR provisioning is lower. Such impact was witnessed in multiple cases such as the French one following the conclusion of its long-term capacity market auctions (*"Appel d'Offres Long Terme"* – AOLT) through which 253MW of battery storage systems were contracted out of a 377MW total of new capacity uptake (Figure 5).

A Clean Horizon analysis shows that the deployment of 100MW of new battery storage capacity could lead to an 18% fall of FCR revenues, which is directly translated in Figure 6. The analysis replays the FCR auctions by integrating additional storage shares (i.e. by introducing additional "floor" bids in the bid ladder for each day of the auction).

So, as previously mentioned, the market had to cope with such price movements in order to offer additional flexibility to asset owners so that they can tap into new and additional revenue streams while ensuring project viability.

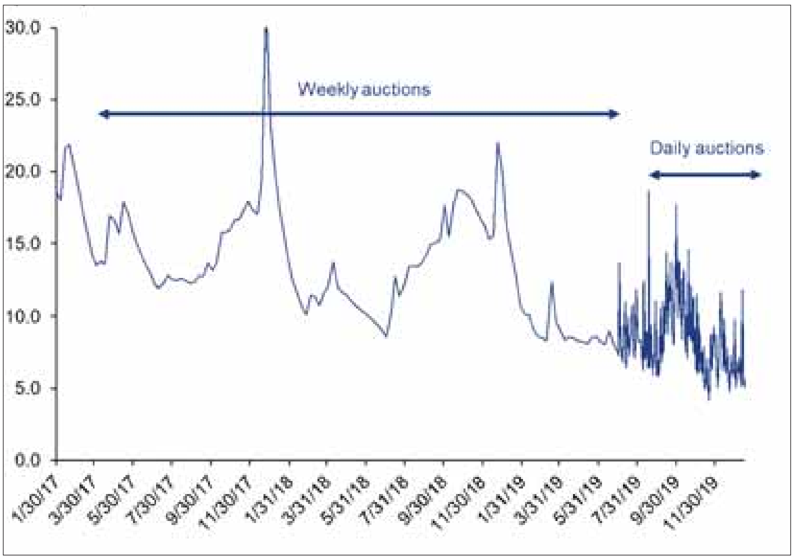


Figure 4. Evolution of the FCR marginal prices over the last three years (coupled market) (€/MW/h)

Figure 5. Volume awarded for each delivery period per company in French AOLT

New revenue streams emerge as stakeholders are progressively aware of energy storage potential

Arbitrage on the balancing markets

July 2020's change in the FCR auction timeline will allow storage to diversify its activity within the same day. In France, at least two other ancillary services are evolving towards a storage-friendly configuration in the next two years: the Balancing Market should open to standalone storage systems by the end of 2020 following the recommendation of the French Energy Regulation Commission (CRE); and the French secondary reserve (aFRR) is expected to open itself to new participants by mid-2021, therefore allowing the current dedicated generators to move on to different activities while creating a new potential source of revenue for storage systems.

Regarding arbitrage on the balancing market, the imbalance management structure is quite similar among multiple European countries such as France and Germany. The TSO can adjust system imbalances through two mechanisms: the balancing market (ex-ante) and imbalance settlement (ex-post).

An asset that offers imbalance management services can either be remunerated by providing tertiary reserves (balancing market) or by contributing positively to system balance in order to benefit from the Settlement Price afterwards. In both cases, the remuneration depends on forecast abilities and market flexibility.

On D-1 (the day before delivery day, D), an asset owner can bid on the balancing market through 30-minute blocks (in the French case, 15-minute blocks in Germany) by precising available capacity (in MW) as well as an energy activation price (in €/MWh) for a given direction (upward or downward).

On D day, unexpected fluctuations in generation or demand or forecast errors lead to energy imbalances, which requires balancing assets to ensure system stability. Henceforth, reserves get activated with respect to the merit order of their energy activation prices.

On the Billing Day, the TSO compensates for the additional reserve activation costs by penalising or remunerating market participants depending on their contribution to the imbalance event. The energy is remunerated through the Settlement Price.

Similarly to the FCR concept, national balancing markets (RR or Replacement Reserves) have been moving towards a European standardisation of the product since 2019 with the MARI (for manual Frequency Restoration Reserves or mFRR) and TERRE (for Replacement Reserves) projects. The main goals are to establish a common platform as well as 15-minutre auction blocks, which will be favourable to storage.

Grid investment deferral

During peak demand periods, the power that flows through the transmission and distribution networks might exceed the load-carrying capacity of such networks and lead to congestion issues. This issue has been addressed by system operators via traditional practices such as investing in new transmission and distribution assets to increase the initial carrying capacity.

However, when such events happen occasionally and for limited periods, the investment in reinforcing the entire network does not seem to be the optimal solution.

Energy storage systems that are located on congestion points can act as 'virtual power lines' (also called non-wires alternatives) to enhance the power system's performance without a need to overbuild transmission and distribution assets. These 'virtual lines' act as an extra lane that appears whenever it is needed to provide the additional capacity required to ensure system reliability and redundancy for a smaller footprint. So, instead of, for example, upgrading a substation capacity from 15MW to an oversized 20MW to address an occasional event,

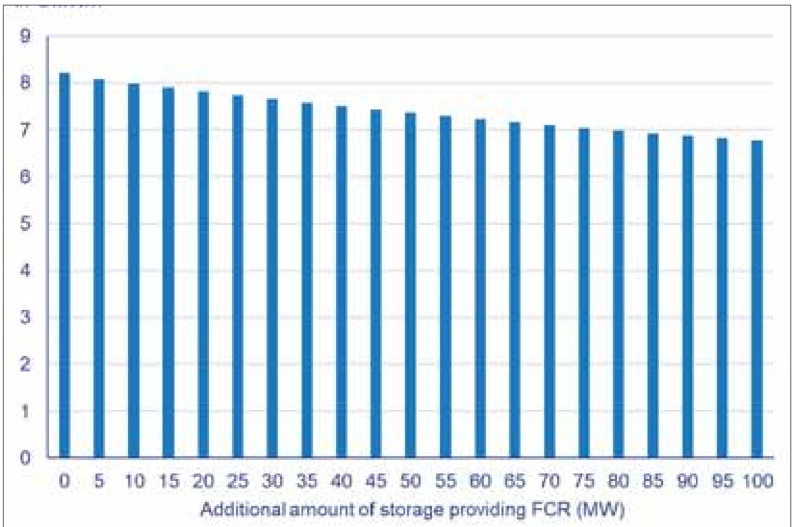
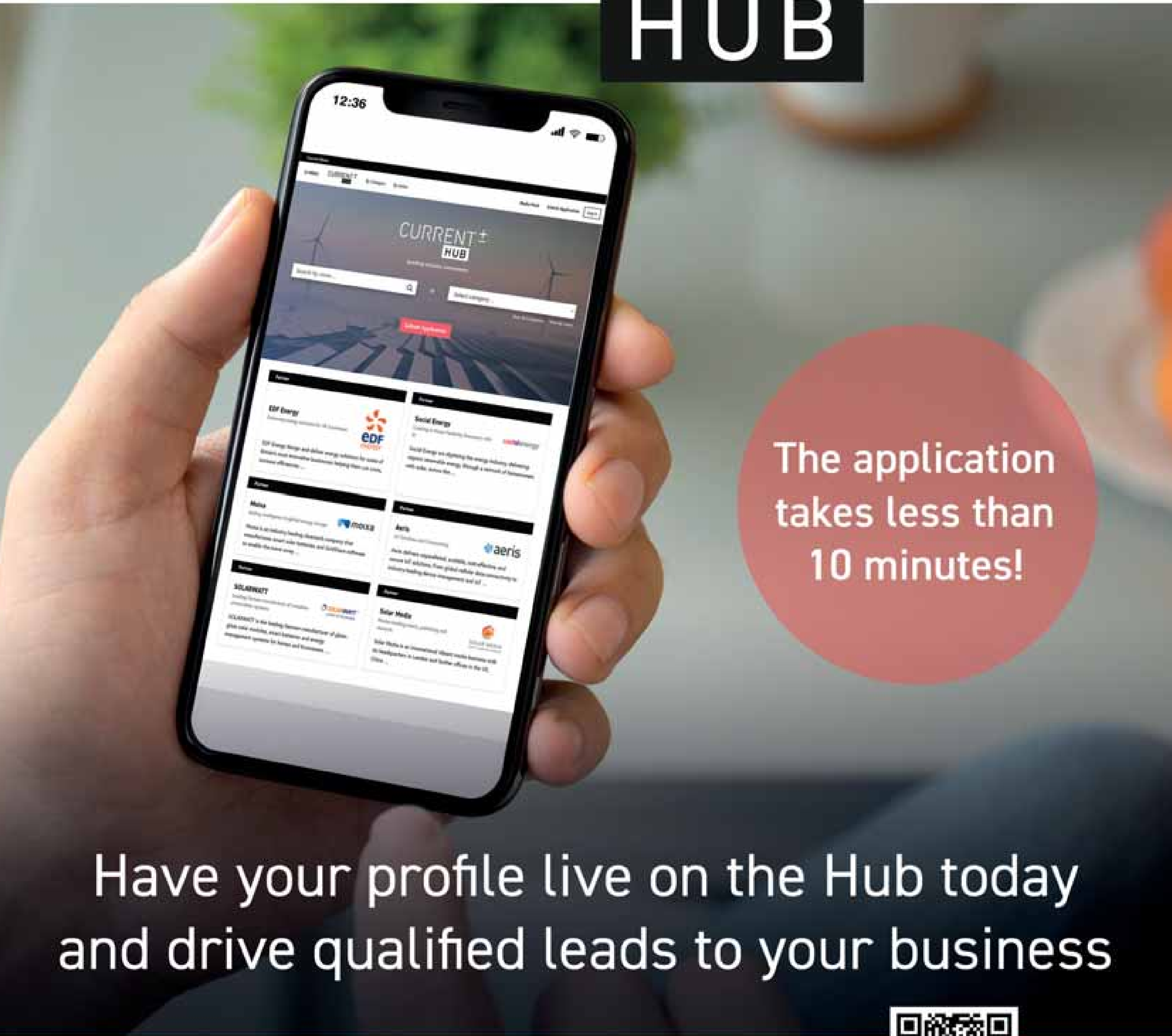


Figure 6. Evolution of the average FCR clearing price in France as a function of the amount of storage deployed (in addition to the already deployed storage). In €/MW/h

CURRENT± HUB



Have your profile live on the Hub today and drive qualified leads to your business

Subscribe for FREE now

Scan QR Code or visit www.current-news.co.uk/hub/subscription

Early Current± Hub Partners:

EDF ENERGY · aeris · moixa · socialenergy · SOLARWATT power to the people

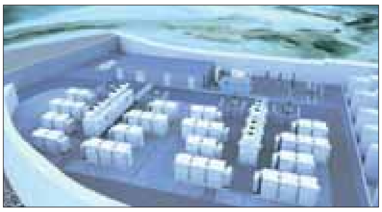


Figure 7. The 10MW/30.2MWh battery at Ventavon, one of the three energy storage systems RTE's RINGO project

system operators can procure the exact storage capacity to meet their demand forecasts. Moreover, as interconnectors could take up to seven (or more) years to get approved and constructed, large-scale battery storage can be operational within two years. Hence, storage systems do not face the same harsh permitting processes as new power transmission lines and poles do.

European countries are showing remarkable interest in storage as non-wire alternatives through multiple proactive approaches.

In France, both the Transmission System Operator (RTE) and the Distribution System Operator (Enedis) started experimenting with non-wires alternatives such as batteries for grid congestion management.

In 2017, RTE initiated the RINGO project, which involves deploying three battery systems totalling 32MW/98MWh to experiment with grid congestion management once they go online in 2021. However, as per the European regulation, system operators are not allowed to partake in energy markets. So, RTE proposed to implement a particular operational protocol: at any time, the net energy balance of the three systems has to be null – when one battery discharges, others charge at the same time.

RTE plans on selling those "virtual line" assets once the experiment is over, and contract third parties to provide the needed flexibility services starting from 2024.

The emergence of new fast reserve products, coupled to lucrative capacity market mechanisms: the Italian case

Italy's National Energy and Climate Plan (NECP) is claiming an ambitious transition to renewables and storage with a total coal phase-out by 2025 and the addition of 18GW of wind capacity and 25GW of solar. Thus, national TSO Terna estimated a need for 3GW of storage to ensure system adequacy and the ability to cope with the evolution of the power mix.

The Italian Capacity Market

In order to ensure security of supply and maintain sufficient generation capacity, Italy launched its capacity market in mid-2019. Similar to the Irish scheme in design thanks to its strike price mechanism, the Italian capacity market is distinguished by the extensive support of new-build, decarbonised assets as they benefit from 15-year contracts (in contrast with existing ones that get one-year contracts).

Storage can participate in capacity auctions and is considered as active if providing balancing services or partaking in the energy market, thus encouraged to stack revenues. It has an advantage over conventional generation thanks to CO2 emission limits (which prevent coal power plants from partaking in the capacity market).

> "Given the growing market interest for Spain from developers, as well as the skyrocketing number of grid-connection queries, new business opportunities should emerge for utility-scale battery storage by the end of 2021"

The two first auctions were held on 06 November 2019 and 28 November 2019 for respective delivery in 2022 and 2023. These two capacity market auctions have awarded:

- One-year contracts to existing capacity (respectively 34.8GW and 35GW), with a remuneration of €33,000/MW/year (common to both auctions)
- 15-year contracts to new capacity (respectively 1.8GW and 4GW) with a remuneration of €75,000/MW/year (common to both auctions)

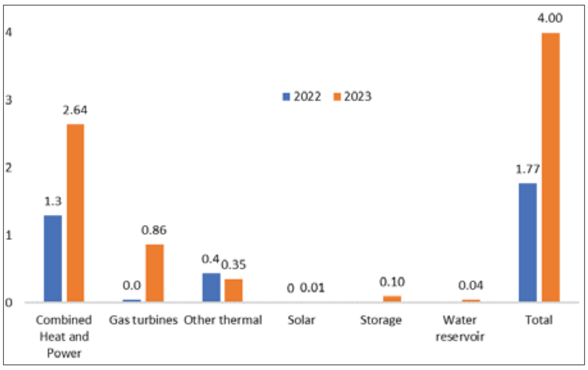


Figure 8. New capacity awarded under 2019's Italian capacity market auctions (by technology). In GW

The 2023 auction saw 90MW of new storage systems being awarded 15-year contracts, which is a very positive sign for the energy storage industry. Applied de-rating factors remain unknown for energy storage systems but would likely depend on storage duration.

Terna to procure 230 MW of fast reserves

Terna has recently announced that the Italian electricity system will face new constraints in the coming decade due to changes expected in the generation fleet such as reduction of system inertia (due to coal phase-out and increase in renewable capacity), increasing steepness of the evening load ramp, and increasing curtailment of renewables due to congestion issues and stability requirements

Fast reserves are seen by the TSO as a solution to compensate for the loss of inertia due to increasing renewable energy penetration and the continuous decommissioning of conventional thermal capacity. The proposed "Fast Reserve" service will not replace FCR but rather be coordinated with it to contribute to dynamic system stability.

Studies led by Terna show that no fast reserves are needed to guarantee system stability as long as the share of conventional generation remains above 35%. With the assumed addition of 13GW of renewables by 2025 (+7GW PV, +6GW wind in the 2017-2025 period) and coal being phased out, there would be more than 1,000 hours during which renewables would have to be curtailed, resulting in the curtailment of approximately 210GWh/year.

This service shall be cumulated with other applications as only 1,000 hours of availability are required. The remaining 88% of the time, the energy storage system will have to operate on other markets such as the ancillary service or wholesale electricity markets. As energy markets are regional, this will result in an interesting locational value for energy storage systems.

This fast reserve service is very similar to the British Enhanced Frequency

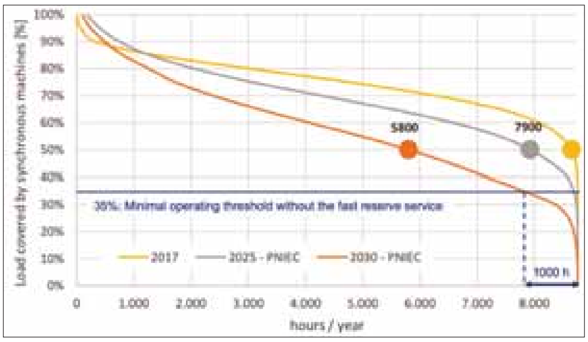


Figure 9. Current and future load coverage by synchronous machines in Italy. Source: Terna

Figure 10. Terna's Fast reserve procurements in Italy

Response service and is perfectly fit for battery storage systems as it:

- Is symmetric (upward and downward);
- Is open to units ranging from 5 to 25 MW (to ensure the resource is spread across the territory and a various fleet of units);
- Will pay for availability with 5-year contracts (commissioning expected by January 1st, 2023);
- Requires 15 minutes of availability in both directions for limited energy reservoirs (i.e. at least 30-min discharge duration batteries);
- Requires full activation in one second.

To prevent further stability issues, Terna will hold an auction to purchase 230MW of fast reserves on 10 December 2020:

- 200MW of fast reserves in continental Italy (100MW in North and Centre North and 100MW in Sicily and the rest of the country)
- 30MW of fast reserves in Sardinia

The price cap for the auction is set at €80,000/MW/year under a pay-as-bid scheme for both areas.

Rise of the Iberian energy storage market: Portugal leads the way and Spain slogs along

In the middle of a global sanitary crisis, Portugal confirmed the next 700MW national solar auction that includes a storage option while Spain opened a consultation on the role of energy storage in the national energy strategy, which includes 2.5GW of battery storage to be installed by 2030.

The Spanish market awaits an imminent regulatory change to initiate the deployment of commercial utility-scale storage

The Spanish electricity mix features a high penetration of wind and hydro power while coal assets are being phased out, compensated by gas-based generation. However, the strong penetration of hydro power renders the grid vulnerable to important seasonal generation intermittence as the Spanish territory is subject to droughts.

While the presence of utility-scale stationary storage remains marginal in Spain today, a goal of 2.5GW has been set up for 2030 under the National Energy and Climate Plan (NECP). Regarding electrochemical energy storage, only 26MW of utility-scale systems are currently operational, including the 20MW Endesa system commissioned in 2017.

Most of these systems are demonstration projects, illustrating a certain interest in storage from major stakeholders such as Iberdrola, Endesa or the TSO Red Electrica (REE). However, the small amount of MW deployed reveals some of the main the obstacles faced by developers, including the regulatory vagueness regarding electrochemical storage installations and the limited revenue streams that can be accessed by energy storage systems.

While the primary reserve was the core business driver of many storage projects in Western Europe, this mechanism is not remunerated in Spain. Three alternative revenue streams could become interesting for storage: secondary reserve, tertiary reserve, and deviation management.

Among them, only the secondary reserve service features an interesting level of revenue, cumulating a capacity remuneration close to €140,000/MW/year with around €25,000/MW/year for activated energy (best case scenario). However, this application explicitly states that pumped-hydro storage can participate, there are no rules regarding the participation of other technologies such as batteries.

One or several storage-favourable regulatory changes should arise within the next year

Despite the ambitious battery storage target set up last year by the Spanish NECP, there is currently no business opportunity justifying the deployment of 2.5GW of electrochemical storage by 2030. Given the growing market interest for Spain observed nationwide from developers, as well as the skyrocketing number of grid-connection queries received by REE in the last months, it is Clean Horizon's opinion that new business opportunities should emerge for utility-scale battery storage by the end of 2021.

This opportunity is likely to materialise if one or several of the following elements happens:

- Significant grid fee exemptions for battery storage;
- Creation of a long-term capacity auction remunerating renewable assets including storage like in France;
- Creation of a new fast frequency

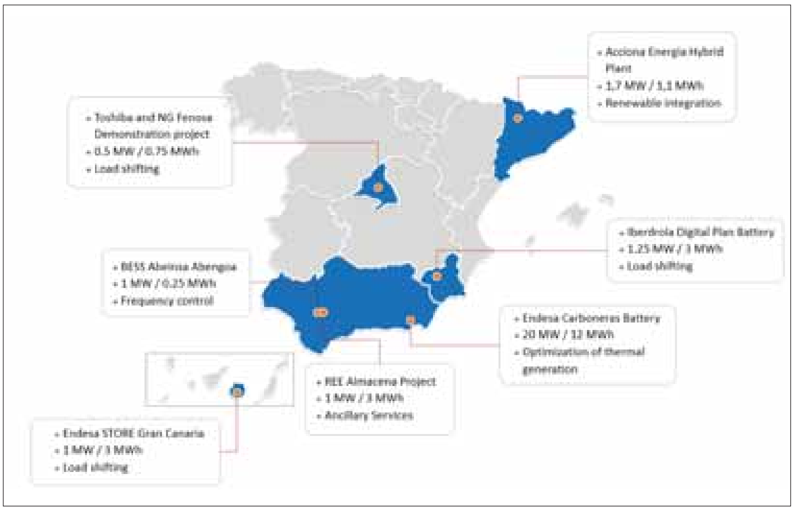


Figure 11. Operational utility-scale battery storage systems in Spain [1]

response service remunerating batteries for available capacity like the Italian approach;

- Opening of the primary reserve through a market mechanism that would enable electrochemical storage participation or adaptation of the secondary reserve rules.

Portugal gives its green light to storage developers with a stepping stone in the next long-term solar auction

The Portuguese electricity sector shares common features with its Spanish neighbour. Indeed, it is characterised by a strong penetration of renewables, mainly wind and hydro. Like Spain, Portugal experienced an historic drop in its coal-based generation in 2019, translating the efforts of the Portuguese government to let go this industry.

Comparable to Spain's, the Portuguese ancillary service opportunities for storage are limited to a lucrative but currently inaccessible secondary reserve:

Primary reserve services are mandatory for large generators and are not remunerated.

Secondary reserve services are remunerated through an attractive payment for available capacity (€/MW) and an additional payment for activated energy (€/MWh). A battery could potentially pull out as much as €190,000/MW/year but the bidding process is limited to day-ahead auctions without intra-day bid modifications, which is not flexible enough for storage.

Tertiary reserves feature limited revenues through activated energy payments, which do not justify a business case.

Portugal opens its national auction to solar-plus-storage systems

The ongoing 700MW solar auction will enable storage to participate in competition with traditional PV systems. The 700MW of new capacity will be awarded to the most economical solutions, regardless of the option model used.

Looking more closely at storage participation, the remuneration model is similar to Italy's new capacity mechanism. Indeed, the solar-plus-storage

> "Portugal's 700MW solar auction will enable storage to participate in competition with traditional PV systems. The new capacity will be awarded to the most economical solutions, regardless of the option model used"

plant receives a fixed yearly capacity payment in exchange for availability on peak times, defined as periods when market prices go beyond a threshold called "strike price".

The strike price is defined as a quarterly variable based on the average marginal costs of Combined Cycle Gas Turbines (CCGT).

The contract between the TSO and the awarded bidder is the following:

- In a normal period, the solar-plus-storage plant is allowed to operate at its convenience, for example by selling energy on the wholesale market;
- When the day-ahead market price goes beyond the strike price threshold, the solar-plus-storage plant must pay the difference between its selling price and the strike price to the system operator;
- In compensation, the plant receives a fixed annual payment in €/MW equivalent to a percentage of a reference maximal price.

This type of agreement benefits both the power producer and the system operator. The power producer can count on a fixed yearly payment for 15 years, mitigating the market risk of its project while the system operator ensures having reliable assets while avoiding price spikes on the wholesale market.

In conclusion, to promote energy storage uptake, two paths are open for Portuguese market operators:

The creation of artificial forecast parameters for the auction inputs, considering a strong increase of market prices in the years to come, thus driving up the potential capacity payments for Option #3 in Figure 12.

The redesign of ancillary market participation rules, especially for the secondary reserve, enabling storage systems to cope with their limited energy capacity without jeopardising accessible revenues on these markets. It can however be noted that the secondary reserve market can already provide significant revenues for storage. A favourable change in the regulation would therefore be a significant upside to a developer basing its bids on a combination of capacity payments and secondary reserve revenues. ■

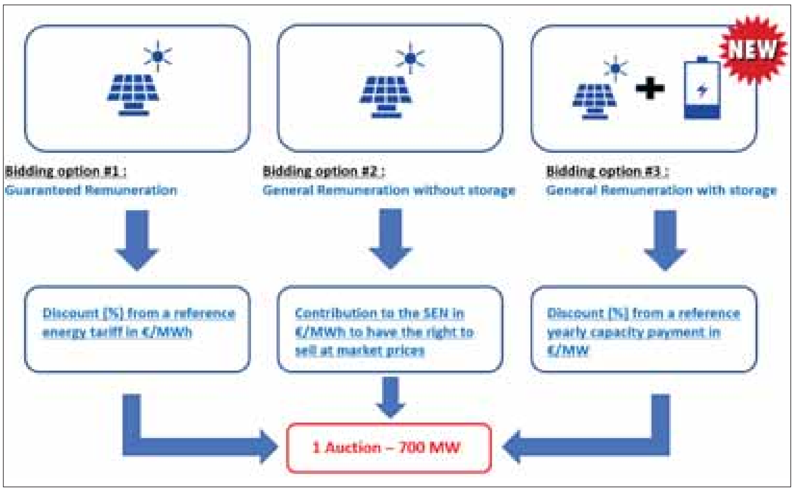


Figure 12 Bidding options for Portugal's 2020 solar auction

References

[1] Data sourced from the Clean Horizon Energy Storage Source – CHESS, Clean Horizon's own database of international large-scale energy storage projects (excluding pumped hydro installations, public projects only)

Author

Naim El Chami has engineering degrees from CentraleSupélec (France) and Saint Joseph's University (Lebanon). He obtained his digital economics and network industries Master's degree from Paris Dauphine University and Paris-Saclay University (France). At Clean Horizon, Naim has conducted multiple energy storage studies on geographies as different as the United States, Latin America, Europe and the Middle East. He is spearheading knowledge management activities in the company as the one-stop person both for market analysis – due to his involvement in Clean Horizon's CHESS storage project database – and regulatory watch – due to his central role in delivering Clean Horizon's monthly analyst note, Update from the Field.

Green hydrogen: the zero-carbon seasonal energy storage solution

Bulk storage | One of the planet's most abundant elements, hydrogen has the capacity to be a game-changer in decarbonising the global energy system, writes Janice Lin, founder and president of the Green Hydrogen Coalition

Back in 2016, I was serving as founder and executive director of the California Energy Storage Alliance (CESA). CESA is membership-based trade association and advocacy group that has helped build California into one of the world's most robust energy storage markets. At that time, CESA did not know exactly where California was headed with clean energy, but we did know other jurisdictions, such as Hawaii, were committing to 100% renewable portfolios. The CESA team was curious – if California created a similar clean energy goal, how would that drive California's energy storage needs? To answer this question, we performed a simple exercise. The CESA team took one year's worth of daily loads from CAISO OASIS data and ran a model that increased the wind and solar on the system until total production matched total energy consumption. Then we plotted the results for every day of the year, as show in Figure 1.

The resulting graphic clearly demonstrated that in a very high, 100% renewable scenario, multi-day and seasonal energy storage solutions would be required to balance the grid. At that time, the largest form of energy storage within CESA's membership was pumped hydro, and even that could not offer nearly enough capacity for seasonal energy storage needs.

Driven by curiosity and resolve, I started a search for a technologically and economically feasible seasonal energy storage solution for California and beyond. I spoke to experts far and wide and evaluated solutions from major energy companies to startups. From my explorations, it became clear: of the commercially available solutions, green hydrogen was the only low-carbon, potentially economically viable option to support seasonal, dispatchable, scalable energy storage for the grid.

In my research, I learned that hydrogen was a mature industrial commodity, with approximately 70 million metric tons sold each year around the world – and that virtually all of this hydrogen produced is sourced from fossil fuels. I also learned analysts were predicting that with the increasingly low cost of wind and solar, green hydrogen via electrolysis would become cost competitive with grey hydrogen (hydrogen made from fossil fuels) in coming years.

Even more exciting, my research uncovered the amazing flexibility of hydrogen molecules. For example, hydrogen gas can power the grid via multiple pathways, either through conversion in a fuel cell or by direct combustion in a gas turbine. Indeed, many gas turbines were already able to combust a blend of natural gas and hydrogen, and several leading manufacturers, such as Mitsubishi Hitachi Power Systems and Siemens, were developing new gas turbines that could consume 100% hydrogen gas.

Understanding that green hydrogen could serve as a drop-in fuel replacement for natural gas *and* provide long duration seasonal energy storage using existing infrastructure was my "Eureka!" moment. By repurposing existing energy infrastructure, I knew green hydrogen held the promise of making our clean energy transition affordable, reliable and scalable.

I became very excited about the potential for green hydrogen to accelerate decarbonisation. At CESA, we reformed our definition of energy storage to include hydrogen storage technologies, including in purpose-built storage facilities as well in pipelines. I'm proud of CESA's work for the storage market in California in general, and especially for introducing green hydrogen into the storage conversation.

At this point, I was so infatuated by green hydrogen's potential that in 2019, after a decade of service, I stepped down as executive director of CESA to launch the Green Hydrogen Coalition. The Green Hydrogen Coalition (GHC) is an educational non-profit dedicated to facilitating policies and practices to advance the production and use of green hydrogen in all sectors where it will accelerate the transition to a carbon free energy system.

The GHC defines "green hydrogen" as hydrogen created from renewable energy sources such as solar, wind, hydro power, biomass, biogas, or municipal waste. The GHC is accelerating green hydrogen

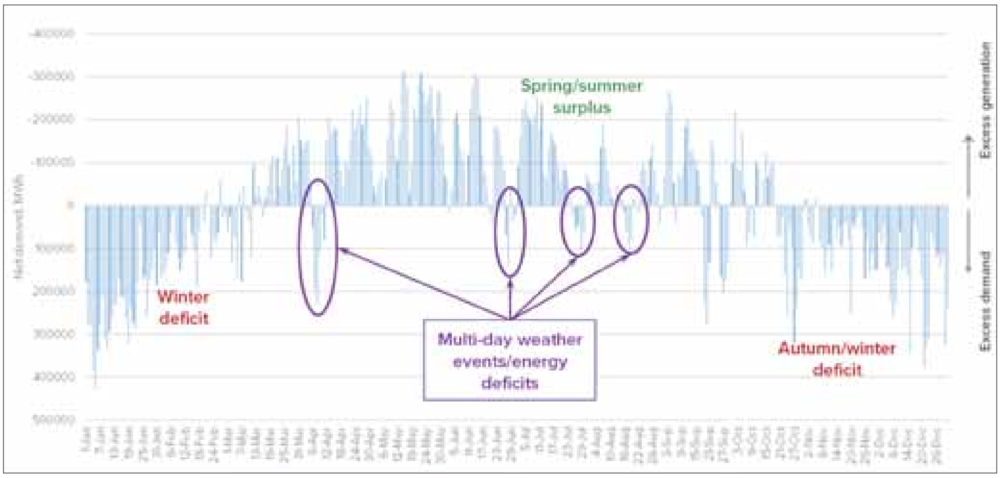


Figure 1. Substantial storage capacity will be needed to support a 100% renewables scenario in California

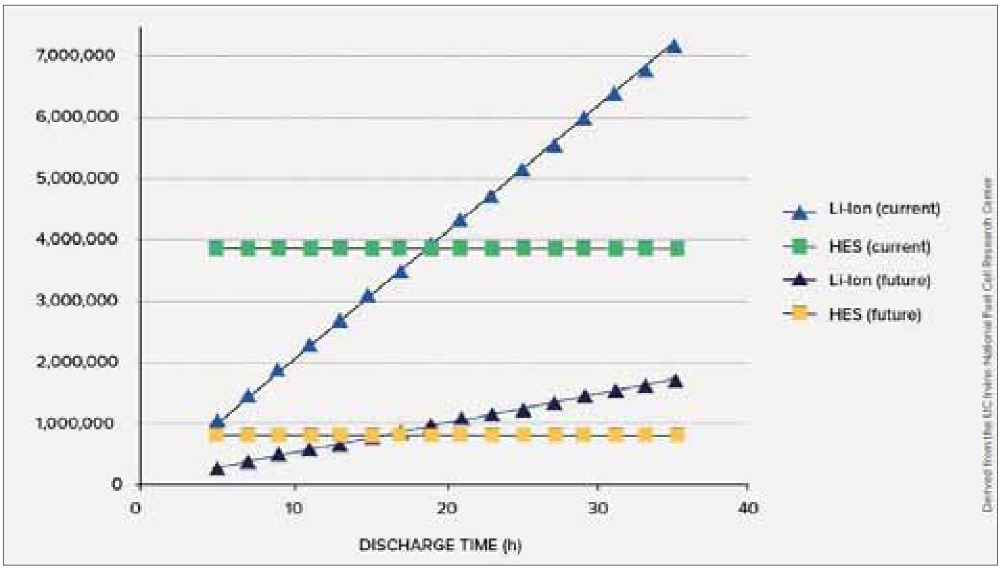


Figure 2. Hydrogen has separate power and energy scaling

infrastructure investment by aggregating demand at scale across sectors and pairing these opportunities with low-cost green hydrogen supply. In this way, our mission covers green hydrogen for seasonal energy storage, but our scope is broader.

Since seasonal energy storage is where my green hydrogen journey started, I wanted to share some reasons I am convinced that green hydrogen is the ideal seasonal energy storage medium:

1. Hydrogen is abundant
2. Green hydrogen offers separate power and energy scaling
3. Green hydrogen can be produced from multiple renewable energy sources
4. Green hydrogen can be stored at scale

Hydrogen is abundant

Lithium-ion battery storage is today's leading and preferred energy storage medium. It is cheap, well understood- why worry about hydrogen? The answer is simple. In a 100% global renewables scenario, it is simply not feasible to solely rely on lithium to meet energy storage needs.

A recent simulation completed by the University of California, Irvine (UCI) showed that global solar and wind dynamic production to meet total world annual energy demand would require the support of nearly 20,000TWh of energy storage.

If all our planet's lithium were dedicated to support grid storage, we would still fall woefully short of the energy storage capacity the grid requires. According to UCI, 20,000TWh of storage would require over 3,000 million tons of lithium, 60 times the amount that exists on Planet Earth. Moreover, that giant lithium-ion battery would only last five to 10 years, after which we would have to build a completely new replacement system to store the energy.

In stark contrast, hydrogen is extremely abundant - the most abundant molecule in the universe. On Earth, hydrogen mainly exists bound into compounds like water, the most abundant compound on the planet. Hydrogen also exists in almost all organic compounds, such as animals and plants that are alive, as well as animals and plants that have long been dead (aka, fossil fuels) – which is why most hydrogen gas is sourced from fossil fuels today. Since hydrogen in one form or another is available almost everywhere on earth, it has great potential to be a locally produced green energy resource for nearly every community.

Simply put, although lithium-ion energy storage is an important part of the toolkit, there is just not enough lithium to support the needs of our clean energy future. Only abundant, available hydrogen can offer the large-scale storage capacity and flexible discharge horizons to support a global clean energy future.

Green hydrogen offers separate power and energy scaling

When a long period of storage, say 10 hours or more, is required to provide power, it may be significantly more cost effective to store energy via hydrogen instead of electrochemical batteries. Hydrogen storage is unique from other storage technologies in that it has separate power (kW) and energy (kWh) scaling, as displayed in Figure 2. This helps save on cost because the size of a fuel cell or generator can be determined independently of the size of the volume of stored hydrogen. A 2019 study by the U.S. National Renewable Laboratory (NREL) found that green hydrogen for energy storage applications of 13 hours or more would make financial sense using today's technology. In the future, it is expected that costs for all energy storage systems will fall, but approaching the 13-15 hour mark, the capital costs for a hydrogen energy storage system are and will be lower than for Li-ion.

Green hydrogen can be produced from multiple renewable energy sources

A promising and scalable method for hydrogen production is electrolysis powered by renewable electricity from low-cost resources like solar and wind. Electrolysis uses renewable electricity to split water molecules into their elemen-

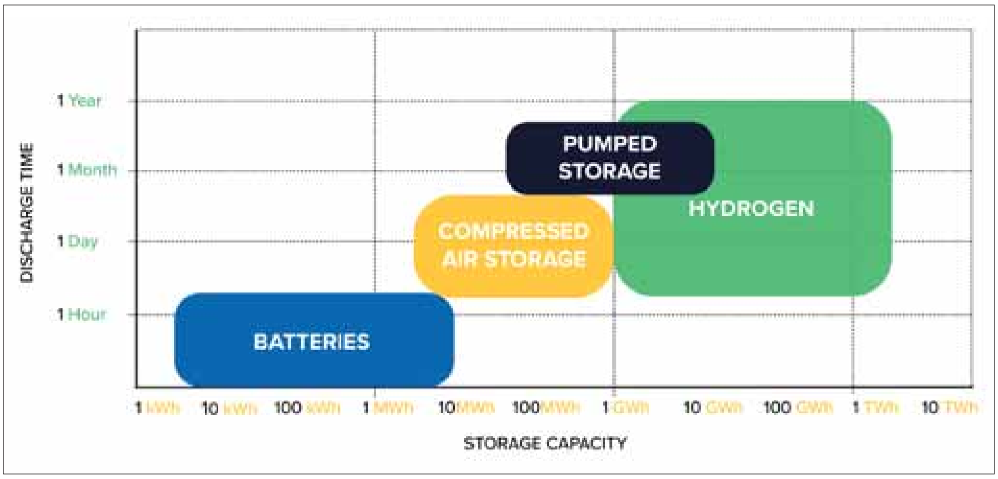


Figure 3. Energy storage capacity vs. discharge time for commercially available seasonal storage solutions

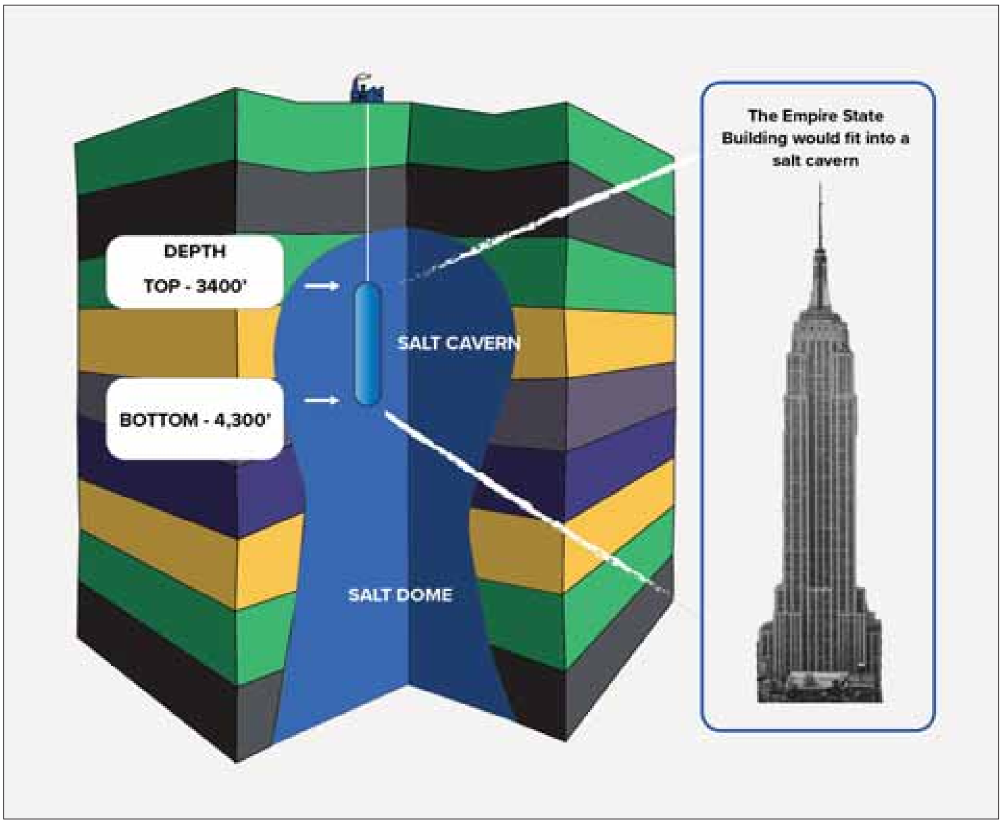


Figure 4. Green hydrogen can be stored in vast salt caverns

tal components: oxygen and hydrogen. The feedstock for green hydrogen is really that simple and abundant: water and clean energy. The process emits no greenhouse gases.

Green hydrogen gas can then be dispatched back to the grid in two ways: it can either pass through a fuel cell, or be combusted as a fuel in a gas turbine. Major turbine manufacturers such as Mitsubishi Hitachi Power Systems are developing hydrogen turbine technology which can replace the combustion units in coal and natural gas fired power plants. The main waste products fuel cells and hydrogen gas turbines are GHG-free: heat, power, and water.

Green hydrogen can also be made from biogas, via steam methane reformation or by thermally converting organic matter such as municipal and agricultural waste into a gaseous form that can be further refined into pure green hydrogen.

Green hydrogen can be stored at scale

Green Hydrogen can be stored via different methods and at different temperatures and pressures depending on the application; each storage method has tradeoffs related to location, scale, duration and cost. For example, hydrogen is already commercially stored in 100% dedicated hydrogen pipelines, as a blend in natural gas pipelines, in above ground stationary and mobile pressurised containers of various sizes, and in underground bulk storage facilities.

In large volumes, it is more cost-effective to use store hydrogen in bulk-storage facilities. Bulk storage can take advantage of natural geological formations such as salt caverns and depleted oil wells. This is a geographically limited opportunity but could bring great financial savings to storing large quantities of hydrogen.

Bulk underground hydrogen storage in salt caverns has been demonstrated as a safe and effective process in the US Since 2016, Liberty County Texas has been home to a very large Praxair underground hydrogen storage cavern. The subsurface Texas facility has a storage capacity of 20 MMCF (566,000 m^3) of hydrogen. Hydrogen is injected into the cavern at pressures over 1,000 psi. The facility is integrated into a 310-mile 100% hydrogen pipeline that serves over 50 refineries and chemical plants.

Bulk storage is an important part of the GHC's first initiative. The GHC is working to support the successful conversion of Intermountain Power Project (IPP) in Delta, Utah, USA. IPP is an 1,800MW coal-fired power plant that is being converted to a combined cycle gas turbine that will initially run on 30% green hydrogen by volume, and ultimately 100% on or before 2045.

At IPP, electrolytic green hydrogen made from wind and solar will be compressed into a massive nearby salt cavern with a storage capacity for 150,000MWh of electricity (See Figure 4). Here, hydrogen gas can be stored for days, weeks, months, and even seasons to be dispatched on demand as a clean fuel for carbon-free gas turbine power generation. The storage capacity of the salt caverns in this location is tremendous - one cavern can hold 5,512 tons of hydrogen gas, equivalent to the hydrogen needed to fill 200,000 hydrogen powered buses, and over 100 such caverns can be built at this location. The stored hydrogen will be used to power a gas turbine that will support offtakers in the City of Los Angeles, California. The stored hydrogen may also potentially fuel transportation, decarbonise the natural gas pipeline, or support production of green ammonia.

Conclusion

Since I first started my search for the ideal seasonal energy storage solution back in 2016, much has changed in the energy world. I am pleased to see that in the last four years, green hydrogen has emerged as a key solution to seasonal energy storage, and to accelerating our low-carbon energy goals more generally. Almost every week it seems I hear about a significant new green hydrogen project. The frequency and size of new projects such as IPP are an indication of an irreversible and growing momentum for a global green hydrogen future. Green hydrogen will be a key solution in our ongoing energy transition and a great companion to drive and store more renewable energy.

Green hydrogen is the super game-changer that can provide bulk, multi-day and seasonal energy storage, and much more. ■

Author

Janice Lin is the founder and CEO of the Green Hydrogen Coalition and the founder and chief executive officer of Strategen. In 2009 she co-founded the California Energy Storage Alliance (CESA) and served as its executive director until 2019. More information on the Green Hydrogen Coalition's work is available at www.ghcoalition.org

For lithium to still lead the way…

Batteries | Although lithium-ion is currently the market leading battery technology in energy storage, this status cannot be guaranteed in perpetuity. Three leading figures from the lithium-ion battery industry give Andy Colthorpe their views how the technology can continue to prosper

Whether or not lithium-ion batteries will represent the dominant force in energy storage in the distant future, the reality is that it dominates the present day of grid-connected energy storage just as it does electric vehicles and consumer electronics. The cost of commercial lithium battery packs has fallen, on average, about 10 times since 2010. Energy and power density improve all the time.

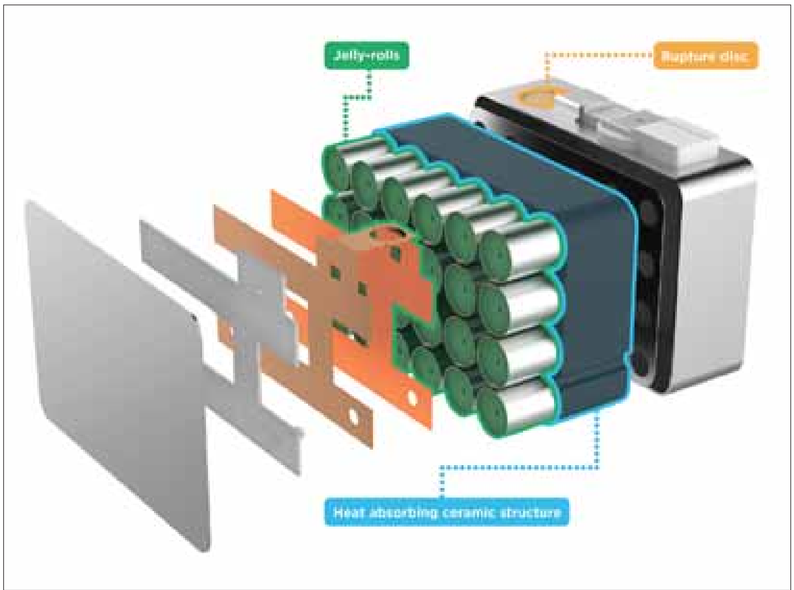
Other technologies certainly need to become more involved in the global market for the energy transition to be a success of decarbonisation and system stability – particularly long-duration storage, thermal and power-to-gas – but for now, lithium is the main event. Three industry thought leaders discuss what lithium does best – and what the industry needs to do better.

The cast

Bo Normark, an energy industry veteran with almost 40 years' experience analysing energy systems, Normark is an industrial strategy executive for EIT InnoEnergy. EIT InnoEnergy is not only an energy innovation accelerator supported by the European Institute of Innovation and Technology of the European Union, it is also a key player in creating and leading the European Battery Alliance – driving billions of euros in strategic investment in supporting and creating the battery manufacturing value chain in Europe.

Christina Lampe-Onnerud is a corporate strategist with a PhD in inorganic chemistry, twice a winner of the World Economic Forum Technology Pioneer award, who wants to change the world of lithium-ion batteries, with highly simplified designs that can be mass produced. Her company, Cadenza Innovation has developed large prismatic 'supercell' designs for use in energy storage systems which are claimed to be cost-effective, safer and more energy dense than many competitors' solutions.

Amrit Chandan's company Aceleron is "all about the circular economy" when it comes to lithium-ion batteries, the CEO and founder of the UK-based startup says.



Credit: Cadenza Innovation

Cadenza Innovation's 'supercell' design, one of a new generation of lithium-ion battery technologies

Chandan holds a PhD in fuel cell technology and along with co-founder Carlton Cummings is creating lithium-ion battery technologies that can be fully recycled, while also assembling packs and systems from repurposed end-of-life cells and modules that are already being marketed into developing countries as low-cost solar-storage solutions.

Will lithium continue to dominate?

First of all, it's important to establish that lithium is not going to be the only technology relevant to energy storage or the renewable energy revolution. Bo Normark says that EITInnoEnergy has identified four main areas of energy storage technologies to focus on: lithium-ion batteries, flow batteries, ultracapacitors and hydrogen.

There's perhaps a false sense of competition out there, but flow and lithium can in fact be complementary, while these technologies can also be differentiated in their relative 'skillsets'. Firstly, Normark says, the advantage of Li-ion over flow technologies is the much quicker response time, meaning that "in the power system, you can do more with a lithium battery than the flow battery".

Scale is also an important factor; that is, the scale of manufacturing of lithium today as well as planned over the next few years.

"I always tend to say that there is an advantage in the lithium battery because basically the technology started on a 'desktop' scale, which means that a small battery per kilowatt hour costs roughly the same as a big one. So, you can choose whether you're centralised or decentralised," Normark says, although he adds the caveat that EIT InnoEnergy has invested in Voltstorage, a German company making residential flow battery systems, which he says could become "quite competitive".

But lithium-ion batteries are evolving and improving all the time. One example is that the way EV battery charging today has

become greatly optimised from a few years ago helps "save the batteries" and extend their lifetime. The change comes quicker than even an industry veteran like Normark could have predicted.

"If you would have asked me one year ago, I would say: 'Yeah, of course flow batteries, they will have a role to play in the big, big batteries because there is an economy of scale.' I'm not so sure about that today actually, because lithium iron phosphate (LFP) batteries are coming down, way down in price. It's very difficult to compete with."

But are lithium-ion batteries safe enough?

"Lithium-ion is the hero of the storage industry. And it can be amazingly reliable and really, really good if you package it right," Cadenza Innovation CEO and founder Christina Lampe-Onnerud says.

There is, however, a debate still to be had about what that packaging should entail, and nowhere does this problem come into starker relief than when it comes to the question of safety. Lithium batteries are relatively safe, but incidents such as the fire and explosion at the McMicken Energy Storage Facility, which caused serious injuries to four firefighters, can have enormous ripple effects throughout the industry. Even in just the past few months there have been several fossil fuel-related incidents causing environmental disaster or deaths. But this does not make the issue of safety of lithium-ion batteries less pertinent.

Lampe-Onnerud – who herself was an investigator of safety incidents with Li-ion batteries before becoming a battery company CEO – says that there remains "misinformation in the general media" and that assertions such as lithium iron phosphate being a completely safe alternative to nickel manganese cobalt (NMC) are "convenient spin by some members of the industry" to promote sales.

"To me, that is what makes the policymakers hesitate. That is what makes the utility companies say: 'we're not sure we're ready'. If we just had a transparent discussion, we would say lithium-ion as a chemistry can use the entire first row of transition metals. They will all have a slightly different [profile] on how quickly or on what trigger causes them to go into thermal runaway, but let's just not fool ourselves. They are all energy materials."

Lampe-Onnerud believes that Cadenza's answer to the problem of thermal runaway – which means of course that impact damage or short-circuits can cause lithium-ion battery cells to catch fire – will be "one of many solutions" to the problem.

The Cadenza supercell is packaged into a larger format than most lithium cells, with a design that means that fire mitigation measures are "on the inside", with recent third-party tests showing that thermal runaway in one Cadenza cell does not then propagate to other cells in the system. For most lithium-ion batteries to be deemed safe from propagation at the moment, they are cloaked in layers of fire mitigation equipment.

"I think the media actually has to explain what is the matter – because there's so much spin in this industry. And so many players, colleagues in my industry that say, 'Oh, you know, we are not at fault.' Well, you're clearly at fault. It's clearly an issue.

"The reason you basically can have systems that are reasonably safe is only because you have to put a lot of safety around them. Big aeroplanes, they have traditional lithium-ion systems. The aeroplanes are safe because the batteries are put in steel chests in the stomach of the aeroplane. That's fine, but it is not affordable."

Lithium batteries are not yet being recycled enough

When Amrit Chandan and Carlton Cummings started up Aceleron, they got their hands on every type of lithium battery they could, from automotive to industrial to medical, consumer and more. And started taking them apart. From this, they realised that lithium batteries are "just not put together or assembled in a way that facilitates easy reuse, or recycling", Chandan says.


Aceleron CEO Amrit Chandan with a battery pack made from repurposed materials

Credit: Aceleron

"And so, Carlton and I came up with this idea of being able to package the batteries in such a way that they're easy to take apart and put back together again so that you could repair them. Because oftentimes what happens within a battery pack is [that] it's not the whole battery packs that will age, all the components age at different rates.

"Which means that you can have a battery pack with one or two things that are not working the way they should do and then the whole pack is considered waste."

With current technologies not yet as effective at recovering lithium as they are the other materials, the current state of the industry is "massively, massively wasteful", Chandan says. Lithium is itself a finite if abundant resource after all. Electric vehicles are far better for the environment than combustion engine cars and using solar power to charge EVs helps pay back a great proportion of the carbon emitted in building them.

"But then obviously, you've got to make sure that we extract as much use from these from these batteries as possible. It isn't very easy to [do that] at the moment," Chandan says.

While the plan for Aceleron is to move further and further into the value of chain of battery supply, including licensing its manufacturing techniques to OEMs as well as building the company's own devices, the company's initial volume sales have come from marketing solar batteries into Africa.

Starting in Kenya, and soon to expand into Rwanda, Aceleron's second life packs are built out directly dealing with and using batteries from e-waste, with support from the Shell Foundation as well as Total, and a recent £2 million investment round closed successfully.

"We've taken the local partnership approach. So we partner with local entities that are already dealing with computer waste and so on – but didn't have a strategy for actually being able to use a battery. It's really costly actually for them to get rid of a container full of batteries because a lot of those ultimately have a lot of life left in them that can be reused."

"Our designs allow us to be cell type agnostic and chemistry agnostic. We currently sell LFP and NMC based packs and cylindrical cells. But we can do sort of anything (any sub-chemistry)."

It's a positive move, and the company wants to branch out into other territories

Artist render of a planned gigafactory by French industrial startup Verkor. EIT InnoEnergy is supporting the venture, which will put Li-ion manufacturing on a grand scale into southern Europe

including Central America soon. Customers already know they'd prefer to use solar with batteries than continue with diesel generators and kerosene lamps that damage their health, cause atmospheric pollution and cost them large expenses in fuel and maintenance. However, the value chain as a whole needs to take better ownership of the issue, Amrit Chandan argues.

"Oftentimes, the attitude within the industry definitely, and this isn't even automotive, this is the solar industry, the attitude is: 'Once it's out of warranty, we don't want to see it, we don't care about it. And so it's not our problem.'

"That attitude has to change, because, again, these are finite resources, and there's limited capacity to deal with the waste in developing regions as it is."

The macro-level challenges: Security, sustainability and the climate crisis

As Amrit Chandan also points out, the global supply chain's reliance on lithium batteries coming from a small handful of places, with a heavy emphasis on China, means that there's an increasing demand for resilience within supply chains.

While gigafactories are being set up around the world, it will take some years before the majority come online, meaning that getting the maximum use out of lithium already in circulation is of paramount importance, without even getting into the potential geopolitical risks or questions of industrial competitiveness.

The sustainability of battery manufacturing sits apart from the finite nature of lithium itself, too. EIT InnoEnergy's Bo Normark agrees that even with "the best of intentions" it hasn't always been easy for those putting lithium batteries into their products to transparently track supply chains. Again though, we can look to the automotive industry for clues of how this could change.

"It's happening now more and more in the automotive industry. If you go back a few years in time, they said clearly: 'We are not getting into the battery business. We will not look at what's happening today.'

"I mean, [now] they are deeply – and they are making alliances with the battery suppliers. They even go back to the mines and make contracts and so the intention is certainly there," Normark says, adding that automotive companies not only have the scale to address the situation but also now have no choice due to customer pressure.

The use of cobalt in batteries is perhaps the biggest sustainability question that often comes up. While newer NMC battery designs use less and less cobalt than before, and of course, LFP batteries use none at all, a lot of ethical questions over the transparency of the cobalt that is used, remains. Normark says that the "interesting twist" to this discussion is that in his opinion, staying out of the Democratic Republic of Congo (DRC), where the majority of the world's industrial cobalt is mined from, "is a bad solution".

"The ambition must be that Congo should be able to use their mineral resources in an ethical way. And we have to put pressure on them, the ones that are buying and because it's not a solution to isolate Africa. You can buy ethically mined cobalt in Congo, and probably most of the miners are theoretically, but there is also a significant number of mines that are not dedicated at all. And the objective of course would be to bring all the mines that you want to use in Congo up to standard."

A lot of these problems – and their possible solutions – remain in the hands of private entities. After, or even during COVID-19, we will see a "technological acceleration", Cadenza CEO Christina Lampe-Onnerud believes. However, while innovators may not need policy support, policy support that mandates innovation helps everyone to progress far more quickly.

New York State, for example, has not only introduced renewable energy and energy storage deployment target policies, it has also helped directly fund research and technology development, Lampe-Onnerud points out. That "drives innovators and it drives opportunities", she says. Answering the call of a worldwide crisis can be so much more rewarding than attempting to deny or ignore it, Lampe-Onnerud says, while admitting that reports on things like methane leaks can be "extremely scary".

"It is very important that the battery industry as a whole takes this into consideration: there is a big puzzle being resolved right now, with storage, with wind, with solar. Their integration into the existing grid is critical. Let's not get so discouraged by news: we've got to engage, be price conscious, we [Cadenza Innovation] offer one solution but everybody has a responsibility to get involved, we don't have a lot of time and we have an enormous opportunity." ■

advertisers & web index

next issue

Tackling grid connection problems

Merchant revenue models

Floating solar and bifacial

SUBSCRIBE TODAY! www.pv-tech.org/power

JA SOLAR

Stock Code [002459]

DEEP BLUE 3.0 | 545W+

Born for The Present Making The Future

www.jasolar.com

Harvest the Sunshine

Vertex

Lower Voltage, Higher Module String Power Output

600W/550W high power,
with more than **21%+** high efficiency

- Multi-busbar and dense interconnection technology
- Extremely high string power for maximum usage of field
- Lower BOS cost and optimized customer value

www.trinasolar.com

Trinasolar