PV TECH POWER

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TWO-FACED

WHY SOLAR'S NEXT SUCCESS STORY HAS TWO SIDES

A PV Tech Power bifacial special report

Cell and module technologies | Standards | Bifacial system design


PV 3.0, 360W+
3.0

PV TECH POWER

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Introduction

The potential of bifacial modules is well known and many a manufacturer has made them the centrepiece of their trade show booths. No doubt this year's SPI will be the same. Scratching below the surface however, reveals that bifacial modules still have a long way to go if they are to become the mainstream choice.

In this edition's special bifacial focus Dr. Radovan Kopecek, of ISC Konstanz, looks at the staggering range of bifacial module technologies. He looks at which cell types and module configurations are likely to win out as bifacial tech chases down standardisation and with it, bankability (p.18).

That leads us seamlessly into Vahid Fakhfouri, head of R&D at Pasan, part of the Meyer Burger Group. He is leading efforts to produce a new set of IEC standards to improve labelling on bifacial modules and ensure would-be buyers are able to compare "apples-to-apples" (p.20).

In the third instalment of our bifacial special, we move on from the modules to system design. Naftali Eisenberg and Lev Kreinin, from the Israel-based start-up SolAround present the findings from test sites in Israel and Germany with a variety of system formations and under varying climatic conditions (p.23). The improvements in yearly energy yield are extremely promising.

As energy storage becomes an increasingly important, and prevalent, component for utility-scale PV power plants we've teamed up with our colleagues at Energy-Storage.News to present a beefed up showcase of news, analysis and technical briefings on all things storage. Head to p.101 to check out the new-look section including our run-through of 10 of the leading storage system integrators (p. 116).

Elsewhere in this issue, the Institute for Solar Energy Research in Hamelin (ISFH) presents a method for module failure detection in the field with no need for disconnection and at an impressive rate of 200 an hour (p.81).

We take a look at the role of robotics in speeding up the construction of large-scale solar power plants (p.60). Ben Willis assesses the future direction of tracker technology as competition, and the pressure to find new cost reductions, heats up (p.63).

Away from utility-scale projects, UK developer Syzygy Renewables presents the path to designing and executing commercial-scale projects with optimal returns for the client (p.49).

We couldn't not mention the Section 201 case, which at the time of writing is just a few weeks from its first vote at the US International Trade Commission. I run through some of the core arguments and summarise the first hearing on p.28.

The team will be out in force at SPI this year so please do get in touch if you'd like to meet up to discuss the global safeguard case – or anything but! – and we'll be delighted to oblige.

John Parnell
Head of content, Solar Media

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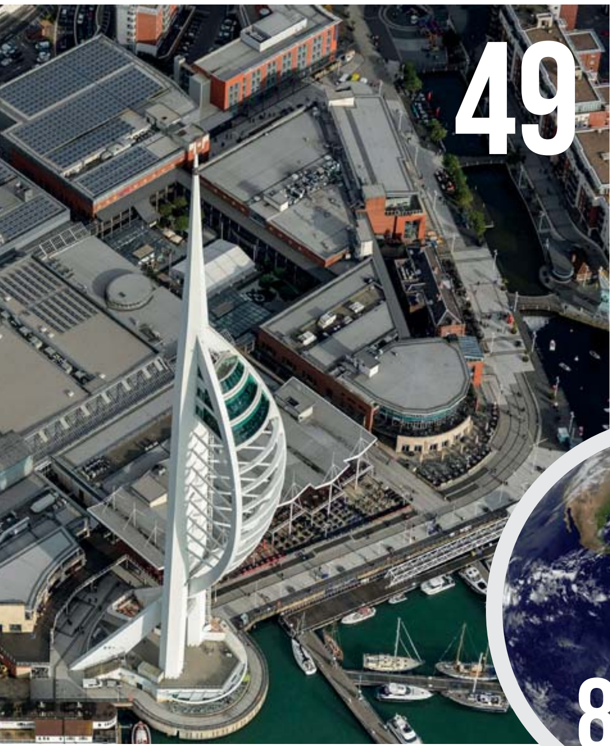

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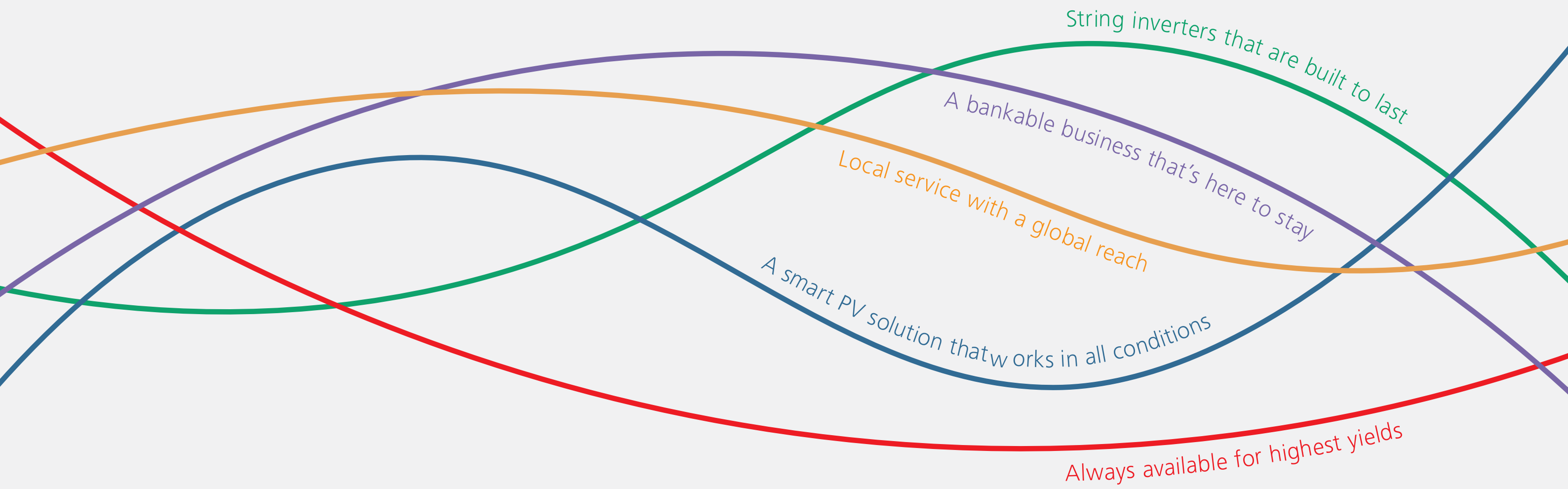

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EUROPE

SolarWorld

SolarWorld 'reboots' as Frank Asbeck gets approval to buy key assets

SolarWorld AG founder Frank Asbeck has been given approval to buy the major manufacturing and R&D assets of the company. The new entity, SolarWorld Industries GmbH takes over the production facilities and distribution businesses in Europe, Asia and Africa. Production is expected to start next week with 500 employees across its sites in Arnstadt, Freiburg and Bonn. "I am delighted that after tough negotiations, we have succeeded in developing a future for SolarWorld production," said Asbeck. "With this restart, we will ensure that solar products are still being developed and produced at a highest level in Germany." The company will continue its transition to mono PERC-only cells production.

Credit: SolarWorld

Frank Asbeck remains in control of SolarWorld's manufacturing assets

Trade

Replacement scheme for MIP proposed by European Commission

The European Commission has proposed an alternative floor price setting mechanism to replace the minimum import price's (MIP) current linkage to Bloomberg prices. The price level has been criticised for being too far above global market prices for solar. The Bloomberg prices are calculated in US dollars making the MIP level susceptible to currency fluctuations. A document released by the Trade directorate on 19 July proposed a schedule of prices for the next 14 months in an effort to offer some transparency.

Tenders

Spain awards 3.9GW of PV capacity

Spain awarded 3,909MW of solar PV capacity and 1,128MW of wind capacity to 40 companies in its July auction, which was originally set to be only a 3GW tender. A spokesperson for Spanish solar association UNEF said: "We think that this is a good spread of project sizes, as both utilities and companies are included as auction winners. As we can see from the winners list, the winning companies are among the most consolidated ones (Alten, Alter, Gestamp, Solarpack, Rios Renovables) in the Spanish PV sector." Three utilities, Enel Green Power España, Engie España and Gas Natural Fenosa, won a total of 638MW of capacity.

France tender hands out contracts for 500MW of solar

France awarded 507.6MW of PV to 77 developers in its second major large-scale solar auction, for projects ranging between 500kW and 17MW capacity. The average price proposed by the winners was €55.5/MWh (US$65) for projects of between 5-17MW capacity, which was deemed a "historically low price" by the French authorities. For all projects combined, the average price was €63.9/MWh. In the first 535MW auction, the average price for all projects was slightly lower at €62.5/MWh. The latest auction is part of the country's 3GW large-scale solar plan, which is being enacted through auctions of around 500MW every six months for three years.

Floating solar

Dutch floating solar pilot arrays set sail

A Dutch consortium of government agencies, R&D facilities and solar companies have launched two of four pilot floating solar projects on the Slufter on the Maasvlakte. Two systems were launched on the Slufter on 14 July from Texel4Trading and Wattco, which has partnered with France-based floating solar pioneer, Ciel et Terre, using its 'Hydrelio' system. The two other pilot systems from Sunprojects and Sunfloat are expected to be launched in the same stretch of water soon. Subject to the trials, plans could include 100MW of floating solar systems on the Slufter.

UK

More than 1GW of post-subsidy solar seeking planning permission in the UK

There is a 3GW pipeline of solar projects in the UK planning system including 1GW of new post-subsidy projects. The findings came from PV Tech's market research division. UK developer Hive Energy confirmed plans for a 40MW subsidy-free site to be built in the summer of 2018. PV Tech's market research team is also tracking planning documents for a 100MW project, which is considered likely to be given approval by the end of 2017.

AMERICAS

M&A

AES and AIMCo buy sPower for US$1.6 billion

The US$1.6 billion sale of major utility-scale solar developer and operator FTP Power LLC (sPower) to AES Corporation and Canada-based investment manager Alberta Investment Management Corporation (AIMCo) has been completed. Private investment firm Fir Tree Partners agreed to sell sPower to the AES and AIMCo joint venture back in February this year. Jeffrey Tannenbaum, chairman of the board of sPower and founder of Fir Tree Partners, said: "It is our clear hope that sPower, led by its highly-talented team, serves as a major catalyst for the acceleration of AES' portfolio to renewable energy, and that its positive impact continues far into the future."

SunPower and First Solar to collectively sell yieldco

US-headquartered PV manufacturers SunPower and First Solar are expected to collectively sell their stakes in their joint venture yieldco, 8point3 Energy Partners. Initially, First Solar had announced plans to sell its stake in the yieldco in May 2017 as it sought to recoup its investment and boost its balance sheet during the time of heavy capital expenditure requirements. It is undergoing the manufacturing migration from its Series 4 CdTe thin-film modules to its large-area Series 6 module format. During SunPower's second quarter

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Section 201

Trade row rivals trade insults at Washington hearing

The initial hearing in the Section 201 trade case took place on 15 August with neither side holding back. Matt Card, executive VP of commercial operations, Suniva said: "As a country, we will have ceded manufacturing of the next meaningful source of electrical generation to China and its proxies in Southeast Asia and other global outposts. As we continue to stress the needs of energy independence as a country, the US, in fact, will have no control of its own destiny when it comes to power generation from the sun." Matt Nicely of law firm Hughes Hubbard & Reed and legal counsel for SEIA called solar "an American success story" in his opening comments. "Its continued success could be destroyed by the misguided actions of the two Petitioners and their small group of supporters – whose workers represent less than 1% of all those that work for this dynamic American industry. That the two Petitioners would even bring this case demonstrates their poor business judgment – and their hubris. They seek a public remedy for their own, private failings," he added.

Credit: SolarWorld

A vote on whether to proceed with the case will take place by 22 September

earnings call, management noted that its own assessment of attracting a new investor to replace First Solar had led to the realization that the demand from potential investors centred on purchasing the yieldco in its entirety.

Brazil

Brazilian Development Bank provides US$163 million to 191MW solar project

'Silicon Module Super League' (SMSL) member Canadian Solar and major renewables form EDF Energies Nouvelles has announced that the Brazilian Development Bank (BNDES) has provided the project financing for the 191.5MWp Pirapora I PV power plant, the first PV project BNDES has supported. EDF EN do Brasil, EDF Energies Nouvelles' local subsidiary had previously acquired an 80% stake in the project from Canadian Solar, which is supplying modules manufactured in the State of Sao Paulo, Brazil, meeting local content requirements for the financing to come from BNDES.

Brazil to surpass 1GW of installed PV in 2017 and 13GW by 2026

Brazil released its long-awaited 10-Year Energy Expansion Plan proposition, PDE 2026 in July, projecting the country to reach more than 13GW of solar PV deployment by 2026. The previous month, the Brazilian Solar Association ABsolar predicted that 2017 would see country's installed PV base increase from 100MW to 1GW. Projects from tenders as long ago as 2013 are expected to come online this year.

Chile

Chile's 2,200GWh power auction to kick off in October

Participants in Chile's next 2,200GWh per annum power auction have been invited to submit proposals on 11 October, followed by bids on 31 October, according to the National Energy Commission (CNE). Contract awards will be publicly announced and Power Purchase Agreements (PPAs) signed on 3 November. The auction is for power to supply the central and northern grids, known as the SIC and SING, from the start of 2024 for a period of 20 years.

MIDDLE EAST & AFRICA

Turkey

Istanbul municipality launches first floating solar plant in Turkey

The first floating solar (FPV) power plant in Turkey was officially operational on August 4, 2017 as part of a testing phase that could lead to a significant number of systems installed by the Istanbul Metropolitan Municipality (IBB) on reservoirs, lakes and dams. Istanbul Water and Sewerage Administration (ISKI) with Istanbul Energy commissioned the 250kW testing system, located on the Büyükçekmece lake, near Istanbul, deploying a total of 960 multicyrstalline (60-cell) modules of 260W.

IBC Solar completes 3.43MW Turkey project

The Turkish subsidiary of integrated PV firm IBC Solar has completed a 3.43MW solar project in the province of Niğde. The solar plant, which uses 13,200 modules, has now been handed over to the investor, Akım Elektronik. Niğde, is the third large-scale project that IBC Solar Turkey has commissioned since the beginning of the year.

Tamesol enters Turkish market with 37MW portfolio of projects

PV module producer Tamesol has signed off on a partnership deal with Arevo Enerji Sanayi Ve Ticaret that will see Arevo import 130,000 units of Tamesol's PV modules for a number of PV projects in Turkey. In total, the PV modules will be installed on seven projects that will have a combined generation capacity of 37MW.

Middle East

Iran eyes 100MW solar plant with Italian firm

An unnamed Italian company will build a 100MW solar plant in Hormozgan Province of far south Iran, according to the region's governor Jasem Jadri. A total of €140 million (US$162 million) will be required for the project's construction. No other details on the project were provided. The official noted that the agreement has been made possible by the Joint Comprehensive Plan of Action (JCPOA) of 2015 in which China, France, Germany, Russia, the UK, the US, the EU, and Iran reached a peaceful agreement over Iran's nuclear programme.

Work starts on 30MW project in Iran

The Iranian minister of energy was on hand to officially commence construction of a 30MW project in the country's North Khorasan Province. The plant, in the city of Jajarm, will be the largest in Iran and follows on from the completion of two 7MW installations and a 10MW site earlier this year. The minister, Hamid Chitchian, said the project was a stepping stone for the development of larger renewable energy projects, according to a statement from the

Egypt

Acwa Power wins 165.5MW of PV projects in Egypt's second FiT round

Acwa Power has been awarded three solar PV projects in the Aswan Province of Benban, Egypt, under Round 2 of the Feed-in Tariff (FiT) programme, by the Egyptian Electricity Transmission Company (EETC). The firm has signed a power purchase agreement (PPA) with the Government of Egypt for all the projects, which have capacities of 67.5MW, 70MW and 28MW respectively. The projects will require total investment of US$190 million. The projects expected to achieve financial close and commence construction by Q4 2017 in collaboration with local firms Tawakol and Hassan Allam Holding.

Credit: GettyImages/duncan1890

Acwa Power has signed a power purchase agreement with the Government of Egypt for all the projects.

government's Renewable Energy and Energy and Energy Efficiency Organization of Iran (SATBA).

Dubai switches on 10MW renewables-powered 'Sustainable City' project

A 10MW 'Sustainable City' has been switched on in Dubai, with Trina Solar panels helping it to meet all of its power needs from clean sources. The Sustainable City comprises 500 residential villas, a 170-room hotel, mosque, school, swimming pool and an equestrian club and track and has been billed as one of the largest sustainable cities currently operating in the Middle East. Trina Solar's Duomax panels – 40,000 of them – were selected because of its frameless design which limits dust accumulation, and its dual glass feature which makes the panels more durable.

Africa

World Bank provides US$150 million credit for Kenyan off-grid solar

The World Bank is providing US$150 million in credit for off-grid solar energy in marginalised communities of Kenya. The public and private sector collaboration will give solar access to businesses, schools and health centres, reaching 1.3 million people in 277,000 households. Diarietou Gaye, World Bank country director for Kenya said the project will support growth of communities through energy devolution bringing opportunity and prosperity. An International Development Association (IDA) was approved to provide access across 14 underserved counties in the North-eastern area as part of the North Eastern Development Initiative (NEDI). IDA provides grants to poor countries for projects that boost economic growth, reducing poverty and improving living standards.

AfDB to help finance 32MW PV project in Chad

The African Development Bank (AfDB) will fund the construction of Chad's first large-scale solar project. The installation, which will have an installed generation capacity of 32MW, is set to be developed in Chad's capital city of N'Djamena. AfDB also plans to support other projects within the country, including the electrical interconnection project between Chad and Cameroon – along with the rehabilitation of the existing National Electricity Company (SNE) plant.

ASIA-PACIFIC

Australia

First Solar tops 500MW of Series 4 module orders in Australia

Leading CdTe thin-film module manufacturer First Solar has secured a 241MW (DC) module supply contract with Australian EPC firm, RCR Tomlinson. The latest contract is for two major PV power plant projects, bringing its contracted business in the country to over 500MW in the next 12 months. First Solar will supply its Series 4 modules to Edify Energy's Daydream (180.7MW) and Hayman (60.2MW) solar projects in Queensland, Australia with construction on the projects is scheduled to start in the third quarter of 2017, with module delivery in the fourth quarter of 2017 and through the first quarter of 2018. More than 2,026,565 Series 4 modules will be deployed using single-axis tracking technology from Array Technologies.

Credit: First Solar

First Solar will supply its Series 4 modules to Edify Energy's Daydream (180.7MW) and Hayman (60.2MW) solar projects in Queensland

Australia

Equis to build 1GW solar project in Australia

Singapore-based renewable energy firm Equis Energy is to build a 1GW solar project in Queensland that would be the largest in Australia. The Western Downs Regional Council has approved the AU$1.5 billion (US$1.19 billion) plans for the installation located 21 kilometres south-west of the Wandoan township. The Wandoan South Solar Project will cover 1,424 hectares of land and is expected to create up to 600 jobs across three stages of development.

CEFC finances 200MW of Queensland projects

The Clean Energy Finance Corporation (CEFC) has provided a AU$90 million loan to two Edify Energy solar projects near Collinsville, north Queensland, Australia, which are soon to start construction. Engineering firm RCR Tomlinson also announced that it has won the AU$315 million EPC and O&M contract for the two projects, the 150MW(AC) Daydream Solar Farm and the 50MW(AC) Hayman Solar Farm. Edify recently signed a power purchase agreement (PPA) for the 150MW farm with the utility Origin.

RCR wins EPC contracts in Victoria

RCR also won a AU$28 million EPC contract with Solar Powerstations Victoria for the 19MW Swan Hill Solar Farm in Victoria, earlier this month. Australian funds manager, Impact Investment Group (IIG), will fund the solar farm's construction. RCR now has over half a Gigawatt of large-scale solar projects in its order book and more than a Gigawatt currently being developed or progressed under early contractor involvement processes.

Edify signs PPA with Origin for 150MW Queensland solar farm

Australian renewable energy firm Edify Energy has signed a power purchase agreement (PPA) with the utility Origin for a 150MW solar farm in Queensland. The Daydream Solar Farm will be located on a 433-hectare site north of Collinsville in northern Queensland using single-axis trackers. It will generate approximately 380,000MWh of electricity a year. Construction is expected imminently with electricity generation slated to start in mid-2018.

Elecnor bags US$139.2 million EPC contract for second 137MW Australia PV farm

Spanish infrastructure, technology and renewable energy company Elecnor has secured a €117.4 million (US$139.2 million) EPC contract for a PV farm in Australia. The contract was awarded for Bungala Two; the second phase of Bungala One. On completion this will be Australia's biggest solar PV farm. The Elecnor project will have a power capacity of 137MW bringing the total capacity of the first two phases up to 275MW. The third phase is under development and will add 100MW, for a grand total of 375MW.

Malaysia

Malaysia's 460MW solar auction heavily over-subscribed

The opening bids in Malaysia's 460MW(AC) large-scale solar auction have shown significant over-subscription with roughly 1,632MW(AC) of submissions. The Energy Commission of Malaysia revealed that prices ranged from RM0.3398/kWh to RM0.53/kWh (US$0.08 - 0.12). These were for projects of 1-30MW(AC) capacity in the Peninsular Malaysia (360MW(AC) allocation) and the eastern Sabah/Labuan regions (100MW(AC) allocation).

Huawei providing smart solutions to challenging Malaysian solar project

Leading solar PV inverter supplier Huawei said it had won the supply bid for Malaysia's first 50MW(AC) utility-scale PV plant project based on its ability to provide smart solutions to the projects challenging location and environmental conditions. According to Huawei, the Sabah project is deploying its FusionSolar Smart PV Solution, including smart PV string inverter SUN2000-42KTL, and smart array controller that integrates the SmartLogger, PLC, and Anti-PID Module functions. The company said that around 2MW of systems has already been commissioned at the power plant, which is expected to be completed by the end of 2017.

Product reviews

Modules | Canadian Solar's 'Ku' PV modules lower hotspot risks boosting energy yield and reliability

Product Outline: Canadian Solar has launched a 'cool' PV module range, dubbed 'Ku' modules. The new PV module series is based on Low Internal Current (LIC) module technology to provide better module energy yield and reliability.

Problem: Continued development of high-efficiency and thus higher-output PV modules can lead to increased issues with cell hotspots caused by shading, which produces excess heat in any shadowed cell and can lead to permanent damage. Hotspots can be caused at various cell manufacturing process steps such as incomplete edge isolation as well as poor cell current matching at the module assembly stage.

Solution: The Ku Module portfolio uses Canadian Solar's proprietary black silicon cell technology. The black silicon cell efficiency exceeds that of the current standard polysilicon cells in the market, according to the company. The LIC module technology is intended to reduce NMOT (NMOT: 43 ± 2 °C) and lower hotspot risks, resulting in better energy yield and reliability.

Applications: Residential, commercial and utility-scale markets.

Platform: The new Ku Modules portfolio is available in both poly- and monocrystalline forms. The Ku module family consists of the KuMax (144 cells), KuPower (120 cells), KuBlack (120 cells) and the corresponding double-glass KuDymond. The KuMax modules have a power class of up to 360 Watts.

Availability: Available since June 2017.

Modules | HT-SAAE's 'Hyper Black' high-efficiency polycrystalline modules reach 280W-plus output power

Product Outline: Shanghai Aerospace Automobile Electromechanical Co (HT-SAAE) has launched the 'Hyper Black' PV module series, offering an output of 280W and above for a 60-cell module and a lower balance of system per watt.

Problem: The technique used in diamond-wire slicing can significantly reduce polycrystalline silicon wafer costs. Compared with the conventional acid texturing technique, the black silicon technique can solve problems in the texturing process and improve the uniformity of a cell's overall appearance. Black silicon can also reduce silicon-related costs and increase cell efficiency resulting in cell performance gains.

Solution: The products adopt the metal-assisted chemical etching (MACE) technique, raising the cell efficiency by up 0.3% to 0.5%. The cell efficiency level for mass production with the advanced PERC technique can reach up to 20.0% and the output power can reach 280W and above for a 60-cell module.

Applications: Residential, commercial and utility-scale power generation.

Platform: The Hyper Black PV module series are made with diamond-wire slicing technique, which reduces costs. The nano texture method leads to uniformity in a cell's overall appearance. Compared with the HIGHWAY poly-crystalline PV products (260W), it generates an increase of 9.6% in power output per square meter, and a reduction of 4.8% in BOS per watt. It has passed the anti-ammonia gas test, anti-salt mist test, anti-dust and anti-PID test.

Availability: Currently available worldwide.

Yield forecasting | Imec and EnergyVille launch precision PV energy yield simulation software

Product Outline: Imec and EnergyVille are introducing new simulation software that accurately predicts the daily energy yield of solar cells and solar modules under varying meteorological and irradiation conditions. Imec's model combines optical, thermal and electrical parameters to provide detailed insight on thermal gradients in the solar module.

Problem: Solar cell efficiencies and PV module performances are typically only measured under standard lab conditions. However, in reality, PV modules are exposed to varying meteorological conditions in terms of irradiation, temperature and wind, which, in addition, all vary during the course of the day.

Solution: Imec's model starts from the physical parameters of the solar cells and the used materials, and includes on top of that their variations due to changing external conditions. This enables a more precise assessment of the effects of solar cell and module technology changes on the energy yield of these PV cells and modules. It is also claimed to improve short-term energy yield forecasting, which will lead to lower lost opportunity costs and better energy management for PV power plants and residential solar systems.

Applications: Simulation software for high accuracy modelling of daily energy yield of solar cells and solar modules in residential, commercial and utility-scale segments.

Platform: The model is claimed to offer better accuracy (root mean square error of only 2.5%) than commercially available software packages for energy yield estimation. It can also be used to make a rapid assessment of material and technology changes at the cell and module level and their influence on the levelised cost-of-electricity (LCOE).

Availability: Available since June 2017

Modules | LG launches its first AC module with integrated microinverter to simplify installations

Product Outline: LG Electronics USA has launched the 'NeON' 2 ACe module in collaboration with Enphase Energy. The high-efficiency AC module uses Enphase's latest IQ6 microinverter technology integrated at the module assembly stage.

Problem: Notably in the US, residential PV installation 'soft costs' have remained relatively high compared to many other regions. Recent market analysis by GTM Research has also highlighted that 'customer capture' costs on a cost-per-watt basis are set to rise. This puts increased pressure on reducing installation costs. Recent rapid-shutdown (NEC 2014) compliance can also increase the BOS (balance of system) costs with the addition of rapid-shutdown devices and increased cabling.

Solution: LG NeON 2 ACe brings together high-performance and a simplified user experience, combining the processes of logistics, installation and monitoring. Installation becomes a quick, two-step process, eliminating the need to install the two products separately as well as unnecessary components like extra wiring and bypass diodes. Higher reliability can be achieved due to the micro-inverter being pre-tested and integrated onto the module at the manufacturing assembly stage. The NeON 2 ACe utilises new "cello" technology, which replaces the industry standard three busbars with 30 thin wires. A strategically positioned 15mm distance separates the DC module and the microinverter, mitigating any impact to performance and reliability by allowing sufficient air-flow for cooling.

Applications: Residential rooftop.

Platform: LG NeON 2 ACe also comes equip with LG Electronics' 12-year unit warranty and a 25-year warranty for the microin-verter.

Availability: Available since July 2017.

Modules | LONGi Solar pushes p-type mono-PERC 'Hi-MO1' module series to 325.6W power output

Product Outline: LONGi Solar has upgraded its 60-cell 'Hi-MO1' module series, achieveing a power output of 325.6W under standard testing conditions (STC) with a conversion efficiency of 19.91%, verified by TUV Rheinland Shanghai Lab.

Problem: Launched in 2016, LONGi Solar's Hi-MO1 module series was claimed to be the only p-type monocrystalline module in the industry with a first-year power degradation of less than 2%, as well as other features such as low light-induced degradation (LID. With a power output of 316.6W under standard test conditions (STC), the module setting a new record in tests by TÜV Rheinland. However, further conversion efficiencies and high output make a significant contribution to LCOE reduction.

Solution: Recently, LONGi Solar received a report from China's National Center of Supervision and Inspection on Photovoltaic Products Quality showing that the conversion efficiency of LONGi Solar's monocrystalline PERC cell had reached 22.17%, breaking the company's own record and reaching a leading position in the industry.

Applications: Residential, commercial and utility-scale markets.

Platform: Hi-MO1 modules are based on advanced PERC cell and mono-Si low LID technologies. LONGi also offers the Hi-MO2, a bifacial version, developed on the basis of Hi-MO1's low LID technology.

Availability: Launched in 2016 with continued upgrades.

BIPV | Midsummer offers complete BIPV CIGS thin-film metal roof systems

Product Outline: Sweden-based PV manufacturer Midsummer and metal roofing company Clix Steel Profile have developed a flexible CIGS thin-film solar cell process that provides a complete solution for BIPV/BAPV metal roof systems.

Problem: The lack of a low-cost new-build roofing system that is BIPV ready has limited adoption but changes to building regulations in Europe and certain US states will be stipulating solar PV is compulsory for new buildings, including residential and commercial.

Solution: Midsummer has developed a rapid process for the production of flexible thin-film solar cells using sputtering of all layers of the solar cell. This allows for scalable and cost-effective manufacturing of CIGS cells. The roof plates are produced with integrated lightweight, flexible panels using any type of coated steel. The panel is integrated at the roofing factory, thereby reducing installation time and cost. All connectors are well protected for snow and ice and easily accessible if necessary.

Applications: Membrane roofs, portable power plants, marine installations, vehicle usage, landfill covers or other infrastructure projects.

Platform: Each panel is mounted on the roof plates using an elastomeric butyl adhesive tape designed to provide strong tack and adhesion under outside condition in the field. The standing seam roof is then installed by linking the roof plates together in one step. The module connectors are hidden under the ridge capping meaning there are no visible connectors, cables or junction boxes when the roof installation is complete.

Availability: Available since April 2017.

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Product reviews

Trackers | NEXTracker's advanced tracker control system boosts yield with self-learning

Product Outline: NEXTracker has launched 'TrueCapture', an intelligent, self-adjusting tracker control system for solar power plants. TrueCapture's technology is designed to continuously refine the tracking algorithm of each individual solar array in response to existing site and weather conditions.

Problem: Energy production losses from construction variability, terrain undulation and changing weather can limit the yield and LCOE advantages of single-axis trackers. Backtracking was first introduced in 1991, offering a significant improvement in PV plant energy yield. It was optimised for flat arrays and low diffuse conditions. However, it was not linked to individual row tracking for real world conditions such as hilly terrain and partly cloudy or fully diffuse conditions.

Solution: TrueCapture is claimed to be the first tracker solution to simultaneously solve the above issues, leveraging forecast-based tracking behaviour algorithms for clouds, fog or haze and row-to-row hybrid closed-loop self-learning that corrects the panel direction to minimise production loss due to shading and clouds. Wireless self-powered controllers on the tracker sync with the smart panels and the NEXTracker SCADA system to control each independent row. TrueCapture's technology is said to typically deliver 2-6% energy gains.

Applications: Utility-scale PV power plants using single-axis tracking systems.

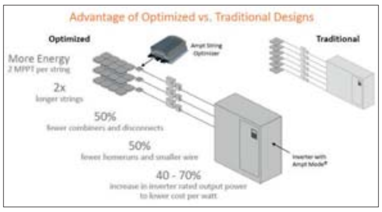
Platform: With TrueCapture, proprietary smart panel sensors provide real-time shading information on each tracker row. The data is integrated with design parameters and processed by machine-learning software to build a virtual 3D model of the job site. An intelligent control engine combines the model with the latest meteorological forecast data to calculate and send updated and optimised tracking commands to every independent row.

Availability: Available since July 2017.

Inverters | Rosendin Electric and Ampt offer inverter repowering of PV power plants

Product Outline: Rosendin Electric and Ampt have announced the availability of a new offering to repower large-scale solar PV systems that are underperforming or that require inverter replacement. The solution uses Ampt String Optimisers to improve power plant performance and increase return on investment.

Problem: As PV power plants age, many inverters experience significant faults and downtime, or fail after reaching their expected operating life. Often the original model inverter is either expensive or inefficient compared to modern inverters, or is no longer available. In the past, this has meant substantial reworking of the system, or caused portions of the PV plant to remain offline.



Solution: Ampt String Optimisers are DC-to-DC converters that put dual maximum power point trackers (MPPTs) on each string of PV modules to improve the system's lifetime performance. Ampt's patented technology is claimed to recover approximately 60% of energy losses caused by the electrical imbalances which occur as systems degrade. When used to repower existing PV systems, Ampt optimisers are connected to the existing wires and combiners and include optional wireless communication for remote monitoring and enhanced O&M.

Applications: Rosendin Electric's repowering service includes a performance assessment, engineering, installation of Ampt String Optimisers, and re-commissioning of the system.

Platform: Ampt optimisers allow 1,000V inverters to deliver full rated output power in 600V systems. Likewise, 1,500V inverters achieve full rated output power in 1,000V systems with Ampt. The result is a lower cost per watt inverter utilising modern technology and a higher performing PV array..

Availability: Available since July 2017.

Inverters | SMA Solar's 'CORE1' string inverter lowers commercial install times by 60%

Product Outline: The new Sunny Tripower CORE1 inverter from SMA Solar Technology reduces installation times for commercial PV systems by up to 60% and is aimed at optimisng commercial self-consumption of solar power.

Problem: Commercial and industrial rooftop EPCs and project developers are requiring a number of key features from string inverters such as faster installation and future proofing.

Solution: With a capacity of 50 kW, the Sunny Tripower CORE1 is scalable up to the megawatt range. The unique design enables over-dimensioning of the PV array of up to 150%. At the same time, the six independent MPP trackers guarantee optimal energy production for every use, even in shading. The fully integrated design of the CORE1 takes care of low balance-of-system costs, simpler processes and lower material expenses. Alongside the 12 direct string inputs, the CORE1 also contains a DC disconnector and, as an option, AC and DC overvoltage protection. SMA's intelligent 'OptiCool' cooling system is reliable and ensures maximum energy production, even in challenging conditions.

Applications: The Sunny Tripower CORE1 is a free-standing string inverter for decentralised rooftop and ground-based PV systems as well as covered parking spaces.

Platform: The Sunny Tripower CORE1 has 12 direct DC inputs, which can be controlled using the integrated DC switch. The parallel connection featuring two DC inputs for every MPP tracker eliminates the need to use string fuses, thus cutting labour and material costs.

Availability: Currently available.

Inverters | SolarEdge's S-Series power optimiser monitors heat abnormalities in PV systems

Product Outline: SolarEdge Technologies has announced the expected availability of its new S-Series power optimiser that has up to 40% higher power density, is 38% smaller, and introduces a new safety feature that extends safety to the connector level.

Problem: The S-Series power optimiser's new safety feature is designed to detect heat abnormalities and initiate shutdown before an arc occurs in order to prevent potential fires.

Solution: Power optimisers increase energy output from PV systems by constantly tracking the maximum power point (MPPT) of each module individually. The power optimisers monitor the performance of each module and communicate performance data to the SolarEdge monitoring portal for enhanced module-level maintenance. Each power optimiser is equipped with the unique 'SafeDC' feature which automatically shuts down modules' DC voltage whenever the inverter or grid power is shut down.

Applications: Residential and commercial rooftop markets.

Platform: The MPPT per module allows for flexible installation design with multiple orientations, tilts and module types in the same string. When working with SolarEdge inverters, SolarEdge power optimizers automatically maintain a fixed string voltage, allowing installers even greater flexibility with longer strings and strings of different lengths in order to design optimal PV systems. The SolarEdge power optimisers are compatible with c-Si and thin-film modules and have a 25-year warranty.

Availability: From 2018.

Modules | The 'Solarion M210' 48-cell glass-foil module used for low-load-bearing roofs

Product Outline: OC3 AG, formerly Solarion, is offering its new generation of solar modules specifically designed for relatively low-bearing residential, commercial and industrial rooftops. The 'Solarion M210' is a glass-foil module consisting of 48 monocrystalline solar cells.

Problem: Low-bearing residential, commercial and industrial rooftops are widely used around the world, especially in large-area flat rooftops. Conventional crystalline and thin-film modules are difficult to install in such applications, due to weight constraints.

Solution: The Solarion M210 glass-foil modules are encapsulated framelessly between a glass panel and a plastic roofing membrane, providing a low surface load that is about nine kilograms per square meter, making PV installations on low-load-bearing flat roofs possible. The system also provides higher area utilisation compared to elevated systems.

Applications: The frameless encapsulation of solar cells between TPO or PVC and glass provides mechanical stability, durability and ease of use for low-bearing roofing applications.

Platform: The modules are certified according to IEC 61215 as well as IEC 61730 and for flat roofs with an inclination between two to twelve degrees. The 2mm front glass is tempered and very resistant to hail and other mechanical impacts.

Availability: Available since June 2017.

Trackers | Soltec's 'SF7' single-axis solar tracker achieves up to 5% greater yield

Product Outline: Soltec's 'SF7' next generation single-axis tracker is claimed to provide up to 5% greater yield and offer a lower LCOE.

Problem: Single-axis solar tracker systems have gained a significant share of the utility-scale PV power plant sector, due to yield gains over fixed-mount systems of between 10-20% on average. However, continued cost reductions and improved yields are required to meet continued pressure on LCOE.

Solution: Soltec's 'SF7' single-axis tracker is designed to eliminate array-gaps on the tracker at all the pile mounting locations. SF7 achieves complete tracker module fill that enables greater yield. By reducing the parts count and installation labour, SF7 is also claimed to achieve a lower installed first-cost. The net result is a greater benefit/cost ratio that defines Soltec's principal innovation criteria to increase tracker cost-effectiveness. SF7 incorporates DC Harness and String Runner installation innovations that combine to better manage PV array wiring with less cabling material and less installation labour

Applications: Utility-scale PV power plants.

Platform: Other key features of the SF7 include the fewest piles-per-MW, greatest installation tolerances on steep slopes and irregular land, and the greater site-fill options of a short tracker that mounts twice the modules per independent-row tracker length. SF7 is self-powered, and provides tracker level Near Field Communications.

Availability: Available since June 2017.

Who's who at the leading edge of bifacial PV technology

Cell and module technology | One of the defining trends to emerge so far in 2017 has been an explosion of interest in bifacial PV technology. In the first of three articles in our bifacial special report, Radovan Kopecek looks at some of the key technologies vying for position at the vanguard of fast-growing part of the market

Bifaciality is now strongly entering the PV market, as the technology is becoming more and more mature and bankable. In total, at the time of writing, we have about 200MWp bifacial PV systems installed – with exponential growth [1]. These are mostly ground-mounted PV systems on fixed-tilt mounting and a couple of flat rooftop systems using mostly n-type silicon technologies. Plans for large bifacial systems have been announced lately, for example a 90MWp system by EDF in Mexico [2]. In 2018 we expect to have about 1GW total installed bifacial system power – in 2022 20% of the yearly module market share is expected to be bifacial [3], representing about 20GWp.

The question is now: which technology will win the race in the future? The more bifacial one? The less expensive one? All for different applications?

State of the art in bifacial cells and modules

Currently almost all the existing 200MWp installed bifacial PV systems are based on nPERT (n-type passivated emitter rear totally diffused) or HJ (heterojunction) technologies. This might change in the future in favour of bifacial PERC (passivated emitter and rear cell), as more and more PERC producers are entering the bifacial stage – for example, China's LONGi [4] and Trina Solar [5] are strongly going in that direction. Germany's SolarWorld AG tried to survive the current cost crisis by getting rid of its mc-Si production and instead focusing on PERC and PERC+ (bifacial PERC) production – however that was too late and the company had to file for insolvency; now it seems set to continue as 'another' company, SolarWord Industries GmbH, bought by SolarWorld´s founder Frank Asbeck [6] most likely with a focus on bifacial. Table 1 summarises the most prominent cell concepts currently on the market.

Currently the PV market is still dominated by standard monofacial mc-Si and Cz-Si cells with fully Al-BSF (aluminium back surface field) [7]. The average efficiencies in production are around 19% for mc-Si cells and around 20% for Cz-Si cells. The bifacial factor is 0, as the rear side is fully covered with Al-paste resulting in a homogeneous back surface field. Opening of the Al rear contact in this case will not help, as the opened areas would remain "unpassivated" and the device will tremendously lose out in efficiency terms. Therefore a rear side passivation by a dielectric is needed, which will result in a PERC cell.

Since 2014/2015, after the previous PV overcapacity crisis, PERC technology has been rapidly moving into the PV market [7], as the additional efficiency benefit justifies the additional rear side passivation and lasering costs. PERC mc-Si solar cells currently reach efficiencies of >20% and Cz-Si PERC cells of >21% in production. The market share of PERC technology is about 13% [3, 7]. If you now open the rear side Al metal contact (printing grid or fingers) the passivation between the Al-metal keeping the high Voc and Isc and the light can penetrate into the rear side as well. Therefore, if you optimise the rear side metallisation geometry without reducing the fill factor too much, the PERC cell can be made bifacial with a bifacial factor of about 0.7. This number is limited by lateral conductivity in the solar cell, conductivity of the Al-paste and alignment precision of the Al-grid on the laser openings.

In nPERT and HJ devices the bifaciality factor is much higher – namely 0.85-0.95%. The reason is because high-quality n-type Cz-Si material is used, the lateral conductivity in the substrate is higher due to the use of a rear side conductive layer (P-BSF in the case of nPERT and P-doped amorphous Si for HJ) and the rear side metal contact is a highly conductive firing through or low temperature Ag paste (so no precise alignment is needed as with PERC). The average efficiency in production is now exceeding 21% as well, similar to PERC solar cells. However, due to the approximately 5-10% greater cost associated with n-type Cz-Si substrates at the moment, the cost of ownership is in most cases slightly higher. Therefore the market share for these bifacial n-type technologies is currently only about 5%. However, when it comes to efficiencies exceeding 22% it is much easier to go the nPERT or HJ way as the

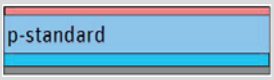
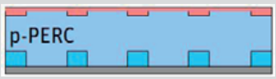
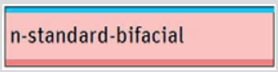
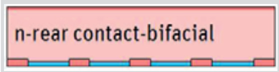
	Standard Al-BSF	pPERC	nPERT/HJT	nIBC
				
Market share 2017 [%]	80	13	5	2
Efficiency 2017 [%]	20+	21+	21+	22+
Bifaciality [%]	0	70+	90+	80+
Market share 2022 [%]	40	30	20	10
Efficiency 2022 [%]	21+	22+	23+	24+

Table 1. Technology share, efficiency and bifaciality numbers of screen-printed low-cost industrial cell concepts

n-type material quality will not limit the cell efficiency. Therefore we believe that nPERT and HJ technology will gain more and more importance in future applications. The trend is visible already today and every large solar cell producer has an n-type roadmap on its agenda.

The last cell concept on the market is the IBC (interdigitated back contact) solar cell. In the case of the ISC Konstanz´s ZEBRA technology even this cell concept is bifacial [8] with a bifacial factor of 0.8%, so even higher compared to the bifacial PERC technology. IBC cells at the moment have a market share of ca.2% – mostly produced by Sunpower; however Sunpower´s cells are not designed to be bifacial. China's Jolywood has ambitious plans to go bifacial n-type IBC with 10GW production capacity [9].

By 2022 market shares will have shifted in favour of high-efficiency advanced cell concepts [3]. One of the reasons for this is that the module costs in a system are becoming so low that an increase of the power of the modules makes the PV system LCOE much cheaper as the balance of system is reduced. Therefore increasing the power of a module is much more important than further reducing its cost. For this reason standard Al-BSF technology will decrease its market share to about 40% [3] and PERC will be increased to 30%. The remaining 30% will be distributed among n-type technologies – nPERT, HJ and IBC. In addition the International Technology Roadmap for PV (ITRPV) forecasts a 20% bifacial technology share in 2022 [3]. We believe that most of that will be covered by n-type technologies – mainly by nPERT.

There are two additional technologies that might become interesting and therefore should be mentioned in this context: mcPERCT by RCT Solutions and pPERT by SolAround. Both technologies are designed to use low-cost p-type substrates and still have high efficiency and high bifaciality potential. Both concepts are p-type technologies with a B-diffusion on the rear side, which allows the use of higher resistive and therefore higher lifetime wafers. pPERT from SolarAround might become a good alternative for nPERT, if the cost difference between the p-type and n-type Cz-Si wafers will remain between five and 10% in future.

Figure 1 shows a list of companies that are involved in bifacial solar cell business at the moment. Most of them are involved in nPERT production such as PVGS, Yingli, LG electronics, HT-SAAE, QXPV and Adani. Now a "new star" rises on the horizon with

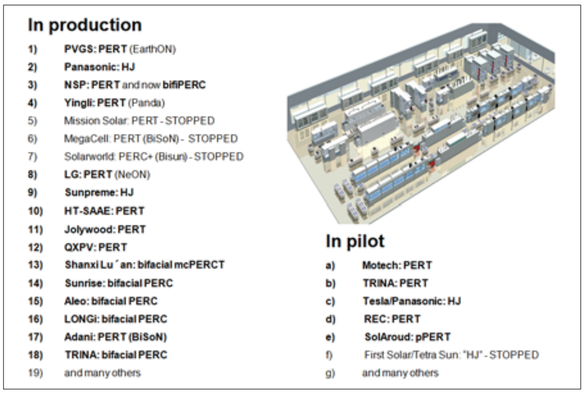


Figure 1. Companies in production and pilot production of bifacial solar cells

Jolywood who announced 2.1 GW nPERT production in 2018 [10]. A couple of the cell producers is using the HJ process such as Panasonic and Sunpreme. If the Panasonic/Tesla Buffalo site will be involved in bifacial cell production remains unclear. However there are also many bifacial PERC producers such as NSP, Sunrise, Aleo, TRINA and LONGi. LONGi is the most aggressive among these companies, stating that bifaciality will become mainstream in two years from now [4].

Bifacial modules on the market were developed in a rather evolutionary process, as many module manufacturers were moving towards double-glass products anyhow. However bifacial cells can be included even in standard (glass/white backsheet) modules, glass/transparent backsheet modules and double-glass modules in a classical way. Only the rear side soldering has to be slightly adapted as the precision must be higher. Depending on the chosen module technology the bifacial benefits are of course different.

The best suited technology from a lifetime and maintenance perspective is the double-glass module technology, which can also be produced without a frame, saving costs in aluminium. The more and more used half-cell technology is also beneficial, as the current in bifacial modules will in this way be reduced. Special shallow junction boxes, which are placed at the module side, have already developed for bifacial products. Therefore the module market is well prepared for more and more bifacial cells becoming available.

Bifacial PV system trend

The coming trends in the installation of bifacial modules are likely to see this technology used largely for ground-mounted, fixed-tilt systems or for white flat roofs. However there are more and more PV system applications coming on to the market that will be able to incorporate bifacial modules, such as single-axis trackers specifically designed for bifacial modules [11] or vertical east-west oriented bifacial PV plants [12]. An interesting application would be also using the modules in vertical sound blocking systems on highways, particularly in countries such as Germany with numerous north-south highways. Bifacial modules are becoming so cost effective that more and more business cases of different applications are coming up. The building-integrated PV sector is also very keen on bifacial double-glass modules [13].

We believe that with bifacial technology we enter another era of innovative and lowest cost PV. With this evolutionary technology using double-glass bifacial modules in large ground-mounted and flat rooftop installations we not only increase the lifetime of the system but increase the power density in that systems, which lead to lowest LCOEs ever. With the standardisation for bifacial measurements and improvement of bifacial simulations supporting system planning for installers, bifaciality will become even more bankable and become an important part of PV´s future. ▶

Many of these topics will be explored in the bifacial workshop bifiPV2017 taking place in Konstanz, Germany, on 25 and 26 October this year. Further details are available at ***www.bifiPV-workshop.com***

Author

Dr. Radovan Kopecek is one of the founders of ISC Konstanz, which has played a central role in developing some of the bifacial technologies now being commercially deployed. He is currently the leader of the advanced solar cells department. ISC Konstanz is establishing a research centre in Antofagasta, Chile, focused on developing desert-ready solar technologies, including bifacial.

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IEC standard for power rating of bifacial PV devices

Module rating | The power gains offered by bifacial over monofacial PV technologies are not yet expressed through any common industry standard. Vahid Fakhfouri describes an international project he is leading to produce a new bifacial IEC standard that will eventually aid the clear labelling of bifacial modules

IEC standards [1][2] describe the Standard Test Conditions (STC) and appropriate apparatus for the measurement of photovoltaic current-voltage characteristics. Accurate electrical characterisation is important to set the value of photovoltaic devices. Currently, the specificities of bifacial PV devices and their I-V characterisation are not covered by these standards. This makes it difficult to accurately characterise them. The new standard project IEC 60904-1-2, initiated and led by Pasan (member of the Meyer Burger Technology Group), aims to fill this gap. The project team of 18 international experts, with the help of 20 guest experts, submitted a committee draft in May 2017 to the national committees and an official release of this standard is expected in autumn 2017.

The bifacial challenge

Identification of the PV stakeholder's needs and an understanding of the technical challenges were required in order to propose a coherent standard. I-V characterisation must provide comparability between bifacial devices and must highlight the gain offered by bifacial compared to monofacial technology.

In laboratory environments, comparable measurement results are required in order to provide measurement traceability. The needs and the possibilities are different in laboratories compared to PV production environments. In production environments, I-V characterisation must be well matched with the production throughputs, and the apparatus must be compatible with the production specificities, such as low footprints, automation of the equipment and device handling. Furthermore, I-V characterisation of bifacial devices should be available at a reasonable cost.

In the future standard, I-V characterisation is extended to quantify the bifaciality coefficients of the device and the power generation gain it can yield.

Measurement method

The approach chosen by the project team is very similar to the one used in the determination and the use of the temperature coefficients [3]. These coefficients are determined in laboratories, through a rigorous process, on samples of a cell or module technology. The results are then used in production environments to correct the measurement results of production batches of the same technology. Similarly, for the I-V characterisation of bifacial devices, the bifaciality coefficients and the bifacial power gain are to be determined on samples in laboratories. These are then used to assess the production output.

Bifacial characterisation in laboratories

In order to determine the bifaciality coefficients of the test specimen, the main I-V characteristics of the front and the rear sides must be measured at STC (irradiance $G=1000W{\cdot}m^{-2}$). A non-irradiated background must be used in order to avoid the illumination of the non-exposed side. The background is considered to be non-irradiated if the irradiance is measured to be below $3W{\cdot}m^{-2}$ on the non-exposed side of the device. In order to fulfil this requirement, it is highly recommended to limit the size of the test area to the one of the devices under test using apertures

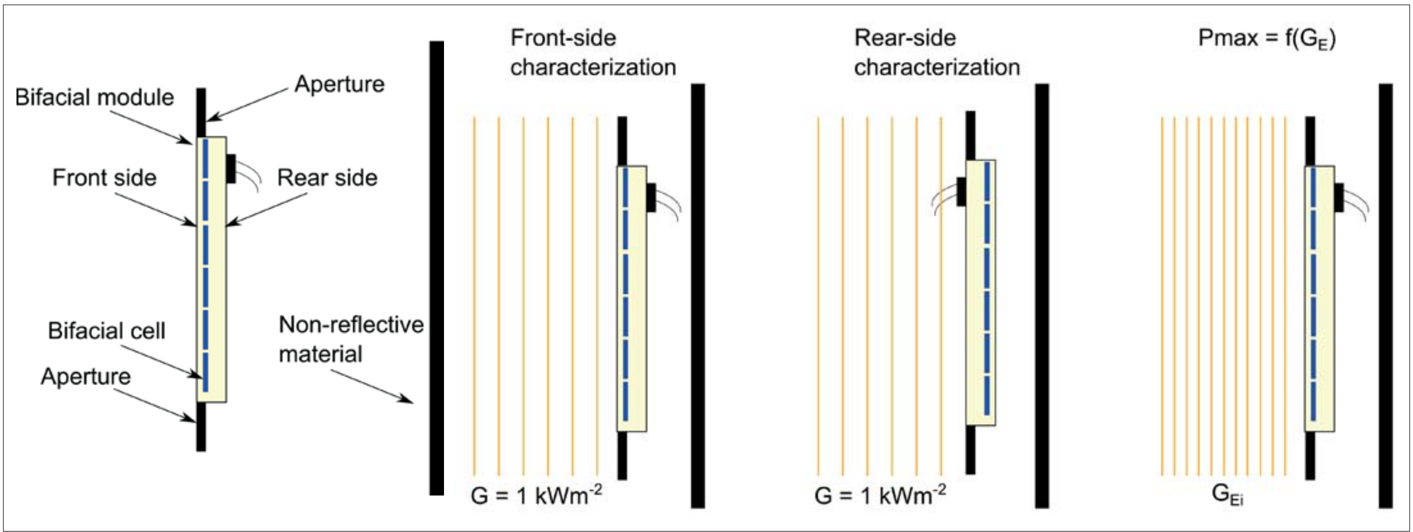

Figure 1. Left: scheme of a bifacial PV module and the required non-irradiated background and aperture. Right: bifaciality coefficients and bifacial power gain measurements

Figure 2. Pasan's bifacial-compatible contacting solution PCB^{TOUCH}: with non-irradiated background and the possibility for background compensation

as illustrated in Figure 1. Materials with minimised reflection in the wavelength range corresponding to the spectral responsivity of the test specimen, placed at a suitable distance from its non-exposed side, shall be used to reduce the irradiance level (non-reflective material).

In the case of bifacial solar cells, the use of low-reflectivity materials to manufacture cell holders may be insufficient to reach irradiance values below 3 W•m^{-2}. In that case, background compensation may be performed by extrapolating the short-circuit current as a function of the background irradiance.

Bifaciality coefficients φ_{Isc}, φ_{Voc}, and φ_{Pmax} are the short-circuit current, open-circuit voltage and maximum power bifaciality coefficients respectively, and correspond to the ratio of the key data of the front and the rear sides:

$$\varphi_{Isc} = \frac{Isc_r}{Isc_f},\ \varphi_{Voc} = \frac{Voc_r}{Voc_f};\ \text{and}\ \varphi_{max} = \frac{Pmax_r}{Pmax_f}$$

The gain in power generation yielded by the bifaciality of the device under test must be determined as a function of the irradiance on the rear side. *Pmax* of the device must be measured on the front side at equivalent irradiance levels corresponding to 1,000W•m^{-2} on the front side plus different rear side irradiance levels G_{Ri}. The equivalent irradiance levels are determined as functions of the bifaciality coefficient φ ($\varphi = Min(\varphi_{Pmax}, \varphi_{Isc})$) according to the equation below:

$$G_{Ei} = 1000\ W{\cdot}m^{-2} + \varphi{\cdot}G_{Ri}$$

At least three different equivalent irradiance levels are required (i=1,2,3,…).

Example: A device with bifaciality of φ=80%, must be irradiated, on the front side at G_{E2} =1160Wm^{-2} to provide the equivalence of G_{R2}=200 $W{\cdot}m^{-2}$.

Two specific *Pmax* values, $Pmax_{BiFi10}$ and $Pmax_{BiFi20}$, for G_{R1}=100 W•m^{-2} and GR2=200 W⋅m–2 respectively, must be reported. If the equivalent irradiance levels do not correspond to G_{R1} and G_{R2}, $Pmax_{BiFi10}$ and $Pmax_{BiFi20}$ must be obtained by linear interpolation of the data series *Pmax* versus G_E.

Bifacial characterisation in production

In production environments, a reference device, assessed by an accredited agent and of the same technology as the devices to be tested must be used to calibrate the solar simulators at STC (G=1000 W•m^{-2}) according to IEC 60904-1. To assess bifacial gain $Pmax_{BiFi10}$ and $Pmax_{BiFi20}$ must be reported for each device tested in production. These values will be calculated based on the *Pmax* value determined at STC (i.e. without the contribution of the rear side) and the slope of the *Pmax* versus rear side irradiance function provided for the reference device.

Conclusion

The proposed standard is a pragmatic solution that enables "apples-to-apples" comparison of bifacial devices and highlights the bifacial gain. It is simple and compatible with existing measurement equipment and is applicable for both PV cells and modules. The aim of the standardisation work is to be an enabler in the further expansion of the bifacial technology.

I take this opportunity to thank the project team members and guests for their valuable contributions.

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[2] IEC 60904-9: Solar simulator performance requirements

[3] IEC 60891: Procedures for temperature and irradiance corrections to measured I-V characteristics

Author

Vahid Fakhfouri trained as a microengineer and obtained a PhD in nanotechnologies from the Swiss Federal Institute of Technology in Lausanne. Vahid worked for the watchmaking industry as a micro-nano manufacturing expert before joining Pasan in 2009. He is currently head of R&D at Pasan SA, a member of the Switzerland-based Meyer Burger Technology group. Pasan is the world reference for I-V measurement equipment in the photovoltaic cell and module manufacturing industries. Vahid is also an active member of the International Electrotechnical Commission (IEC) and has been leading the standard project for I-V characterisation of bifacial PV devices since 2016.

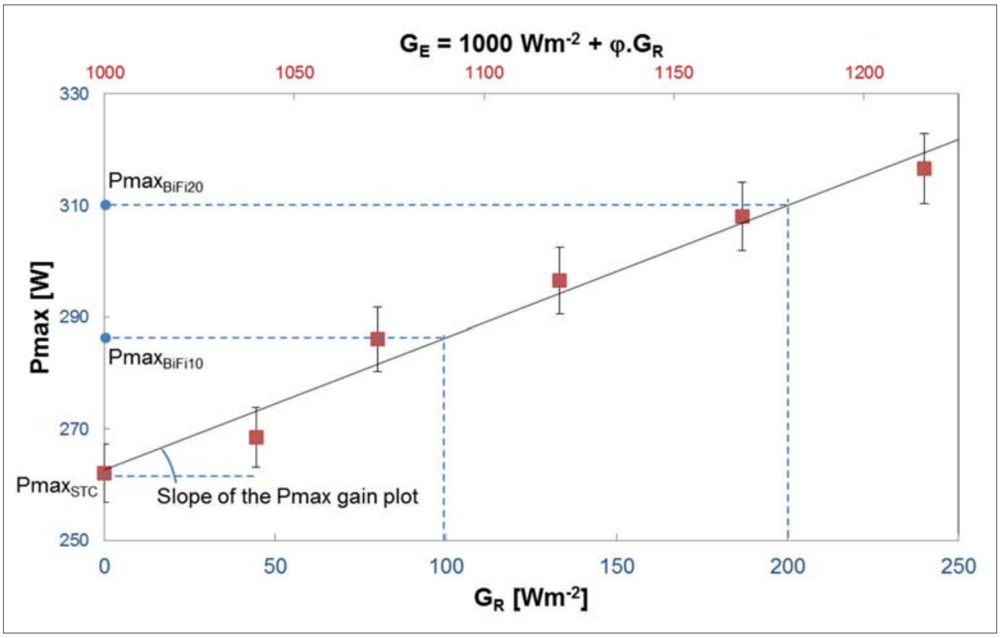

Figure 3. Example of a Pmax gain plot for a bifacial reference module

Understanding energy gain in bifacial PV systems

Bifacial systems| The additional power provided by the active rear side of bifacial modules depends on a multitude of factors. Naftali Eisenberg and Lev Kreinin look at how the gains in a bifacial PV system can be influenced by local conditions and system design decisions

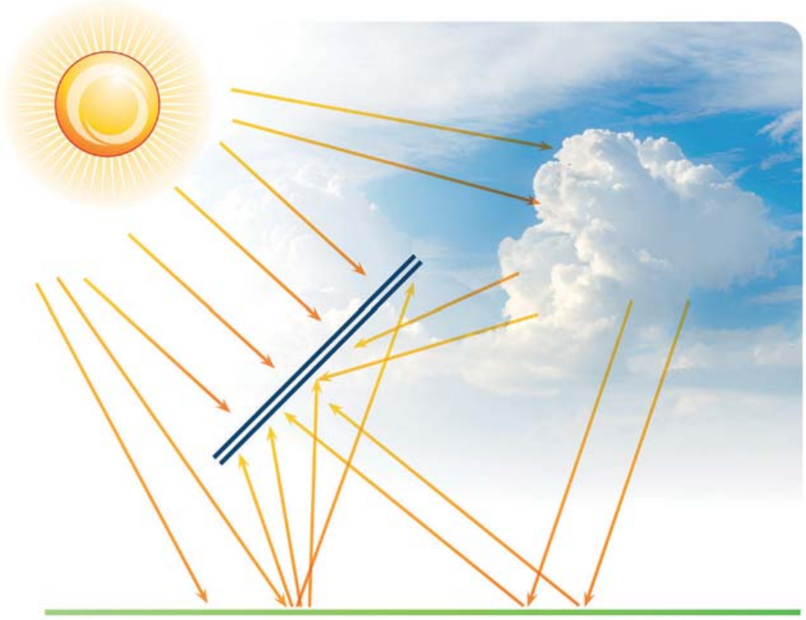

Figure 1. Terrestrial bifacial PV system

The beauty of bifacial PV systems is in the increased generation provided by the additional light energy collected on the back side of the modules. After the first space application of bifacial solar cells in the 1970s to supply additional energy, using the Earth's albedo [1,2] it was demonstrated that such cells are also very attractive for extra energy generation on terrestrial applications.

A module placed outdoors as in Figure 1 will generate energy according to irradiation incident on its front and back simultaneously. This irradiation is generally composed of direct (plus some diffused) sunlight on the front and reflected diffused (and sometimes direct) light on the back.

Whereas energy generation by regular monofacial modules is well studied and foreseeable, the forecast experience of energy production by bifacial modules is very limited. Among the factors affecting the back energy generation are:

1. Illumination conditions dependent on geographical, climatic and temporal factors:
   - Sun elevation
   - Diffused/global radiation
2. Module and system design parameters:
   - Module "bifacial factor" (back/front short current ratio)
   - Module inclination
   - Distance between rows
   - Stand-alone/field system
   - Module elevation above underlying surface
   - Distance between modules in the row
   - Albedo of underlying surface

All the above factors impact mostly on the back irradiation and therefore on the added energy generation, or 'energy gain' (EG). The energy yield of bifacial module E_b, with the subtraction of the energy yield of monofacial module E_m, under the same conditions will result in the energy gain. To exclude an effect of possible difference in the front powers of both modules the yield should be normalised relative to nominal front power of each module. Therefore the correct definition of the energy gain is:

$$EG = \frac{Eb}{Pfb} - \frac{Em}{Pfm}$$

Where P_{fb} is the power at standard conditions of a front-illuminated bifacial module and P_{fm} is the power at standard conditions of an illuminated monofacial module.

Energy gain is not constant for a given module and depends on the factors mentioned above. The range of possible energy gain values characterises the energy production ability of the module and system. In parallel to energy gain, additional factors can be used to characterise the energy production capability of a bifacial module. They are equivalent efficiency and equivalent nominal power.

Equivalent efficiency of a bifacial cell or module is the efficiency of a monofacial cell or module providing the same energy as the bifacial one.

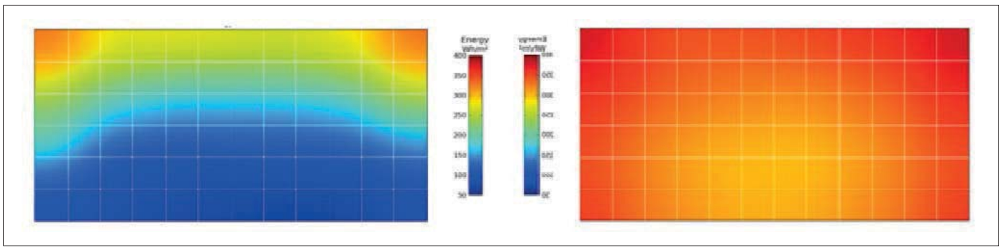

Figure 2. Non-uniformity of back side irradiance for a 30° tilted module as a function of module elevation. Left diagram 8cm and right diagram 58cm over ground

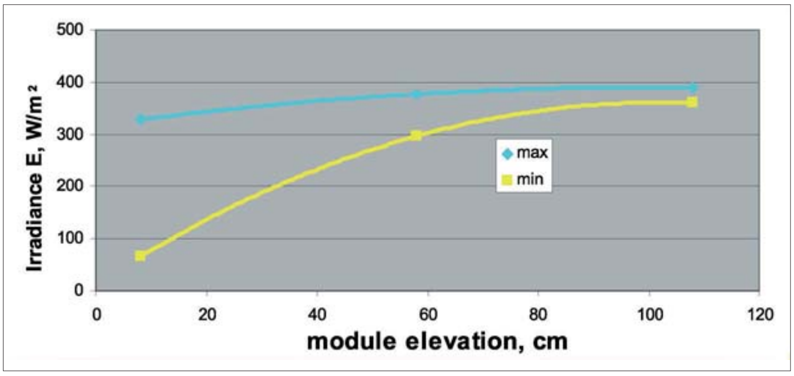

Figure 3. Illumination non-uniformity characterised by maximum and minimum back irradiance on the module as a function of module elevation (albedo of the underlying surface is 50%)

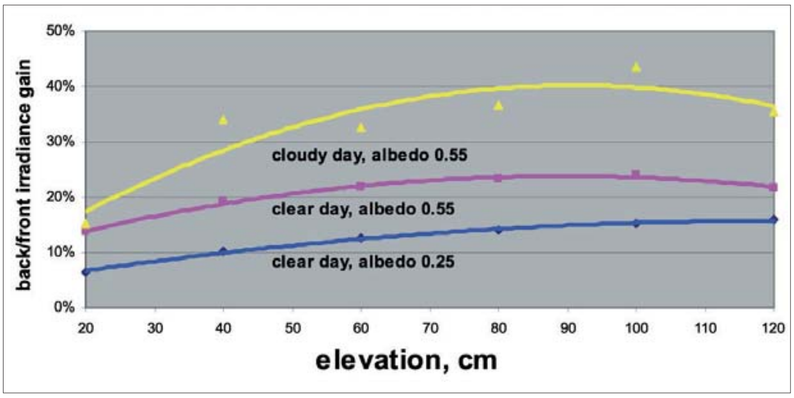

Figure 4. Irradiance gain as function of weather, albedo and panel elevation

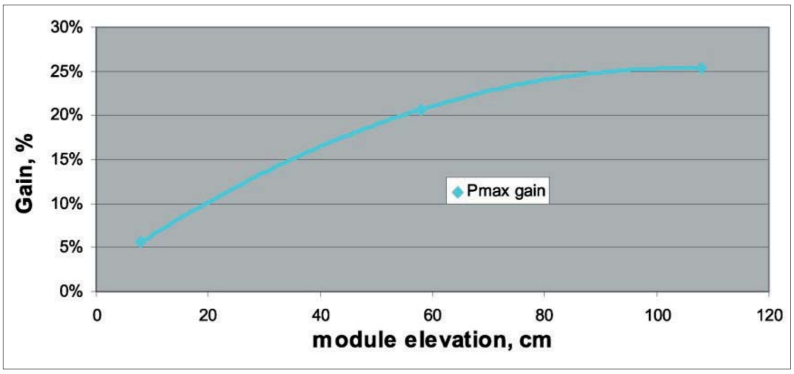

Figure 5. Maximum power gain (limited by minimal back irradiance) versus elevation for a bifacial module at a fixed tilt of 30° (bifacial factor is 71%)

Therefore the equivalent efficiency of a bifacial cell or module can be expressed by the following:

$$\eta_{b\,equ} = \eta_{fm} .(1+EG)$$

In the same way the equivalent power of a bifacial cell or module will be expressed by:

$$P_{b\,equ} = P_{fm} .(1+EG)$$

Module back irradiance characteristics

Rear irradiance non-uniformity is one of the important factors which should be taken into consideration when designing or evaluating bifacial system energy generation. Examples of the back module irradiance distribution are shown in Figure 2 [3]. Measurements were made in Jerusalem (31° north latitude) on 29 May at noon. Irradiance on horizontal surface, 1,006W/m^2; diffuse to global radiation ratio, 0.11; underlying surface albedo, 50%; tilt of module, 30° from horizontal.

As can be seen, the back irradiance is non-uniform, and the non-uniformity depends dramatically on the module elevation. The irradiance values are in the range of 66-328W/m^2 in the case of lower module elevation, i.e. varying ~five times, and in the range of 360-390W/m^2 in the case of highest elevation, i.e. varying ~ 10% only. Figure 3 summarises the changes of back module irradiance, i.e. non-uniformity, versus module elevation. The curves reflect the range between minimum and maximum back irradiance for the case where the module is fixed with a 30° tilt and mounted in a field where the distance between rows (in a south-north direction) is 150cm and between separate modules (in an east-west direction) 20cm.

The reflectivity of the underlying surface is the dominating effect on the back irradiance. Minimal back irradiance increases nearly proportionally to the albedo of the underlying surface, when the diffusion component of the solar irradiation is small. This can be seen in Figure 4 for two albedo cases: 0.25 (blue curve) and 0.55 (red curve). Minimal back irradiance will be used for the irradiance gain evaluation necessary for the power gain determination.

Uniformity of back irradiance is significantly better under conditions of predominantly diffuse radiation. Figure 4 also illustrates comparative data on irradiance of the panel rear side for different weather conditions. For the cloudy day the illumination conditions measured were: global irradiance, ~190 W/m^2; diffuse/global ratio, 0.98. In the case of cloudy weather (predominantly diffuse radiation) uniformity of irradiance is significantly better even at low elevations (yellow curve). Comparison between this curve and the red one shows also that the ratio of back to front irradiance is higher in the case of diffuse sun illumination (43%) than in the case of nice direct illumination (~24%).

Electrical contribution of the module back

The electrical measurements of the module back only (with the front covered with a non-transparent sheet) and of a module with both sides illuminated (front by sun, back by scattered light) shows that the back contribution is limited by the lowest irradiated area. This restriction of back contribution in the module maximal power, P_{max}, is illustrated in Figure 5 for the module, which has a bifaciality factor of 71%. The increase in gain with the elevation raise is largely determined by the irradi-

Figure 6. Rooftop test field in Jerusalem

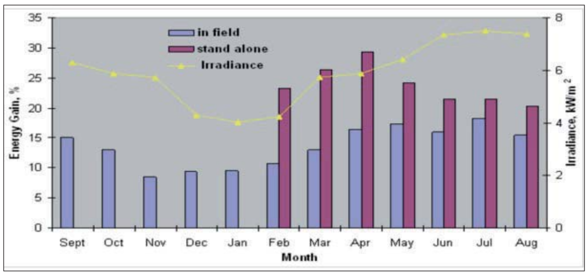

Figure 7. Monthly energy gain of a bifacial vs. a monofacial module

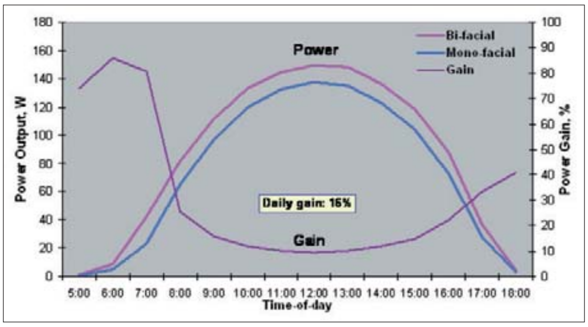

Figure 8. Daytime energy generation by regular and bifacial in-field installed modules

ance distribution improvement and to a lesser extent by the increase of absolute irradiance on the back (see Figure 3).

Outdoor monitoring

Comparative outdoor measurements of bifacial and monofacial modules and systems were undertaken in several geographic locations [3-6].

One of the monitoring sites is Jerusalem (latitude 31°47' north). Figure 6 shows a view of the roof test station. Comparative measurements of bifacial and monofacial modules were made when modules of both types were mounted inside the "field" of several module rows. The modules were oriented at a fixed position south with a 30° tilt. The distance between rows (in a south-north direction) and between separate modules (in an east-west direction) was 150 and 20cm, respectively. Elevation of the module lower edge was 70cm.

The summary of comparative monitoring of bifacial and monofacial modules is shown in Figure 7 as monthly energy generation gain [4, 5]. The bifaciality factor is 71%, the albedo of the underlying surface 50%. The generated energy gain is normalised by nominal module front power at standard conditions. The measured bifacial gain varies depending on time of year in the range 9 -20% with annual gain above ~15%. During this experiment, the energy production was determined by integrating the DC power of the modules measured every three minutes.

The gain for a standalone bifacial module for several months is also shown in this figure. As can be seen, the standalone bifacial module provides ~22 to ~30% energy gain (an additional ~3 to ~13% compared to in-field module energy gain). It should be mentioned, that the maximal power generated by a bifacial module in standalone conditions is the value which should be used as an analogue of the monofacial module power at standard conditions for a safe module and system design.

Some details of comparative monitoring of energy generation by monofacial and bifacial modules are presented as time-of-day dependence. An example of such dependence for a sunny day is presented in Figure 8. [4,5]. The increased gain can be seen for the morning and evening hours, when the portion of scattered radiation is larger. (Due to the site topography causing shading of the sun in the evening, when it is below ~20° above the horizon, the contribution of the back of a bifacial module is decreased in the afternoon). In the morning the direct sun rays hit the back (in the time frame between the spring and the autumn equinoxes). Because of the morning and evening effects, the daily gain is significantly higher than during the middle of the day.

The same type of measurements for a day with prevailing diffused radiation (Figure 9) shows a significant increase in gain when diffused radiation dominates: ~38% when the diffused/global radiation ratio is 88% compared to ~16% when 89% of radiation is direct sun radiation.

At low illumination (morning and evening) the energy generated from a monofacial system is low, and the DC-AC conversion efficiency of the inverter is low or even below working level. A bifacial system provides not only a gain in DC energy generation, but shifts the inverter into effective working mode. Therefore the energy generated by a bifacial system in the morning and evening is increased due to two reasons: bifacial gain and higher DC-AC conversion efficiency.

Another monitored system was located in Geilenkirchen, Germany, latitude ~51° north (Pohlen test site, monitored by Fraunhofer ISE) [5]. The flat rooftop systems with separate inverters were composed of six bifacial and seven monofacial modules. The modules' installation parameters were: height, 0.3m; tilt, 15°; N-S row distance, 2.5m. An albedo value of 78% was measured at the beginning of monitoring and ~ 55% after ~one year.

According to monitoring data, the energy generated due to the back contribution exceeds 20% every month. A jump in bifacial gain during January to February illustrates the additional advantage of bifacial modules: after snowfall, the contributions of the backside of the bifacial modules increase due to high snow reflection. In the same time, the front side covered by the snow generates less energy, and so the gain value increases significantly. A 23% annual bifacial gain is evaluated. The equivalent power of each of the bifacial modules (i.e. the power of a monofacial module able to generate the same energy as a bifacial one) is 307.5W, while its front power is 250W. The equivalent efficiency of the cells is 22.75%, while their front efficiency is 18.5%.

Simulation of system gain

Examples of bifacial system performance simulation for different field design parameters can be seen in Figure 12 (the location of the field is Hannover, Germany, latitude 52° 22') [6]. Panel tilt is equal to the latitude of the given place. This panel position provides the maximal energy collected by the panel front. The basic bifacial module used for the calculations was built with solar cells having a front

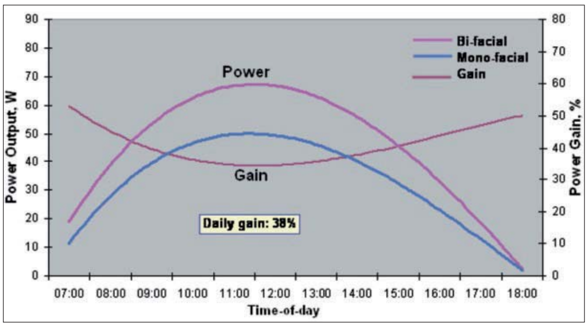

Figure 9. Monitoring of energy generation by regular and bifacial modules on a cloudy September day when diffused/global radiation ratio was 88%.

Figure 10. Rooftop test field in Geilenkirchen

Figure 11. Monthly energy gain of a bifacial versus a monofacial PV system

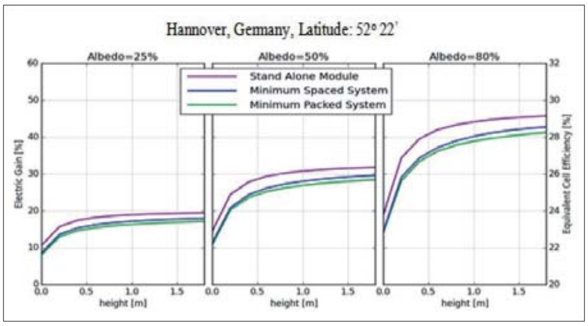

Figure 12. Examples of forecast calculations for bifacial PV system with different design parameters

efficiency of 20% and a bifaciality factor of 90%.

The electrical gain is shown as a function of the distance of the panel lower edge to the ground (panel height). The calculations are performed for three types of system: packed min, i.e. minimal north-south distance providing no shading on 21 December, noon; spaced min, i.e. minimal N-S distance x 1.5; single panel. Three albedo values were chosen in the range of typical coatings: tarred roof, dry soil (25%), white agricultural canvas, polluted white roof coats (50%) and cool white roof coat, snow (80%).

It can be seen that two design parameters are most influential on the gain: panel elevation and the albedo of the underlying surface. Increasing the elevation of the panel above the underlying surface results in multiplication of the gain. The positive effect of the panel height increase is starting to saturate at 0.4-0.5m. The increase in gain due to higher albedo is obvious – the gain is approximately directly proportional to the albedo.

There is no dramatic effect from the row spacing of the field. Therefore the north-south distance between the rows can be selected without taking the gain into consideration. Even using bifacial cells with moderate front efficiency in a PV system is equivalent to the creation of monofacial systems based on cells with 26-28% efficiency, what is close or above the achievable maximum.

Conclusions

Simultaneous monitoring of I-V characteristics of mono- and bifacial modules and systems demonstrates the superiority of bifacial over monofacial types of PV energy generators.

The yearly energy gain of an in-field bifacial versus a monofacial module in a low latitude position (Israel) with an underlying surface albedo ~0.50 and a module bifaciality factor of 71% is above 16%. For a higher latitude location (Germany) the energy gain is above 23%. These values can be easily increased above 23% and 30% respectively by optimisation of the PV field design and by increasing the bifacial factor to 90%. This was shown both through outdoor monitoring and simulation.

According to calculations, the equivalent efficiency of bifacial solar cells with 20% front efficiency embedded in the modules of bifacial systems is in the range 26 -28%. The values of energy generation and equivalent efficiencies, which can be realised using modern bifacial cells, are far above the levels of the best regular monofacial silicon cells. ■

Authors

Professor emeritus Naftali Eisenberg is founder and CTO of Solaround, an Israel-based company developing advanced p-type bifacial cells and modules. He is the head of the Jerusalem College of Technology Center for PV Solar and the former chief scientist of the solar energy pioneer company Luz, which installed 360MWp solar thermal systems in the 1990s, and founder and CTO of B-Solar, the first company that developed p-type bifacial cells and modules.

Dr. Lev Kreinin is chief scientist of Solaround based in Israel. His career started in solar cell R&D for the Russian space programme, specialising in bifacial cells for the first space solar arrays. From 1992 he was an associate professor in the Jerusalem College of Technology. From 2009 to 2013 he was chief scientist of bSolar Co based in Israel, focused on the development, testing and production of p-PERT bifacial solar cells. The same R&D direction was continued in the frame of Solaround.

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Adding imports to injury

Credit: zimmytws/Getty Images

Trade dispute | Battle lines have been drawn as another trade dispute convulses the US solar industry. John Parnell reports on an increasingly bitter war of words as the case hearings get underway

At the time of writing, many in the downstream US solar industry are feeling the weight of an impending period of darkness. An inevitable and unavoidable event that will stop solar power generation in its tracks. The solar eclipse on the 21 August is, happily, a predictable and manageable event. A similar eclipse in Europe during March 2015 passed without incident as transmission operators were able to put plans into place. The UK's National Grid pointed out that demand suppression created by the number of people gawking at the sky would offset the impact of lost solar generation and, in the event of bad weather keeping people indoors, there would be less PV-sourced power to come offline anyway.

The solar eclipse, while a dramatic event, is predictable and easily solvable. The more concerning shadow hanging over the US solar industry is of course the Section 201, or Global Safeguard trade case.

The arguments of the case began to take precedence in the weeks running up to the first public hearing in mid-August. The initial petitioner, Suniva, was under the spotlight as its majority Chinese ownership generated questions about its motive for making solar imports into the US more expensive. Its insolvency was also a focus. The so-called "blackmail" letter from Suniva's largest creditors, SQN Capital, created a stir. The company, which is paying Suniva's legal fees via its debtor in possession finance, offered to pull the case if the China Chamber Of Commerce For Import & Export Of Machinery & Electronic Products (CCCME) thelped it recover its debt. In a letter now made public, SQN offered to end its backing of the safeguards case if the CCCME found a buyer for Suniva's assets, valued at around US$50 million.

From there, competing studies on the impact of tariffs on US solar jobs presented cheese and chalk alternatives for the domestic solar value chain in an environment with punitive duties on all solar imports. More substantive arguments began to rear their heads as the hearing neared and the apparent strategies of either side's argument were taking shape.

What they want

Before running through the core arguments that the Us International Trade Commission (ITC) will hear, let's take a look at the remedies requested by the petitioners. The initial complaint requests a tariff of US$0.40/W for cells and US$0.78/W on modules, that includes the 40 cents component from the cells. They ask that these last for four years. In addition they have asked for duties from the two previous anti-dumping cases in the US to be "distributed equitably". In addition they want the formation of a development fund for the domestic industry using tariffs from the 201 case and finally, that the president instigate negotiations to "restore a supply and demand balance in the global market".

The hearing in August was to determine whether US manufacturers had suffered 'injury' as a result of imports

If the ITC decides that imports are the reason for the domestic industry's woes, it will then recommend a set of remedies to President Trump. The final decision on what form these will take, if any, rests with the White House.

Representative

One of the earliest facts that must be established is whether the two petitioners in the case represent the US solar industry. The SEIA trade body insists that the ITC should be considering the entire solar value chain as one entity and not separating out the manufacturers. By this definition, it says the petitioners represent less than 1% of the US industry.

A running theme in the case, and trade cases before it, is the way that the same information can be presented so very differently without either being inaccurate. The petitioners argue that between them, they are the largest (SolarWorld Americas) and second largest (Suniva) US cell and module manufacturers.

Adding imports to injury

The case, it must be remembered, applies to all imports of cells and modules. For it to proceed, it must be shown that imports caused injury to the US domestic manufacturers. The added complication is that this import-induced injury must be singularly identifiable in order for the ruling to remain compliant with the World Trade Organisation's rules on safeguard measures.

"The existence of the causal link between increased imports of the product concerned and serious injury or threat thereof. When factors other than increased imports are causing injury to the domestic industry at the same time, such injury shall not be attributed to increased imports," the WTO states. This means any other impacts on domestic manufacturers muddy the waters.

Step forward the SEIA with a slew of criticism of the petitioners' business practices and alternative reasons for their struggles. These included a failure to switch 72-cell modules in order to capture the utility-scale market. In its pre-hearing brief, it backed these up with signed affidavits from customers of the petitioners and former employees. The following excerpt gives a taster of some of the SEIA's criticisms:

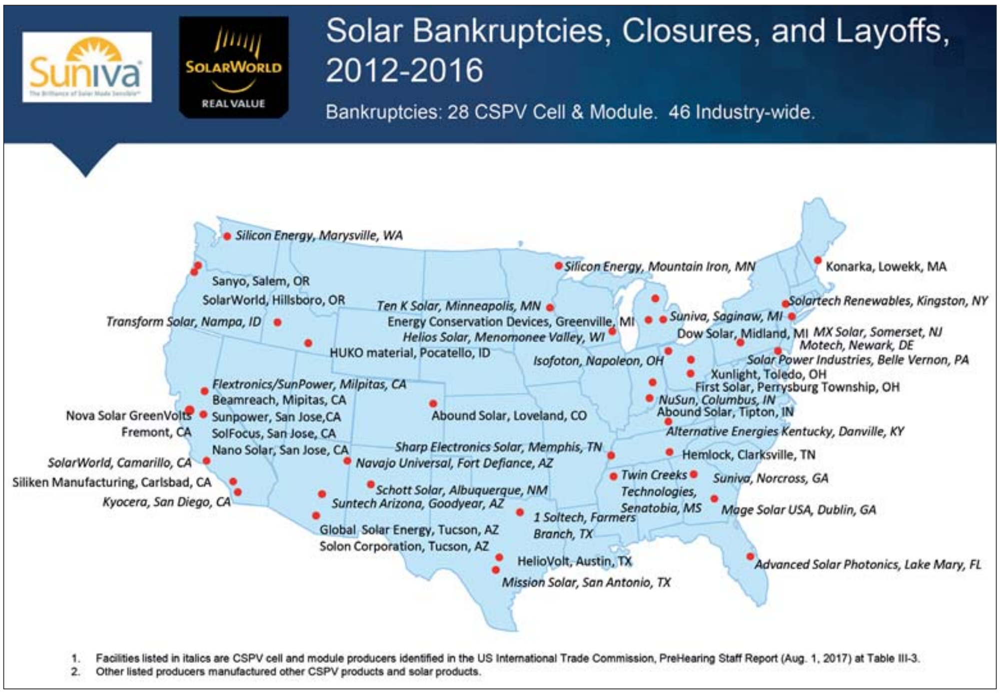
"Suniva experienced quality problems with panels assembled in their own module manufacturing facility located in Saginaw, Michigan. The facility did not have airconditioning in the fabrication area nor the proper "clean room" environment as one would find in other module manufacturing facilities owned by the larger cell and panel manufacturers. They also had a large amount of turnover in this facility making it a challenging to keep skilled labor.

"From time to time, Suniva would have white labeled product (cells and panels) made by contract manufacturing with a Suniva label. These products were produced outside the United States, primarily in Asia. Suniva also contracted with an unaffiliated company, Silfab in Toronto, Canada, to assemble panels for the small utility market. This arrangement required Suniva to provide bill of materials (BOM) or components to Silfab for assembly. Suniva routinely delayed or failed to ship components and Silfab could not produce panels in sufficient quantities."

The response from the petitioners to the claims of the SEIA was heated to say the least.

"SEIA's statements are false, misleading and disingenuous, and their tactics are shameful in the face of the thousands of real American manufacturers who have lost their jobs due to unfair imports from China and globally. SEIA has yet to offer any constructive path forward to helping US manufacturing. In fact, SEIA's own pre-hearing brief acknowledges injury to the US industry, including other companies' bankruptcies. This is not about the two companies that lasted the longest; this is about nearly 30 companies and nearly an entire industry that has shuttered their doors in the last five years. Is SEIA's next step going to demean all of the workers and investors for all of those companies?"

Another consideration for the ITC is the



Credit: Suniva/SolarWorld Americas

interplay between these perceived "errors" as presented by the SEIA and the undoubted increase in imports. Keeping in mind the WTO rule on discounting injury that has multiple simultaneous sources and the task looks like a difficult one.

Just ahead of the hearing, Suniva and SolarWorld published a map with the locations of the all the US solar manufacturers that they say have either cut staff or closed completely.

Guessing

Attempting to guess how the ITC's four voting members judge this material is a fools' errand. If two commissioners back the imposition of remedies, the case will proceed.

Few are willing to publicly predict what will happen but compressed procurement timelines would suggest that those in need of modules are hedging their bets.

First Solar, whose thin-film panels are exempt from the case, has refused to comment on the investigation when asked by this publication. CEO Mark Widmar did tell an analyst call that the company had seen increased urgency from customers to secure orders but that the company would not use its status to hold customers over a barrel.

"I'm not looking at this as some opportunistic ASP grab that we could get into the marketplace. I mean, we're going to engage customers from a relationship standpoint and a long-term partnership perspective and capture the right appropriate value for the product, not necessarily trying to be overly optimistic because of a potential trade dispute that may happen or may not happen," he said.

US solar manufacturers claimed by the trade-case petitioners to have shed jobs or closed down due to unfairly priced imports

Politics

The known unknown in the final outcome of the case is the Trump administration.

"This part of the case is a factual investigation by the commission, there may be more of a political element at the end, assuming there is a positive injury determination and the president declares a remedy," says Timothy Brightbill of law firm Wiley Rein and legal counsel for SolarWorld Americas in the case. "The administration has a great deal of discretion in that process. We think given the administration's focus on US jobs, on US manufacturing that they should also want a remedy that is comprehensive, that treats everyone the same and doesn't make any exceptions or exclusions."

There is an air of inevitability growing that the ITC will indeed find evidence of injury but it could still choose not to recommend any punitive remedies. Australia's anti-dumping case found evidence of harm but ruled that measures were against its best interests.

Whether or not the remedies would be good for the industry as a whole is almost a moot point. The first glimmer of hope after the darkness of the mud-slinging in the build up to the hearing would be an open dialogue between all sides and an eventual agreement. On past experience of solar trade cases, the petitioners could be forgiven for feeling that no deal is better than a bad deal. Right now certainty in any form would be a great relief.

The ITC must vote before 22 September on whether or not to recommend trade remedies.

Highlights from the hearing

Matt Card, executive VP of commercial operations, Suniva

"As a country, we will have ceded manufacturing of the next meaningful source of electrical generation to China and its proxies in Southeast Asia and other global outposts. As we continue to stress the needs of energy independence as a country, the US, in fact, will have no control of its own destiny when it comes to power generation from the sun.".

Stephen Shea, formerly vice president at Beamreach Solar

"Beamreach was forced in Chapter 7 bankruptcy in large part because of the surge of low cost imports. Beamreach could not keep pace with the rapid reduction in prices driven by imports, first from China, then from countries like Taiwan, Vietnam, Malaysia, Korea, etc. and the resulting glut of product quickly destroyed the profit margins."

Matt Nicely, legal counsel, SEIA

"Solar is an American success story, whose future remains bright. Its continued success could be destroyed by the misguided actions of the two petitioners and their small group of supporters – whose workers represent less than 1% of all those that work for this dynamic American industry. That the two petitioners would even bring this case demonstrates their poor business judgment – and their hubris. They seek a public remedy for their own, private failings."

Representative Jason Saine (R-NC, 97th district)

"As a policymaker, every day I am faced with decisions that can create trade-offs, and therefore can create winners and losers in any industry. Imposing tariffs on imported modules is NOT the way to go about saving solar manufacturing. It is about providing a government handout to two companies that apparently couldn't provide their customers with the specific kinds of products or sufficiently high-quality products they needed for their installations. As I understand you will hear today, if this petition is granted, it may save a few hundred cell or module manufacturing jobs, but there are many thousands of good manufacturing and installation jobs that will be lost."

Quality in India: battling the stereotypes

Quality | The speed of solar deployment in India has raised concerns that quality maybe sacrificed for expediency. As Tom Kenning reports, although there are warning signs of a potential quality problem, efforts are underway to nip it in the bud

Some of India's early PV plants suffered problems from heavy wind, but quality is improving

The breakneck pace of PV deployment in India over the last two years has come hand in hand with warnings from some quarters that poor implementation of projects will come back to bite the industry. Certain commentators regularly express fears over low quality standards in modules, construction and even some of the most basic components. They tend either to pigeonhole Indian business attitudes as being too price sensitive or blame Chinese equipment imports. With the relentless plummeting of Indian solar tariffs, critics are also concerned that EPCs are cutting corners.

To be sure, some of India's earliest solar plants have demonstrated a worrying lack of resilience to extreme weather conditions, particularly high winds. And the problem has proved sufficiently worrisome to attract the attention of the Indian government, which has introduced new quality standards and inspection protocols, while threatening to bar poorly performing companies from the sector altogether.

Yet to say that India is becoming a haven for poor quality PV equipment and shoddy workmanship would be premature and an unfair generalisation. The warning signs are undoubtedly there that quality could become a problem for India's fast-growing but still comparatively young PV sector. A closer look, however, reveals plenty of efforts going on to curb the processes and practices that could cause a potential problem to become an actual one with potentially damaging consequences for the sector.

To open this inquiry, it's best to look at the past history of Indian plant mishaps. Manish Singhal, head of business development at top Indian EPC firm Mahindra Susten, categorises two kinds of key failures in the early years. The first was PV structures flying away under heavy gusts of wind, due to poorly designed foundations. The second, less visible problem was the frequency of micro-cracks in the offerings of some of the first thin-film module suppliers to India.

"Obviously quality is a concern and we've had issues with modules for example in early stages of the market," says Jasmeet Khurana, associate director of consulting at Bridge to India. "There was a US-based company called Abound Solar. It sold modules into India and some whole projects [and modules] stopped, and they were not around to replace them. There are some stories like that, but overall I think it is a concern and people now do a lot of things to make sure they are getting the right product."

Singhal says that all other examples of faults have been very small in size and number, although he adds that eight or nine major failures in the last five years

Module import quality, analyst and EPC perspectives

Some Indian news outlets have reported a stabilising of module prices, which puts pressure on developers who have won projects with extremely low tariffs on the assumption that module prices – one of the largest expenses in a solar project – would continue to fall. Industry members share their views on this supply and the delicate interplay between price and quality:

Finlay Colville, head of solar intelligence at Solar Media

"The price outlook for solar panels in India will depend on a host of factors, most notably the levels to which Chinese suppliers need to ship lower quality multi c-Si panels overseas, directly from Chinese factories.

"Over the past couple of years, the Indian market has been the lowest price globally for solar panels, with this coming from a blend of Chinese oversupply of multi, coupled with the emphasis on site capex taking precedence over any higher quality or power variant that would have added several pennies to the costs at the panel level.

"While the Chinese market is certainly running at levels which make pricing and quality of module supply a priority, there are potentially multiple gigawatts of lower power multi produce that may simply not be able to get sold in China.

"India would be the default route for this, and this may simply ensure that India keeps importing this type of offering from China."

Lavleen Singal, director at Acira Solar

"When developers go to buy, they want the cheapest stuff. I wouldn't be surprised if some [Chinese] material comes to India at lower than international prices.

"Europeans are being sold these modules at 50 cents (for example) and we are buying them at 45 cents… tell me; are we smarter than the Europeans? I'm trying to imply that they are giving us rubbish quality."

Singal claims that certain Chinese manufacturers are outsourcing services at various stages of the production of modules and as a result, quality is suffering, even if testing is being done at the main factories in China.

Jasmeet Khurana, associate director, consulting, Bridge to India:

"Modules prices in India are lower than module prices in China even though modules are coming from China. There are export incentives within China and the feed-in tariffs from China are higher so they are able to sell at higher cost within China.

"I'm not sure it's true and to what extent, but there is concern that there is still some differential in quality between what's being sold from a tier-one company when they sell to the US versus what they are selling to India. There might be some difference in the bill of materials so that concern is there."

is actually a rather large number. But he also agrees the industry is wising up – switching into a kind of "stabilisation mode" and starting to understand the importance of getting the EPC service right.

For example, more evidence can be found in Indian firms now negotiating the complete bill of materials (BOM), including everything from cells to backsheets, when discussing module prices.

"That trend came into being because there was something called the 'Indian BOM', which basically means that manufacturers were giving a slightly below-standard bill of materials to projects in India," adds Khurana. Now module purchasers are testing materials at every level to make sure they get what they were promised.

The move from a shaky, windswept start to a more robust practice in India is also confirmed by Jonathan Selwyn, director at international advisory firm, Solar Consulting, which has overseen a number of projects in the country. "It's fair to say there was very variable quality in the early solar farms and rooftop projects, but I'm very pleased to say that in two years, there's been a very rapid development in the quality of projects and know-how on the ground from local partners and international operators," he says.

Indeed, for Selwyn, there's now no distinction between Indian PV projects and those seen springing up across the rest of the globe in mature markets, but he highlights the perennial need to have a local partner in India to get a solid project completed to a high standard. "They are the ones who really know how it all works," he says.

If quality is indeed improving within India, then one of the major flashpoints of the future will be the supply of modules from China, the country responsible for the majority of imports to India. Suspicions are high due to the low prices of goods sold to India when compared to other markets (see box, above). However, some commentators have brushed off these worries by claiming that Indian firms are just talented at negotiating a tough deal.

> "The entire value chain is going to have very strict standards because I don't want my Indian people to ever suffer from bad quality equipment. Those companies that do not live up to good quality standards will not be allowed to participate"

Quality standards

The Indian government appears to have heard the concerned voices and recently decided to implement stricter quality standards for solar tenders, including inspections for modules, cells and wafers, as energy and mines minister Piyush Goyal announced at Intersolar Europe in Munich back in May. Issuing a warning to both developers and manufacturers at the Indo-German Energy Forum, Goyal said: "Bear in mind we are watching, we are watching your performance."

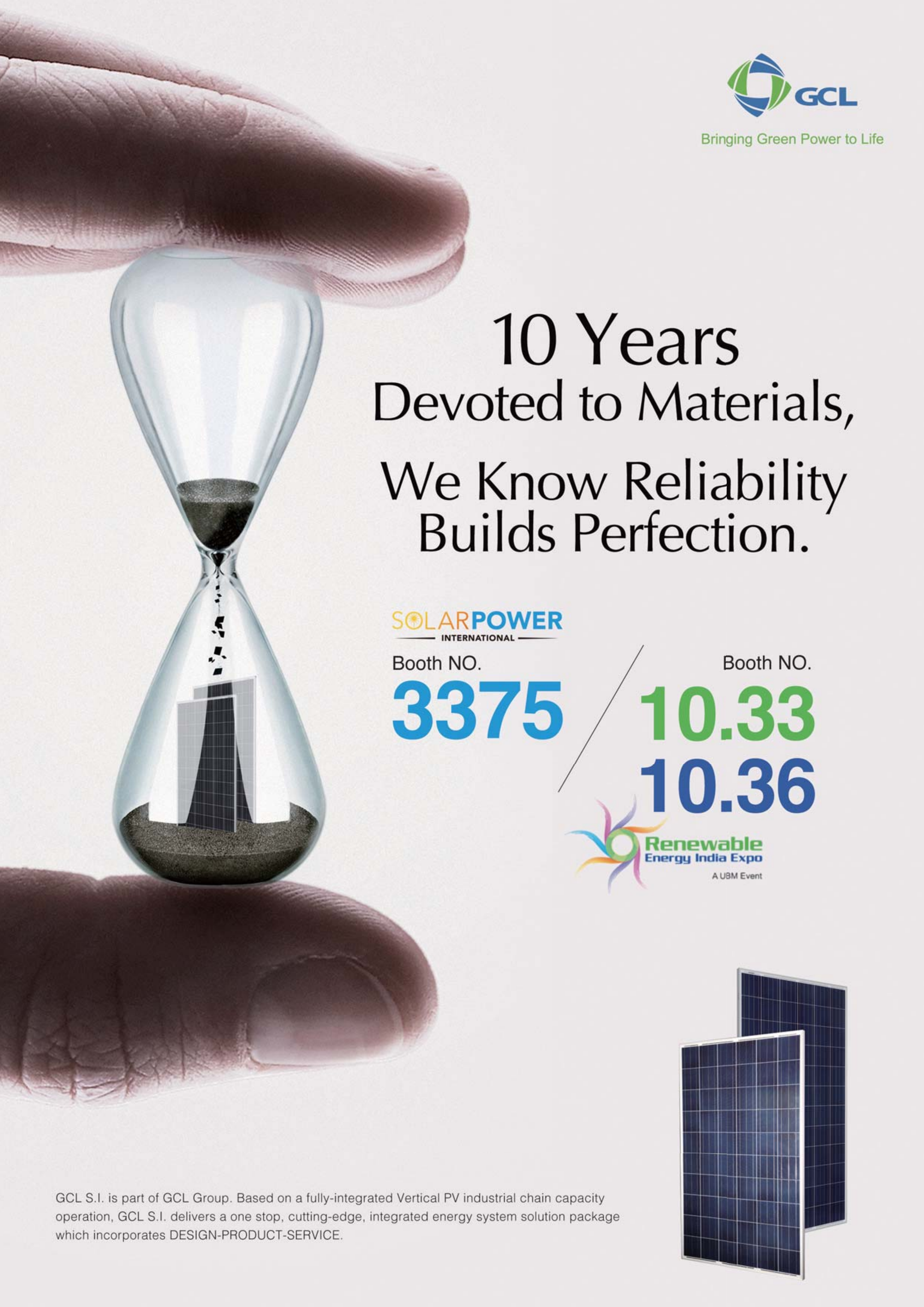
The Ministry of New and Renewable Energy (MNRE) had already released a draft technical regulation for testing and standardisation of solar equipment last August. Since then, manufacturers from Taiwan, China and India have all told PV Tech Power that tier-one manufacturers tend to have to give their lowest priced bill of materials to the Indian market, given the Indian focus on cost reductions. This has led to fears about whether other less reliable equipment is entering the country.

"Quality standards are going to be tightened for all future bidding going forward," said Goyal. "There will be inspection of facilities before we approve people for their ability to participate in tenders, so even developers will have to procure from approved companies [only]."

However, these new quality standards will not be imposed on contracts that have already been bid out. Instead, all future tenders will have "strict standards" on modules, with any manufacturer at home or abroad requiring approval. Comparable rules for the entire value chain, including for cells and wafers, will follow.

Goyal said: "The entire value chain is going to have very strict standards because I don't want my Indian people to ever suffer from bad quality equipment. Those companies that do not live up to good quality standards will certainly not be allowed to participate..."

While such rhetoric may have cheered the most pessimistic observers of India's steamrollering utility-scale market, Khurana says that the draft regulation standards for solar equipment are effectively only a copy of IEC standards. Therefore the only real change is that solar manufacturers will also have to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obtain certification within India. Indian authorities will have the right to go and inspect any batch of solar modules, at an Indian fab or in warehouse storage, to make sure that they are still complying with the standard.

Khurana also believes that Goyal's comments were more targeted towards off-grid and distributed generation projects, because in that segment it is very difficult to negotiate your bill of materials.

Ultimately, developers in India will need to engage in third-party testing beyond just the IEC standard – a marker which many feel is too easy to pass. Such independent verification would help stamp out the chances of significant potential-induced degradation (PID).

Another source, a manufacturer from India, tells *PV Tech Power* that he is more positive about the stringency of the proposed new standards claiming that imports will have to be certified by an agency within the country for example the National institute of Solar Energy (NISE) or the Bureau of Indian Standards. The banking sector will then not be able to finance products that are not certified, which the manufacturer claims is crucial for India given its trajectory of becoming a plus-10GW annual market in the coming years.

EPCs

The blame for poor quality can't just be flung abroad. Thus, the revelation that India has the cheapest EPC services in the world is worth investigating. Mahindra's Manish Singhal says that the Indian EPC space is divided into three segments: one for projects of 50MW+ capacity, where only a handful of organisations have the bandwidth and the financial capacities to compete; the second is concentrated around 5-10MW projects where there is huge competition; and the third, 1-2MW segment is even more crowded.

"At the kind of tariffs that we have in India, it's really getting challenging to have a balance between quality and cost," Singhal adds. "We have a bottom line already set in sight – below this we will not go. There are many who pick the deals at very low numbers. How they are managing I cannot comment, but […] they may see some kind of failures. Already there are examples in India. People cut corners on the structures, they reduce the structure tonnage and they play on the factor of safety a lot. These examples have been there since last three, four years."

Lavleen Singal, director at Indian EPC firm Acira Solar, also says that the Indian industry struggles by trying to do too much on its own and then cutting corners.

"They overlook key aspects and they end up [using] a makeshift solution," he says. "That's what happened in CSP and I see that happening in PV as well."

Indeed, when asked to predict what aspect of the Indian industry was most likely to surface as an issue in five years' time, Khurana predicts that if anything it will be the overall quality of construction, in terms of practices followed for cabling, engineering and implementation. Such problems will be driven by having to complete projects in short time periods and the use of unskilled labour.

Other components

Bridge to India has already highlighted the need to educate the sector and ensure high performance standards in a rapidly evolving market. The consultancy started with a report on how poor implementation of DC cables has caused underperformance in India, with other prevalent component blunders soon to be analysed.

Again, Manish Singhal claims that issues with DC cables would not be prevalent in the higher capacity projects where the top five or six EPC players and consultants all use TÜV-certified cables, whereas less robust practice is "very prevalent" in the 5-10MW segment. Here customers are also less well informed and often lack the bandwidth to appoint consultants

"That's an area where something can go wrong. Where people use locally manufactured cables which are not TÜV-certified, there are no quality standards available."

Lavleen Singal also lists a range of other potential problems such as shaking from high winds causing micro-cracks and a lack of long-term guarantees on transformer and inverter combinations. There are also risks of blowouts caused by poor connections and the ensuing risk of having to start production from a plant months later than wanted and with the added cost of replacing cables.

The newbies

While, it has been easy to list a number of potential calamities, there has been plenty of positivity about the progress and improvements in Indian solar. Thus for Khurana, the worries should not be directed at the large projects sprouting up from major players, but rather at those projects being developed by one-timers and newbies. For example, while many big names stayed away from the recent 1.5GW tender in Tamil Nadu, a huge number of first time players have won capacity. The emphasis on spreading smaller-sized projects across different taluks (small regions) of Telangana has also attracted new names.

"These are the kinds of vulnerable developers who are a) inexperienced and b) also under pressure to beat the price and tariff benchmarks, which are already very low," Khurana says. "I think they should hire a technical consultant who is able to make sure that everything is done properly and implemented properly.

"If you are an inexperienced player and you are trying to meet tariff expectations which have been set by more experienced players, who have learned how to optimise and still maintain some quality, then it gets really difficult for you to have a profitable project, or at least a profitable project on books, and still have all the quality ensured within your projects."

Price pressure has been a key factor in many of the problems mentioned above, so the recent enforcement of the Goods and Services Tax (GST), which will tax modules at 5% and other components most likely at 18% will be a cause for more concern, let alone the now official launch of an anti-dumping investigation on cell and module imports from China, Taiwan and Malaysia, the outcome of which – albeit unlikely – could raise project prices further. ■

Credit Solar Promotion GmbH

India's energy minister Piyush Goyal has warned solar companies that they face closer scrutiny on quality

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The growing pains of curtailing UK solar

Grid | Solar generators in the UK have been facing the prospect of having large volumes of capacity temporarily shut down due to grid capacity constraints. David Pratt reports on the efforts being made to minimise the impacts of curtailment

Credit Wight Community Energy

This year has already proved to be a record breaking time for UK solar, with the spring sunshine of May delivering a generation peak of 8.7GW and meeting almost a quarter of demand for a half-hour period. However, the fact that the UK has become a c.13GW market in less time than the transmission system operator National Grid predicted in 2012 it would take to reach 2.5GW throws up some issues, not least the suitability of the country's power system to deal with this change.

RegenSW, a not-for-profit organisation working to facilitate clean energy across all sectors, has noted an uptick in curtailment as a result of rising levels of renewables in the UK and the need to carry out upgrades. Project manager Olly Frankland explains:

"In terms of the number of outages they are probably going up. The planned ones are normally on behalf of connections when there's a need for reinforcement in order to put more solar or more wind on to our networks. So we're a victim of our own success to a certain degree as the more renewables we need on, the more outages will be necessary to upgrade the network."

The risk of summer switch-offs

The effect this can have was exemplified earlier this year on the Isle of Wight, a small island just four miles off England's south coast boasting 70MW of solar across 15 sites owned by some of the largest solar asset owners in the UK.

All were caught off guard in January this year when distribution network operator (DNO) Scottish and Southern Electricity Networks (SSEN) put out a notice of full curtailment for April. This was a result of National Grid conducting work on its super grid transformer serving the island.

Wight Community Energy's 3.95MW scheme was fully curtailed in April, and had been under threat of a summer of switch-offs, as a result of grid upgrades

As Nicola Waters, chair of industry body the Solar Trade Association's strategic grid working group, explains: "Some outages are outside the DNOs control as they receive instructions from National Grid about curtailment that is required."

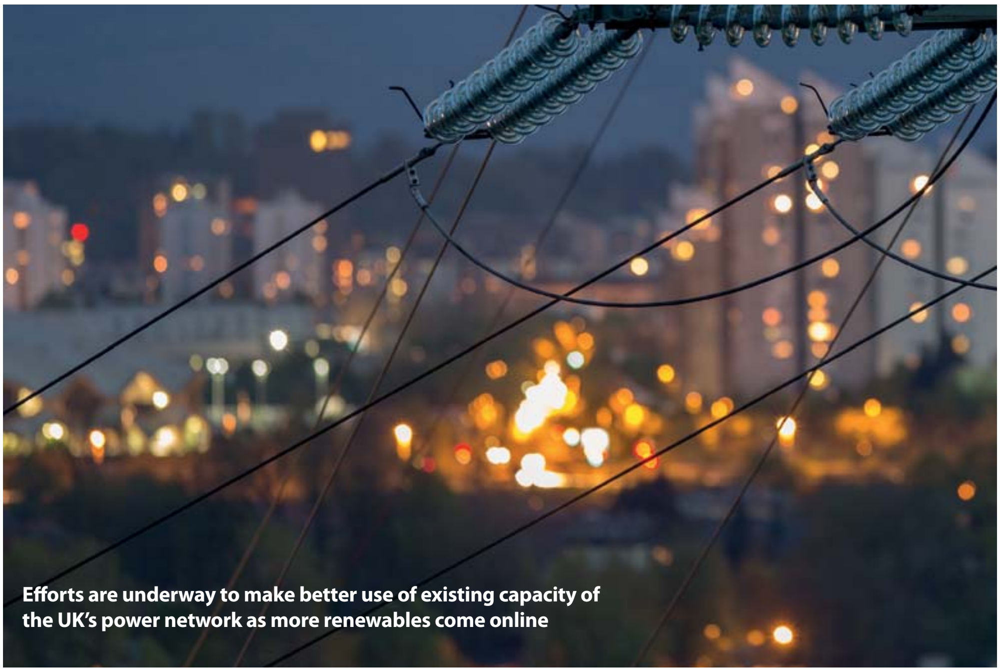
Generators like Wight Community Energy (WCE), a publicly funded energy scheme responsible for a 3.95MW solar farm, were notified just a few months before and had no choice but to face a switch-off in the absence of time to negotiate. This resulted in full curtailment of some generators on the island such as WCE, which saw the expected annual output of the community solar farm cut by 8.1% (410,577kWh), resulting in £46,521 of lost income.

A letter received by WCE chair Colin Palmer suggested worse was yet to come, with SSEN planning to schedule upgrade works to its 132kW overhead lines between July and October. Combined with additional plans by National Grid scheduled for August, the island's generators were faced with a daunting prospect.

"We would be fully constrained from July to October; that was the original position," Palmer said back in June. "This is an unprecedented level of outage beyond anything I've ever experienced in 25 years in renewables. The other generators who are equally affected are as surprised as we are."

The plans would have put over half of revenues at risk as a result of what was dubbed by WCE as "years of under-investment in island infrastructure". To make matters worse, SSEN was said to be "extremely difficult to engage effectively with" in the weeks following notification.

The issue was particularly acute for the Isle of Wight, according to Waters. "Curtailment for existing assets is a widespread issue but it's the concentration of curtailment that gives some asset owners sleep-



Credit National Grid/Getty Images

Efforts are underway to make better use of existing capacity of the UK's power network as more renewables come online

less nights," she says.

The amount of solar generation in the small locale of the island in combination with infrastructure upgrades, the age of the network and the nature of the work needed all played a role in what would have seen 54% of revenues lost, and as Water adds: "There is no official requirement for the DNOs to keep generators 'on' as much as possible."

Faced with this possibility the generators – including the likes of Octopus, Bluefield, Low Carbon and Magnetar – banded together to confront the issue head-on and present a united front to SSEN in an attempt to limit the impact of the plans.

Following a few short weeks of intense negotiations, much of the curtailment is now being avoided with expected losses reduced to 15% after the group reached an agreement to be moved on to an inter-trip system, providing SSEN with greater transparency and visibility over the amount of capacity on the local grid. Instead of counteracting this by curtailing whole periods of expected instability, the inter-trip system allows SSEN to be more flexible.

Rob Rabinowitz, head of generation at Mongoose, which manages around 80MW of predominantly community schemes and worked on the negotiations on behalf of WCE, explains: "The problem they have there on the island is that they have parts of time where there appears to be quite a lot of capacity on the grid but at any point that could change very quickly and if they don't have control over the inter-trip they may not be able to turn you off quickly enough. But the inter-trip gives them the transparency and visibility to be flexible with the levels of curtailment."

The solar asset owners were also able to come to an arrangement with utility RWE to use the existing and underutilised grid capacity from the standby Cowes power station on the island. In the absence of curtailment avoidance, Waters explains that making commercial agreements with other asset owners to "flex capacity on the network" can prove to be a successful route for solar generators.

However, the key strategy to take away from the Isle of Wight case is that the reductions in losses would likely have not been avoided were it not for the adoption of a consortium approach in negotiations, led by the smallest of its members.

"We're a victim of our own success as the more renewables we need on, the more outages will be necessary to upgrade the network"

"There were a couple of things in our favour, one was that we are a community group which I think made SSEN a bit more cautious about ignoring us because the story of [big energy] versus small social enterprise would not have played well," Rabinowitz says. "Other members of the consortium had engaged with SSEN and hadn't managed to get proper engagement from the DNO and I think that's a lesson."

Palmer adds: "After a lot of negotiation with SSE, I'm very pleased because I think we have a much better relationship with them. They've created a generators forum where all the generators who are or want to be on SSE's network can get together and discuss issues with them. I see that as a direct result of what we've been doing."

However the fact remains that while not as drastic as originally thought, losses of 15% are still an issue particularly in cases such as those on the Isle of Wight which have faced consecutive years of losses as grid upgrades look to catch up with the modern nature of networks.

Making contact in the absence of alternatives

As this process continues, all while levels of intermittent generation from renewables increase, so too will curtailment and so the first thing that generators should look to do is follow the example set by the Isle of Wight consortium and engage with DNOs.

As mentioned by Palmer, SSEN has already implemented a generators' forum to facilitate this process with the help of RegenSW, which is also working with another DNO, Western Power Distribution, on a similar initiative.

While seemingly obvious, forums do offer a solution to a simple yet significant hurdle – namely finding the right person to talk to at a DNO, as Rabinowitz explains: "There are the people you'll be getting notifications from, if there is a curtailment there will be the people who are responsible for that particular project, there are those who are responsible for running the control room and then there are the people responsible for long-term strategy overall. You've got a complicated structure in a big organisation so the biggest challenge we had was finding the right person to speak to."

Creating and maintaining an open dialogue through such forums is key to mitigating the impacts of planned curtailment periods in the absence of offline solutions. While it is conceivable that generators could use battery storage to store electricity at times of outages to the grid, such a process would face considerable barriers to success, not least due to the change needed in a network agreement to facilitate this solution.

"If you put a battery on you need new grid connection agreements and a lot of engineering due diligence to make sure everything is set up to fit with the DNO, which is going to look into the system electronically to make sure it is set up safely," Rabinowitz says.

"I don't think DNOs at the moment could handle that kind of solution and I'm not sure the cost of the technology and the hassle would make it worthwhile. It feels like the kind of thing that could happen in the future; we just couldn't get it to work."

Frankland agrees, pointing out that the unpredictability of discharge from storage in comparison to solar could provide DNOs with challenges they often would not want to face.

"From a DNOs point of view they have to model the impact of any generation they have on their network. With solar it's easy as you've got the basic generation curve but with storage you don't really know when it's charging or discharging. It is likely DNOs will offer a choice of an unconstrained connection on which they will model the 'worst' case scenario for the network or a constrained connection which may reduce the amount of income streams available to the battery developer," he says.

Taking the reins of active management

This is of course not to say that DNOs are doing nothing to address the issue; accounts from the Isle of Wight suggest that once engaged in negotiations SSEN worked hard to assist generators. Rabinowitz links this to the ongoing transition to a DSO, or distribution system operator, model which sees regional operators take a more active role in the management of their systems.

In an effort to take on this role and more accurately manage regional networks to use them to their full capacity before requiring upgrade works in service of customers, DNOs are adopting new 'flexible' network connections to allow more renewables to connect. At the time of a connection, new generators are being offered agreements that fall under 'active network management' (ANM) protocols whereby generators are offered faster and cheaper connections if they are willing to accept a level of curtailment.

"This is good for both parties," says Nicola Waters. "DNOs are obliged to offer connections when they are requested so this gives them a way to deliver this obligation. It's good for asset owners as in theory it gives them a cheaper connection."

However, there is little way of knowing what level of curtailment this could lead to. One DNO routinely offering these flexible distributed generation (FDG) agreements is UK Power Networks (UKPN) after carrying out a trial in 2014 known as a Flexible Plug and Play.

Steve Halsey, UKPN's distributed generation development manager, explains: "When we receive an application for a FDG connection we show the customer what sort of curtailment a contract would include, giving them the opportunity to make an informed decision early on."

This prediction is based on "complex algorithms calculated on an annual basis", with Halsey adding that some UKPN customers have reported that actual curtailment is lower than the level initially anticipated.

As of July, 37% of FDG connected under ANM (111MW) is said to be connected to UKPN infrastructure, second only to SP Energy Networks with 40% (119MW). This has saved UKPN customers more than £70 million in spending to upgrade the network, as well as losses that would have been accrued from this work taking place.

In return, Halsey says customers have benefitted from both the speed of delivery – an important feature for UK solar in recent years with the diminishing windows for lucrative access to feed-in tariffs and Renewable Obligation certificates – and cheaper connections.

"As demand for electricity increases with the electrification of heating and transport for example, managed connections (whether by use of ANM or timed connections) are likely to be more widely used. Managing supply and demand and the flow of electricity on our networks will become more and more important as we transition from a DNO to become a DSO," he adds.

The work is also not limited to DNOs, with National Grid increasingly getting involved – not least with UKPN. The two network operators are in the midst of the Kent Active System Management trial, which runs until December 2017. This aims to improve the service to existing generators by making better use of capacity on the network.

Enhanced monitoring is deployed on customer sites to enable full visibility of their status and output in real time, which it shares with National Grid's control room through an 'inter-control centre protocol' (ICCP) to improve operation of the transmission and distribution network and avoid curtailment of renewables.

Incentivising curtailment

UKPN and National Grid are also developing a constraint management market that new generators can bid for in their willingness to be curtailed, which will later be offered to existing generators. If the customers are called on they will be compensated, potentially creating a market for curtailment and offering generators a form of compensation currently lacking from the market.

Efforts like these are being made across the UK, whether it's from the development of local tenders to offer incentives to decrease output, to projects like SSEN's NINES initiative in Shetland. This has combined domestic demand-side management (DSM) with a 1MW battery at Shetland's main power supply, Lerwick Power Station, and new monitoring and control systems to form an advanced ANM system.

This was then used to manage five renewable energy schemes connected to the distribution electricity network and according to SSEN allowed more than 8.5MW of new renewable energy to be connected on Shetland.

As the DSO transition continues and solar makes its inevitable march to widespread grid parity in the UK, the risk of curtailment may be growing but for the UK this may not be as serious a prospect as it once was. Developing technologies, markets and incentives are set to offer new abilities to turn down generation, leaving asset owners a new economic chance to find alternative uses for their clean energy resources. ■

Managing technical risks in PV investments

Risk mitigation | The EU-funded Solar Bankability Project has developed a framework for managing the potential legal, technical and economic risks associated with PV projects. Here, members of the team behind the project set out some of the key tools and guidelines that have been devised to ensure ongoing quality management over the entire lifecycle of a PV power plant

In the Solar Bankability project the term 'solar bankability' was defined as an active quality management process where all stakeholders in the approval process of a PV project attempt to identify potential legal, technical and economic risks through the entire project lifecycle. These risks need to be quantitatively and qualitatively assessed, managed and controlled. Despite a wide overlap in this process, the focus and the assessment criteria will vary depending on whether the stakeholder represents an investor, a bank, an insurance company or a regulatory body, as illustrated in Figure 1.

The guidelines and tools developed in the project can be considered as steps towards standardisation and de-risking for the PV sector and are to assist stakeholders in developing their own individual risk management strategy along the lifecycle of a PV project through risk identification, assessment, management and control (Figure 2).

Risk identification

In PV financial modelling, inaccurate inputs (e.g. costs, yield) will inevitably result in incorrect calculations of revenue, cost, cash flow etc., thus giving an inaccurate assessment of the investment-worthiness of a PV project. Financial model inputs are strongly influenced by technical assumptions. In the project, we have compiled a list of 20 most common levelised cost of electricity (LCOE) technical assumption risks by carrying out gap analyses on the technical assumptions used in samples of present-day PV financial models and plant yield estimation reports. Focus was then placed on technical risks during the whole PV project value chain, and on those risks which are relevant to the calculation of the PV LCOE. The failures are tabulated in a so-called technical risk matrix (available at www.solarbankability.org).

Technical risks due to poor assumptions in PV financial models

To compile technical risks which could impact PV financial models, we surveyed samples of present-day PV financial models, EPC and O&M contracts, and plant yield estimation reports. These samples are from large-scale and commercial PV plants in France, the UK, Germany, Italy and the Netherlands developed between 2011 and 2016. The survey highlights that in general there is neither a unified method nor a commonly accepted practice for translating the technical risks into PV financial models.

Gap analyses were performed systematically according to the phases in the PV project life cycle and whether the root causes are likely to occur before or during the PV operation. The results show that technical gaps generally exist across all PV project phases. They occur in all elements of the PV LCOE, namely CAPEX, OPEX and energy yield estimation. The root causes of risks could be introduced either during project development (procurement, planning and construction, i.e. EPC) or during PV operation (O&M). The list of important gaps identified in the analyses were presented in [1].

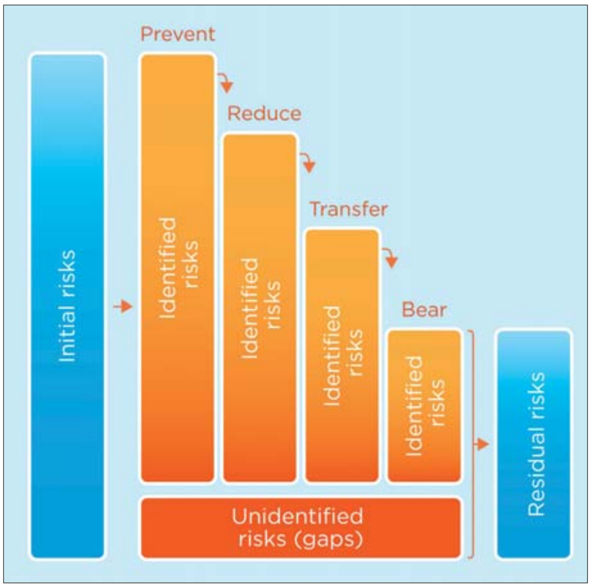


Figure 2. Potential plan for the management of technical PV project risks

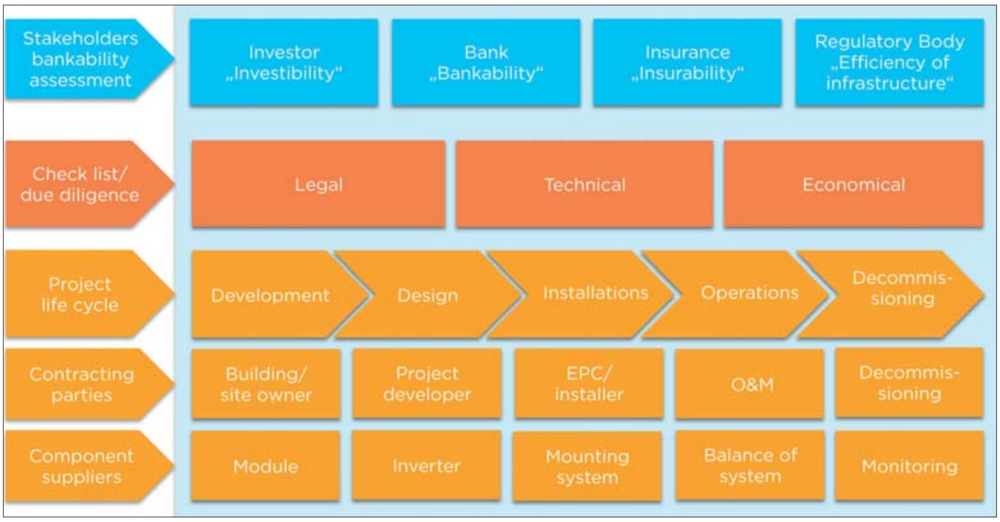


Figure 1. Solar Bankability assessment from different stakeholders' perspectives

A. MODULES	B. INVERTERS
Product testing/development	
Failed insulation test Incorrect cell soldering Undersized bypass diode Junction box adhesion Etc.	Inverter derating issue Maximum power point tracker issue
PV plant planning/development	
Soiling losses Shadow diagram issue Modules' mismatch Uncertified modules Etc.	Inverter wrongly sized Incorrect IP rating Inverter cabinet inadequately ventilated Inverter exposed to sunlight Etc.
Transportation/installation	
Module mishandling (glass breakage) Module mishandling (cell breakage) Module mishandling (defective backsheet) Etc.	Inverter configuration incorrect Missing contact protection Inverter has no surge protection Etc.
Operation/maintenance	
Improperly installed Hotspot Delamination Glass breakage Snail trails Etc.	Fan failure and overheating Theft or vandalism Grounding fault Firmware issue Etc.
Decommissioning	
No product recycling procedure defined or implemented	Inverter size and weight issue

Table 1. Example of risk matrix for PV modules and inverters

For more details on this topic, see the full Solar Bankability report [2].

Technical risks causing plant failures over PV project lifetime

Based on a statistically significant number of existing PV installations, we documented the technical risks that can affect solar plants, either during development or operation. More than 1 million PV plant failure cases were collected from multiple databases comprising more than 750 PV plants and roughly 2.4 million components (including ~2 million modules and ~12,000 inverters); this portfolio corresponds to 442MWp of PV plants nominal power, i.e. roughly 0.5% of the installed capacity in Europe. Each failure collected was categorised based on which PV plant component the failure occurs. All collected failure cases were compiled and allocated to each project phase and each component. In total, more than 140 types of technical risks have been identified and documented in the risk matrix. Table 1 gives some examples of technical risks for PV modules and inverters, while all 140 technical risks are described in detail in [3].

Risk assessment

Once risks were identified, we have built upon existing studies and collected available statistical data of failures with the aim to i) suggest a guideline for the categorisation of failure, ii) introduce a framework for the calculation of uncertainties in PV project planning and how this is linked to financial figures, and iii) develop a methodology for the assessment of the economic impact of failures originating from different phases in PV project life cycle. Subsequently, three tools have been developed which can be used in the PV technical risk impact assessment:

- A cost-based FMEA (CPN methodology), which provides an assessment of the related economic impact caused by a certain risk.
- LCOE sensitivity analysis Excel calculation tool which allows for the simulation of different risk scenarios (individual or combined several risks) and the resulting LCOE values.
- Cash flow risk categorisation which was determined by cash flow modelling on different risk scenarios on a customised tool.

Risks in yield estimation during planning

Some of the technical risks listed in the risk matrix have an economic impact on the overall uncertainty of the energy yield. These uncertainties can impact either the expected yield during the planning phase, or the actual yield during operation.

In the Solar Bankability project we have reviewed available public yield reports and scientific literature in order to quantify the impact of uncertainties in yield estimation of PV plants. The review exercise of current practices shows that the various uncertainties could have an overall impact as high as ±10% on the estimated energy yield. These uncertainties are in turn used to calculate the exceedance probabilities for a PV plant estimated yield (e.g. P90/ P50). The uncertainties are typically calculated by fitting the dataset to a standard probability distribution (often assumed Gaussian/ normal). However, when possible (e.g. solar resource) for more accurate determination of uncertainties, a more precise analysis would benefit from the use of an empirically established probability distribution.

CPN methodology: new tool for technical risk economic impact assessment

For the PV industry to reach a mature market level, a better understanding of technical risks, risk management practices and the related economic impact are essential to ensure investors' confidence. With this in mind, we have developed the CPN methodology to assess the economic impact of technical risks occurring during the O&M phase of a PV project, and how the risks affect the LCOE and business models of PV projects.

As explained in [1], the CPN methodology assigns a cost priority number (CPN) to each technical risk based on how it impacts the costs of running a PV plant or a portfolio of PV plants. The impacts are related to the economic losses due to downtime (utilisation factor) and component repair or substitution, expressed in euros/kWp or euros/kWp/year. Thus, the overall CPN value for various components and failures would correspond to the true operational costs for various scenarios without differentiating in terms of cost ownership (insurance, O&M, module warranty, etc).

Impacts of technical risks on CPN

The CPN methodology was applied to

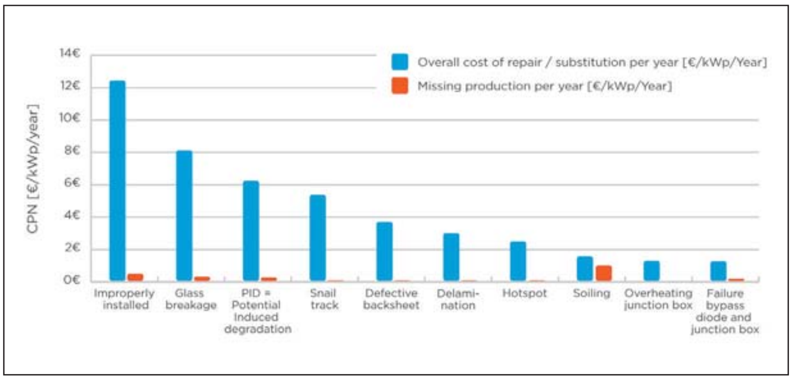


Figure 3. CPN, repair costs and performance losses for top 10 risks for PV modules of all system size

the risks included in the matrix. The risks are ranked by their CPNs to see which have the highest economic impact. To assess the impact of failures for various O&M strategies, we defined two extreme types of scenarios. In the first scenario, we assumed that failures are never detected; this scenario is called "never detected". In the second scenario, we assumed that the failure is fixed after detection using a lead time to repair/substitution of one month.

The analysis of CPN for PV modules for all market segments combined is shown in Figure 3. The blue bars represent the scenario where the issues are detected and fixed (either by repair or substitution), and the red bars represent the "never detected" scenario causing only plant downtime. As can be seen in this figure, the 10 dominant module risks for all PV systems range from installation issues to material/processing defects to maintenance practice. The dominant risks with high economic impact (high CPN) such as bad quality installation, glass breakage and potential-induced degradation (PID) can be distinguished from low-order risks with small impact (low CPN) such as soiling and shading. The improperly installed module failures comprise of various failure modes such as module mishandling during the installation, damaged frame, clamping system etc. Overall the common failures such as glass breakage, improper installation or PID bear a higher level of economic risk.

The economic impact in the never detected scenario (entirely due to downtime), (red bars in Figure 3) appears to be minimal for the module failures. The dominant factor in the failure fix scenario (blue bars in Figure 3) here is the cost of substitution. This is because for PV modules, repairing modules is not a preferred solution as the action could void the module manufacturer's warranty restriction resulting in warranty claim exclusion. Thus, substitution of the defective module is the preferred procedure. Few possible module repair actions generally involve minimally intrusive procedure such as module surface cleaning or bypass diode replacement.

It is important to highlight that a lower CPN value for the "never detected" scenario does not mean that this strategy is more cost-effective than fixing the problem. Power losses will increase over the years and the existing or impending failure could also pose safety risks.

When looking at the top 10 module risks for each market segment, the trend reflected in Figure 3 applies to larger-scale PV systems. This is because for such systems, different defect detection techniques from basic visual to advanced inspection tools are available.

For small-scale residential, it appears that failures which could be detected by basic visual inspection are the ones which are dominant; defects requiring advanced inspection tools tend to escape detection due to the absence of the use of such tools.

Impacts of technical risks on solar PV generation cost (LCOE)

In the project, we also assessed the relative impacts the identified technical risks would have on the PV LCOE via sensitivity analysis, thus pinpointing the areas where mitigation measures should be prioritised.

The LCOE sensitivity analysis was performed by varying six LCOE input parameters (CAPEX, OPEX, yield, discount rate, yearly degradation and system lifetime) by ±20%. Each input was treated as if one is independent from the others. The analysis includes three different market segments: <5 kWp residential PV systems, <1 MWp commercial rooftop PV systems and >1 MWp utility scale ground-mounted PV systems (see Table 2). Three scenarios have been selected for this analysis – one representing PV systems in mature markets such as Germany (low scenario) where high competition has driven the CAPEX and OPEX prices down

Table 2. LCOE results for the three selected scenarios

Input parameter	Low scenario	Medium scenario	High scenario
CAPEX [€/kWp]			
Ground-mounted utility (≥ 1 MWp)	€ 900	€ 1000	€ 1200
Commercial rooftop (< 1 MWp)	€ 1000	€ 1200	€ 1400
Residential (up to 5 kWp) (VAT excluded)	€ 1300	€ 1400	€ 1600
OPEX [€/kWp/year]			
Ground-mounted utility (≥ 1 MWp)	€ 13	€ 15	€ 20
Commercial rooftop (< 1 MWp)	€ 10	€ 10	€ 18
Residential (up to 5 kWp) (VAT excluded)	€ 5	€ 5	€ 9
Performance Ratio 'PR' [%]			
Ground-mounted utility (≥ 1 MWp)	86%	84%	86%
Commercial rooftop (< 1 MWp)	84%	82%	84%
Residential (up to 5 kWp)	82%	80%	82%
POA irradiation [kWh/m2]	1331	1821	1168
Discount rate [%]	4%	8%	6.5%
Degradation rate [%]		0.5% linear	
Lifetime [years]		25 years	

Market segment	Low scenario	Medium scenario	High scenario
LCOE without any mitigation	*[€cents/kWh]*	*[€cents/kWh]*	*[€cents/kWh]*
Ground-mounted utility (≥ 1 MWp)	5.4 – 8.1	6.2 – 9.3	10.3 – 15.5
Commercial rooftop (< 1 MWp)	5.8 – 8.7	7.0 – 10.7	11.8 – 17.8
Residential (up to 5 kWp)	6.9 – 10.6	7.9 – 12.2	12.5 – 19.2

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PERC cell
Back surface passivation
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5BB cell
Lower series resistance
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Microcrack protected /PID protected
Triple EL tested for high quality control
Applied anti-PID cell and high reliability encapsulation material

300W
Output power can reach 300W and above for 60-cell module

21.2%
Cell efficiency level for mass production up to 21.2% and above

7%
Output power increase of 7% per unit area (compared with 280W)

4.7%
A 4.7% BOS reduction per Watt (compared with 280W)

*48pcs, 50 pcs ,60pcs,72pcs modules and other options available

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FORTUNE 世界 500	Bloomberg TIER 1	60YS Based on nearly 60 years experience in solar technology R&D by CASC	10 million+ 10 million+ USD R&D investment per year	1.8 billion+ Corporate ' s total assets is over 1.8 billion US dollars	100+ Over 100 independent intellectual property rights for cell & module	600+ Established over 600 PV power plants in China and overseas

* All above information on technical parameters is for reference only. HT-SAAE reserves the right to modify.

	Description
Business model 1	Residential rooftop PV system with crystalline modules located in central Europe (5.6 kWp, c-Si, Germany)
Business model 2	Residential rooftop PV system with crystalline modules and battery storage located in central Europe (5.2 kWp c-Si + storage, Germany)
Business model 3	Utility scale ground mounted PV system with crystalline modules, central inverters, located in northern Europe (7.6 MWp, c-Si, UK)
Business model 4	Utility scale ground mounted PV system with CdTe modules, string inverters, located in southern Europe (0.6 MWp, CdTe, Italy)

Figure 4. Four business models selected for technical risk impact modelling

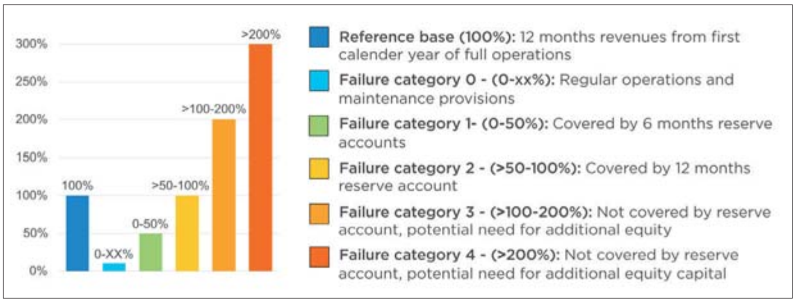

Figure 5. Categories to measure the impact of technical risks on PV project cash flow

and the market bears less regulatory risk; the second representing systems in markets such as Italy (medium scenario) with a relatively high discount rate and where the irradiation level is high and the CAPEX and OPEX are in the mid-range among the values in EU region; and the last scenario representing PV systems in countries such as UK or Netherlands (high scenario) with high CAPEX and OPEX but with irradiation level rather low and a relatively moderate discount rate. For more details on this topic, see the full Solar Bankability reports on the Best Practice Guidelines for PV Cost Calculation: Accounting for Technical Risks and Assumptions in PV LCOE [5].

Impacts of technical risks on business models

Modelling the economic impact of technical risks on the cash flow of PV projects requires the selection of the underlying business models, selection of associated technical risks, likely risk scenarios and the underlying cost assumptions. Since there are no commercial risk modelling tools available in the market that allow analysing technical failures and their economic impact over the lifecycle of PV systems, a customised financial modelling tool has been developed based on the PV project cash flow to measure the impact of technical risks on PV investments.

Four representative business models as shown in Figure 4 were then selected for the financial modelling of technical risks. In the selection process, various criteria were considered such as PV system size, module and inverter technology, ground or rooftop mounting, solar electricity feed-in tariff and self-consumption, geographic location and climatic conditions.

For each business model, 10 to 12 typical technical risks from the risk matrix were selected and their impacts assessed for both individual risks and risk scenarios with a combination of up to four risks.

Four different impact categories have been introduced to classify the influence of technical failures on the cash flow model. In an analogy to the debt reserve account used by banks during debt financing, the categories measure the financial impact in relation to the revenues during the 12 months from the first calendar year of full PV project operations (Figure 5). For more details on this topic, see the full Solar Bankability report on Financial Modelling of Technical Risks in PV Projects [4].

Risk management

The framework for the assessment of the economic impact of technical risks allows for the analysis of how these risks can be managed, through mitigation or risk transfer. The effectiveness of the mitigation measures was assessed by evaluating how their implementation changes i) estimated yield, ii) the CPN and iii) PV LCOE and business models. Analysis was also carried out on who is best placed to take on the risks and at what point in the process this should happen.

Mitigation of risks due to yield uncertainties during planning

Analysis was carried out in the Solar Bankability project to identify mitigation measures to minimise the different uncertainty components.

The analysis highlights the range of the available insolation data as the most important factor affecting the uncertainty of the yield estimation. The results show that there is a group of cases assuring a low level of uncertainty (4.55% to 8.70%). They all refer to the use of long series of either ground or satellite measurements of insolation.

Among the analysed scenarios (see Figure 6), the best case corresponds to the use of 20 years of measured values of Global Tilted Irradiance (GTI), showing also that a lower uncertainty is ensured when a) validated ground measurements are used instead of satellite measurements and b) time series of plane-of-array irradiance are available without the need to apply transposition models. Results show also that using a combination of long-time series of satellite data with a short series of measured data is preferable over just using satellite data. In cases where a PV plant is to be installed in a location with high insolation variability, the uncertainty of the yield estimation is also negatively affected.

Among the parameters that are not related to either insolation variability or solar resource, the uncertainties related to shading and soiling effects, and to the use of the right transposition model, play a role in the uncertainty of the final yield. In general, the uncertainty of the final yield

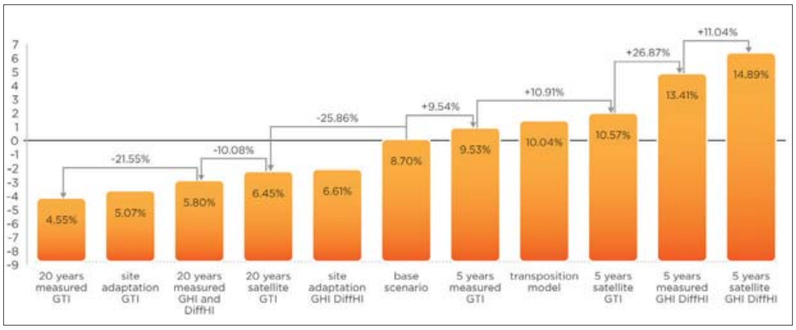

Figure 6. Impact of mitigation measures on yield assessments compared to the base scenario


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solar technology
THE POWER OF RISING VALUE
Capacity 4.5GW/year
Bloomberg TIER 1
Global, Tier 1 bankable brand
Photon RANK 2
Photon Independent field testing
- Ranked in the top 2 of 176
12/25 years
12 years product warranty
25 years linear power warranty
$
Strong Financial Data(2010-2016)50%

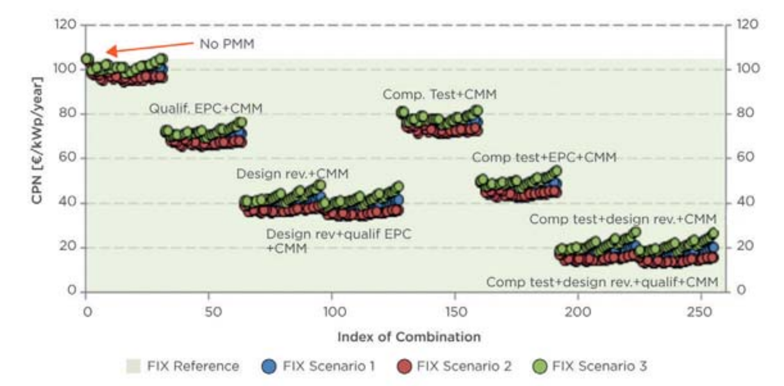


Figure 7. CPN with mitigation measure combinations for the overall CPN

of the PV plant used in the analysis can range between 4.6% and 14.9%. The latter becomes 16.6% in the eventuality that the planner has the worst information quality available.

The exceedance probabilities calculated using these uncertainties can lead to a P90/P50 ratio reduction of up to 20%. The uncertainties could thus have a significant impact on the estimated energy yield.

For more details on this topic, see the full Solar Bankability report on the Minimising Technical Risks in Photovoltaic Projects – Recommendations for Minimising Technical Risks of PV Project Development and PV Plant Operation [6].

Mitigations of risks during operation and the impacts on CPN

Mitigation measures must be identified along the value chain and assigned to various technical risks. Some failures can be prevented or mitigated through specific actions at different project phases. For example, for PID, the mitigation measure could be using different encapsulant or glass during the product manufacturing phase, or installing PID boxes during the operation/maintenance phase (for reversible PID). Others can be prevented or mitigated through a more generic action. For example, the monitoring of performance or visual inspection can be considered as generic mitigation measures that can have a positive impact on the reduction of the CPN of many failures. In summary it is important to understand how mitigation measures can be considered as a whole to be able to calculate their impact and thus assess their effectiveness.

By analysing the technical risks previously identified, we put forward eight mitigation measures for PV technical risk management. They are categorised into two main categories. Preventive measures are applied before the risk occurs to prevent it from happening. They are component testing, design review and construction monitoring, and EPC qualification. These measures can be implemented during the early phases of PV project lifecycle and are likely to increase the CAPEX. Corrective measures are mitigation measures that aim to reduce higher losses and costs, if the risk has already occurred. They are basic and advanced monitoring, visual and advanced inspection, and spare part management. The costs are mostly related to the OPEX due to the implementation during the operation and maintenance phase.

The cost-benefit analysis can then include the combination of various mitigation measures and derive the best strategy depending on market segment and plant typology. In addition to this, it is important to assess in the CPN analysis who bears the cost and the risk to derive considerations not only on the overall economic impact of the technical risks, but also on cost and risk ownership.

Mitigation measures will have different impacts on the costs of yield loss due to downtime and the costs of repair or substitution, thus changing the overall CPN value. The new CPN value arises from the cost-benefit analysis by adding the CPN after mitigation to the cost of the mitigation measures. Figure 7 shows the results of calculating the costs of the failure fix scenario for selected failures when applying combinations of the eight selected mitigation measures mentioned before.

The CPN analysis above shows that for 99% of all mitigation measure combinations, the scenarios will result in economic benefit by reducing the CPN to values lower than the reference (€104.75/kWp/year). Savings up to €90/kWp/year appear possible for the best combinations of selected mitigation measures. Furthermore, we can conclude that in general, mitigation measures which reduce the failure occurrence have the highest impact due to the related reduction in substitution costs. In fact, the highest savings can be achieved by applying all three preventive measures (component testing + design review + qualification of EPC). On the other hand, corrective mitigation measures (CMM) such as basic and advanced monitoring and visual and advanced inspection appear to have less impact on the CPN. In reality CMMs can further reduce the CPN by around €3/kWp/year, which is of fundamental importance to apply effective O&M strategies which suffer at the moment of high cost pressure.

For more details on this topic, see the full Solar Bankability report on the Minimising Technical Risks in Photovoltaic Projects – Recommendations for Minimising Technical Risks of PV Project Development and PV Plant Operation [6].

How risk mitigations will Change PV LCOE

The analysis of the impact of implementing various scenarios of the above eight mitigation measures was extended to how it could affect the final PV LCOE value. There are only a dozen or so mitigation combinations which are most effective in reducing PV LCOE across all three market segments for all three scenarios. The conclusions drawn from the analysis of mitigation measures' impacts on PV LCOE are summarised in Table 3 below.

For more details on this topic, see the

- PV LCOE reduction in the order of 4% to 5% is observed for all cases.
- The different combinations of mitigation measures have a larger impact in lowering the LCOE for scenarios where the higher CAPEX, OPEX, and/or discount rate results in a higher LCOE.
- Mitigation measures which are most effective in lowering PV LCOE are similar across all the market segments and for all scenarios.
- The most effective mitigation measures are those implemented at the *early stage of project lifecycle*. Those implemented in the operation phase still show some positive impact on LCOE but less gain is found.
- Although the implementation of mitigation measures increases either CAPEX, OPEX or both, the overall LCOE decreases as the gain in yield surpasses the extra cost incurred.
- The mitigation measures most effective in lowering PV LCOE are:
  1. Qualification of EPC;
  2. Component testing prior to installation;
  3. Advanced monitoring system for early fault detection.

Table 3. Relative impacts of implementing different combinations of risk mitigation measures on PV LCOE

full Solar Bankability reports on the Best Practice Guidelines for PV Cost Calculation: Accounting for Technical Risks and Assumptions in PV LCOE [5].

Best practice in EPC and O&M contracting for risk mitigation

From the risk identification, we have found that technical risks are linked to poor assumptions in PV financial models. These risks could be introduced either during project development (EPC) or during PV operation (O&M). Since EPC and O&M contracts provide the technical framework of the whole PV project lifecycle, it is important to ensure that all technical aspects of EPC and O&M contracts are based on best-practice quality. To this end, a set of six checklists for utility-scale (ground-mounted) and commercial rooftop PV installations have been developed to serve as guidelines for best practices in EPC and O&M technical aspects (available at www.solarbankability.org):

1. Best practice checklist for EPC technical aspects
2. Best practice checklist for O&M technical aspects
3. Best practice checklist for long-term yield assessment
4. Checklist for as-build documents – type and details
5. Checklist for record control
6. Checklist for reporting indicators

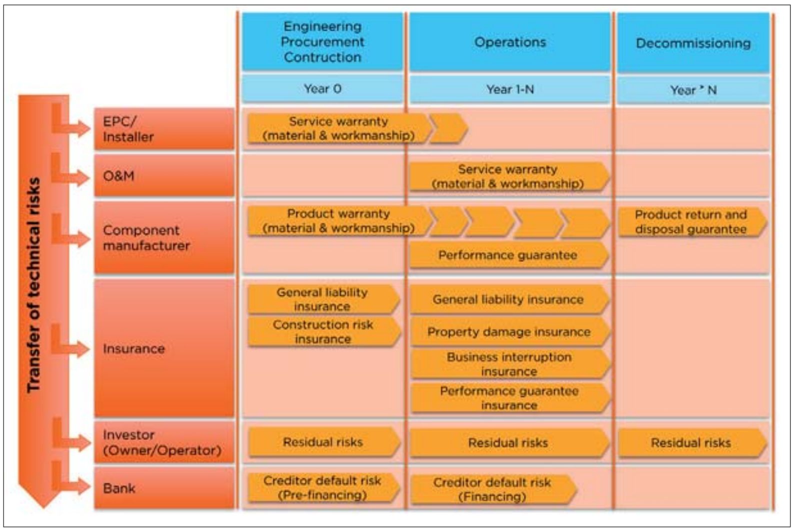
Transfer of technical risks to relevant parties

Besides risk mitigation, risk transfer is an integral part of any risk management strategy. Solar Bankability suggests transferring the ownership of technical risks to those parties which are best positioned to control them along the project life cycle (see Figure 8). An effective transfer of ownership will depend on a professional understanding of the underlying legal documents such as contracts, guarantees, warranties, insurance policies and credit agreements, and their corresponding durations.

The installer or EPC is liable for the material and workmanship during the construction phase. The O&M operator is liable for the material and workmanship of his services. The component manufacturer must meet the warranty and performance guarantees and disposal guarantee for their products. Mandatory and optional insurances can cover financial risks caused by external or internal factors. For all risks which are not covered by the above measures, the owner/operator of the PV project will be held responsible with their equity capital. Banks are last in the risk transfer chain and only get involved in cases of a creditor default.

For more details on this topic, see the full Solar Bankability report on the Technical Bankability Guidelines: Recommendations to Enhance Technical Quality of Existing and New PV Investments [7].

Figure 8. Potential plan to transfer technical PV project risks



Risk controlling

The regulations set by financial regulatory bodies require institutional investors to introduce a hierarchically independent risk management function. This function oversees the firm-wide risk management including ongoing risk control and transparent risk reporting at least once a year. Institutional investors can either enhance their own risk management organisation and build up an in-house team specialised in PV risk assessment or they can access external rating services, which are being offered by specialised consulting firms or international rating agencies.

The checking of technical risks for large commercial and utility-scale PV projects is often transferred to specialised owner's engineers. They ensure the professional supervision of the engineering, construction and commissioning of the PV plant, and provide ongoing risk monitoring during the operational phase with regular risk reporting at least once a year.

For residential PV systems, the owner is responsible for the risk management. Most of these systems are not covered by a regular service and maintenance contract. Therefore, a regular check-up of the PV system is recommended every few years depending also on the availability of an online monitoring system.

Recommendations for risk management strategies

Based on the findings of the project, we recommend different stakeholders develop their own individual risk management strategy along the lifecycle of a PV project using the four-step process of risk identification, risk assessment, risk management and risk control. Solar Bankability provides best-practice guidelines and concrete tools to better manage technical risks throughout the PV project lifetime. The ultimate responsibility of project risks remains with the owner and operator of the PV plant. With the help of a professional risk management plan they can significantly reduce and transfer the initial risks associated with a PV project.

We would like to note that although the risk management strategies above are recommended for commercial and utility PV systems, residential PV system owners are advised to follow a simplified version of the risk management strategy used for larger systems.

Final takeaways

Based on the findings of Solar Bankability project, the following conclusions and recommendations can be derived:

1. Technical risks can have a major impact on the total project risk rating scheme.
2. The occurrence and impact of technical risks for different business models vary and depend on the system size, system technology, geographic location and climatic conditions.
3. The occurrence of technical risks follows a bathtub-shaped curve with high occurrence at the beginning and end of the PV

project lifecycle.

4. Technical risks can be systematically organised in a risk matrix.

5. Technical risks need to be defined using a standardised nomenclature.

6. Technical risks can have an economic impact in terms of uncertainty on the energy yield or in terms of CPN (directly or indirectly) or can be a precursor for failures occurring in a later stage of the PV project.

7. Different options are available for the economic assessment of technical risks:

- CPN methodology;
- LCOE sensitivity analysis;
- Cash flow categories.

8. The cash flow model is most sensitive to risks in the early PV project life cycle.

9. Mitigation measures which prevent risks or allow early detection are most effective.

10. Corrective mitigation measures in plants where preventive mitigation measures were considered can have an important impact

11. The mitigation measures most effective in lowering PV LCOE are:

- Qualification of EPC;
- Component testing prior to installation;
- Advanced monitoring system for early fault detection.

12. Small residential PV systems tend to be more sensitive to the impact of technical risks than large utility scale PV power plants.

13. A professional risk management strategy should become integral part of each PV investment.

14. The risk management function should be hierarchically independent and can be provided by qualified in-house or external third party experts.

15. PV systems with a professional risk management will fall into the category of qualified infrastructure investments. Their risk/return profile is favourable over other asset classes.

Acknowledgements

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Optimising commercial rooftop PV


Credit Syzygy Renewables

System design | Despite the decline of subsidies in the UK, well designed commercial PV systems still offer potentially attractive financial benefits to businesses. Kirsty Berry and Andrew Hancock of Syzygy Renewables detail some of the key considerations in designing and executing a commercial solar system that will deliver maximum return on investment

Gunwharf Quays, Portsmouth, UK. Rooftop PV offers substantial benefits to businesses, but only if designed correctly

There is often a misconception that the process that takes place between deciding to adopt solar PV to generate power for on-site consumption and having a wonderful installation pumping away on the roof is a very simple one. There are a range of things to consider when investing capital to ensure that your money is well spent, and you have a fit-for-purpose, well-specified system that will stand the test of time. It is easy to get it wrong and spend too much money on a poorly specified system


East/West facing system on flat roof


South facing system on flat roof


Flat-to-roof system on South/East/West pitches


Upstanding South Facing system on East/West pitches

Examples of typical rooftop array configurations, clockwise from top left (a) east/west-facing system on flat roof, (b) south-facing system on flat roof, (c) upstanding south-facing system on east/west pitches, (d) flat-to-roof system on south/east/west pitches

Furthermore, the market and financial metrics for projects have both changed dramatically over the past seven years. The reduction in feed-in tariffs means there is less margin available to contractors, and high levels of exported energy will hurt any financial appraisal; the combination of these two alone mean that procuring the right installation to achieve your financial objectives and to ensure it is built to last, is arguably more difficult now than it was in 2010.

There are many questions to consider the answers to which will impact the size and design of a system, and they need to be considered together. What is the right size system? What are my objectives? Which of these is the main driver? Am I simply trying to generate as many kilowatt-hours from my roof space? How can I maximise the financial return (savings) for my money? Is my roof suitable? How much electricity are we using and when are we using it? What are my plans for reducing my consumption? Am I about to move my business onto LED lighting and reduce my load by 30%? What is the best hardware? What warranty should I expect from my contractor? What sort of maintenance regime can I expect? How will this affect the design?

This article aims to provide some useful pointers and provide a framework for you to use when you are considering making the decision to generate your own energy, in the process reducing your grid costs, providing your business with a long-term hedge for a substantial element of your power costs and of course reducing the business's carbon footprint.

Building – physical constraints

Connection point

Every PV project that is connected to a building that has a grid supply must have a connection agreement from the distribution network operator (DNO).

It is generally sensible to try and minimise the amount of energy a system will spill to the grid. The value of a unit of energy used on site is significantly higher than the amount you will receive from the energy suppliers for energy you sell to them. Systems that export a lot of energy will show longer paybacks – this is something to get right when sizing the system.

Identify the best point of connection within the building. This will often be at the main distribution board, however in very large buildings, getting to the distribution board can require long cable runs and add significant cost. Ideally your board will have been designed with future unidentified uses in mind and have a spare breaker, and incoming cabling that can take the capacity you wish to have installed. Hopefully you will have an electrical schematic for your building.

Commercial buildings will have an incoming grid electricity connection point, a 'supply MPAN', provided by the local DNO. The supply should be suitable for the building's load requirements, and will have a DNO-agreed capacity, which reflects the maximum load draw in kVA (KW), or MVA (MW), the supply can provide. The supply will also be constrained by the size of the cables, and fuses between the MPAN, and the DNO's supply transformer. It is therefore important to consider both the supply fuse sizes and the agreed kVA capacity.

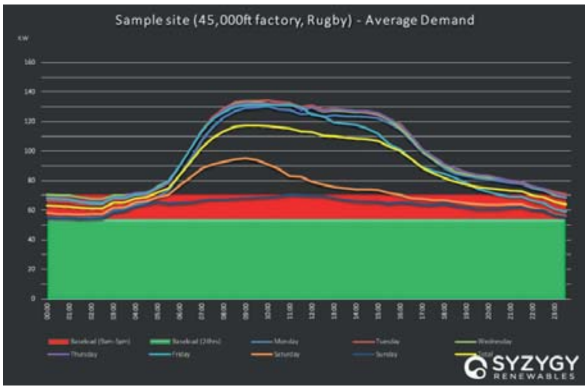

Figure 2. Average 24-hour load profile for an actual occupier, annual consumption 750,000kWh per annum

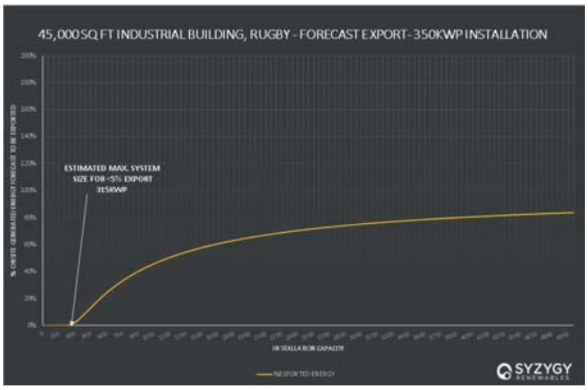

Figure 3. Effect of solar PV generated energy on existing consumption and forecast exported levels

Roof area – things to consider

Roof type: The design of your roof will have a material impact on the range of framing and fixing options that would be considered. Most industrial buildings have either a 'trapezoidal' or a 'standing seam' roof sheet, both of which can generally be fixed to. Standing seam roofs can be clamped on to, thereby avoiding additional penetrations. Many office buildings have flat roofs with membrane or asphalt surfaces; in most instances a 'ballasted' system would be specified.

Rooflights: Avoid covering rooflights if possible. Not only do they provide natural light and help reduce lighting costs, they are also a weak point of the roof. A safety and access margin of 500mm should be maintained around skylights.

Structural loading: What load can the roof suppor. In the example we explore below, the building has 0.25kN/m of available load which is plenty for most designs of loading tolerances. Flat-to-roof installations tend to impose a spread load of 0.15kN/m2 and ballasted systems can impose significantly more than this, and generally not less than 20kN/m2.

Shading: Trees, vegetation and all manner of structures can cause shading, and unless space is at a premium, the areas that will shade should be avoided. Where this is difficult, the inverter selection, and possibly string design will need to factor this in. String design can certainly limit the impact of shading, however we would recommend looking at module level optimising, and some inverter manufacturers can cater specifically for this.

Module orientation: There is not a 'one size fits all' solution for how PV installations are designed. The physical constraints outlined in this article will impact the range of solutions available; however there are several suitable solutions to choose from. Modules can often be orientated (within design limitations) to optimise kWh/kWp on any surface material, orientation or pitch. There are specific dual-orientated east-west, and single orientated ballasted, or penetrative framing systems for flat roofs. There are also 'flat-to-roof', and 'upstanding pitched' penetrative framing systems for pitched roofs. The choice of framing design is dependent on structure and loading tolerances, roof material, space, positioning, layout, orientation, pitch, and the necessary choice to achieve an optimised design for maximum self-consumption.

East-west: This is often the most efficient use of space if high output is the requirement, sacrificing efficiency in return for a greater quantum of generation, with typical power curves flattened throughout each day. East-west oriented modules perform better at lower pitches, however pitches less than 5° are likely to need more regular cleaning because dust settles and the water run off angle means they are less effective at 'self-cleaning'. We would recommend 10° where possible. East-west PV systems provide a more even spread of power throughout each day compared to a south-facing system, but require a greater m² coverage for the same total kWh. An east-west design can be the optimal solution where the building's electricity demand is fairly flat and evenly distributed through each day. East-west systems are often used on large industrial roofs to maximise capacity. This can be a cheaper way to install (less framing and greater economies of scale), however outputs on a like-for-like basis could be as much as 15% lower than a south-facing installation on the same building – the right choice will be driven by the original objective. In many cases pitching modules facing south on an 'east-west' pitched roof whilst more expensive will deliver a better financial performance and improve payback periods.

South facing: Modules orientated south optimise kWh/kWp output at around 35-40° pitch, with typical power curves peaking at midday. This orientation can be utilised to provide power where the building's electricity demand is greatest for example between 10-3pm. As the pitch of the panels increases (if on a flat roof) more space is required to allow for the shading between rows.

Existing usage

System sizing is primarily driven by the existing and future energy consumption within the building. Most medium and large commercial buildings will have a smart meter from which half-hourly data can be exported. This data should assessed to get an understanding of how much and importantly, when, electricity is being consumed.

Worked example

The charts below use actual data from a project Syzygy Renewables recently advised on. It is a 45,000 square foot industrial building near Rugby, with the potential to install up to 350kWp on the roof adopting an 'east-west' design.

Figure 2 shows the current daily load profile; note the weekend reduction in consumption, falling to a steady baseload of between 60kW and 70kW. Bearing in mind the weekends represent 28% of the year, sizing a system to meet weekday peaks will most likely export significant amounts at weekends (which will have an impact on paybacks).

The grid connection for this project allows the generator to export the full 350kW. If the grid connection was restricted or even prohibited export, the system should be sized at a DC level to operate within the baseload (the amount of demand that is constant throughout the day/week). Figure 3 shows a way to approach calculating the correct size for an installation. If the grid connection prohibits export, the system should be sized to sit within the baseload; in this example the AC rating (Net Declared Capacity) of the system should not exceed 80kW, which means the DC rating (aggregate capacity of the modules) should not exceed c.100kWp. If, however, the project has a grid connection agreement that allows export there is less pressure to keep the size within the baseload paramaters, and sizing to allow up to a theoretical 10% export is a sensible approach – in this instance. This is where 'Export Analysis' is a good idea to understand how much a range of system sizes would export.

Figure 3 shows that the system should not exceed 100kWp if export is restricted, whereas the system would export approximately 5% at 175kWp. Further on, this article briefly explores battery storage, which provides building owners and occupiers with the ability to deploy significantly greater renewable energy capacity without spilling to the grid.

Examples of the factors to be considered in a financial appraisal

Forecast system output (use a reliable database)	Maintenance budget
Construction costs (EPC contractor – fully inclusive fixed price contract)	Full replacement of inverters in line with warranty (we would recommend procuring a 10-year warranty)
Structural survey costs	RPI forecast over 25 years (3.5% is the Bank of England's latest published 25-year forecast)
Grid connection costs (if any)	Today's delivered daytime energy cost per kWh and energy cost increases over 25 years (we would not recommend applying more than 6%; the compounding effect will over inflate potential returns/reduce payback periods if this is over estimated.
Planning cost (likely to be permitted development, however to qualify for feed-in tariffs confirmation from the local authority will be required)	Business rates

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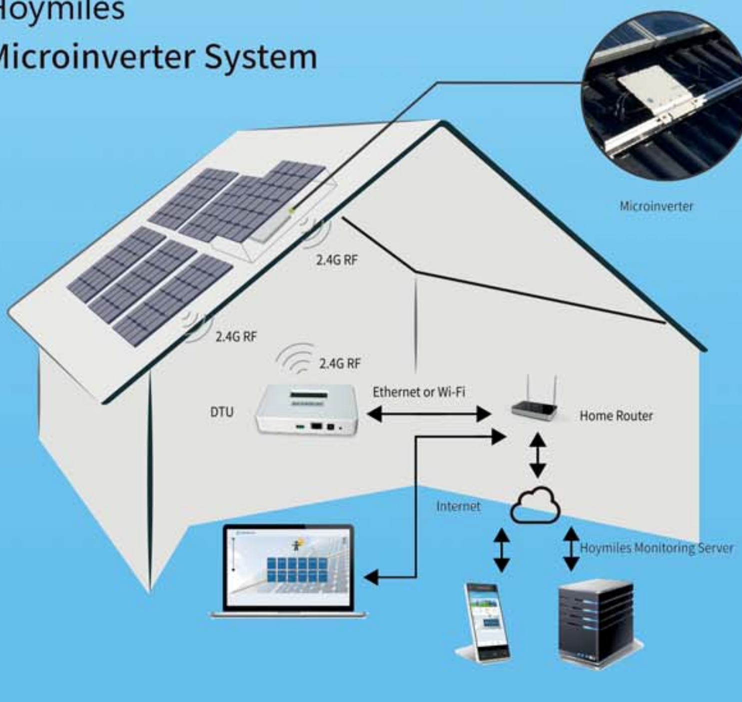

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For 1 PV panel

MI-500/600
For 2 PV panels

MI-1000/1200
For 4 PV panels

	System parameters	System capacity (kW)	Module orientation and pitch	Energy consumed on site	Forecast output, kWh (year 1)	Project cost	Payback (years)	Percentage demand from PV (%)
1	Maximum capacity and generation	350	East-west/10º	75%	295,000	Highest	11.1	30
2	Optimise efficiency	207	South facing/15º	90%	195,000		9.0	23
3	East-west facing (5% max. export)	200	East-west/10º	95%	170,000		9.4	21
4	South facing (5% max. export	175	South facing/15º	95%	165,000		9.0	21
5	East-west facing (no export allowed)	114	East-west/10º	100%	95,000		9.6	13
6	South facing (no export allowed)	105	South facing/15º	100%	100,000	Lowest	9.0	13

Table 2. Six different scenarios put into an appraisal model to understand the financial benefits

Feasibility

We now understand what could be installed using the available space. We have also looked at the energy usage to identify the forecast level of export for any given system size. The next step is to undertake a financial appraisal for a range of scenarios.

This is where running a sensitivity analysis applying a range of scenarios will help identify the right system size and layout approach for specific requirements. A typical 'weigh up' is between whether the objective is to reduce the carbon emissions associated with occupation (i.e. generate as much energy as possible from the available space regardless of levels of export) or to maximise savings and minimise payback period, the latter being most prevalent.

The reason why increased levels of export tends to hurt the financial returns for a project are because the 'value' of an exported unit of energy is c.5 pence (export tariff), whereas the replacement value (saving) achieved when the energy is consumed on site is the delivered daytime cost of a unit of electricity, which is often more than twice this level. The appraisal will need to consider some of the factors shown in Table 1.

An appraisal will enable you to identify the right system size, and put a budget together for the project. Consideration should now be given to the more detailed specification and what is required from the chosen contractor.

Table 2 shows the 'top line' outputs from a sensitivity analysis of six potential solutions. In this instance, the client decided against the largest system (350kWp) because the forecast export of 25% would have added over two years to the payback. The client chose to pursue option two, balancing a higher reduction in grid consumption whilst preserving a forecast payback of nine years.

Procurement

EPC contractors are continuing to experience severe pressure on margins, and whilst there are many excellent contractors out there, there are some that will sacrifice system optimisation for cost savings. The key to successfully procuring a system is in the work carried out before you tender: measure twice and cut once.

There is always a balance to be struck between capital costs and value in the long term. When specifying the equipment, it will be important to consider the design life of the project i.e. how old is the building? Is the project receiving subsidy or funding? What are the expected returns on investment? Ease of access for repairs or replacement and whether there is on-site support to monitor the performance are also considerations. (Most PV systems are remotely monitored, enabling any issues to be quickly identified and rectified but it may be necessary to examine equipment on site from time to time.) The insurance company for the building may also impose certain requirements, particularly in respect of fire safety.

The warranties offered with equipment should be assessed. In the fast-moving PV market, it may be decided that insurance-backed warranties are necessary. Choice of contractor and contract structure will also help ensure optimum performance for the system. What PV experience does your contractor have? What is the most appropriate form of contract to use in relation to the project size? What are the payment terms and are bonds or parent company guarantees appropriate? Consider tying the construction contractor into a maintenance contract for some period to help ensure the quality of build.

It will be important to consider performance expectations for the installation and possibly imposing penalties relating to any failure to generate as expected. Performance obligations may be based on the overall energy yield of the system (what output did your contractor forecast, what database did they use?), hours of operation (availability) or a combination of the two and this may be related to a measurement of the actual solar energy at the site. Within the specification it is important to define how the expected performance of your PV system is forecast; different software packages can produce vastly different predictions and even when using the same software, the results can vary greatly with different sets of climate data.

Often commercial projects take place on sites operating over long hours, possibly 24-7 and any constraints on the construction programme should also be set out clearly in the contract. The choice of point of connection is critical as at some point a shutdown may well be required to connect the system; the impacts of this need to be identified at an early stage in the design, and factored into the build programme.

Failing to consider these factors can result in the wrong contractor and poor equipment, for example smaller cable

sizes, cheaper panels and inverters – do you know what you are buying? It will do you no harm to provide a very detailed specification that not only covers all of the obvious compliance and regulatory matters, but also ensures that cheaper equipment cannot be used, shading mitigation has been considered within the design, cable sizing is optimised, approved manufacturers have been used for certain elements such as datalogger, pyranometer, type of ballast, even UV resistant cable ties, demonstration of wind load calculations and structural sign off.

Ongoing operation

Ensuring that your PV system operates properly is key to maximising the return on investment. Although solar panels themselves should not require a lot of maintenance over their lifetime, it is essential to keep them clean and to carry out regular servicing on the installation. How often cleaning is required will vary hugely from site to site and is driven of course by the environment within which they are located. From time to time, there may be a requirement for a reactive maintenance visit to rectify technical faults. For a system above 100kW, it is probably sensible to procure the project with a two to five-year maintenance agreement.

On top of ensuring that access to the equipment is satisfactory, other design considerations can also decrease the need for cleaning. Higher-pitched panels (usually tilted by more than 5°) will better self-clean when it rains. Panels mounted on frames without wind deflectors could provide a welcome shelter to birds. We would always recommend wind deflectors are installed on 'pitched up' systems – these are simple matters to consider at the design stage, but expensive to rectify post construction if issues arise.

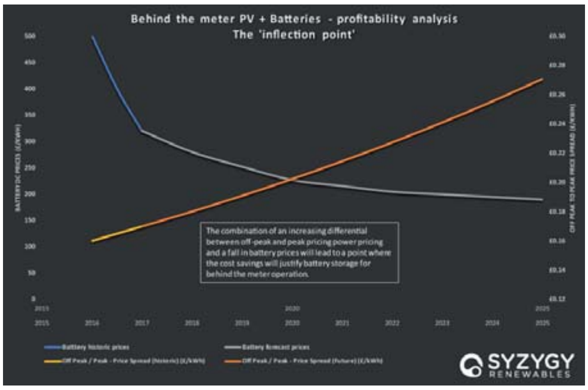

Figure 4. The inflection point after which rising energy prices and falling battery costs will combine to make behind-the-meter storage profitable

Another feature to consider in the planning stage of the project is the location of inverters. Once again, providing easy access to them would allow for easier fixing and inspections. However, care must be taken if inverters are installed outdoors, as they will then be exposed to dirt, rain, heat and could suffer more frequent breakdowns.

Finally, to ensure technical issues are picked up at the earliest stage, and therefore rectified quickly, installing a remote monitoring of the system is essential. A wide range of monitoring equipment exists, and can provide information at the plant level up to the panel level. The amount of detail needed depends on multiple factors such as the location, the size of the system or the type of equipment, and should be determined with a cost/benefit analysis in early stages of the project.

Battery storage

In recent years, the strong development of renewable energies and the decrease in lithium-ion battery prices have led to increased interest in stationary battery storage. In what the industry calls 'behind the meter' operation there are generally three reasons for using battery storage in a commercial setting:

- Back-up supply
- Reducing energy costs (cheap charge – use at peak times/absorb spill from embedded generation)
- Cost avoidance: avoiding costly capital expenditure on increasing the supply capacity to the site

To generate a financial return from a battery, it is likely that the first two approaches will not provide a reasonable payback on their own; therefore, providing the National Grid with a range of services in addition to the 'on site' strategy is a way to generate additional income (income stacking) to generate that financial return. For example, batteries in certain geographic locations can produce a 'stack' of revenues through the provision of grid services (such as frequency regulation or capacity market). There are companies, called Aggregators, who can manage your battery within a larger portfolio, who are providing the National Grid with a range of services.

As of today, the cost of batteries is still too high to show a short enough payback to the majority of behind-the-meter users. The cost of peak energy varies significantly from region to region. However, prices are decreasing fast, especially for Li-ion batteries, driven by the electric vehicle manufacturers, and we are close to the inflection point where energy prices, which are generally rising, and battery costs, which are falling, will combine to make behind-the-meter operation profitable in its own right – so keep watching. Figure 4 shows how the likely inflection point will be reached.

The right design

In summary, solar PV is a fantastic technology that should deliver low cost energy for many years to come. The trick to getting it right is in the work undertaken before any construction takes place. Lower subsidies mean sizing correctly has never been more critical, as is understanding that the cheapest solution is not necessarily the best, that this is a long term investment and that it is therefore important the installation delivers what you expected it to, year in, year out.

There will be maintenance that needs to be undertaken, but the cost of this can be reduced through effective design. If you are not deeply technical, or have a good understanding of how to get the right technical and commercial solution, it is probably worth getting some independent advice. There is a cost attached to this, but a good consultant should pay this back through enhanced specification, helping you avoid over sizing, making sure it has been built correctly and that your warranty package is robust – protecting your investment into the future. ■

Authors

Andrew Hancock graduated from Reading University in 2007 with an MSc in renewable energy, technology and sustainability. Over the past 10 years he has worked for some of the leading UK solar installation companies, and has gained valuable experience in most areas of the solar business. Positions include installation and site management, to key design and technical management. Andrew joined Syzygy Renewables in July 2016 and works in the asset management team.

Kirsty Berry has a masters in engineering from Manchester University and Technische Universitat Berlin and a MSc in renewable systems technology from Loughborough University. Her career in renewables started at BP in 1998 after which she spent 17 years at Solarcentury where she was latterly head of health and safety. Other roles at Solarcentury include project management. She is now senior project manager at Syzygy Renewables.

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KEHUA TECH draws the new outline of "PV+" with distributed systems

With the rapidly evolving technologies and the increasing trend towards decentralization, three-phase string inverters have made great strides in the solar market in recent years. Riding on the trend, KEHUA is drawing the new outline of "PV+" with distributed systems.

1. What is "PV+"? What changes will it bring to the energy market?

As is already known, China is currently actively promoting an "Internet+" national strategy, which is increasingly having a greater and deeper impact on all industries. As a new business model, "Internet +" has brought major changes to small and medium-sized enterprises. In the new energy sector, we first proposed the concept of "PV+" in China to enable a more innovative approach to our distributed PV systems in areas never previously considered.

Innovations based on the "PV+" model would be a reform rather than complete change to the energy market. Large, utility-scale centralized solar plants have been the conventional mode of electricity generation for decades. However, limitations on availability of land and infrastructure and rapidly urbanized economies pose challenges to this model. Although not a new concept, distributed generation is now gradually gaining ground the world over.

Distributed generation produces energy closer to the user, rather than transmitting it from a remote power plant. Power is generated and stored locally and works in parallel with the main grid, providing power as needed and utilizing the main grid at other times. Distributed or "rooftop" solar allows residential users to lower their electricity costs. "PV+" is keen to enable more businesses, municipalities, traffic systems and other entities to also take advantage of cost savings, at the same time reducing stress on the micro-grid by providing more reliable power.

KEHUA's industrial rooftop project for a factory in Bangkok, Thailand

As string inverter architecture becomes more resilient and more widely available, distributed systems present huge development potential and broad market prospects for "PV+" applications, allowing the concept to become a way of life for all areas of social economic industries and public utilities.

2. After becoming an accepted part of PV solar for residential and industrial rooftops, in what new fields will "PV+" come into play?

As well as traditional residential and commercial rooftops, we now have a multitude of opportunities for development in new areas such as agriculture, fishery, transportation and data centers and one example encapsulates this perfectly.

"PV+ Agriculture" and "PV+ Fishery" are two of our typical projects in the non-C&I (Commercial and Industrial) segment. We have constructed a 20MW distributed PV plant for a farm in the Shandong province of China. The combination of distributed solar photovoltaics and agricultural cultivation allows for land to be utilized more creatively for multi-dimensional purposes. This scenario is repeated with fish farming, with another 3 distributed 20MW power stations previously treading water in the east of China in Jiangsu province now working to deliver added value to customers by dual use of land and green power supply.

At the same time, we are the pioneers of "PV+ traffic" in the field of transportation. In the metro sector, we have built a distributed PV power station for a metro company in Guangzhou City, in the south of China. The power station not only generates green energy for the metro system itself, but this can also be transmitted to the high voltage power grid of the rail transit system with solar power effectively supporting the other energy sources.

Another 300 kW distribution PV power station entered operation last year for Xiamen international airport, in combination with our EV charger solution. This generates over 400,000 kilowatt hours of electrical power for the day to day running of the airport.

3. What's the outlook for the company with "PV+" in the global market?

The Chinese market where we have our roots is the fastest growing, but we are also producing more income from overseas in the utility-scale market. We have actually been working in overseas markets since 2010 and have already provided solutions to 200,000 users across over 100 countries. For string inverter systems, with our upcoming new products we are definitely seeing more opportunities in developed markets such as Europe and the US. Our three phase string inverters on the other hand will be highly popular in the less developed areas of Asia and Africa.

We firmly believe that "PV+" can develop further. Over recent years, by participating actively in the 'Belt and Road' initiative, we have secured a

PV+ Agriculture, Fishery, Airport, Metro

string of projects with our solar PV solutions in industrial and infrastructure applications. For the infrastructure segment in particular, we believe that our decades of experience of power supply in this field will enable us to be very successful in the years to come.

4. How has KEHUA become so successful globally with its products? What can you say about the company's R&D and commitment to quality?

KEHUA originally specialized in the power conversion industry, with 29 years of experience in converters, and it is still the largest critical power manufacturer in China. From the perspective of technological origin, KEHUA can definitely lay claim to a long-standing superiority in inverter technology.

We have 3 R&D Centers in China, including a National Technology Center, with a total of 700 highly experienced engineers providing technology support for customers across the globe. We are additionally fully capable of providing a service which encompasses system integration, customization and EPC sub-contracting.

We have built 5 modern manufacturing bases domestically, covering a total area of over 200,000 square meters. With a commitment to the philosophy of "Live for quality", the KEHUA Production System (KPS) has been developed as a lean production management tool, incorporating both an external and internal production supply chain. The KPS is based on a lean production philosophy to ensure effective process control by visualization, informatization and tabulation methods. Insight to the process and production of all products is implemented via a stringent quality control system (QMS), including bar-codes, automatic testing equipment (ATE) and Ongoing Reliability testing (ORT). KEHUA's branding recognition and reputation has been built over many years on its highly effective QMS.

With a foundation in the critical power and converter disciplines, our products and solutions are widely used in sectors such as finance, industry, transportation, communications, government, nuclear power, medical, electricity and cloud computing. With a wealth of experience in power supply across multiple industries and with extensive knowledge of operational and electrical power environments, we are specialized in dealing with industry-specific products and solutions. This experience and specialization will naturally enable us to continue to develop "PV+" as a project all over the world.

Going forward, what is the trend for development in string inverters? What do you think differentiates the various players and their products?

With more manufacturers engaged in the solar market, companies are keeping their competitive edge through technological innovations. The leading players especially are looking to tie in their clients by developing advanced technologies, investing significantly in R&D to continually produce new products. The resulting technology upgrades and innovations will continue to be the overriding trend in the inverter sector. Among specific areas of focus are:

Higher unit capacity

String inverters are increasing in power capacity and low capacity central inverters are gradually being replaced, even in utility-scale applications. The unit cost of a system can be reduced by increasing capacity. KEHUA will soon launch its own 100kW string inverter range to provide flexible choices to its customers.

The mainstream of intelligent fans cooling

The heat from internal power loss and environmental temperature is a great challenge to the reliability and lifespan of an inverter. By contrast, our research indicates that products with intelligent fan cooling systems have an almost 40%-50% longer lifespan when compared to air-cooled systems.

Therefore, it is logical that the adoption of high protection intelligent fan cooling has become a common development for string inverters.

Anti-PID protection

Potential-induced degradation (PID) in PV modules can cause significant power loss through adverse environmental factors or system voltage stress, avoidance of which requires a string built-in anti-PID function. KEHUA's SPI-B series (20kW-100kW) string inverters can be installed with Anti-PID modules to reduce the negative effect of PID.

Higher voltage system (1500Vdc)

The 1500Vdc voltage level is a major change towards increasing efficiency and reducing costs in PV power generation systems. Compared to 1000 Vdc, a 1500Vdc system allows a higher quantity of string inverters to reduce cable power loss and construction costs, with system efficiency increased by 2%. KEHUA launched its 1500Vdc range of string inverters - SPI-B 1500V Series (100~125 kW), in 2017.

According to Global Market Insights, Inc., "String Inverter Industry revenue is projected to make significant gains of 15% over the period of 2016-2024." There is unquestionably a huge opportunity in front of us and the future is very bright.

ABOUT THE PERSON:

Joey Chen, General Manager of International Sales & Marketing at KEHUA TECH. He has worked in energy industry for over 10 years with recognised expertise on Solar PV and Energy storage.

Bringing the factory floor to solar plant construction

Construction | Automated systems to speed up the construction of PV power plants have become a key tool in building bigger and cheaper projects. Sara Verbruggen looks at some of the state-of-art technologies helping the industry drive down system costs

Credit: Brittmore

As PV plants have grown in size and pressure to reduce the levelised cost of energy for solar power has increased, some companies have turned to automation and robotics for addressing various phases of developing and building ground-mounted PV plants.

Automating elements of construction and installation reduces labour costs, in the same way that greater automation in PV module production processes have helped to reduce manufacturing costs. Automation also speeds up overall PV project development. A project that can be built in 10 months instead of 12 costs less, not only because equipment and staff are on site for less time, but also because the PV plant can be commissioned earlier to start producing electricity and earning revenues sooner.

"Industrialising installation optimises the project's development and speeds it up, in the same way that greater automation in PV module production processes has helped to reduce manufacturing costs," says Hans Jürgen Sauter, chief sales officer at Krinner, a German company that has developed an automated ground-screw foundation process.

Robots

Another company that has developed some novel construction techniques is California-headquartered Brittmore. Established in 2010, the company's approach comprises three core elements that help to make PV construction more like a factory operation and less like a construction site.

These are an on-site panelisation process, dubbed SolStak, in which modules are assembled into panels on site or nearby. The technique is compatible with crystalline and thin-film modules, framed and frameless. The other element is a proprietary mounting system, SolWay, which is compatible with the third element – an automated installation process. Automated technologies are deployed to efficiently install panels, including shuttles that map installation positions, automated loaders that lift the panels on to the end of the array before shuttles deliver them into position.

Brittmore's robots are small and portable so that the installation is done from the centre of the PV array outwards, so no heavy equipment is required to move up and down aisles, which can create dust and mud and risks breakages as the panels are picked up and delivered to their destination in the array.

Automation is playing an increasingly prominent role in plant construction

Brittmore's typical customers are solar engineering, procurement and construction (EPC) firms. The company started out by supplying EPCs with a full turnkey service that covers racking, panel assembly and panel installation. More recently, however, Brittmore shifted its business from that of a turnkey structural balance-of-system installer, which was necessary to help the company develop the technology, according to co-founder, Bram Britcher.

"The focus is now on the endgame business model, which is to license the technology to EPCs. We have several companies in the US interested in licensing the technology for upcoming projects in both California and Tennessee," he says.

A core robotics element of the system is an automated large panel PV shuttle, which moves atop the rack carrying and positioning panels in each row of the array. The technology includes an auto-loader, which together with the PV shuttle can accomplish the installation of 40 or more panels an hour. For short rows the number is up to 60, while for rows longer than 200m, or on slopes, the rate is lower as the shuttle transit time increases.

The shuttle travels the length of the rack mapping all installation positions. No programing is required. Aisle breaks in an array can be bridged with temporary rails, extending the area that can be reached from a central material handling location. Heavy equipment traveling between array rows is not needed.

The PV shuttle functions autonomously. A central site manager can configure the shuttles, monitor them and start or shut them down remotely.

Brittmore's panelisation process means modules can be delivered to the site, or close by, and assembled, including fixing junction boxes, assembly panels, by framing the modules or working with frameless modules.

Modules are riveted to the rail instead of clamping, which eases cleaning on the front surface as no dirt is trapped at the clamp.

"The industry has found that panelisation really cannot be done remotely. The additional shipping cost of the large assemblies, which are also at a lower packaging density, is prohibitive," says Britcher.

The only effective means of panelisation is on site or nearby and various EPCs do mechanical panelisation. However, Brittmore is one of a few companies able to provide adhesive-based panelisation on site. The mobile adhesive technology was developed with a grant from the US Department of Energy.

The BoS cost reduction achievable with Brittmore's technology is around 15% in a licensing model, the company claims. Installation times are compressed, improving the economics further. Faster project completion means lower cost of capital and quicker energy revenue. The deployment cost is justified at 1.5MW or larger.

Britcher says: "Traditional BoS installation has come down in cost with incremental improvements to installation labour and high volume rack manufacturers lowering prices significantly. However, conventional racking is nearing design and manufacturing optimisation. Raw material cost is the limiting factor."

In high heat, labour costs greatly increase as workers require frequent breaks to prevent overheating, or work has to occur outside of daylight hours. Using Brittmore's panel installation process, 90% of the construction crew works comfortably under a shade structure outfitted with fans as they assemble the panels from modules and other components. Out in the field, robots are able to do the heavy lifting.

Well grounded

German company Krinner's automated ground screw process was instrumental in the rapid execution of the 300MW Cestas solar farm completed in late 2015, near Bordeaux in France. The plant, developed by Neoen, was Europe's largest solar farm when it came online. It was built in eight months, with each installation team completing 4MW a day.

To date nearly 3,000MW of PV plants have been built using Krinner's technology. In 2001 The company developed an alternative to concrete foundations, using ground screws and automated installation, adapting the technology for PV plant constructions six years later.

Six years before Cestas, in early 2009 Krinner completed a 54MW plant with QCells, now Hanwha Q CELLS close to its headquarters, to demonstrate how the ground screw technology, combined with automated screw positioning and installation, optimised the foundation construction phase of the PV plant development. When the 54MW plant was built, it had the distinction of being one of the largest PV plants in the world at the time.

Credit Neoen

Krinner's ground screw process helped it build France's 300MW Cestas project in just eight months

In less than a decade Krinner is still pushing the limits of PV plant development. The company is starting soon on a 1.2GW solar PV project in Abu Dhabi, in the United Arab Emirates, which will be one of the largest in the world, when built. The plant will cover an area of 7km by 2km. In total 700,000 screws will provide the foundations for the project. The phase of installing them will take around 20 weeks, requiring 30,000-35,000 screws to be installed a week.

"Industrialising installation optimises the project's development and speeds it up, in the same way that greater automation in PV module production processes has helped to reduce manufacturing costs"

"A PV plant of this sort of scale needs automation. There really is no alternative," says Hans Jürgen Sauter, Krinner's chief sales officer.

As PV costs have fallen and new markets have opened up, many of these are in regions where radiation levels are high and so are the temperatures, and difficult terrain, such as rocky and very uneven ground, can be challenging for construction. Countries where plants have been built or are being constructed using Krinner's technology include South Africa, Chile, India and Bangladesh.

To construct the Abu Dhabi project the foundation work, racking and installation of panels will take place at night.

Of BoS costs, mounting is the biggest portion, and foundation or structural BoS costs tend to be about 10%. Krinner's approach speeds up the construction of foundations and the racking assembly designed around it. However, the company has also reduced the weight of its racking to squeeze further savings.

"We have optimised the processes of foundation construction, racking and module installation. We can compress the time required to construct PV plants and meet really challenging schedules," says Sauter.

Like Brittmore, Krinner has also turned its attention to developing a panelising process at the site. Tents are constructed at project sites where the panelising takes place and modules are rolled along to the exact position. Sauter sees this as the future.

Harsh environments

Alion Energy, based in California, focuses on PV projects being built in rocky or harsh environments as these tend to be areas with the maximum solar irradiation and therefore best LCoE, according to Mark Kingsley, the company's chief executive.

"We chase dust clouds, rocks and corrosive soils. The company focuses on PV In harsh environments as these remains the futures lowest cost areas to produce solar energy," says Kingsley.

Alion Energy developed the use of

slip-form concrete extrusion to create fully ballasted systems at low-cost and at scale. The approach avoids up to $0.04/W in drilling costs and also eliminates subsurface corrosion issues that are common where driven posts are used, the company claims.

"To speed up construction the rest of the PV industry benchmarked highway construction and adopted guardrail post driving as a methodology," says Kingsley. Alion Energy investigated how the concrete, slip-form extruded, curbs and gutters along the side of highways were built and adapted this technique for constructing extruded concrete rails to replace posts and metal racks for installing panels on.

The company has also developed what it claims to be a unique single-axis-tracker designed to reduce steel mass from 65 to 30 tonnes/MW. This has been achieved through an 'A' format, rather than a 'T' format frame that most trackers have.

The parts can be carried by two construction workers and avoid the use of heavy equipment on site. This, combined with savings on torque bolt connections due to greater use of factory pre-assembled components, speeds up installation. Construction times and costs are reduced significantly.

"We found that by reducing the mass of component parts and eliminating pre-drilling and torque connection, we were able to drive down costs in the harsh environments we target," says Kingsley.

However though Alion Energy used automated installation for a 4MW project in Lancaster, California, several years ago, since then the company has refocused on advanced mechanical design and automating operations and maintenance (O&M). Taken together these provide both short-term and long-term cost advantages, according to Kingsley.

"We found the demand for O&M robots vastly exceed that for automated installation. However, by improving designs our systems to be installed by robots, we also made them easier for non-skilled labour to assemble in harsh environments," Kingsley says.

Another company that has built its business model around enabling PV construction in difficult and challenging terrain is Florida-based TerraSmart. Challenging sites – ones that are rocky, dry, dusty, with challenging soils – tend to be cheaper, saving developers money.

Rather than pay for equipment to prepare the ground by removing or breaking up rocks, TerraSmart offers developers and their EPCs a ground-screw foundation system that overcomes these issues, in much the same way as Krinner has found large screws can be driven into the rockiest terrain to provide firm foundations on which to install racking and mounting, even on sloping and hilly areas.

TerraSmart has not only crunched down costs in its racking and foundations – reducing materials and weight and simplifying components – but has also invested in automating site surveys, which can take many days, even weeks, over large sites.

The company has developed its own drones to fly over sites record and take images to provide detailed topography data to reduce costs in the mapping stage. Recently the company launched an autonomous precision survey rover to ensure greater accuracy and also speed in the site surveying stage.

As PV plants have grown in size, the need for automating phases of the pre-commissioning stage has increased. The companies that are enabling faster, yet more accurate, PV plant construction have evolved business models that are about much more than hi-tech robots. They are attacking the opportunity to reduce LCoE from every angle, be it site selection, to surveying, to constructing the foundation, to how mounting structures can be simplified or made with less material.

Krinner's process

Before the installation of its screws, Krinner undertakes extensive preparation, which includes soil sampling and 3D modelling of the soil, down to 1.5m depths, as well as photographing the surface, using aerial drones. In the next phase, automated robotic vehicles drive over the site and map out where exactly each screw will be driven into the soil.

The automated robots can accomplish 4,000 survey points in a 24-hour period. The data that they record is processed on a cloud server, called the Krinner Cloud Cockpit. The cockpit provides an overview about every single step of the project. Screws are selected based on the condition of the soil at the site, or a particular part of the site. Even coatings are adapted depending on specific site conditions for maximum corrosion protection and to minimise maintenance costs.

Human operators traverse the site in vehicles that use GPS co-ordinates to precisely fix in the screws, based on the dimensions of the panels being used. Attachments such as hammers can be used to embed screws in even the rockiest ground. Where the ground is uneven the vehicles will automatically level so the screw is always installed vertically.

The racking has been designed to be quickly assembled by workers once the ground screws have gone in. The panels are lifted manually to be loaded between the two racks and are pushed along to the other, followed by more panels until the racking is full.

Krinner has produced about 100 vehicles that are used around the world. Thirty of these are the latest version which use x-y coordinates for accuracy down to a few millimetres when positioning the screws. About 20 of these will be deployed at the Abu Dhabi project.

Credit: Krinner

Krinner's ground screw robot is to be used on the giant 1.2GW Sweihan project in Abu Dhabi

Track to the future

Credit: Array Technologies

Technology | Falling prices have seen single-axis trackers become standard issue in utility PV plants in many parts of the world. As the tracker market becomes more crowded, manufacturers are developing increasingly sophisticated technologies to stay ahead of the game and support wider PV power plant innovation. Ben Willis reports

The presence of single-axis tracker systems in ground-mounted PV arrays has gone from oddity to near ubiquity in the space of just a few years. Until only relatively recently trackers were regarded as an expensive anomaly, but a combination of rapidly improving economics and a boom in utility-scale projects at latitudes where trackers add the most value has seen them become almost a default technology choice.

In its most recent report on the tracker market, analyst firm GTM Research documented a 250% jump in tracker installs between 2015 and 2016, from 5 to 12.6GW. By 2021 GTM predicts that annual tracker installations will grow to 37.7GW, accounting for over half of all ground-mount PV systems.

The tracker boom has brought with it the inevitable jostling for position by established players and new market entrants looking to get in on the action, one of the main reasons why trackers have become much more affordable. “It’s a very crowded marketplace, meaning that not only have tracker prices fallen by virtue of products being more optimised, built at bigger scale, there’s also been a lot of general market competition,” says GTM Research senior analyst, Scott Moscowitz. “Because of the number of vendors out there, folks have been forced to drop margins to lower their prices.”

This trend looks set to continue, with GTM predicting that tracker prices will continue falling by 5-7% annually through to 2021. For project developers this of course is a welcome fact, bringing prices down to a level where the relatively greater capital expenditure required to finance a tracker is more than offset by the greater yields and therefore returns a tracker will enable a PV system to generate over its lifetime.

Innovation in tracker technology will become increasingly important as the sector becomes more competitive

For tracker vendors, meanwhile, increasing price pressures will mean an ongoing struggle to stay competitive. According to Stavros Mastorakis, technical director of Spain-based tracker specialist, Mecasolar, the price of trackers will always be dictated by their basic raw material – steel. “As of today, on cost approximately 70% corresponds to the cost of the steel. The price has a limit it can go down, because practically if you want to have a system that complies with local regulations there’s a minimum of steel you need to use, if you are supplier

A or supplier B. So in the pushdown in prices, the tracker will come to a point where it will go to its bottom price and it will be very difficult to go below that," he says.

That fact will place an increasing emphasis on the ability of tracker manufacturers to continuously improve their products to ensure they remain relevant. According to GTM, ongoing design refinement that eliminates parts, minimises electrical components and reduces structural requirements will be a key priority for tracker suppliers, as will an ongoing awareness of how tracker systems must keep up with developments in other areas of PV power plant technology.

A number of recent notable product announcements offer some clues as to where the priorities are likely to be for tracker firms in the near future. Some of the emerging trends that look set to shape the tracker landscape in the years to come are outlined below.

Predictive O&M

One development that is likely to become a defining characteristic of next-generation trackers is the incorporation of 'intelligent' capabilities that enable predictive maintenance of components. Broadly speaking, the single-axis market is split between so-called centralised and decentralised – or distributed – architectures, the former using a central drive to power multiple rows of modules, the latter having drives for independent rows. Both architectures have distinct advantages, but a challenge with decentralised systems is the generally larger number of components they utilise.

"Predictive and preventative maintenance is a big focus, especially with the proliferation of decentralised tracking systems that have a large number of components in the field," says Moscowitz. "So if you can figure out a way to minimise failures and address them before they occur that could be really beneficial. But that's not specific to decentralised trackers; centralised trackers can look at ways in which they can increase performance as well and we expect all types of trackers to get, in a word, smarter. There's a software and hardware element to tracking systems and even marginal benefits can be significant over the 25-30 year lifespan of a tracking system."

Undoubtedly with exactly this in mind, leading US tracker manufacturer NEXTracker last summer announced the acquisition of BrightBox Technologies, a tech firm with specific expertise in predictive modelling software and machine-learning. At the time NEXTracker said it expected the acquisition to enhance its capabilities in a number of areas, including improved remote monitoring and asset management of systems using its technology.

Meanwhile, Mastorakis explains how Mecasolar is incorporating similar predictive capabilities in its Hyperion single-axis tracker: "The system information that you can gain during operation can give you some indication of what is happening to the system and how you can react from a predictive point of view and reduce your downtime in the operation. At the end of the day a tracking system is a machine that will always give you some feedback about what is going on. Through our control system we are recording continuously all the operating data of the system, so our maintenance engineers can connect all over the world to existing installations to find out what is happening to the system [and] do some predictive maintenance to reduce the downtime of the plant."

Moving with the times

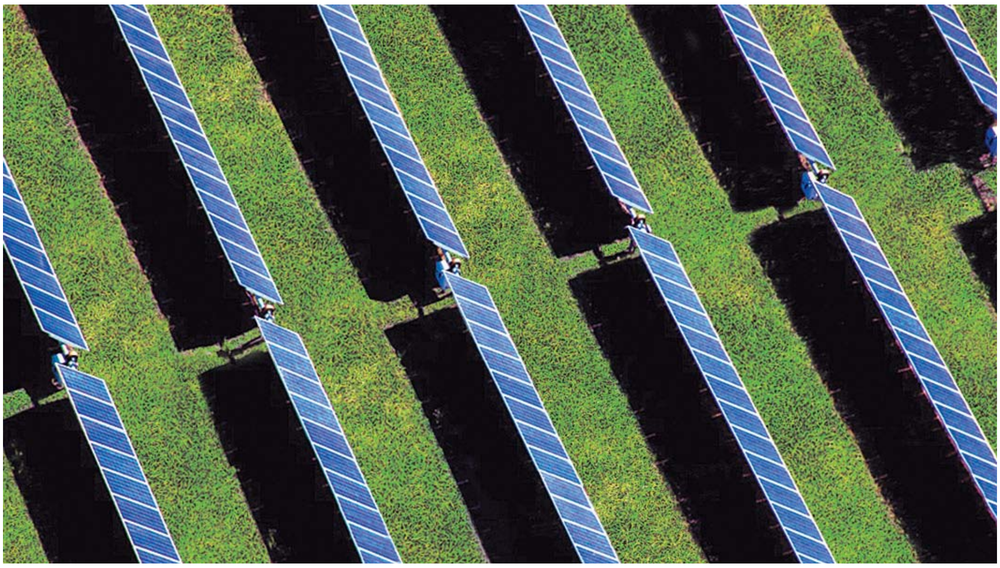
Tracker companies must of course also have an eye to developments taking place in other aspects of PV power plant technology to ensure their products keep pace with the rest of the industry. "Tracker vendors are always monitoring what their customers are doing either from the module or inverter perspective and figuring out how to adapt to that. And they have to be very reactive to those technology trends otherwise they get left behind," says Moscowitz.

One recent example of this point is the general industry-wide shift towards 1,500V plant architecture. This phenomenon affected all parts of the PV power plant supply chain, including tracker suppliers, which had to introduce a number of design modifications to adapt to the higher power systems. Looking ahead there are several other big-picture trends that are likely to have a bearing on tracker design or where trackers may indeed be integral in expediting wider power plant innovation.

Cleaning

Cleaning is a significant consideration for PV plant developers and operators, particularly in markets where soiling from dust and sand is prevalent. Hitherto, much cleaning work has been undertaken either manually, or via cleaning systems fitted to the back of vehicles, but the trend is increasingly towards automated solutions as the appropriate technologies become cheaper and the size of plants makes manual cleaning impractical and costly.

This development will have obvious implications for tracker suppliers, says Lux Research analyst, Tyler Ogden. "Single-axis suppliers need to be aware of the increasing adoption of robotic cleaning systems in certain markets with high soiling like the Middle East, India, even the south-west US," Ogden says. "These systems are primarily built to be compatible with fixed-tilt racking, and



Credit: Mecasolar

Mecasolar's Hyperion tracker enables predictive maintenance to reduce plant downtime

Credit: NEXTracker

NEXTracker's NX Fusion Plus solution is among the first to integrate storage and tracker technologies

there are some additional complications around making them compatible with trackers. So that's also an area where tracker companies need to branch out and form development partnerships. And it could be an area of differentiation."

Indeed for market leading firm Array Technologies, tracker-compatible robotic cleaning is a key priority and, says company president Tom Conroy, a central plank of its technology innovation roadmap.

"In some markets around the world panel cleaning is a very big issue, and the initial panel cleaning technology being deployed is tractors," Conroy says. "Now it does not appear to many people that tractors are going to be a long-term solution for cleaning. One of the obvious problems is road maintenance – so for a 100MW project, in order to do tractor cleaning you've got to maintain about 400km of roads for 30-50 years in order to not have potholes in the roads and these cleaners punching holes in modules. Array has an aggressive robotic cleaning programme underway that will reach a whole other level of efficiency and reliability and be a breakthrough for the market."

Conroy ventures no further details, but Array says it is expecting to begin rolling its robotic cleaning system out by mid-2018.

Storage

Another major industry-wide development is the advent of energy storage. Conroy is unconvinced that the "economically optimised" place to implement storage in a PV power plant is at the tracker level.

Nevertheless, what now seems like the inevitable integration of PV and storage technologies has caught the interest of NEXTracker, which at the end of 2016 lifted the lid on its 'NX Fusion Plus' solution. This brings together a NEXTracker Horizon solar tracker, battery, storage-enabled inverter and control software into one package that, owing to NEXTracker's distributed architecture, can be deployed in as many or few individual rows as required, the company claims.

Mecasolar is also actively pursuing a storage solution, which Mastorakis describes as a "turnkey" system integrating modules, tracker, inverter and batteries. The system, on which Mecasolar is collaborating with three partner companies and which it has been trialling for the past year or so, will be tied together with a dedicated SCADA control system the company is developing that will bring the different technologies under "one umbrella" and ensure ease of use.

Bifacial

As we explore elsewhere in this edition of *PV Tech Power* (see pages 18-26), bifacial module technology looks set to play an increasingly important future role as the solar industry begins to embrace the advantages offered by modules that generate power from their back as well as front sides. As a relatively new technology, how bifacial modules can best be deployed in conjunction with single-axis trackers is still a relatively unexplored area. GTM's Moscowitz believes that most trackers can currently be installed with bifacial modules, but concrete examples of this combination of technologies – or indeed the power gains they jointly offer– are few and far between.

One tracker company that has made some early moves forward in this area is Spain's Soltec, which at the end of 2016 was chosen by Italian utility Enel Green Power to provide a tracker solution for a bifacial test project in Chile. The 1.72MW 'La Silla' project is claimed to be the first to combine bifacial modules and single-axis trackers in a utility-scale power plant.

The company used its SF Utility Tracker for the project, employing a design that incorporates gaps between modules that allow additional sunlight to reach the ground surface for reflected radiation. As Soltec communications manager Tim Murphy explains: "In the case of bifacial PV tracking, it is the tracker application that both eliminates backside shading and achieves the higher mounting location (key to increasing bifacial performance) that is demonstrating product maturity to the customer's advantage.

"The bifacial tracking case is resolved simply by the SF tracker standard feature of two-up portrait module mounting whereby backside shading by the torque-axis is effectively eliminated, and bifacial performance is increased by the height of installation."

It seems likely that La Silla will be the first of many utility PV projects to come that will combine the benefits of bifacial modules and single-axis trackers.

Niche solutions

Although the technology debate over the relative merits of single- versus dual-axis trackers has for now been overwhelmingly won by the single-axis variant, there are likely to be niche markets where similarly niche solutions are more appropriate than the products offered by mainstream suppliers.

France-based start-up HeliosLite has developed what it claims is a tracker solution that can fill such a gap. The company describes its tracker as '1.5-axis', and maintains that it offers most of the performance advantages of a dual-axis tracker, but at a much reduced cost owing to a simpler mechanism.

CEO and co-founder Jay Boardman explains that the HeliosLite tracker is "not a 'me-too' but a 'me-also' product". "We heard from developers that they have atypical projects – hillsides, snowy regions, weird forms, waste recovery sites, things like that – where, for whatever reasons, today's very good one-axis horizontal trackers don't fit the bill. So this isn't meant to be a gadget, it's bringing a new type of tracking to other types of markets."

Boardman says the sweet spot for the HeliosLite tracker is projects below 10MW, possibly in off-grid or isolated locations, where the performance advantages of a tracker are desired but may not be available. The technology is also well suited to more northerly or southerly latitudes, where dual-axis trackers are more effective than single but have so far proved too expensive to gain more than tentative foothold, Boardman adds.

The company has piloted the tracker in France and on a small project in Abu Dhabi, and is now seeking partners with which to roll the technology out commercially. South Africa, Morocco and India are among the target markets cited by Boardman.

"We can't compete with today's one-axis horizontal trackers, which are very good products for their markets, but there are so many other markets that would be very good for tracking, from rural electrification projects to industrial projects in northern and southern latitudes, where tracking makes a lot of sense but where solutions don't work because they're not designed for that kind of configuration," Boardman concludes.

HeliosLite's 1.5-axis tracker is claimed to be suited to niche markets where mainstream trackers are less well adapted

Getting the basics right

But while technological innovations such as those outlined above will undoubtedly play an important role in helping tracker companies maintain their competitive edge, so too will a continued focus on getting a few basic practices right. For example, says Mecasolar's Mastorakis, as solar continues to globalise and new markets open up, tracker manufacturers must be able to offer products that fit the specific and varied needs of the end user.

"We have to be more project oriented and we have to optimise the operating conditions of the system project by project," he says. "It's not always feasible; it's not the same to optimise a 1MW project in Turkey as a 500MW project in the Atacama – they are very different conditions. But this is where we need to arrive; we need to provide what our customers really want for the area and the conditions where he's having the system."

GTM's Moscowitz echoes this, emphasising that tracker companies should not let technological innovation become a distraction from getting the right fundamental building blocks in place to ensure long-term sustainability.

"Trackers are large capital intensive investments for long-term utility-scale solar assets, so any type of feature really has to show some type of either performance benefit or materially lower upfront or lifetime tracker cost. Otherwise they're just gimmicks. The primary differentiator for a tracker company is going to be a competitive price, a superior track record and strong relationships with customers. The primary feature that buyers are looking for is just a very reliable product and a company they know will be there to service the product over its lifetime." ■

Project briefing

WORLD'S LARGEST FLOATING SOLAR PROJECT: MAKING USE OF THE UNUSABLE

Location: Huainan, Anhui, China
Project capacity: 40MW

The technical feasibility of floating solar PV and its long-term durability have often been questioned, but this year's commissioning of a giant project on a lake in eastern China has launched the technology into the global spotlight. The 40MW plant boasts an unprecedented scale and makes use of traditionally redundant, flooded mining territory. Major PV inverter manufacturer Sungrow Power Supply Co developed, built and owns the project in Huainan, south Anhui province. The firm has demonstrated that such plants can be constructed efficiently and connect to the grid in the first instance, but investors will no doubt watch its performance closely in the coming years.

Floating solar power plants are becoming increasingly popular across the globe (see box, next page) with their ability to reduce water evaporation in many applications. Simultaneously, the cooler ambient air, resulting from the immediate proximity to water, particularly in hot and humid environments, limits the solar panels' exposure to the 'temperature coefficient' issue that can cause performance degradation.

The Chinese government has been strongly encouraging renewable energy programmes, says Xiao Fuqin, Sungrow's chief engineer of floating PV technology. The National Energy Administration (NEA) is now pushing the PV industry to participate in its Top Runner Project programme in which floating solar is included.

The Anhui mining region was chosen since the land was already heavily damaged, which made obtaining permits very easy. The depth of the lake also prevents it from being useful to commercial fisheries. "The whole point of this plant is to take high advantage of the min-ing ground which is already destroyed – and to help the environment," explains Cao Renxian, chairman and president of Sungrow.

The location also benefitted from being less remote compared to typical mining regions. This helped with the logistics of bringing PV equipment to the project. In fact the biggest challenge only came after the long-haul transportation when Sungrow had to shift equipment from the shoreline onto the lake.

However, the flooded mining area is still sinking fairly rapidly. Its depth currently sits at around four to 10 metres, but it is expected to reach as deep as 15 metres in the near future, says Renxian.

Danger waves

Sungrow assessed the natural conditions of the project location before starting construction since not all water zones are suitable for PV technology. Variables included water velocity, wind grade, water area and wave height among others.

"Based on these environmental variables, we considered how the wind load, wave and water flow would influence the floating power station, so that we could guarantee the safety of the floating block under extreme conditions by carefully designing the anchoring system," says Fuqin. "If the wind grade or wave height of a certain water area goes beyond the safety estimation (e.g. large natural lake or sea surface), we would refuse to construct any floating power station over that water area."

Preventing large waves is perhaps the most obvious risk for an onlooker to identify and indeed it remains one of the biggest risks even for experienced solar installers. Preventing damage to modules from humidity is critical but perhaps comes lower down on the priority list.

Floating tech

The floating systems are kept in place by multiple specially designed anchors. Meanwhile, flotation devices were provided Sungrow's Floating PV Technology subsidiary. Renxian says that unique floats for cabling also had to be designed. Furthermore, the effects of humidity and potential-induced degradation (PID) are major considerations given the proximity to water.

The project used modules from multiple Chinese brands. Major supplier JA Solar supplied its monocrystalline double-glass modules designed to offer greater protection against moisture ingress, high anti-PID performance and resistance against corrosion.

Renxian says the base of the floating systems should be carefully designed and resistant to fatigue. The systems therefore had to be tested and simulated many times before coming into real use. Even the distancing between each base had to be carefully simulated, particularly since the water will also be used for cleaning purposes. Renxian claims that Sungrow can promise at least 20-years of use on its

By Tom Kenning

floating systems and is also confident that the water cooling effect allows for higher energy production than on land.

While a lot has been claimed about the effects of water cooling on a module's output, Fuqin is careful not to exaggerate, adding: "The cooling effect has been proved to be helpful for increasing module generating capacity. All comparisons up to now are based on assumptions; after our pragmatic verification, we think the increasing of module efficiency would not reach 10%."

Sungrow's SG2500-MV central inverter solution was deployed at the floating plant, featuring the integration of the inverter, the transformer and the switchgear, as a turnkey station. In addition, the combiner box SunBox PVS-8M/16M-W supplied by Sungrow was customised for a floating power plant's applications, enabling it to work in a stable condition in such an environment with high levels of humidity and salt spray.

Most significantly, this was also the first time that a central inverter had been used in a very large, utility-scale floating solar plant. "A lot of the equipment in this PV plant, including the central inverters and transformers, are all actually floating above the water, so not only the module set that everyone can see but most of the core equipment," explains Renxian. "In this way we can save a lot of cable use."

Sungrow also set up its own transmission lines from the floating matrix to the booster station and then to the grid-connection point. Power from the project is also being sold to utility State Grid Corporation of China (SGCC).

"The banks are willing to provide us financial support because even though the ROI of these floating plants can be a little bit lower than the other ground-mounted PV plants, this kind of plant doesn't have a real estate problem," adds Renxian. However the firm has not given any indication of the overall costs of the investment.

O&M on water

The number of construction employees working on site at any one time oscillated from between 90 to 150 people. Meanwhile, around 20 people are assigned to performing the operation and maintenance (O&M) of the equipment, with regular water area weeding and panel cleaning required.

Rather than water being a hindrance to effective cleaning of the panels, Fuqin says that the power station itself being afloat on water can be used to the O&M team's advantage. Water is of course readily available and can be easily collected for cleaning purposes. For this to work though, Sungrow had to design in at early stages an O&M dock, laneway and pedestrian path; in other words there are specifically sized gaps between the bases to allow for water collection and access. However, there is generally less dust on these floating systems than ground-mount projects so even the necessary frequency of cleaning is reduced.

"We have equipped the project with a complete monitoring system," Fuqin adds. "By equipping different kinds of automatic alarm monitor facilities such as cameras, GPS system, dip angle monitor system and water level monitor system, we can increase the efficiency and facilitate the troubleshooting progress."

Renxian says that robotics will also be

used for some of the cleaning process, but has not provided any more detail.

Another world record

While a 20MW floating system in the same Chinese region had been the largest operating plant since early 2016, and as if the 40MW giant wasn't enough, Sungrow is already well under way in building another 150MW floating solar project in the same area. This will again be the world record in terms of capacity on completion, which is expected before year-end.

"The on-site booster station and delivery circuit of the power station is about to be complete, and the construction of the over-water part has already started," explains Fuqin.

Future floaters

The lessons learned from such enormous projects are manifold and will pave the way for Sungrow to establish itself as one of the top floating solar players going forward.

"By continuously summarising, adjusting and perfecting our blueprint, we successfully made our project more practical, safe and economical," says Fuqin. "Also, we have collected and studied much experience in the aspect of construction, and these experiences could help avoiding detours in similar future projects, increasing efficiency greatly."

Looking worldwide, he believes that all countries with abundant solar resources and suitable water areas would have good potential for floating solar systems, such as many Southeast Asian countries, as well as Japan and India. Indeed, Sungrow is hoping to offer its complete floating PV knowledge worldwide, having learned key lessons from its initial projects. It already has interest from customers in Japan and Southeast Asia with its offering of a total solution including the integration of the base and the inverter on the floating system.

Exponentially increasing activity on other floating projects across the globe suggests that this segment offers a huge opportunity for the solar industry and governments that are lacking in available land space. ■

Floating solar sets sail

The completion of Sungrow's system has coincided with the announcement of a number of other innovative floating solar projects:

Ciel & Terre starts building 70MW floating PV project with LONGi mono modules

France-based floating PV specialist Ciel & Terre (C&T) International has commenced con-struction of a 70MW floating solar plant for Chinese state-owned developer CECEP on a clay quarry lake in Anhui Province, China. Once compete it could be the world's largest floating solar plant, but only briefly, because Sungrow is also due to complete its 150MW floating plant before the end of the year. C&T's 70MW project will include monocrystalline modules from Chinese manufacturer LONGi Solar (formerly Lerri Solar). Central inverters will be put on stilt platforms on the shoreline of the quarry lake so as not to interfere with neighbouring farm activity.

Hanwha Q CELLS developing 80MW rotating floating solar project in Korea

Hanwha Q CELLS has signed an agreement with Korea Hydro & Nuclear Power (KHNP) to build an 80MW rotating floating solar project on a reservoir in South Korea, which would be the largest of its type in the world. Hanwha Q CELLS Korea would be responsible for supplying the PV modules for the project, while EPC work would be carried out by Hanwha Solar Power under Hanwha Chemical in collaboration with Korean floating solar specialist Solkiss. Solkiss had developed a solar powered rotating technology for a complete floating solar system, acting like a conventional single-axis tracking system, generating up to a further 20% in electricity generation.

Korea Rural Community Corp. to develop 280MW floating PV portfolio

The Korea Rural Community Corporation intends to develop a 280MW portfolio of floating PV systems in South Korea. The portfolio will feature three PV systems that will be developed in three man-made lakes located across the country. The three installations will be located in South Chungcheong and South Jeollanam provinces – featuring a pair of 100MW projects and an 80MW site in Goheung county. The three installations are expected to be completed by 2019.

Floating solar pilot projects in the Netherlands set sail

A Dutch consortium of government agencies, R&D facilities and solar companies have launched two of four pilot floating solar projects on the Slufter on the Maasvlakte, a water region used for contaminated harbour dredging sludge. The four different floating solar pilot projects will be overseen by the National Consortium Zon op Water (Floating Solar), which includes ECN and TNO working together in the Solar Energy Application Center (SEAC) and is aiming to demonstrate the feasibility of floating solar in rough water conditions. Two systems were launched on the Slufter on July 14 from Texel4Trading and Wattco, which has partnered with France-based floating solar pioneer, Ciel et Terre, using its 'Hydrelio' sys-tem. The two other pilot systems from Sunprojects and Sunfloat are expected to be launched in the same stretch of water soon. Subject to the trials, plans could include 100MW of floating solar systems on the Slufter.

Istanbul municipality launches first floating solar plant in Turkey

The first floating solar (FPV) power plant in Turkey officially became operational on 4 August 2017 as part of a testing phase that could lead to a significant number of systems installed by the Istanbul Metropolitan Municipality (IBB) on reservoirs, lakes and dams. Istanbul Water and Sewerage Administration (ISKI) with Istanbul Energy commissioned the 250kW testing system, located on the Büyükçekmece lake, near Istanbul, deploying a total of 960 multicyrstalline (60-cell) modules of 260W (STC). Two separate FPV systems are being evaluated.

First ever hydro-electric and floating solar project operating in Portugal

Ciel & Terre International has collaborated with Portuguese energy firm EDP (Energias de Portugal) Group to design and build the first floating solar project at an existing hydro-electric power station at a dam located at the mouth of Rabagão river in Montalegre, Portugal. Working with EDP subsidiaries, C&T developed a 220kWp floating solar power plant, using 840 solar modules on its 'Hydrelio' mounting platform, occupying an area of around 2,500m^2 and cost around €450,000. The pilot project was initiated by EDP back in 2015 and has been operating since the end of November 2016. C&T expects the plant to generate 332MWh of electricity in its first year.

Solar life-cycle management:

Is the spectre of lost returns holding solar energy back?

Data | The collection of inaccurate data at any point in the life cycle of a solar plant will undermine almost every aspect of the investment accounting. Mark Skidmore, Samantha Doshi, Matthias Heinze and Christos Monokroussos from TÜV Rheinland discuss the importance of precision data gathering in mitigating risk for builders, operators and financiers

The global PV power plant fleet now exceeds 100GW and is projected to reach terawatt levels within the next 10 years. Where the demand for installed power increases, the need for cost reductions follows closely behind, which calls for better methods of product quality surveillance. As aging PV fleets enter cycles of sale and re-acquisition, and subsidies decrease and tax incentives fall, secondary buyers must evaluate their asset's ability to fulfil their return on investment (ROI). This raises the value of assessing the precise financial performance of a PV system. With new energy trading mechanisms, the reliance on precise data and its complexity will only increase. In this paper the general principles of precision data gathering are described, and EL imaging in particular is highlighted.

"With new energy trading mechanisms, the reliance on precise data and its complexity will only increase"

Background

Reductions in capital costs and improvements to system efficiencies for solar power plants have spurred a dramatic growth in solar energy. In Q1 2017 the USA added 2GWdc of PV power, following an unprecedented year of more than 15GWdc installed in 2016 [1]. The industry is poised to continue this growth at a rate of 7.2% per year until 2050 [2].

Tax incentives have been a key motivating factor for investing in solar, so much so that often first owners are eager to step away from a project once the tax benefits have been fully utilised. This means that a change of ownership is likely to occur within a time frame in which the system is still new enough for potential failures to be hidden from secondary buyers.

It has become common practice, supported by mediocre independent engineer (IE) reporting, to optimise systems for an initial favourable performance ratio, which often means that DC watts are installed beyond actual need. The performance ratio is in this context is often understood to be simplified (i.e. not corrected for VAR and inverse availability, as defined by the IEC standard) as:

$$ACPR = \frac{\left(\sum_{1\text{Year}} P_{\text{predicted}}\right)/\text{kWh}}{\left(\sum_{1\text{Year}} P_{\text{actual}}\right)/\text{kWh}} \quad (1)$$

This performance ratio has all the elements of uncertainty (i.e. not just P90) associated with it that affect a power plant, which investors may not be aware of.

DC leveraging has the 'benefit' of spreading fixed system costs over a broader wattage base at the expense of overinvesting, along with perhaps an initial AC performance ratio (ACPR) greater than 1. The unintended consequence of this DC leveraging is that it masks performance defects by exceeding production targets, or through, for example, inverter clipping as shown in Fig. 1.

For the first short-term owner, the excess capacity creates a 'clipping bank account', which yields extra capacity that widens the shoulders on the production curve (blue clipping curve in Fig. 1). This helps ensure that the plateau (in case of clipping or contractually limited feed-in) is as flat as possible for as long as possible. However, as the system degrades with time, the clipping bank account gradually draws down. The extent of the degradation is further hidden through AC performance, as most plants do not employ string monitoring, and the only view of the DC performance is through AC performance.

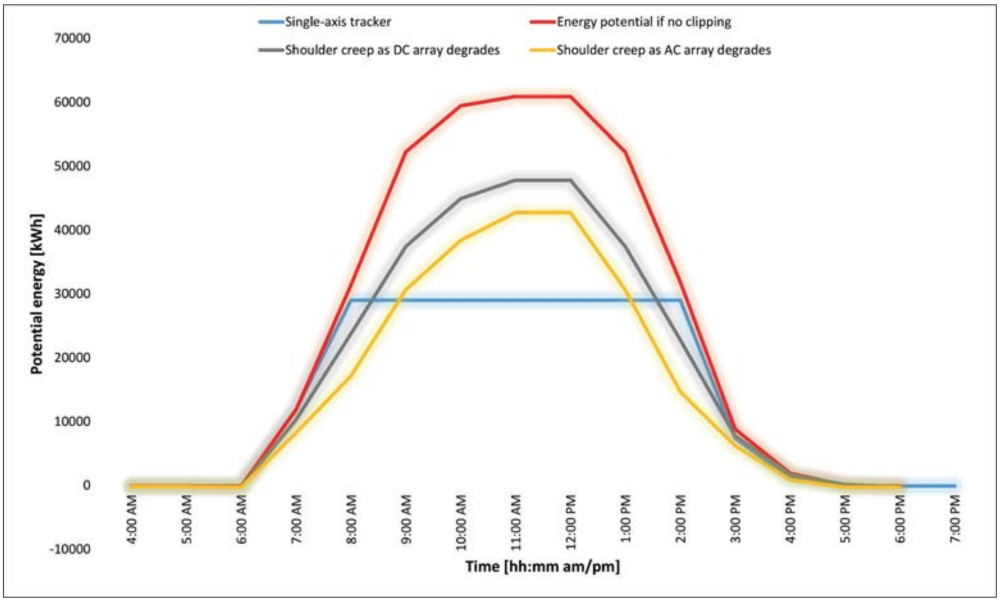


Figure 1. Defect masking through increased DC/AC ratio

Oftentimes the DC performance is being compared with weather data, but most on-site weather stations, if available, are uncalibrated and inaccurate over time. Note that calibration uncertainty is one of the factors affecting *u*PMAX, the overall measurement uncertainty:

$$u_{\mathrm{PMAX}} = k \cdot \sqrt{u_1^{\,2} + ... + u_N^{\,2}} \quad (2)$$

where, u_i = standard uncertainty for uncertainty source *i*, and *k* = coverage factor (*k* = 2 for 95% confidence interval).

"Bad data has the potential to invalidate warranty claims on underachieving components"

For secondary buyers, it becomes imperative to accurately determine the physical and electrical health of their assets in order to ensure that their investment can meet return expectations, reduce financing cost and minimise capital deployment. The potential owners must be able to vet power plants through sound IE due diligence assessments, so that they can leverage price reductions and premiums on the basis of quantified underperformance.

Calibration as an asset

The challenges involved in collecting data begin from the moment the site is selected, and continue through design and component selection to installation, commissioning and O&M. Thus, from mischaracterisation of component performance, defective discovery tests and inappropriate pre-installation, to inaccurate measurements of the system's effectiveness during periodic assessment, bad data has the potential to invalidate warranty claims on underachieving components, as well as overvaluing (or undervaluing!) a system upon secondary sale.

By way of example, TÜV Rheinland was recently called in by a project owner who was preparing to file a warranty claim against a manufacturer in the hope of curing financial shortfalls from a system performance deficit. The owner had already conducted tests with a third-party subcontractor in order to characterise, on a percentage basis, how much the solar array was underperforming in respect of the warranty; TÜV was tasked to validate these results by carrying out coincident, same day, same time measurements. Upon retesting with calibrated and spectrally matched instruments (as opposed to the uncalibrated, spectrally unmatchable instruments that had been used by the subcontractor), TÜV measured 10% lower irradiance levels than those indicated in the initial tests (Fig. 2). If the sensor believes that the irradiance is higher than what the module actually absorbs, the module performance will appear lower than it actually is.

From lab to field – more data, accurate data, appropriate data

Defects in power plants are not only caused by defective components but also built into power plants, despite the

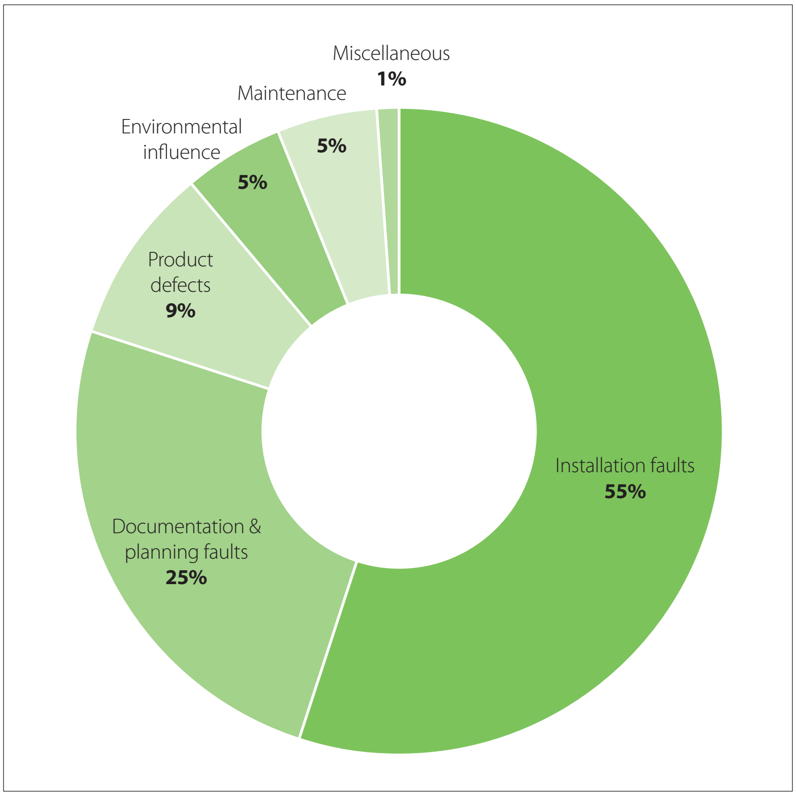


Figure 3. Percentage of serious defects noted by category

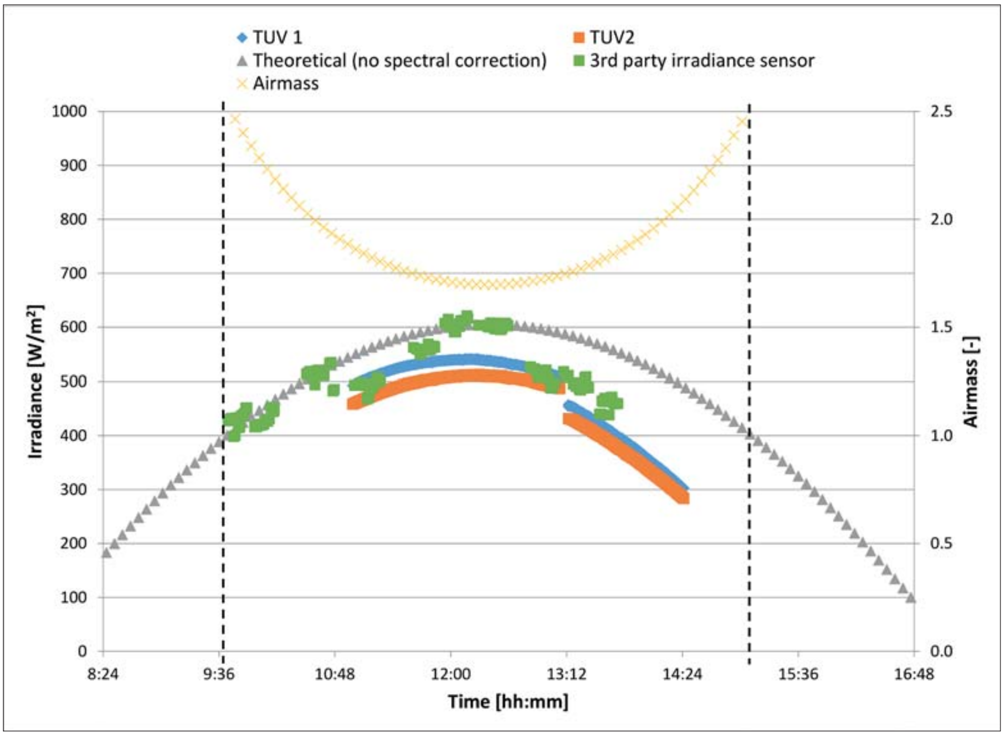


Figure 2. Measured plane-of-array (POA) irradiance comparison

best efforts of all parties involved. Many of the defects are simply not visible to the naked eye or cannot be derived via simple measurements. The results of a TÜV internal study from 2014 to Q1 2015 determined that 30% of power plants showed serious defects, while more than 50% of these defects were attributable to installation errors (Fig. 3).

Product quality is affected by the fiercely competitive markets, low financial recourse, personnel fluctuations, tight commissioning deadlines, indifferent IEs and supplier issues. These might result in abbreviated planning and installation using inexperienced sub-contractors, which in turn causes defects being built directly into solar installations, masked by the aforementioned clipping bank account.

Even those who think they are choosing the best products are bound to be disappointed with systematic defects originating directly from the manufacturers or as a result of improper handling on site. As the secondary market matures, current and future system owners must understand the status and value of systems looking forward. Installation contractors must employ accurate data to defend themselves against disputes from claims of nonvisible damages to defective components.

Especially for modules, it is vital to characterise the complexities of degradation. This way, poor-performing modules can be removed before they impact on the ongoing output, or, at minimum, their state documented to prevent future litigation. Since early-life degradation is often a very subtle phenomenon, solar industry stakeholders tend to believe it cannot be detected through typical outdoor monitoring. This perception is being disproved in the market, as field-testing services are now available to detect early-life degradation issues at appropriate time intervals and sensitivity levels, and with meaningful measurement accuracies. The testing of modules in the field means that results can be acquired without moving modules from their in situ locations.

One predictive method – electroluminescence (EL) imaging – takes advantage of the radiative interband recombination that occurs among excited charge carriers in solar cells. To obtain the image, the testing contractor operates a solar module as a light-emitting diode, so that it can detect the emitted radiation with a sensitive Si-CCD camera. For EL images, the solar cells are supplied, via their metal contacts, with a defined external excitation current while the camera takes an image of the emitted photons.

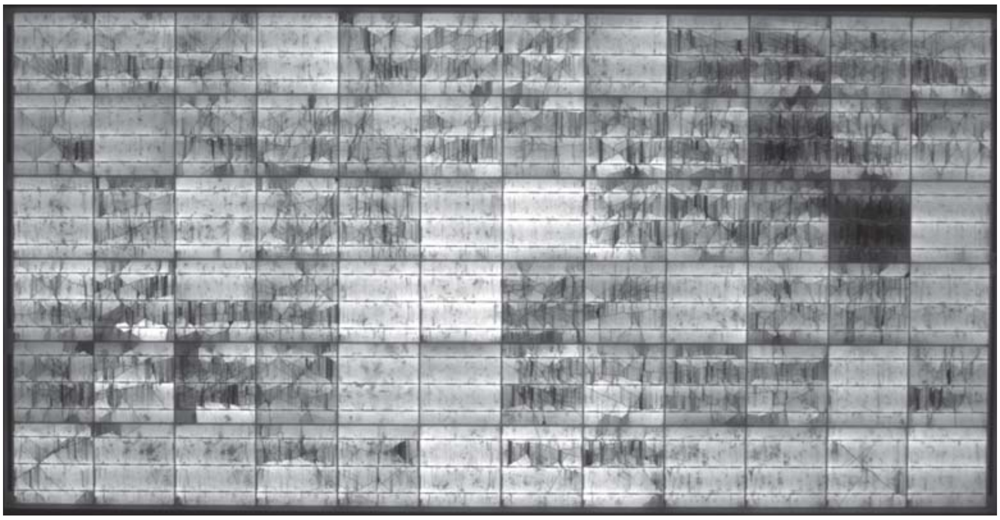


Figure 4. Field EL imaging, with modules installed in situ

As a general rule, damaged areas of a solar module will appear darker than fully functional areas (Fig. 4). EL techniques provide a much higher resolution than that produced by infrared (IR) images, and reveal many details, such as:

- Microcracks
- Bad finger contacts
- Electrical shunts
- Interconnection and solder faults
- Resistance faults
- Fragments in broken cells
- Electrically separated cell areas
- Grain boundaries
- Crystallisation faults in cell material

Overall, when deployed properly, baseline and periodic EL images allow system owners to finely chart and characterise dips in module performance. They can accurately determine if production shortfalls are the result of manufacturing defects or originate from damage that was inflicted after delivery to the installation site, or if the shortfalls are merely expected fall-off. With the use of EL imaging in combination with lot inspections at the manufacturing site, transportation issues become equally visible.

"The production of a traceable product-quality lineage provides protection and accountability"

In a recent case, TÜV Rheinland used EL imaging to conduct pre-installation module testing for an EPC client. The tests revealed that more than 40% of the client's modules had arrived on site with a defect which was otherwise imperceptible via alternative test methods. Moreover, these defects were of such a nature that they would worsen over time and prematurely accelerate the system's expected performance decline, which may conceivably be non-linear. The EPC was able to cease installation activities and initiate a replacement of the damaged product by the manufacturer.

Whether you are a component manufacturer, system owner, or system operator, the production of a traceable product-quality lineage provides protection and accountability, fundamentally establishing a strong level of trust among all parties. If a financier knows that such a lineage can weed out underperforming components early, and recoup losses in instances where underperformance can be traced to specific manufacturing defects, they are going to be more inclined to continue investing. If manufacturers know that they are not going be held responsible for on-site damage or design failure they too can breathe easier. Financial interests are protected for all stakeholders by involving a third-party process at critical milestones that uses scientific methods to produce standardised data across the value chain.

Managing for long-term returns – a function of measurement scope

Once solar modules have been fully deployed and are operational in the field, the focus for owners and investors shifts primarily to billing-meter data.

These owners most likely contract an asset management company to collect data about ongoing performance of the project. The data gathered relates to daily operations, but may also be generated from periodic inspections and maintenance. The questions are: how is this data used, how is it collected and who collects it? For example, system commissioning is often performed by the installation contractor, who is typically not motived by the accuracy of the data, but rather by the fact that the measurements trigger the next milestone payment. Along with this, installation contractors are not trained in accurate repeatable measurements and the applicable standard IEC 62446, nor are they familiar with calibration and factors affecting accuracy. The outcome is not just inaccurate data, but worse – non-comparable data (e.g. data with unknown accuracy). Generally, measuring the AC meter and cursory DC measurements does not provide insight into the performance or plant status. Yield or complex performance ratio – taking into account all environmental factors (e.g. soiling), equipment factors (e.g. degradation), business factors (e.g. demanded performance reduction IEC 63019) and technical complexity – is a necessary metric for measuring and optimising performance as well as maintaining the value of the asset.

The purpose of baseline information – continuous, compatible data – is that it can be used in a comparative manner to assess and predict degradation and future performance. In the case of solar modules this is done specifically to monitor warranted performance. For this to happen the module performance ratio, corrected for environmental (e.g. temperature and irradiance) and device factors (e.g. specified degradation), has to be taken into consideration. Other components (e.g. inverters) must be equally vetted for lifetime performance and should be subjected to continuous and periodic measurement. Remote monitoring on its own is therefore not sufficient: verifiable data, along with all performance factors and accuracy data, must be collected using standardised methods (e.g. IEC 61724) and recorded at milestone intervals.

No system owner will be able to test every module across its project (or projects), because of the high cost and long lead time: thus statistical sampling is essential for the propagation of good data [3]. As an example, advances in EL imaging technology enable owners to be more precise with defect detection, as well as allowing them to investigate larger sections of their arrays more efficiently. The use of EL imaging provides for a much greater sample size and ultimately yields a more accurate, and more statistically significant, representation of site performance than was possible just a few years ago.

With a larger scope of data at their disposal, market stakeholders have the ability to establish a whole new set of business goals and outcomes, and make more informed decisions.

Improve plant output, in real time

Better data will lead to improved operations. The first area affected will undoubtedly be the improvement in O&M efficiency, as well as the likely reduction in O&M costs on the basis of the accurate and timely data employed using methods such as cost priority number (CPN) to trigger cost-optimised O&M. This enhanced data and increased operational efficacy will surely be selling points in the secondary market by reducing the risk to new buyers and adding a measure of control that was not previously available.

Improve plant longevity

With a greater volume of functional data in hand, owners are better positioned to identify system weak points as well as system strengths. With independently conducted periodic milestone measurements of key system elements (inverters, modules, etc.) and continuous monitoring, CPN-based maintenance becomes an important tool for cost reduction and performance optimisation. As data patterns emerge, pending failures become manageable.

> "Documentation and irrefutable, precise data reduce doubt and uncertainty"

O&Ms prove their worth

Finally, in recent years owners and investors have thrown down the challenge to O&M providers to provide better communication about the value they are adding to projects [4]. O&M companies are not certified or trained to any central overarching standard. They are typically not subjected to process or data validation, as in the case of their construction counterparts. This all needs to change. Owners will be frugal with O&M dollars if this data is available to them, independently obtained, compatible and timely, using IEC (or IECRE) standards. O&M performance will not be measured relative to predicted performance, but will be flexible and based on precise and sufficient data. O&M contracts have often been signed with the contractor who built the system, a fundamental conflict of interest if used by the O&M as a way to recoup income that may have been lost in the construction negotiation process.

The key to communication lies in data about whether, and how, the operator has made a noticeable difference to plant performance and energy yield. It is not just about taking actions to improve yield, however: operators have to prove what they really did. The quality of documentation – the status, not just plant performance – has become an important metric in the value chain, and it is data that feeds this burden of proof.

A qualified IE will provide the trust to deliver the data needed for all stakeholders to interact in the project, continually and at critical life-cycle milestones, using standardised processes and measurement methods and precise, compatible data.

Risk mitigation in context

In order for investors, owners and other solar stakeholders to achieve long-term value, the focus will always be on narrowing down causal factors for performance loss, removing all sense of uncertainty, and mitigating risk.

Risk takes different forms for different stakeholders. For instance, EPCs and installation companies need to manage short-term risk; not only do they need to safeguard against initial performance shortfalls, but they also need to prove that their handling of the product did not alter the state of the product in any way. Documentation and irrefutable, precise data reduce doubt and uncertainty.

System owners and investors, on the other hand, need the system's output to not only cover and exceed a defined term of debt payments, but also produce maximal returns once the investment is free and clear.

The unifying factor for mitigating both of these risk profiles is to move away from the 'check the box' mentality that has become the norm for system testing. Solar products must already be certified *safe* by nationally recognised testing laboratories (NRTLs) [5], and the question deserves to be asked: what does the industry stand to gain if it holds itself to the same principle when testing for system quality and performance as well?

If manufacturers, owners, operators and investors all operate from the standpoint that the component life-cycle testing process must be calibrated, traceable and standardised, then trust among industry actors and lifetime value can each be unleashed to its true potential. The impact of bad data on operations, cash flow and ROI is just too great a risk to accept.

The industry has laid the groundwork with the SGIP 'Orange Button™' [6] and IECRE [7] standards, and so it is perhaps time for the industry to employ all the tools at its disposal.

Authors

Mark Skidmore has over 14 years' experience in the solar industry, and over 18 years' experience in the construction contracting industry. A registered professional electrical engineer (PE), certified energy manager (CEM) and NABCEP solar professional, he holds a university degree in mechanical engineering and is the solar plant services manager at TÜV Rheinland, Tempe (USA).

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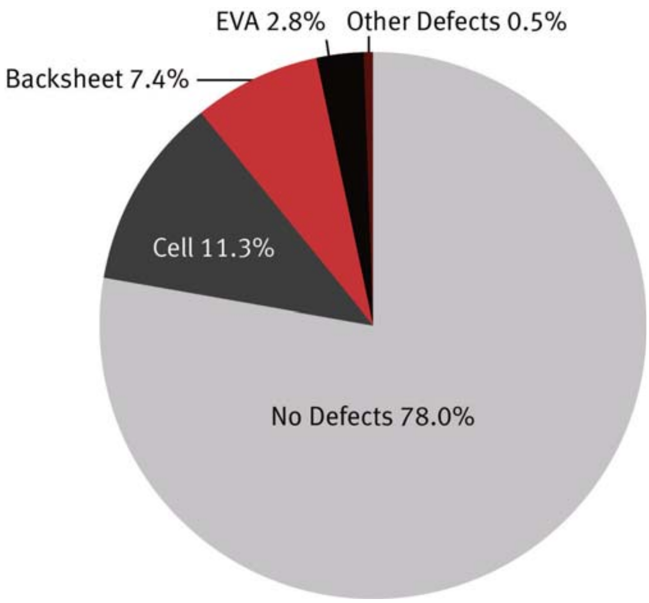
New solar panel backsheet testing standards needed as the PV market grows

The photovoltaic power market has grown at an impressive rate in the past several years, marked by new utility-scale projects in emerging markets and rooftop PV installations in mature markets. Utility-scale growth is occurring mostly within the world's sunbelt regions, i.e., Africa, the Middle East, India, Southeast Asia, Latin America, and the western US, while the rooftop segment is dominant in Europe and Japan.

Falling system prices have been a key driver of this recent growth and competitiveness, but upfront costs are only one part of the equation for long-term profitability within the solar power industry. Maximising any given system's cumulative power output over its lifetime is critical to lowering the levelised cost of electricity (LCOE) and maximising investment returns. The less reliable the system, the less certain the investment. Consider this correlation: when a panel's expected lifetime is reduced from 25 to 20 years, the LCOE increases by over 20%.

Solar panels are exposed to significant environmental stresses over their lifetimes, including UV radiation, extreme temperatures, thermal cycling and humidity, usually in combination and under load. The current International Electrotechnical Commission (IEC) standards for solar panels are primarily based on a set of accelerated testing protocols originally designed to track panel failure after manufacturing (infant mortality) and not to predict the longer term performance of the panel over its expected lifetime

The current standards also provide no segmentation by climatic zone or by application, and the environmental stresses panels are subjected to can in fact vary wildly from location to



Data from 190 installations surveyed by DuPont in North America, Europe & Asia Pacific from 45 module manufacturers, >450 MW, > 1.9 MM modules (2016). Range of exposure: from newly commissioned modules to 30 years in service; from hot to cold climates.

location. For instance, the average temperature in Riyadh, Saudi Arabia, is 27°C, whereas the average temperature in Munich, Germany, is only 10°C, with about nine times the amount of precipitation.

Application type is another important factor; a panel in a ground installation operates at an average temperature of 25°C higher than ambient air temperature, whereas rooftop panels operate at about 15°C higher than ground.

The importance of the backsheet

A solar panel's backsheet is especially vulnerable to the effects of weathering and repeated stress. The backsheet adhesion, UV resistance and mechanical strength are all critical factors to its longevity, and by extension, the longevity of the entire panel.

The solar industry is witnessing higher panel failure rates as unproven, poorly performing backsheet materials appear on the market. Cracked and damaged backsheets can have significant implications for a panel's operational condition and safety, i.e., they can cause the panel's electrical insulation to fail, posing a safety hazard and a potential ground fault.

Data from a global field survey of solar panels, conducted by DuPont, showed that 22% of panels studied were affected by some form of visual degradation with an average of four years in the operation. The DuPont survey also found that the top two components showing defects were cell and backsheet, with cell accounting for 11.3% and backsheet accounting for 7.4% of defects, in the panels studied.

The rate of backsheet degradation was correlated to the climatic zone and installation application type: the higher the temperature, the higher the rate of degradation. The DuPont study found that respectively 26.4% and 26.3% of backsheet degradation occurred in hot and arid and in rooftop solar applications, more than three times the average backsheet degradation.

The rate of backsheet degradation is also influenced by the panel mounting configuration. Almost twice as much degradation occurs in rooftop applications as in ground installations, due primarily to differences in thermal stress. On average, the operating temperature of rooftop installations is 15°C higher than that of ground installations. The DuPont survey found that backsheets in rooftop applications demonstrated more than three times as much degradation (26.3%) as those in ground installations (7%). Yellowing of the backsheet was the most common defect observed, and indicates the loss of maximum elongation of the polymer materials, which causes brittleness, increasing the risk of cracking under mechanical stress.

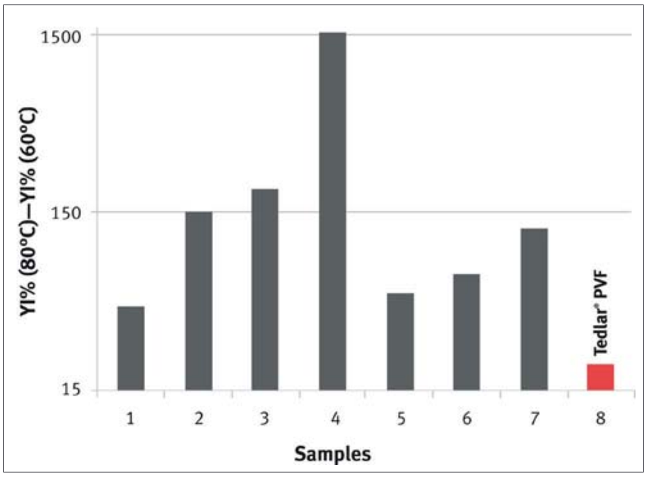
Results of the Fraunhofer Study

The Fraunhofer Institute for Solar Energy in Freiburg, Germany, conducted round-robin tests on solar panel backsheets for analysing the effects of UV stress and at different temperatures.

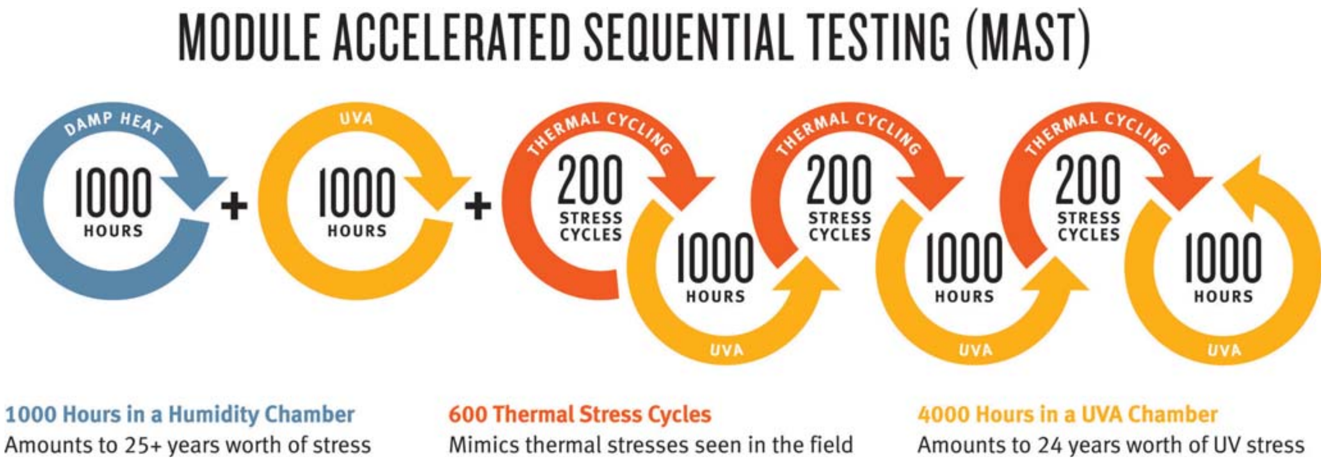
The key finding in the Fraunhofer study regarding yellowing sensitivity was that yellowing starts at UV wavelengths of less than 360nm and that different backsheets degrade differently with UV exposure. Fraunhofer observed that yellowing only requires the presence of UV intensity to trigger degradation, and, as noted in the DuPont field observations, it shows a strong dependence on temperature.

In DuPont's field observations, the rate of backsheet degradation increased over time with all backsheet materials except for Tedlar® polyvinyl fluoride (PVF). In addition, the rate of degradation was very low in older photovoltaic systems in the DuPont field survey, because most of those featured Tedlar®-based backsheets.

The survey also found that Tedlar® PVF backsheets had a



Backsheet yellowing of different types of materials – exposed to a constant amount of UV. Variation of yellowing is measured at two different temperatures (60°C and 80°C).



very low rate of degradation in all climatic zones and application segments, much lower than all other backsheets. Fraunhofer, likewise found that there was no yellowing in Tedlar® PVF backsheets, while yellowing was very high in PET-based backsheets.

The need for better testing standards

In the absence of reliable quality assurance standards, field observations are invaluable for determining best practices for solar panel materials selection. However, it has been clear for some time that new accelerated testing protocols are needed to mimic the forms and extent of materials degradation observed in the field. Existing IEC quality standards are not stringent enough to differentiate between the quality of different backsheet materials.

Developing an alternative accelerated testing methodology rests on the rationale that tests need to match actual degradation observed in the field. Until now, lab testing methods haven't been sufficiently demanding to demonstrate the impacts of long-term aging on PV modules.

With this in mind, DuPont has introduced a test method called Module Accelerated Sequential Testing (MAST), which consists of a series of stress tests applied to a single module. The tests follow this general sequence: exposure to damp heat, followed by repeated UVA exposure and thermal cycling.

DuPont proposes sequential MAST testing to help replicate the main forms of degradation affecting backsheet materials. The MAST protocol combines the most critical stresses of the operating environment – UV irradiation, humidity, temperature and temperature cycling. The levels of these stresses are taken from field exposure levels and analysis of degradation of fielded modules.

The MAST method more accurately predicts the long-term performance of PV module materials than conventional test methods, and the results MAST produces are more consistent with field observations. MAST testing utilises the critical stresses from the field and matches results from the field for the major backsheet types – PET, PVDF, polyamide and Tedlar® based backsheets.

Addressing the problem of backsheet degradation

As noted earlier, the PV market is growing especially fast in higher-temperature climatic zones and in applications that can be harmful to panels, e.g., rooftop, and DuPont's field observations have demonstrated that the rate of degradation is significantly higher in hot and arid climates and on rooftop applications.

The backsheet sub-component is particularly sensitive to environmental stresses, with a rate of degradation that increases significantly with thermal stress and UV exposure. Yellowing is a sign of degradation that affects a backsheet's mechanical integrity. Cracking and delamination are particularly critical defects—raising the likelihood of a loss of electrical protection and increased risk to personal safety—and, when observed, imply the need for panel replacement. A DuPont case study has shown that the economics of replacement can have an even greater impact than that from power loss over time.

Solar panel installers can mitigate these risks by selecting the most robust materials with respect to UV and thermal stress factors. Tedlar® PVF has proved to be the most dependable backsheet material through the years, as shown in the global field surveys conducted by DuPont. This observation was supported by the Fraunhofer third-party study, which demonstrated that Tedlar® PVF based backsheets are the most resistant to yellowing and the stress of higher temperatures.

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Detecting cell cracks and other PV module failures with UV fluorescence

Module failure | Defective modules causing power losses in PV systems need to be easily detected with a rapid and cost-effective inspection method. Researchers from Institute for Solar Energy Research in Hamelin (ISFH) explain how UV fluorescence of module encapsulation polymers is used for the fast detection of module failures under daylight conditions without disconnection, allowing the inspection of up to 200 modules in an hour during daytime

Finding damaged modules impairing the PV system performance: a cost-intensive issue

Detecting PV module failures to determine the origin of a power loss in an operating PV system is a key issue for the sustainability of that system. To keep operating costs as low as possible the diagnostic methods need to be rapid, non-destructive, allow for a flexible service time and no shutdown during the inspection. Whereas single string I-V curve automated monitoring allows for the localisation of a damaged array, a further technique needs to be employed to identify the module(s) causing a possible power loss.

Commonplace techniques for the detection of PV module damage are the infrared thermography (IRT) and the electroluminescence method (EL). Electroluminescence is usually employed in the laboratory and requires the electrification of a PV module with a current at half or equal to the nominal short circuit current (Isc), which for usual commercial modules implies using a power source on the field with a current output of ~8A @ ~30V per PV module. The EL image is captured in the range of 1000nm to 1200nm with a camera [1]. For the use in the field, whole strings of modules are electrified at once to reduce the rewiring effort, thus requiring a more powerful power source. The capture of electroluminescence images in the field is usually done overnight, and recent developments in unmanned aerial vehicles (UAV) allow for a fast capture of the arrays [2,3]. The use of an adequate camera such as an InGaAs detector [3] opens the potential to capture electroluminescence images during the day in the field.

The throughput of this method is mostly limited by the rewiring effort. However electroluminescence images reveal the current path in the solar cells and thus allow for the detection of cracks in the solar cells and an estimation of the criticality of them. Furthermore, EL reveals interrupted cell interconnection ribbons, short circuits and cell shunts. The infrared thermography reveals temperature inhomogeneity and allows for the detection of hotspots caused by shunts as well as cracked cells or short-circuited bypass diodes [4]. This technique is easier to implement than EL as it does neither require the disconnection of the modules from the rest of the PV system, nor their electrification with an external power source. Nevertheless, the modules need to be in operation under a sufficient solar irradiation (>600 w/μ^2) in order to induce detectable thermal features.

Figure 1. Fluorescence outdoor inspection system (FLOIS) in operation on a PV generator

Principle of UV fluorescence measurements of EVA

The UV fluorescence of ethylene vinylacetate (EVA) used as pottant in PV modules has been investigated as a phenomenon parallel to the degradation of EVA polymer and its additives. The fluorophores' excitation wavelength lies in the near UV range between 300nm and 400nm. The emission spectrum is in the visible range, mainly between 400nm and 600nm. It has been shown that the excitation as well as the emission wavelength increase with the duration of the weathering of a module [5]. In the presence of oxygen and light, the fluorophores are degraded. During field exposure the appearance of fluorophores in the modules is hindered in places where oxygen can diffuse through. Typically oxygen diffuses through the backsheet and through the EVA between the cells. Thus the fluorophores accumulate only in the material encapsulated between the silicon solar cells and the glass. A potential application for the detection of cell cracks has been mentioned by King [6], and used later in the lab by Schlothauer [7] and on a larger scale PV plant by Köntges [8]. When a cell is cracked, oxygen can diffuse through the crack and reach the material in front of the cell, leading to an extinction of the fluorescence on the crack surroundings. The degradation process of the encapsulation material leading to the formation of fluorescent compounds is accelerated by higher temperatures.

UV fluorescence inspection system

We built at ISFH a mobile UV fluorescence outdoor inspection system (FLOIS) consisting of a lightweight aluminum chassis covered with an opaque cloth. The chassis can be dismounted for transport and is adjustable to the size of the common commercial 60-cells modules. The top of the chassis is equipped with UV light emitting diodes (LEDs) and a digital camera. The images are processed and saved by a laptop contained in a backpack along with a lithium battery which supplies the UV LEDs and the camera.

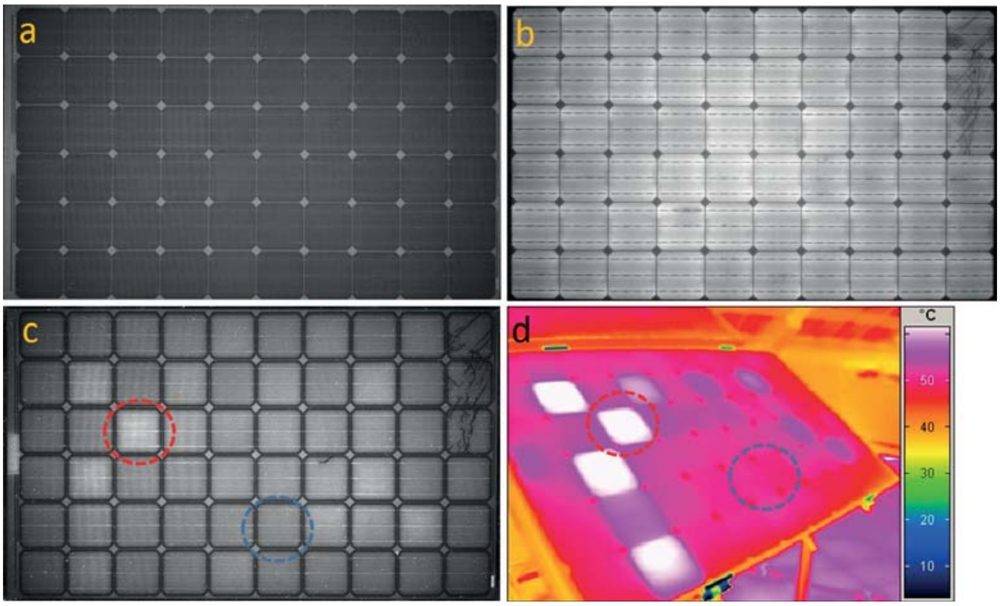

Figure 2. Fluorescence (a) and electroluminescence (b) images of a transport-damaged new PV module before sun exposure. Fluorescence image (c) of the module after 70 days of sun exposure in short-circuit and infrared thermography image (d) of the module under an irradiance of 780W/m² [9]

To perform a measurement the chassis of the inspection tool is simply laid down on the tested PV module for the duration necessary to capture the dark field image and the fluorescence image – usually about five seconds, depending on the integration time chosen by the operator. The dark field image is subtracted from the image taken under illumination in order to suppress the noise generated by the light ingress from the backsheet and from the module edges in the eventuality of an imprecise positioning of the hood. The operator triggers the measurement and checks the images in real-time with a smartphone attached to his forearm. As the fluorescence emission is in the blue-green wavelength range, only the blue and green channels of the pictures are processed. To reach the upper rows of PV modules on a rack system, the measurement device can be equipped with telescopic handles. An image of the device in operation is shown in Figure 1.

In the following, we show the application potential as well as the limitations of the UV fluorescence for the detection of module failures. We show how to interpret the features seen in the UV fluorescence images and compare them to the same features from the EL and IRT images.

UV fluorescence image features

We show here an example of the temperature dependence of the fluorophore formation in a module. Figure 2 shows (a) a fluorescence and (b) an electroluminescence image of a new module with three cracked cells. At this stage nearly no UV fluorescence is detectable (Figure 2a). Figure 2c shows the UV fluorescence image of the module after being installed outdoors in short-circuit mode for eleven weeks in summer.

After 70 days of exposure, the module accumulated a sun irradiation of about 360kWh/m². The fluorescence (Figures 2a and 2c) and electroluminescence (2b) images are taken in the lab at a temperature of 25°C. An IRT image is taken outdoors under a sun irradiance of 780W/m² at an ambient temperature of 28°C [9].

The first thing to note on the UV fluorescence image 2c is the typical black framing around the cell edges showing the fluorescence-quenching effect of oxygen diffusing through the backsheet and over the edges of the cells. Furthermore, the cracks in the cells on the upper right corner of Figure 2b and 2c also appear black on the fluorescence image due to the same quenching effect.

The comparison of the fluorescence image with the infrared thermography image of the module reveals that the encapsulating material shows a higher fluorescence intensity where the cell operating temperature is higher. To put this effect better in light, we show in Figure 3 the fluorescence intensity as function of the outdoor exposure duration of the two marked solar cells in the Figures 2c and 2d. During IR measurement, the cell rear side temperatures are measured by thermocouples to respectively 56°C and 65°C. The fluorescence intensity as function of accumulated global irradiation on the module (Figure 3) shows that the EVA material in the module contains fluorophores before it has been exposed to the sunlight. It is known that the lamination process of the module generates fluorophores in the EVA [10, 11]. This initial fluorescence is nevertheless rapidly degraded over the first days of exposure and the fluorescence intensity of the material over both cells increases again with time. After a day of exposure, it is already possible to see a color difference in the fluorescence emission

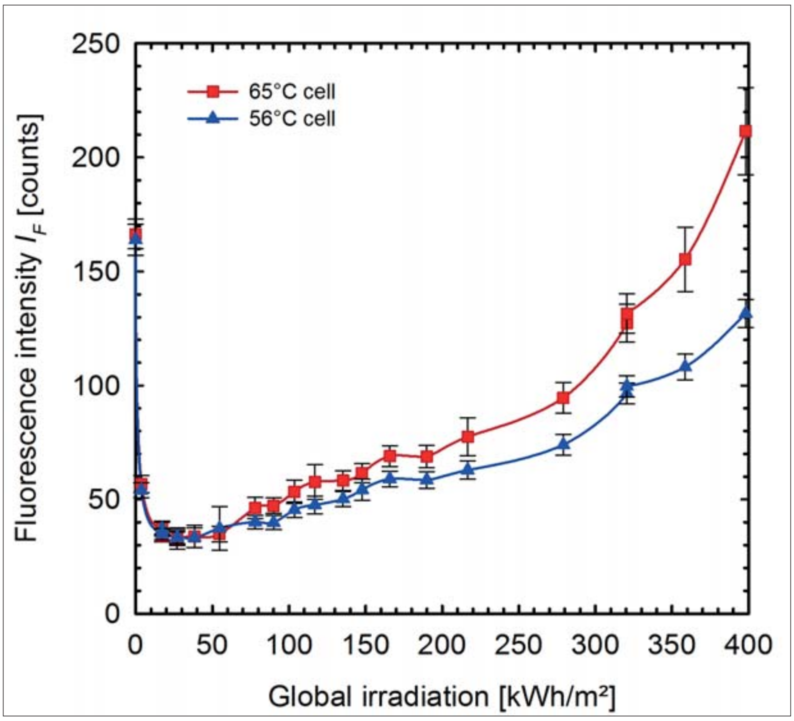

Figure 3. Fluorescence intensity over time measured on two solar cells with different operating temperatures. The lines are guides for the eye

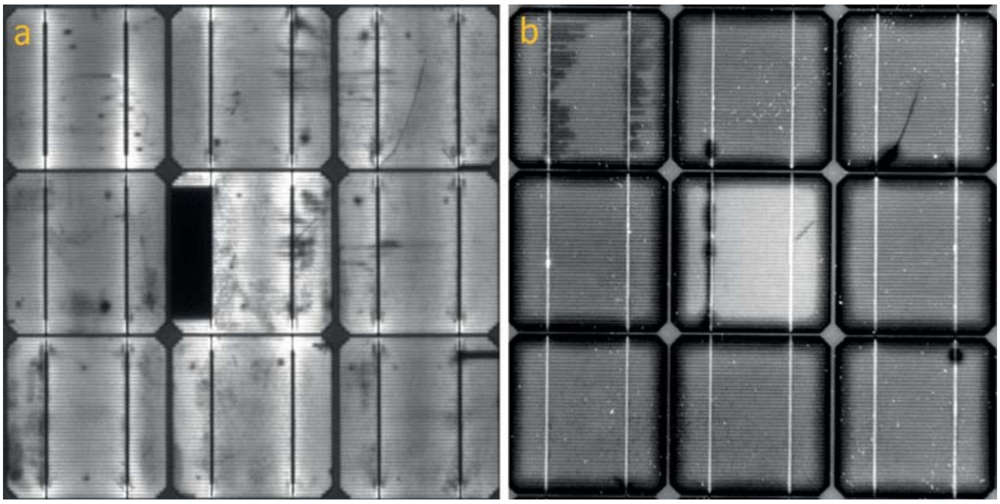

Figure 4. Electroluminescence (left) and UV-fluorescence (right) images of a PV module area showing a cell in which a quarter has been electrically isolated by a crack and which subsequently reaches a higher temperature in operation

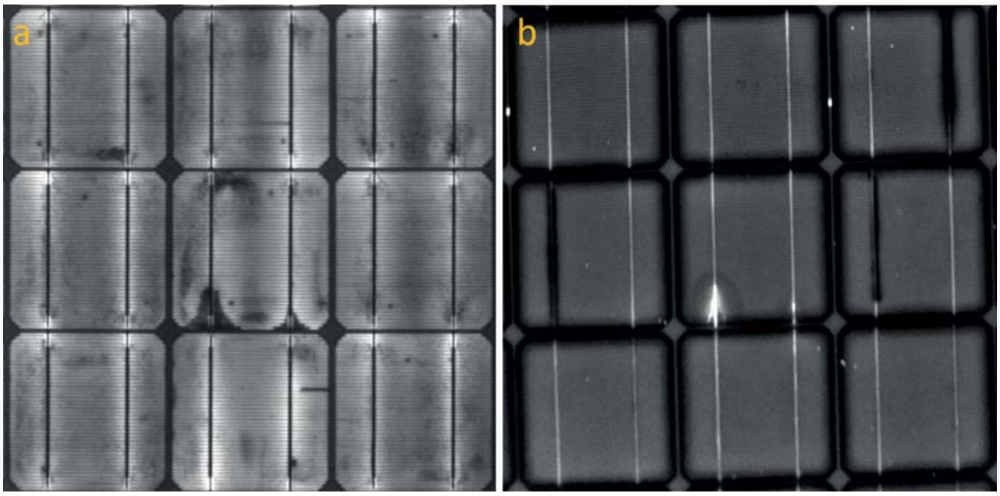

Figure 5. Electroluminescence (left) and UV-fluorescence (right) images of a PV module area with a cell showing damages correlated with a local overheating

between the cells with the human eye. After an irradiation of 360kWh/m^2 (70 days), the measured fluorescence emission is significantly more intense over the hotter cell.

The ability to detect the areas where the fluorophore formation is accelerated by an increased temperature allows one to detect several types of defects.

With this module coming directly out of the production, it is possible to discern the cracks caused during the transport or the handling of the module after 11 days of sun exposure (55kWh/m^2).

Not all cell cracks lead to a power loss but may potentially evolve to power-impairing damage. Electroluminescence is useful to detect cell cracks and determine if a crack is critical as EL allows one to see if a crack is electrically isolating a part of a cell. This information is not directly obtainable with the UV fluorescence technique. Nevertheless, in cases where the cell area disconnected by a crack is large enough to bring the cell to function in reverse bias mode and act as a power drain, the heat generated by the damaged cell results in a locally accelerated formation of fluorophores. Figure 4 shows (a) and EL and (b) an FL image of such a cell in a PV module. The EL image taken at Isc clearly reveals that one of the cracks electrically isolates a quarter of a cell. The corresponding fluorescence image shows that this cell shows an increased UV FL intensity. This cell is dissipating heat and therefore reveals the criticality of the crack.

Shunts in cells or short circuits causing hot spots in modules are also easily observable as shown in Figure 5, where cell damage seen on the EL image results in a bright local spot of fluorescence. A localised intense fluorescence spot is therefore an indicator of the presence of hotspots.

Occurrence of new cell cracks and comparison of cell crack age

New cracks generated after the installation of modules, caused for example by mechanical loads or shocks, may also be detected by UV fluorescence. We characterise the behavior of new cell cracks in a module by introducing new cracks. Before cracking the cells, the module has been exposed for four years to sunlight. Afterwards it is remounted on an outdoor test stand. Figure 6 shows a series of fluorescence images of the newly broken cell in the module at different sun irradiation levels.

The fluorescence along the fresh crack decreases with increasing global irradiation. Already after one day of outdoor exposure the fresh cracks are detectable, as the fluorescence decrease starts immediately. Nevertheless, the decrease rate of fluorescence intensity along these new cracks is low and after a three-month outdoor exposure (85kWh/m^2), it is still possible to distinguish between an older crack and a fresh crack.

Therefore, this feature can be used to detect new cell cracks caused by a hail storm. The module depicted in Figure 7 has been dismounted from a roof PV system that had been installed for 2.5 years in northern Germany. The system has been affected by a hailstorm eight weeks before the measurement, including some modules displaying glass breakage. A star-shaped crack can be seen on a cell (middle row, right) of this module, which evocates the typical breakage pattern due to a hail impact. On the fluorescence image (7b), this crack as well as some other cracks (bottom row, left) show only a partial extinction of fluorescence, while cracks on other cells appear as dark as the framing around the cells.

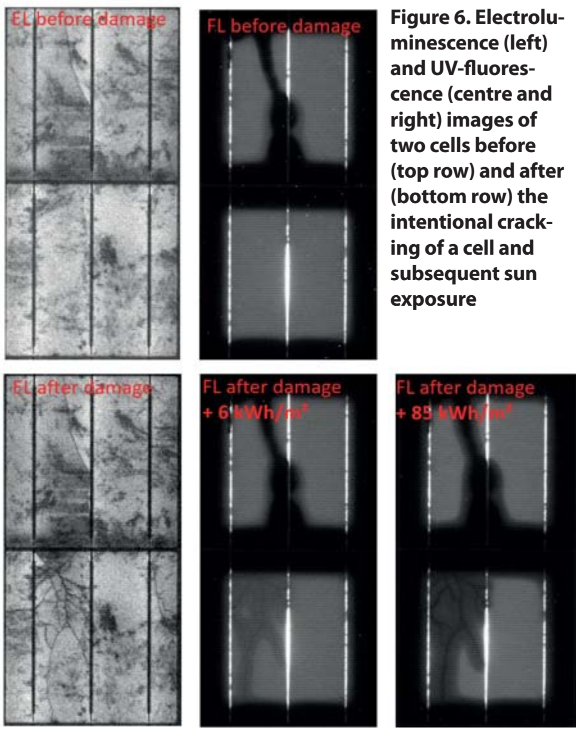

Figure 6. Electroluminescence (left) and UV-fluorescence (centre and right) images of two cells before (top row) and after (bottom row) the intentional cracking of a cell and subsequent sun exposure

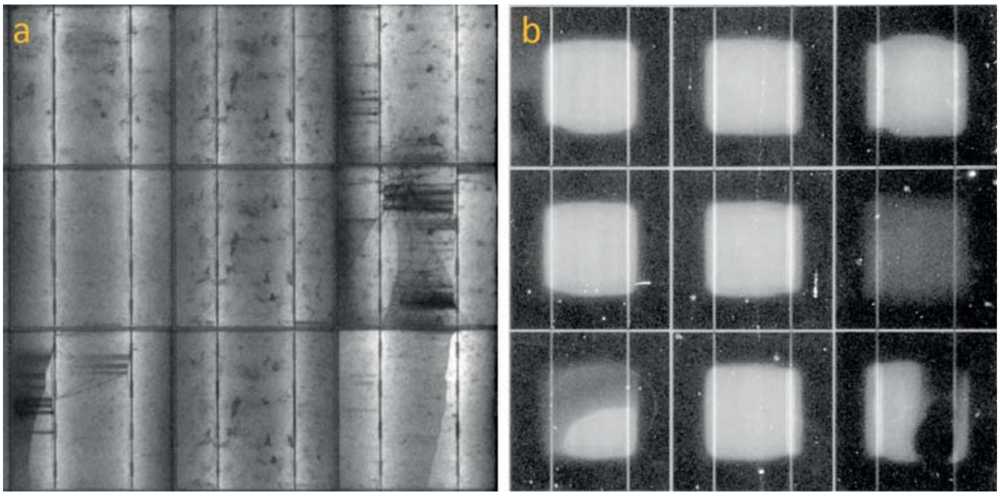

Figure 7. Electroluminescence (left) and UV-fluorescence (right) of a PV module eight weeks after a hailstorm and showing recent and older cracks

We can deduce from the partial extinction along the cracks that these cracks are caused by the hailstorm. We inspected another megawatt-scale field PV system in the same area five months after the hailstorm. It has shown that after this time period, the photobleaching of the fluorophores is so advanced that no contrast between newer and older cracks is measureable anymore. We can recommend the use of the UV fluorescence technique for the detection of damages due to a sudden event in a period of time between one week and six weeks after the suspected occurrence of damages. The timeframes we indicate here are deduced from our experience in the field in Germany in the summertime. For other regions, the local temperatures and irradiation may affect these estimates. The fluorescence in new modules as well as the quenching over new cracks will appear faster in hotter regions. In wintertime, the process will be slowed down due to the lower temperatures and irradiations.

Summary

UV fluorescence of EVA allows detecting cracks in new PV modules as soon as two weeks after their installation and the presence of hot cells three weeks after their installation. The method allows also to indirectly determine if a given crack is so critical that the concerned solar cell dissipates heat, leading to a power loss in the module. The fluorescence method is also able to reveal short circuits and hot spots.

Due to its rapidity, allowing a measurement throughput of up to 200 modules in an hour, this technique can be employed to large parts of a PV system to scan each module for defects. A subsequent electroluminescence measurement on modules with defects might be used to get more detailed information of the failure patterns on the fluorescence images. This technique has been experimented at ISFH with different module encapsulation materials such as several EVAs as well as with silicones.

Acknowledgements

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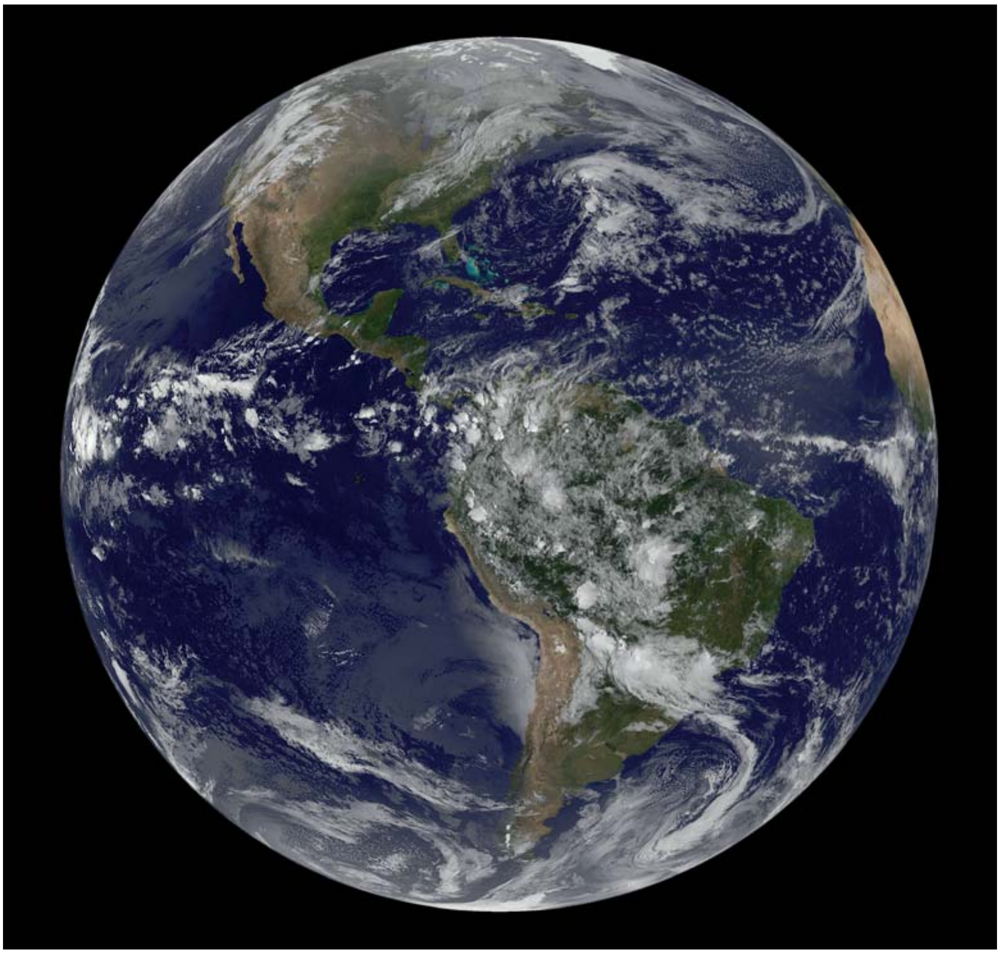
Towards accurate PV power forecasting

Forecasting | Predicting the power production of a PV plant offers a multitude of benefits to plant owners and grid operators. Jose Ruiz-Arias looks at the challenges of accurate forecasting across different timescales and in different climate zones



Credit NASA

The weather system is chaotic and cannot be controlled at will. Neither can solar power, which can only be anticipated with some level of uncertainty. In general, solar power increases the need for operating power reserves to compensate for production drops due to weather fluctuations. However, improved scheduling using solar power forecasting allows minimising such reserves as well as reducing the need for PV power curtailment. For electricity trading, it maximises revenues by minimising the penalties due to mismatches in production bids. All in all, solar power forecasting facilitates the matching of production and demand curves in distribution and transmission grids.

The benefit of solar power forecasting extends over applications at multiple time ranges. For instance, at sub-hourly time scales, forecasting of power ramp rates is used to make a more efficient operation of power storage units. A few hours ahead, solar forecasting is helpful in the operation of secondary electricity markets, in which solar power forecasting is combined with other system variables such as foreseen demand, state of transmission grid or expected generation from other sources in order to come up with the best operating decisions. For day-ahead time periods, solar power forecasting is used to schedule the operation of conventional power plants to accommodate the foreseen solar power generation. At even longer timescales, solar power forecasting is useful to schedule plant maintenance operations.

Expected improvements in satellite and weather observation sensors are expected to boost the quality of solar radiation forecasts at all timescales

PV power forecasting

Forecasting PV power production involves two modelling aspects: 1) modelling the weather, and 2) modelling the PV system. Among the weather factors determining PV production, solar radiation is the most important one, followed by air temperature.

The level of detail and accuracy at which a PV power system can be described are much higher than for describing the weather system. For instance, the layout and technology of PV panels, thermal and electrical losses or inverter performance are all aspects that can be accurately characterised. In contrast, the observation of weather is comparatively highly uncertain. Given the large scale of the Earth's weather system, its observation requires the use of remote measurement techniques (e.g., sensors onboard satellites). Indeed, most often there are no other means of observation.

All in all, the characterisation of weather is at least as blurry as even the loosest characterisation of a PV system. As a practical example, just consider that the uncertainty of solar radiation measurements—starting at 3% in the best use case—is one order of magnitude higher than the uncertainty of power measurements. At the same time, however, the uncertainty of solar radiation forecasts is nearly one order of magnitude higher than that of solar radiation measurements. Therefore, the

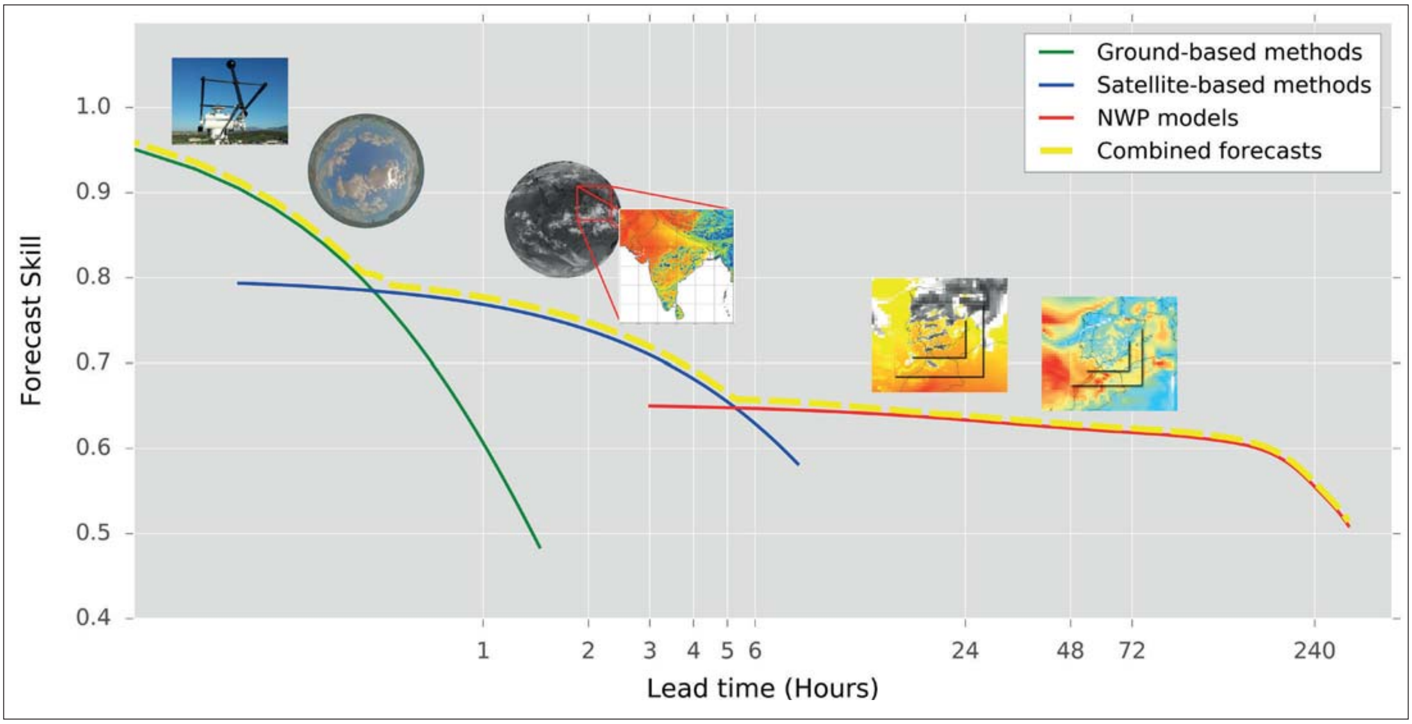


Figure 1. Conceptual plot of forecast skill vis-á-vis forecast lead time for ground-, satellite- and NWP-based forecast methods. The forecast skill values, shown for illustration purposes, are only approximated. The pyranometer and sky camera photos are courtesy of the University of Jaén, Spain

uncertainty at forecasting solar radiation turns out as the dominating factor in the forecast of PV power production. Based on this fact and the worldwide scarcity of public PV production data, the subsequent discussion will be primarily focused on solar radiation forecasting. However, the results here presented are similar to the ones expected for PV forecasting. The focus on solar radiation forecasting allows us to expand our discussion to virtually any location worldwide.

Solar radiation forecasting

Solar radiation forecast can be tackled using purely statistical methods or physically based ones; or, the trend nowadays, using combinations of both. However, what ultimately defines the most suitable approach for each particular application is, most often, the intended forecast lead time, and factors such as computational burden or availability of on-site observations, possibly with near real-time feedback to the forecaster. Lead time, in our context, means the time between the forecast being issued and the time to which it refers. Likewise, horizon lead time is normally used to refer to the maximum lead time involved in each forecast. For example, for some applications, the interest in solar power forecast relies mostly on lead-time ranges of up to six hours ahead or, equivalently, six hours' horizon lead time.

The various solar forecasting methods are here introduced by intended forecast lead time. In this sense, Figure 1 shows a conceptual comparison of the expected forecast skill as a function of forecast lead time for the most important families of forecast methods: i) Ground-based methods, ii) satellite-based methods and, iii) numerical weather prediction (NWP) models. The maximum forecast skill (one) is for a perfect forecast, i.e., matching the uncertainty of actual observations.

Less than one hour ahead

At sub-hourly forecast lead times, the methods based on on-site ground observations provide the highest skill (see Fig. 1) because, at this timescale, weather patterns often change very little and are affected only by local features. In other words, the correlation of weather phenomena stays high. Thus, statistical methods do a great job at casting the current observed conditions into near future times. The forecast is normally issued in the form of solar radiation time series representing the average conditions in the surroundings of the location of interest. These forecasts are most frequently based on the combination of solar radiation measurements with sub-hourly time resolution (ideally, 10 minutes or shorter) and statistical methods such as auto-regressive or state-space models. A trivial model, particularly ubiquitous by its simplicity, is the so-called 'smart persistence', which assumes clouds do not change throughout forecast lead time and only the changes due to the deterministic course of the sun are modelled. However, in general, more sophisticated assumptions are used in production models.

A somewhat different approach to forecasting sub-hourly solar radiation is based on the observation of the cloud field over the location of interest using on-site cloud sky cameras. These are essentially camera systems (as simple as plain surveillance cameras or more specialised and sophisticated systems) staring at the sky. By comparing two or more consecutive images, the overall speed and trajectory of cloud structures can be inferred and used to cast the cloud locations into the future (using similar techniques to the ones used by the satellite-based methods described below). Then, the spatially-distributed solar radiation over the measurement field can be calculated from the predicted cloud field. This technique potentially offers a detailed description of the passing clouds over the PV field,

being even able to resolve cloud shades in different sections of a PV power plant.

However, it is a relatively new approach, still under heavy research to solve multiple challenges that prevent its implantation as a widespread forecasting technique. It requires the on-plant deployment of dedicated hardware systems, with stringent maintenance requirements, and sophisticated software to store, manage and process the large volume of data. There are also technological barriers that limit the ability of the systems to distinguish clouds near the circumsolar region or to detect the altitude of clouds. So far, the proposed solutions involve increasing the complexity and cost of the detection systems but still with too limited improvements. Typically, the forecast horizon using sky cameras does not extend beyond 15 minutes ahead.

Few hours ahead

As the forecast lead time moves from sub-hourly to various hours ahead, the relative importance of remote weather features prevails over local features. In essence, clouds far from the site of interest will be affecting local weather in a matter of tens of minutes to a few hours. As a consequence, local observations are not enough to account for future events and the observation area needs to be expanded. The satellite-based methods then come naturally to the playing field. Figure 1 shows that the forecast skill of ground-based methods is eventually surpassed by the forecast skill of satellite-based methods for horizon forecasts of about half an hour.

Sensors aboard modern satellites provide images of cloud fields that extend over thousands of kilometres. They describe clouds with a spatial resolution in the order of 3 km (even finer for some spectral channels) and a refresh rate between 10 and 30 minutes depending on the satellite. As with sky cameras, the forecasting principle consists of a similarity analysis of two or more consecutive cloud images. From it, the positions of matching cloud structures in the two images are used to determine the speed and trajectory of clouds, which are represented by a spatial field of vectors customarily referred to as cloud motion vectors (CMV). Then, assuming CMV stay the same for the next hours, the future position of clouds is inferred, from which solar radiation is computed.

A major limitation of CMV-based techniques (using both sky cameras and satellite imagery) occurs when the vertical movement of clouds is not negligible with respect to the horizontal displacement, which typically happens with convective and orographic clouds. Contrarily to sky cameras, satellite-based forecasting does not require costly on-site equipment and maintenance. Moreover, the new and forthcoming satellite systems promise spatial and temporal resolutions never seen so far, being soon capable of reaching spatial resolutions comparable to large PV power plants.

Beyond few hours ahead

As shown in Fig. 1, the skill of satellite-based forecasts decreases with increasing forecast lead time. This happens because the spatio-temporal correlation of current and future weather patterns drops off. NWP-based forecasting methods tend to provide higher forecast skill than satellite-based methods beyond typically five or six hours ahead. They simulate the temporal evolution of the entire weather system by solving the equations that describe the atmospheric physical processes. The physical foundations of NWP models make up for the lack of valid information at forecasting times from current observations. NWP models are routinely used by public and private weather services to provide forecasts on a regular basis. They can run over the entire Earth, then being known as global NWP models, or over only a limited area, then being referred to as limited area or mesoscale NWP models. Global models—which are run virtually only by public weather services and research centres due to their huge computational demands—provide worldwide coverage at the expense of limited spatial resolution (currently in the approximated range from nine to 25km) and temporal resolution (currently hourly or three-hourly). The typical refresh rate is once every six or 12 hours, with each new forecast normally providing values up to about 10 days ahead. However, some particular configurations of these models—not precisely focused on solar radiation—simulate the atmosphere up to several months ahead.

Probably the most widely used global NWP models are the Integrated Forecasting System (IFS) of the

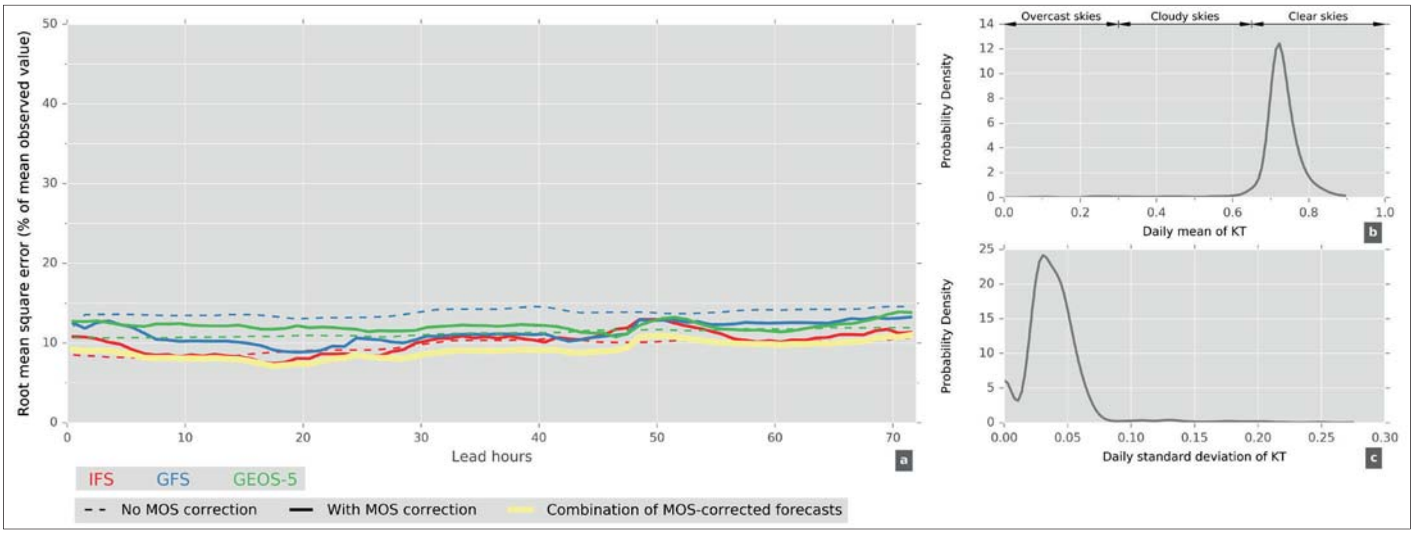


Figure 2. Validation of solar radiation forecasts at a location in the Atacama Desert, Chile. (a) Root mean square error as a function of forecast lead hours for IFS (red), GFS (blue) and GEOS-5 (green). (b) Distribution of daily mean clearness index, KT. (c) Distribution of daily standard deviation of KT. Validation conducted against the Solargis solar radiation satellite model. Validation period: 2016/09 – 2017/04 (eight months)

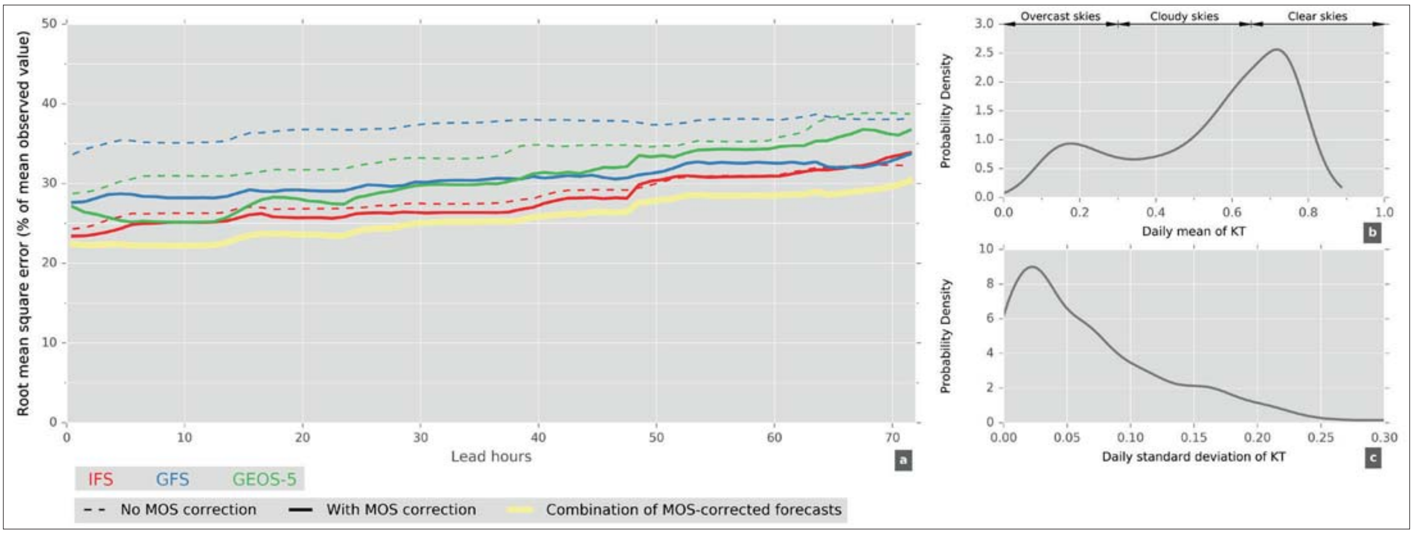


Figure 3. As Fig. 2, but for a location in Tokyo, Japan

European Centre for Medium-range Weather Forecast (ECMWF) and the Global Forecast System (GFS) of the National Centers for Environmental Information (NCEI) of the United States. In contrast, mesoscale NWP models focus on a limited area (e.g., country-wide) and simulate the weather system with increased spatial and temporal resolutions, in the order of few kilometres with sub-hourly outputs. Due to their reduced computational requirements compared to global models, they are often operated also by private entities since they can be adapted to the specific needs of final users.

The development of NWP models—especially as regards global NWP models—has never been particularly focused on solar radiation, with only very few and recent exceptions. Therefore, to forecast solar radiation, post-processing approaches are often used to adapt the forecasts to local features not considered by the NWP model as well as to increase the temporal and spatial resolution. In addition, although all NWP models are physically based and are mostly founded on the same major physical assumptions, some other assumptions are different. For instance, the modelling of convective clouds or the calculation of solar radiation may originate discrepancies in the forecast skills of different models. Overall, the best forecasting approach is normally the use of consensus forecasts that optimally integrate forecasts from various NWP models. Below, some examples of NWP forecasts are shown.

Long-term forecasting

This sort of forecast is required during the early development stages of PV projects for feasibility and bankability studies. Essentially, the foreseen resource for the next years and decades is required to trace down a reliable business plan. Interestingly, no forecasting models are used for this application. Instead, historical observations or typical meteorological year data sets are brought into the chessboard under the major assumption that the future will behave as the past did. Sometimes, historical observations are slightly corrected to account for known error trends or expected climate drifts, when such drifts are deemed non-negligible.

Forecast post-processing

At all levels of forecast and with all forecast methods, the forecasts can be post-processed to diminish errors as long as reliable and accurate observations, not yet used in the forecasting chain, are available. This post-processing is particularly beneficial for satellite- and NWP-based forecasts since, unlike ground-based methods, they typically do not make use of such observations to create their forecasts. This data processing is customarily referred to as 'model output statistics' (MOS) and spans a wide spectrum of methods to combine observations and forecasts, from the simple and ubiquitous linear regression to the recent rise of a comprehensive family of skilful methods jointly referred to as machine learning. The improvement achieved by MOS post-processing highly depends on the quality of observations, the ability of the MOS model and the prevailing weather conditions. In addition, and particularly for NWP-based forecasts, the blending of forecasts from various independent NWP models results in enhancement of the forecast performance, as long as the forecast errors of the individual models are not fully correlated.

NWP forecast examples in various climate zones

In order to give a hint about current solar radiation forecast errors, the performance of three of the best-known global NWP models is assessed at three locations in different continents with varying cloud regimes. The models are IFS, GFS and the Global Earth Observing System Version 5 (GEOS-5) of the National Administration Space Agency (NASA) of the United States. The validation is conducted based on the root mean square error (RMSE) score using reference data from the Solargis solar radiation satellite model.

Figure 2 shows the evaluation at the Atacama Desert, in Chile. This location features a study case with prevailing pristine and cloudless conditions (see Fig. 2b; to be compared later to Figs. 3b and 4b) and thus with little cloud variability (see Fig. 2c; to be compared later to Figs. 3c and 4c). The cloud amount is represented by the clearness index parameter, KT, which roughly represents the cloud transmittance of solar radiation (KT is nearly zero for overcast conditions and one for cloudless skies). The validation of models is shown in Fig. 2a for models with both no MOS (thin dashed lines) and MOS (thin solid lines) post-processing, respectively. Roughly,

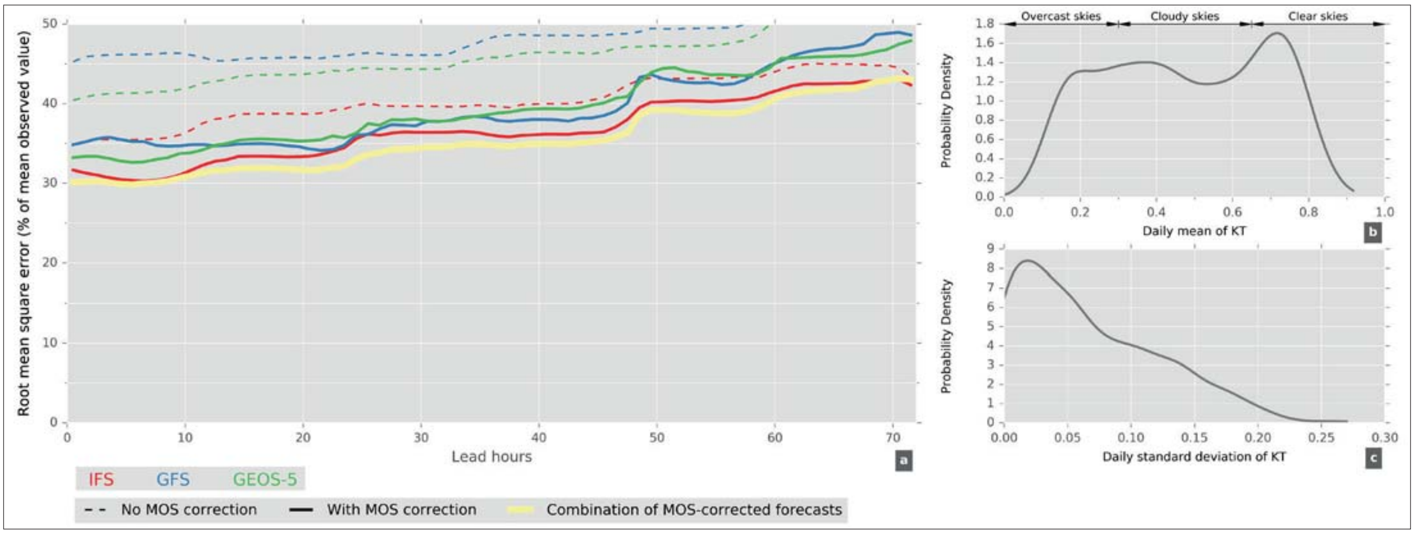


Figure 4. As Fig. 2, but for a location in Bratislava, Slovakia

all models have similar RMSE around 10%. The MOS post-processing does not clearly and systematically improve the initial forecasts. The thick solid line refers to the combined MOS-corrected forecasts, which slightly improve the individual model forecasts.

Figure 3 shows the case of Tokyo, Japan. Now, the relative amount of cloudy days and variability (Figs. 3b and 3c, respectively) increase with respect to the previous location. As a consequence, the overall forecast error of all models increases up to 25% or higher. However, the benefits of the MOS post-processing and the combination of models are now clearer than for the cloudless case. Note also that, unlike for the Atacama Desert, the performance of the forecasts now decreases with forecast lead time, as a consequence of the smaller predictability of cloud-related weather patterns.

Finally, Fig. 4 shows the case of Bratislava, Slovakia, where the relative cloud amount and variability (Figs. 4b and 4c, respectively) is even higher than in Tokyo. Now, the magnitude of forecast errors rises up to 30% or higher, with larger inter-model differences. Again, the MOS post-processing and models blending considerably improve the initial performance, by about 10% on average. The error increase with forecasts lead time is steeper than in Tokyo.

It may be concluded that the predictability of solar radiation decreases with increased occurrence of clouds, although, in parallel, the room for MOS improvements increases. All in all, however, the MOS-corrected forecast RMSE varies from about 10% for prevailing clear and cloudless conditions to more than 30% for locations dominated by cloudy skies where, in addition, the forecast error for three-day forecast horizons may increase by about 10%. The combination of models systematically provides better forecast than any individual forecast model.

Regional forecasting on PV fleets

Thus far, we have focused on pointwise forecasts. However, aggregated forecasts across PV fleets are likewise required in many cases. In general, errors over the aggregated fleet under prevailing stable weather conditions are reduced only marginally, and, to a larger extent, for variable cloud conditions. The rationale is that weather variability produced by passing clouds results in highly uncorrelated solar radiation errors at the different locations of the PV fleet. This leads to cancellation of positive and negative errors when solar radiation is predicted over the entire fleet. Under stable conditions, in contrast, all errors are overall positive or negative, eventually preventing the cancellation of errors. With respect to pointwise forecasts, error reductions of up to 15% have been reported in the scientific literature for locations spread over region scales from 50 to 100 kilometres.

Concluding remarks

Solar radiation forecast errors are the dominating factor in forecasting solar power. The most suitable solar forecasting technique mostly depends on the forecast lead period of interest: i) ground-based methods for sub-hourly time horizons, ii) satellite-based methods up to about five hours ahead, and iii) NWP-based forecasts beyond that period. In general, however, the best results are obtained by intelligently blending forecasts from different approaches and models.

The normal trend is a growth of forecast errors with forecast lead time and cloud occurrence rate. In particular, it has been shown for three state-of-the-art global NWP models that their forecast errors highly depend on the local cloud climatology, varying from about 10% RMSE for prevailing cloudless conditions to more than 30% RMSE for prevailing cloudy conditions. The three-days-ahead solar radiation forecast error may increase by nearly 10% with respect to the intra-day forecast error under heavily cloudy conditions. When the forecast is issued for a PV fleet, the overall error may be broadly reduced by 15% under unstable weather conditions over land scales of about 50 to 100 kilometres. The enhanced capabilities of the satellite and weather observation sensors to come during the next decades are expected to boost the quality of solar radiation forecasts at all timescales.

Author

José A Ruiz-Arias is weather and solar radiation expert in Solargis. He provides support to clients and develops models to assess and forecast solar radiation. Jose has published more than 50 papers in scientific journals as researcher at the University of Jaén, Spain, and the National Center for Atmospheric Research of the United States. He is a member of the IEA PVPS Task 16 on Solar Resource for PV.

Solar Expo 2018 marks major growth in MENA region

The third Solar Expo will take place from 15-18 January 2018, within The World Future Energy Summit, just as solar developments throughout the MENA region are moving into fast-forward mode, with more than 5.7 GW of upcoming projects in the pipeline.

In the United Arab Emirates, Phase III of the Mohammed bin Rashid Al Maktoum Solar Park was awarded last year, with 800 MW for delivery over three phases by 2020. The Abu Dhabi Water and Electricity Authority (ADWEA) has tendered out a solar power plant at Sweihan that will produce a minimum of 350 MW.

The Saudi Electricity Company is currently tendering a 300 MW PV project in the al-Jouf area in northern Saudi Arabia, while Oman is expected to issue a request for proposals for its first utility-scale 200 MW PV project this year. In Kuwait, Kuwait National Petroleum Company, a subsidiary of the state oil major Kuwait Petroleum Corporation, began the tendering process in July for the 1 GW Al-Dibdibah PV solar project planned for the Al-Shagaya renewable energy complex.

Solar Expo will provide the perfect platform for companies to meet the key purchasers and influencers in many of the large projects taking place in MENA. It is hosted by Masdar and the strategic partner is Abu Dhabi Water and Electricity Authority. It will feature a large exhibition and a conference with high level investment forums on Saudi Arabia, Africa and South East Asia. A new tradeshow will be launched alongside, called Energy Storage and Battery Expo, this event will be the first in the Middle East to allow companies with storage technologies to meet key buyers from project owners and consultants from the region.

Adding further momentum to solar growth in the region, Frost & Sullivan predicts that installed solar capacity in the Gulf Cooperation Council area will reach 76 GW by 2020. Against this background, the WFES Solar Expo provides a dedicated platform for the solar industry, bringing together manufacturers and distributors from around the world. The event covers photovoltaic applications and modules, solar thermal power plants, commercial and utility-scale power plants, stand-alone systems and other solutions and services.

Solar Expo 2018 will be the definitive place for industry professionals to see the latest solar innovations. This is an exciting time for the industry in the MENA region, which is seeing continuing price reductions for photovoltaics, rising electricity tariffs, energy market reforms, subsidy adjustments, and a growing demand for desalination and cooling.

Solar Expo and World Future Energy Summit take place as part of Abu Dhabi Sustainability Week with four other co-located exhibitions at the Abu Dhabi National Exhibition Centre, focusing on future energy, energy efficiency, sustainable transport, water sustainability and waste management.

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Digital O&M opportunities in a water-scarce India

Operations and maintenance | India's solar industry has been focused on reaching a hugely ambitious target of 100GW of PV by 2022. But as Tom Kenning reports, the need to get smart on managing and maintaining solar assets is now becoming an overriding priority

Credit: IBC Solar

The current rush in India to deploy huge amounts of PV as quickly as possible has often diverted attention away from the question of how to manage a solar plant five or 10 years after construction. As a result the operations and maintenance (O&M) side of the industry has barely made the news, even though the quirks of Indian climate and regulation represent a handsome business opportunity for both domestic and foreign O&M service providers. The cheapness of labour in India could be seen as a barrier to entry for more tech-focused firms, but in a price-sensitive society, any kind of money saving technique is welcome.

India appears to have been slow at embracing big data solutions, but the South Asian giant may also be at an inflection point in adopting state-of-the-art monitoring software. It is also beginning to take notice of the lessons offered by more established markets where O&M has become a key focus – as is the case for many early movers in Europe. New forecasting rules are set to be taken up slowly but surely, state by state, which could start to drive this data element. Meanwhile, traditional water-based solar plant cleaning methods could also become a crunch point in a country where water shortages are high on the political agenda.

Attitudes to O&M vary in the industry, says Jasmeet Khurana, associate director of consulting, at analyst firm Bridge to India. Inexperienced developers are most likely to overlook the maintenance aspect of a PV plant. For them it can appear to be a minor issue when confronted by the wider process of developing a plant. Operators who see their generation dropping will take action quickly and it would be false to make a broad statement about O&M practices in India, Khurana adds. Nevertheless, there is a sense among industry observers that there needs to be more education in the Indian market to avoid the mistakes originally made in Europe and elsewhere.

Cleaning modules in areas facing water shortages is just one the O&M challenges facing India's solar industry

Opportunities

Plenty of companies have in-house O&M teams in India, as was the case in the early days of European solar, but that should not limit the opportunity for third-party O&M firms.

"A big percentage (by volume) of the project developers are looking for

A new approach to soiling measurement

"Nothing ever stays clean" is a common frustration, particularly with equipment installed outdoors. It picks up dust, mud, soot, salt and many more contaminants that can be generically called 'soiling'. In most cases, the collected contamination on your car or home is just a nuisance. But when you're running a solar energy park this soiling, or 'dust' as it is often referred to, is much more important. Soiling = power lost = revenue lost; maybe penalties incurred for under-performance.

Transmission Loss

Some of the incoming solar radiation is reflected, scattered and absorbed by the dust accumulated on the solar panels, reducing the yield. The logical solution is regular cleaning. But, cleaning from thousands to millions of PV panels is expensive and time consuming; so a well-informed decision has to be made regarding when and where to clean and how often.

For that decision, one needs to know the quantity and the value of the solar energy not reaching the silicon cells. The energy not passing through the glass of the PV panel is called the Transmission Loss (TL). Armed with the TL it is then possible to calculate the revenue loss and decide if it's worthwhile cleaning.

Until recently, determination of the TL was based on a 'guesstimate', experience or on a measurement system with two identical PV panels. One panel is left untouched, becoming soiled, and the second panel is kept clean as a reference. This measurement can be accurate, if the panels used are similar to those used in the park, as it measures the real energy loss. However, accurate measurements need a lot of sun at close to normal incidence to the panels, and therefore only work well about two hours before and after local solar noon, and with little or no overcast.

One soiling measurement point might not be sufficient

Keeping the reference panel clean requires strict planning; it might need to be daily, using manual labour or an expensive robotised system that will need power, often a water supply, and always maintenance. Because of the operational issues, size and price two-panel systems are usually installed at a single location only. This is often not representative of the soiling at a typical panel, nor does it reflect the fact that the rate of soiling varies across the park.

The new OSM technology

To circumvent these difficulties and provide affordable, distributed measurements at multiple points, the people working on the unique Optical Soiling Measurement (OSM) technology at Kipp & Zonen have come up with a radical new approach.

DustIQ does not rely on the comparison of soiled and clean panels, but measures the Transmission Loss of the panel glass directly; day and night, with and without sun. The innovative OSM principle is based on emitting modulated blue light from an LED beneath a glass window and measuring the light reflected from the surface. The more soiling there is on the surface the more light is reflected.

Rigorous testing with dust samples from all over the world has shown a consistent relationship between the intensity of reflected light, the amount of dust accumulated and the subsequent energy production loss of a PV panel. Kipp & Zonen provides DustIQ can measure the Soiling Ratio within 1%, has no moving parts and needs no regular maintenance; just clean it at the same time as the panels around it.

Soiling Ratio is the accountable value

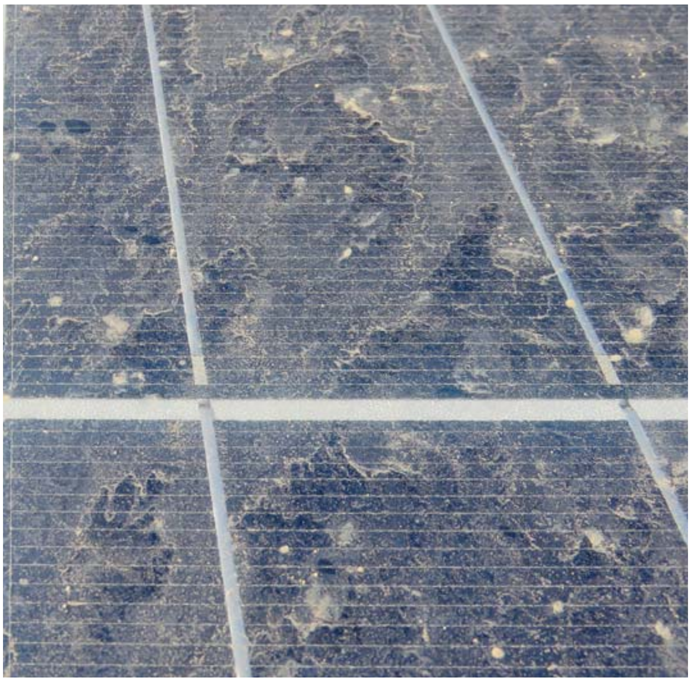
Following the requirements of the IEC 61724-1:2017 standard "Photovoltaic system performance Part 1: Monitoring", the DustIQ measurements are reported as a Soiling Ratio (SR). The SR is

defined as "the ratio of the actual power output of the PV array under given soiling conditions to the power that would be expected if the PV array were clean and free of soiling". When completely clean, the SR is 100%.

Details on DustIQ

DustIQ is small (99 x 16 x 3.5cm), light (4kg) and easy to install. The materials used are the same as in typical PV panels; the textured glass and coatings, EVA sheets and aluminium frame. DustIQ has two identical sensors with independent signal outputs so that if there is unusual local soiling, such as bird droppings, it can be detected. The measurements are transmitted digitally over RS-485 in industry-standard Modbus® RTU format.

PV panel temperature greatly influences the cell performance and it is critical to monitor it. An IEC / NREL compliant sensor has its temperature measurement integrated into the DustIQ data output. This will be supplied by Kipp & Zonen as standard from January 2018.



Map of soiling across a solar plant

Following IEC61724-1:2017 recommendations, it is advised to deploy several DustIQs over a solar park to monitor the variations in soiling patterns. The number of instruments depends on the size of the solar park and ranges from one per 5 MW for small parks to one per 50 MW for 300 MW parks and larger. Using several DustIQs enables a precise soiling map of the complete solar park to be drawn and enables and localised cleaning to be scheduled, thus saving a lot of time and money.

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third-party O&M contractors," says Kelly Mermuys, a business development executive at Belgian renewables analytics service provider, 3E India.

Mermuys says that India has strong technology and big data capabilities for many applica-tions, but not so much for wind and solar at present. Thus the smart monitoring side of O&M represents an opportunity for those with prior experience to bring to India new and improved strategies. "But this gap could disappear very quickly where knowledge exchange between Europe and India can play a key role," adds Mermuys.

France-based O&M analytics software provider, QOS Energy, recently opened a new office in Delhi to meet growing demand from the booming local market. QOS monitors more than 300 plants in India, including some utility-scale projects in Rajasthan.

"It is a very open market with strong Indian players, but many European and North American players want to invest there, which means that there's mix of technology," says Franck Le Breton, CEO of QOS Energy.

Le Breton feels there are very few strong players on the monitoring side in India. He also feels that the level of monitoring required by some of the largest PV players in India will mean technology needs to be imported from abroad. While competition does exist in this area, and will certainly increase over time, there are multiple gigawatts of opportunities available all the way under the government's 2022 target of 100GW of PV and beyond, he says.

Solar EPC in India is much more about the capex model rather than the opex model, claims Eric Daniel, sales director, QOS Energy. However, as the market matures, it is turning towards optimising plant performance. Many independent power producers and asset managers have plants with different SCADA systems, hardware and pricing. Thus, if a problem occurs, it may require unique solutions on each plant. This is another area in which data firms with innovative solutions can offer help. One solution is to render the old Excel spreadsheet defunct, and replace it with automatically uploaded aggregation of data across an asset manager's portfolio.

Big data

"Today India is going by what's available on standard legacy SCADA systems and inputting that into spreadsheets," says Sandeep Nath, CMO of Shri Shakti Alternative Energy, an India-based company that offers specialised solar O&M Solutions and diagnostic services. "They don't have much to do with real-time monitoring and they do not realise the importance of big data. That's the reality on the ground. It's not that they are ignoring it. It's that they haven't prioritised it."


Credit NTPC

Indian utility NTPC is experimenting with automated cleaning solutions on its solar installations

Nath even compares some developers to "headless chickens" under the pressure of building capacity, noting that while they have started to read and learn about the various nuances of O&M, senior managements are still struggling to think ahead about operations from the very start of installing a PV plant.

"In six months to two years all that will change," he adds. "They will get a hang of the right approaches, which work to the right standards."

Plant developers or owners who are contracting O&M providers are now able to demand more than they used to when carrying out due diligence and other checks.

Thus, solar O&M firms need to better communicate to investors the value they are adding to projects through data management and digitalisation, says Uwe Schmidt, director of O&M, at Germany-based integrated solar firm IBC Solar. In a way they need to "step into the shoes of investors" to prove how their new data tools have impacted plant performance and energy yields. Whereas in previous eras O&M performance could be communicated via emails, now tools can gather information and send reports far more effectively and instantaneously, but it's not always easy to explain to investors how a company's O&M actions have translated into higher energy yields for the plant.

"Investors are looking more at the quality side and quality is pretty hard to prove sometimes," adds Schmidt. "You have to communicate; you have to prove what you really did."

Firms that have the right tools for the job and can demonstrate the value they add potentially have a lot to offer in India, particularly in helping the countries so-called discoms (distribution companies). This is particularly the case in the the context of new forecasting rules, which will require both the plant operator and the regional load dispatch centre (RLDC) to provide forecasting of power generation and mean more collaboration between the two sides of energy production and distribution.

"The issue discoms have today is they have no clue now much renewable energy will be produced in the next few days," says Daniel. As a result QOS Energy is already in discussion with some discoms to help them understand forecasting from renewable energy projects as well as how to aggregate information on energy produced across each discom's area.

Cleaning

The more traditional O&M subject is how to clean modules, and on this question India presents some specific challenges. In the hot season, parts of the country can face water shortages, while solar plants tend to collect even more dust than usual in that season. Sand storms are also possible in the deserts of Rajasthan and heavy rains in the monsoon season all over India. The period immediately after heavy rain when the sun comes out can also have some of the highest irradiation, so managing the spikes in energy production can be a challenge for both plant operator and the grid.

"In any state where the site of the solar PV installation is dusty and has a shortage of water availability, the smarter developer will go for waterless cleaning systems," says Mermuys. "The waterless cleaning system is a good mitigation measure."

What was for a time the world's largest solar project, the 648MW Kamuthi plant in Tamil Nadu developed by Adani Green Energy, a subsidiary of Indian conglomerate Adani Group, made the press recently over water issues. Local media reported locals complaining of their ground water sources being tapped by Adani for cleaning its mammoth solar installation. However, Adani said that it had been using automated solutions for cleaning parts of the plant and only required monthly cleans of the project rather than daily – as had been suggested. Whatever the truth, it's clear that water is a sensitive issue here.

Developers should also be considering different PV module technologies than can cope in the various climates including solutions such as anti-soiling coatings, Mermuys adds.

One of the reasons that the focus on digitalisation has been less pronounced in India is due to the low staff costs. So while waterless cleaning solutions are often automated, there is a balance to be found in terms of economics where using multiple staff from the local surrounding area can be both cheaper and rewarding for the local community. However, India's largest utility NTPC, which plans to have a multi-gigawatt solar portfolio over the coming years, has already been experimenting with robotic cleaning solutions.

Security

Security is a big issue in India and project developers will always want the project site fenced, including CCTV cameras and 24-hour basis security personnel on-site, says Mermuys. Theft of PV components, a frequent occurrence in remote areas, typically involves PV modules, inverters and cables, which can impact a project's energy production.

"These criminal acts can force the plant to stop for several weeks and are extremely difficult to prevent," Mermuys adds. "Beside the technical replacement of the stolen electrical components, there is work updating the plant documentation with new inverter datasheet or serial number."

Ultimately O&M goes hand in hand with any solar installation and the quicker India takes it seriously the more optimised its projects will be, but for the foreseeable future the focus is likely to remain firmly on those enormous capacity targets.

Solar operators face new forecasting requirements

Indian states are slowly adopting new forecasting rules that will force solar energy plant op-erators and regional load dispatch centres to provide more frequent and accurate projec-tions of energy production or face penalties.

The Central Electricity Authority (CEA) has been insisting on such forecasting requirements and invariably all state discoms will have to implement them.

3E India's Kelly Mermuys says that project developers may need to attain more accurate tools and software for forecasting generation as a result.

Only Karnataka and a few other Indian states have taken on new forecasting rules so far, according to Bridge to India's Jasmeet Khurana.

Speaking broadly, forecasts will now have to be provided in more frequent windows of time in affected states. Meanwhile, the margins for error have also been tightened, combined with the threat of penalties.

"The only concern is that the older projects have not accounted for these costs, because at that time these regulations didn't exist, so they may have to do whatever retrofitting is required to make sure that they are able to forecast as well," adds Khurana.

The rules are expected to be gradually rolled out in other states as India continues to steamroller its way ahead in renewables deployment, having recently reached a cumulative 15.6GW of solar installations, of which 14GW is utility-scale, according to Khurana.

Industry members are not yet clear what level the penalties relating to forecasting will be set at, particularly as they are going to be introduced state-by-state rather than in one umbrella ruling.

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Introduction

As of this issue, *PV Tech Power's* coverage of stationary energy storage comes to you in association with Energy-Storage.News, Solar Media's website dedicated to the global sector.

If you'll excuse us a very quick history lesson: the site was launched under the brand PV Tech Storage in 2014, after it became undeniable that both industry trends and our readers' interests were piqued by the promise of batteries and other technologies.

Of course, while we focused a great deal of our attention on the market synergies between PV and energy storage, it was always recognised that there was more to the energy storage market than that, and the rebrand to Energy-Storage.News happened a year or two later.

As editor of the site since its inception, I've seen some pretty incredible things and been lucky enough to report on some truly transformative projects and technologies. I've been privileged to get an inside track on what is, essentially, the wave of the future and one of the key enablers of a leaner, cleaner, more efficient way to look at energy.

There have been frustrations too, of course, where perhaps policymakers haven't been quick enough to act, or utilities have dragged their heels instead of adapting. But progress nonetheless has been astonishing, from equipment cost reduction to financing solutions, to the sheer speed at which deployments have taken off in some markets.

In this edition, Todd Olinsky-Paul of the Clean Energy States Alliance (CESA) discusses some of the state-level policies that have made the US host to some of those advanced markets, like California and Hawaii – and where others currently stand.

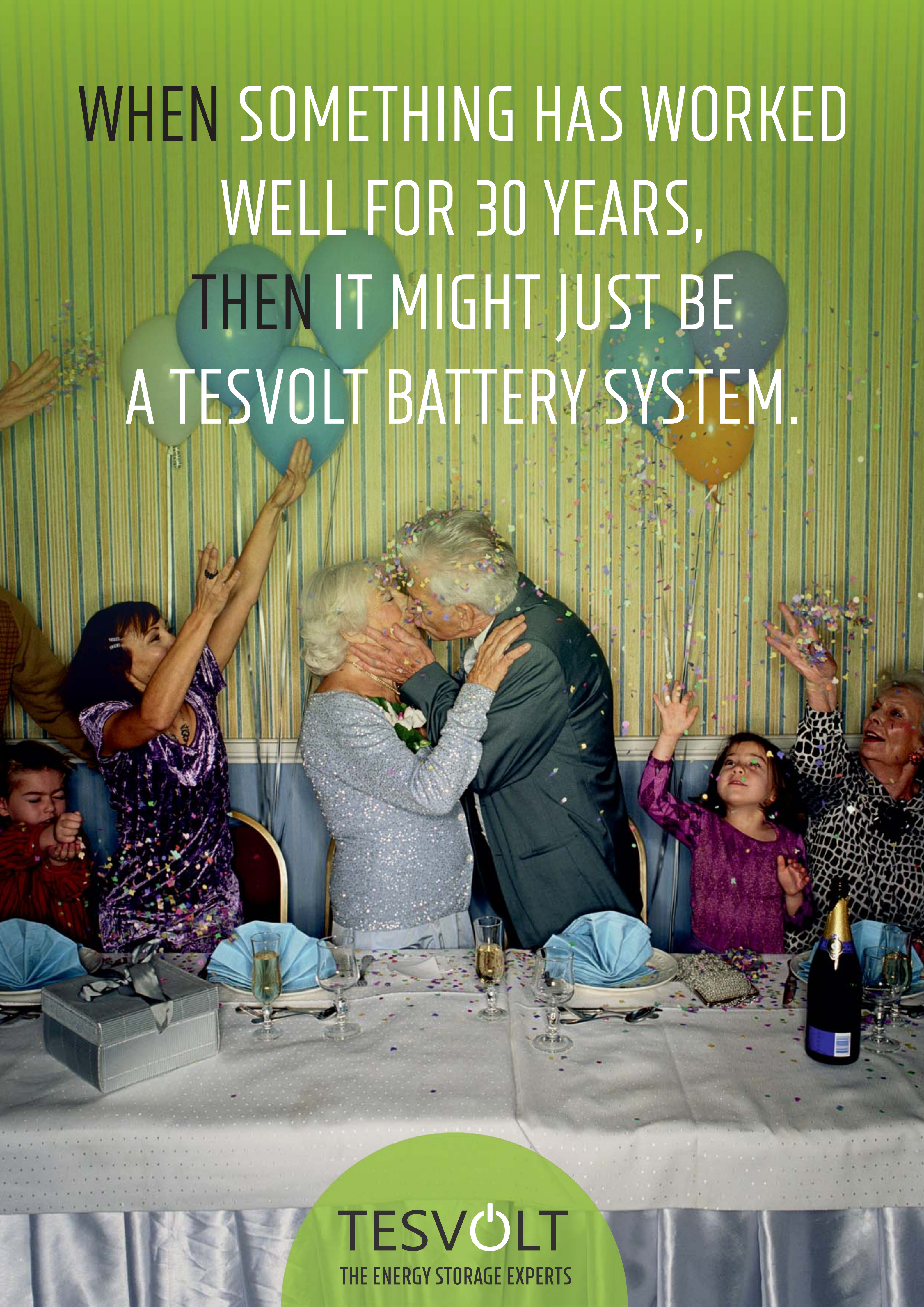
DNV GL's Dr Martijn Huibers and Paul Raats have written about how GRIDSTOR, a recommended practice framework for standardisation aimed at developing a "common language" for stakeholders, could help everyone from investors and insurers to technology providers and integrators mitigate the risks involved in their projects.

We look at some of the top system integrators, the 'EPCs' of the energy storage space, if you will; the companies that are taking on projects, designing them and putting them in the field. While there are other, undoubtedly strong competitors, the likes of AES, RES, Younicos, NEC ES and others we looked at have been instrumental in shaping the market thus far and are likely to continue being influential.

We also have a look at energy storage in the UK, which is frequently quoted among the top markets globally and has in place a 3.5GW pipeline of potential utility-scale systems waiting to go. Solar Media scribe David Pratt looks at policies and market milestones, while analyst Lauren Cook delves into that pipeline and emerges with some strong insights.

We are very excited to be part of this edition of *PV Tech Power* and we hope you find this section informative and useful.

Andy Colthorpe
Solar Media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Energy storage saves Arizona utility from building 20 miles of transmission, distribution lines

Credit: AES

AES will supply two of its Advancion systems for the Arizona grid project

Rather than rebuild miles of electricity transmission lines, utility Arizona Public Service will install two battery storage systems totalling 8MWh in rural Arizona – making it one of the first electricity companies in the US to utilise batteries instead of traditional infrastructure.

The two 4MWh Advancion batteries are made by AES Energy Storage. Construction will begin this winter. While the use of energy storage to replace or complement the role of traditional wires, cables and substations has long been talked about, there has been little in the way of traction since. At present most utility-scale storage systems are providing grid-balancing or renewables integration – or both – rather than being seen as an alternative to transmission and distribution (T&D) infrastructure spending.

French island tenders push down solar-plus-storage prices by 40%

Tenders for solar-plus-storage projects on French island territories including Corsica, Guadeloupe and Martinique in August resulted in winning bids often 40% lower than the victors of previous reverse auctions.

An existing remote microgrid project integrating renewable energy and energy storage, on the Portugese island Graciosa.

Credit: Younicos

Two recent government tenders will see over 75MW of projects developed, one focusing on solar PV paired and co-located with energy storage and the other looking at PV self-consumption without energy storage.

There were a total of 109 winning projects: 67 of those, totalling 63.3MW, will be "PV systems equipped with storage devices" while the remaining 42 projects, adding up to 11.8MW, are self-consumption with PV alone.

The solar-plus-storage projects attained a guaranteed purchase price for their generated power of €113.6 (US$133.97) per MWh, easily competitive with other generation in those territories, likely to be linked to diesel genset use. Power prices on the islands are at around or over €200 per MWh. Solar-plus-storage systems will be between 100kW and 250kW generation capacity each.

Middle East interest in energy storage 'ramping up significantly'

Grid-connected energy storage systems in the Middle East are forecast to reach 1.8GW by 2025, according to analysts IHS Markit.

Interest from the likes of government agencies and utilities comes primarily from the burgeoning interest in utility-scale PV plants, an energy asset class which the region has wholeheartedly embraced in recent years.

"We are hearing a lot of interest from government supported agencies and utilities in the region to at least explore storage in the first step but in the long term commercially deploy it," IHS Markit analyst Julian Jansen said.

In August, a PPA was signed for what is claimed to be the Middle East's largest solar-plus-storage project, 11MW of PV coupled with a 12MWh battery storage system in Jordan, overseen by minister of energy and mineral resources Saleh Al Kharabsha.

'Saltwater battery' maker Aquion Energy back from dead under new ownership

Aquion Energy, maker of energy storage batteries and whole systems based on a novel electrolyte with a chemical composition similar to saltwater, is back in business. The American company, which began production in 2014, went bust in March, offloading 80% of its workforce and sending its website offline.

In July, Aquion emerged from Chapter 11 status, the bankruptcy protection law under which it had been compelled to file agreements. The new owners are a "majority-American joint venture" headed by CEO Philip Juline.

India's first major solar-plus-storage tenders cancelled

India's first major large-scale solar-plus-storage tenders, tied with solar parks, were cancelled by the Solar Energy Corporation of India (SECI) in July.

In June, tenders at Pavagada in Karnataka (200MW solar) and at Kadapa in Andhra Pradesh (100MW solar) had been delayed mainly due the sudden drop in solar prices across India, but a few weeks later the tenders were officially dropped altogether. In both cases, each 50MW of capacity was to be coupled with 5MW/2.5MWh of battery storage. The benchmark tariff for the projects was INR4.43/kWh (US$0.069), but since the tenders were first announced, solar prices plummeted across India.

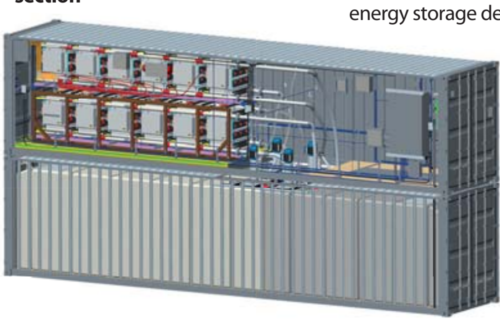
VIZn claims to deliver energy storage for renewables at record low price

Utility-scale zinc-iron flow battery maker VIZn Energy claims it can deliver energy storage to pair with solar or wind at a "record low price" of just US$0.04 per kilowatt-hour.

VIZn said that energy storage could now be added to grid-scale wind or solar PV installations at a lower price than new coal-fired generation in the US, which Bloomberg New Energy Finance has benchmarked at around US$0.06 per kWh.

In addition to the low cost integration of renewables, utility-scale energy storage developers may also be able to benefit from adding various other revenue streams for their projects, such as ancillary services for grid operators, thus creating a revenue stack which could further enhance the economics of their installation.

VIZn Energy's flow battery in cross-section



Credit: VIZn Energy

Steps states can take to advance energy storage

Policy | State governments and agencies have a key role to play in fostering the growth of energy storage. Todd Olinsky-Paul of the Clean Energy States Alliance looks at the key policies, programmes and incentives being used by America's pioneering storage states

Credit RES Americas

With the federal government refocusing on fossil fuels, state clean energy policy is now more important than ever in bringing renewable energy and energy storage technologies to scale. And indeed, some states are beginning to step out as leaders on energy storage policy, as they have done for wind, solar and other clean energy technologies. But there is still a lot of work to be done at the state level if storage is to fulfill its potential as a revolutionary technology for both grid-scale and behind-the-meter applications.

Utility procurement

California, of course, seized the early lead in 2013, with its aggressive 1.325GW utility energy storage procurement mandate (an additional 500MW was added in 2017). The mandate specifies separate procurement targets that must be met by each of the state's major utilities by 2020; in addition, it identifies separate targets for storage sited on the transmission grid, distribution grids and behind customer meters in each utility territory, meaning that utilities must procure storage in a variety of sizes, locations and applications. Additionally, the mandate specifically excludes large pumped hydro, to avoid the situation where a few big hydro projects might crowd out battery storage.

The state followed up with a series of rulings to address interconnection issues, expand markets, enhance the integration of renewables and provide for additional benefits to distribution grids. At the same time, California refocused its Self-Generation Incentive Programme (SGIP) almost entirely on behind-the-meter storage. The current SGIP budget through to 2019 is over US$500 million, with 79% reserved for energy storage projects.

State clean energy policy will be a key driver of future storage activity the US

The result has been a booming market for both grid-scale and behind-the-meter storage in California. The state leads the nation in both commercial- and utility-sited energy storage deployment. Several lessons can be drawn from this:

- The push-pull combination of a utility mandate along with significant customer incentives is critical. It is unlikely that the California markets would have scaled so quickly if both utilities and customer/third-party developers had not been engaged in moving the market forward.
- Incentives and mandates notwithstanding, much of the success of the California market is related to the state's high electricity costs, high solar penetration

Credit Clean Energy Group

A 2MW battery project in Sterling, Massachusetts, which has emerged as one of the leading states in the US for encouraging energy storage

and, most critically, high demand charges, which can be greatly reduced by installing behind-the-meter energy storage systems. This provided a ready market of commercial customers, and it also fueled utility demand-response programmes.

- California benefited from coordination between state policymakers and regulators, and the single-state California Independent System Operator (CAISO); few other states, with the exceptions of New York and Texas, have such an advantage.

Other states have followed suit with utility procurement, but none so boldly. Oregon instituted a 5MWh procurement mandate, which applies to the state's two large investor-owned utilities. Although not a large requirement, it is noteworthy that Oregon chose to express its mandate in terms of megawatt-hours, rather than megawatts. And a few other states, including New York and Nevada, have authorised utility procurement targets, though it's not clear yet whether these targets will be adopted. Most recently, Massachusetts announced a 200MWh "aspirational" utility target. And Puerto Rico, back in 2013, adopted rules requiring all new grid-scale renewable generators to include a storage component. Though not technically a target or mandate, this does establish a minimum requirement for energy storage development as a percentage of new renewable capacity on the island grid.

Energy storage is also allowed, in various forms, within several state Renewable Portfolio Standards (RPSs). It may seem that an RPS would be the logical vehicle through which states could require utilities to procure storage. However, it is notable that only four states have an RPS that allows battery storage as an eligible resource; there are no existing RPSs with carve-outs or requirements for energy storage; and none of the recently announced state procurement targets are being developed within an existing state RPS. One reason for this may be that opening a state's RPS to revision can be politically hazardous, as opponents of the RPS may take the opportunity to try to weaken or revoke it. Another issue is that storage, though it offers many benefits, is not the same as generation, and groups that support renewable energy may object to diverting a portion of the portfolio to support a non-generation resource (Massachusetts plans to circumvent this issue by adding battery storage within its Alternative Energy Portfolio Standard – APS – rather than its RPS). Whatever the reason, states have thus far found it easier to create standalone storage mandates or targets, rather than to add storage into an RPS.

Grant programmes

Competitive grant programmes are often the first tool used by states to demonstrate a new technology. They offer a number of advantages, including giving the state a large degree of control over which projects get built, and providing opportunities to learn about the technology, its applications, economics and markets.

Numerous states have awarded energy storage grants under various programmes, including some specifically dedicated to energy storage, and others targeted to storage-related services such as microgrids or resiliency. Notable microgrid and resiliency grant programmes were established in several north-eastern states in the aftermath of Superstorm Sandy, which knocked out grid power to some communities for weeks. These include a US$50 million microgrids programme in Connecticut, a US$40 million resiliency initiative and another US$15 million in storage grants in Massachusetts, a US$40 million microgrids programme in New York, and a US$10 million energy storage grant and rebate programme in New Jersey. State energy storage grants have also been awarded in Vermont, Oregon, California, Washington State and Maryland.

Although there are still emerging energy storage technologies, the established battery chemistries – lead acid and lithium ion – would seem to need no further demonstration, having proved themselves in thousands of installations worldwide. Nevertheless, it is likely that as new states begin to experiment with energy storage, they will want to demonstrate the technology for themselves. Thus, competitive grants are likely to remain an important part of the state storage incentive landscape for some time to come.

In addition to demonstrating the technology, grant programmes are useful for demonstrating new applications and economic cases for storage. This can be particularly effective when state resources are leveraged with federal and private resources, as shown by a number of high-profile projects jointly supported by state energy agencies, U.S. DOE Office of Electricity, and Sandia National Laboratories. Clean Energy States Alliance has assisted several of these innovative projects across the country [1].

Incentives

As states become more comfortable with energy storage, they should begin to move beyond one-off grant programmes, and instead devote public resources to more developer-friendly forms of support. These include predictable, longer-term programmes such as rebates and adders, tax incentives and market-based incentives such as renewable energy credits. An example of this progression is provided by New Jersey, which began its energy storage programme in 2014 with competitive grants, but by 2016 had progressed to a combination of grants and rebates. Other early-adopter states such as Massachusetts and California are also considering storage rebate programmes.

Although California's SGIP is the most successful example of a state energy storage incentive programme, Massachusetts leads the way for development, still in progress, of the most comprehensive suite of energy storage incentives, mostly through adding storage as an eligible technology to existing programmes. As recommended by the state's landmark 'State of Charge' report [2], Massachusetts is working on incorporating storage into its APS; making storage eligible for energy efficiency funds; rolling out a new solar rebate programme, with a storage adder, to replace its SREC programme; and creating a new, stand-alone storage rebate modelled after its existing MOR-EV programme. At the same time, Massachusetts continues to provide grant funding to projects that demonstrate novel and non-monetisable applications.

As the Massachusetts example demonstrates, it may be easier for states to incorporate storage as an eligible technology within existing, funded clean energy incentive programmes, rather than creating new, stand-alone programmes dedicated to supporting storage. The former can be as simple as amending the definition of eligible technology, while the latter requires more work, both in creating a new programme, and in identifying dedicated funding to support it. Additionally, finding political support for storage within an existing programme may be easier than finding political support for the creation of a new programme.

However, there are drawbacks to adding storage to existing programmes. One problem is that adding a new technology without expanding the programme's budget may be seen as a threat by advocates for (and beneficiaries of) the original programme – for example, solar advocates may not wish to share hard-won incentives with storage developers. Another problem with this sort of eligibility expansion is that it ties storage to other technologies – for example, the Massachusetts SMART solar programme will provide a storage incentive, but only if that storage is connected to an eligible solar installation. A third potential drawback is that adding storage as one among a number of eligible technologies – for example, in municipal PACE bonding programmes – may or may not result in more storage being deployed.

Among the many existing types of state energy programmes to which storage might be added, the two most promising are state RPSs for utility-scale storage, and state energy efficiency programmes for behind-the-meter storage.

State RPS programmes, for reasons discussed above, have not been opened to storage in most states; however, 29 states plus the District of Columbia and Puerto Rico have an RPS, and these standards have proven themselves very successful at increasing the deployment of renewables. According to Lawrence Berkeley National Laboratory, more than half of all growth in renewable electricity generation (60%) and capacity (57%) between 2000 and 2016 is associated with state RPS requirements [3]. Thus, the potential growth in storage as a result of state mandates is enormous – especially if states were to create a storage carve-out within their RPS.

Energy efficiency (EE) programmes are likewise an enormous untapped resource. Currently, more than US$7 billion is budgeted annually in state electrical energy efficiency programmes. Traditionally, electrical energy is aimed at reducing consumption of electricity; recently, some state EE programmes have added a solar component, which does nothing to reduce consumption but does reduce the amount of electricity purchased from the grid, helping to make the overall mix of electricity consumed less polluting. Adding storage to EE programmes requires a further shift in the definition of "efficiency", since storage does not reduce consumption and, in fact, may slightly increase it due to losses incurred over time. What storage brings to the table, however, is the ability to both increase self-consumption of solar and shift purchases of electricity from the grid to off-peak times, thereby reducing demand charges and enabling consumers to participate in demand response programmes. Storage can also safeguard the value of solar in the face of declining net metering rates. Electrical energy storage is not yet widely considered an energy efficiency measure, but there are indications that early adopter states are considering adding storage (for example, this is under consideration in both California and Massachusetts for those states' respective 2019 EE plans).

Other state initiatives

There are numerous other steps states can take to support energy storage.

Studies are a typical early effort that helps state legislators and policymakers to learn more about a new technology or market. Numerous states have conducted studies on energy storage and microgrids, with the preeminent example being the previously mentioned Massachusetts 'State of Charge' report. This 2016 report included a modelling analysis of the state's electric grid, which identified not only the optimal amount of energy storage to add to the grid, but also where it should be located, down to the substation level. It also recommended a comprehensive suite of storage-supportive policy and programme initiatives.

Studies such as these can be useful even beyond the state that conducted the study. For example, Clean Energy Group is currently working with an informal group of New England state policy makers who, while their agencies cannot afford to duplicate the Massachusetts study, would still like to learn from it, and apply it to their own state policy efforts.

Tax credits can be helpful in supporting larger-scale storage deployment, although it is unlikely that most states could provide tax credits large enough to replace the soon-to-sunset federal investment tax credit, which applies to storage so long as it is charged by qualifying renewable generation. Maryland recently became the first state in the nation to provide a 30% tax credit on the installed cost of energy storage systems. The credit is capped at US$5,000 for residential and US$75,000 for commercial projects, with a US$750,000/year cap on total credits awarded.

A third approach tried by some states has been to support related complex technologies such as microgrids, in the hope that the resulting projects will include renewables and storage. This approach has met with mixed success. The Massachusetts Community Clean Energy Resilience Initiative, a US$40 million grant programme for municipalities, did result in a number of solar-plus-storage projects; by contrast the Connecticut Microgrids Grant and Loan Programme, a US$50 million grant programme, resulted in relatively few projects that incorporated storage, instead funding numerous microgrids employing cogeneration (CHP) and fuel cells. Similarly, the innovative New Jersey Energy Resilience Bank, despite high initial expectations, has not thus far resulted in any resiliency projects based on renewables and energy storage.

What's next?

As more states take up energy storage as an important part of their overall clean energy and efficiency portfolios, it is to be hoped that they learn from, rather than replicate, the first steps of the early adopter states. Additionally, it would be prudent for states to study the arc of solar PV, as it seems that energy storage is following a similar glide path from niche applications to full commercialisation to grid parity. And finally, states should – and some are already starting to think about this – move early to ensure that low- and moderate-income communities are not left behind in the energy storage revolution. Energy storage, and its many benefits, should not be exclusively for utilities and wealthy corporations.

Some recommendations:

- **Study the regulated markets.** Frequency regulation was a breakout market for storage in PJM, through it was quickly saturated; in ISO New England, utilities can use storage to reduce their demand during regional peaks, reducing capacity and transmission costs so significantly that a 4MWh battery can pay itself off in fewer than seven years. As other ISO and RTO markets develop, new applications for storage may be revealed.
- **Study the connections between utility and customer-sited storage**. The big play behind the meter is in demand charge management; the big play for utilities, at least in some areas, is in capacity and transmission charge management. A facility with a non-coincident load can achieve both, as has been demonstrated by Green Mountain Power in Vermont and Southern California Edison. If utilities want to stay ahead of the storage revolution, they will need to embrace distributed resources.
- **Watch for the tipping point.** GTM Research recently reported that the price of lithium-ion battery packs fell 73% between 2000 and 2016. Every price drop means energy storage becomes an affordable technology for more customers and more applications.
- **Look for standardisation and services.** Aside from further declines in manufacturing costs, the best indicator that energy storage has arrived as a fully commercialised commodity will be the commoditisation of support industries – storage leasing, storage financing, storage warrantees, storage controls and integration.
- **Watch how storage is defined and regulated.** Thus far, storage has mostly ended up in the generation bucket, so far as state policy is concerned – but this is starting to change. It may not seem important, but how states define storage can have a big impact on everything from interconnection requirements to utility ownership. Already, some states have amended regulations to allow utilities to own storage – for example, New York in its REV proceedings and Massachusetts in its Act Relative to Energy Diversity. Utility ownership can bring more resources to the table, but it can also tend to crowd out third-party and customer ownership, if regulatory guard rails are not in place. And states are in the very beginning stages of understanding how to regulate utility-owned storage. ■

Reports on energy storage policy and economics are available from the CEG/CESA websites at www.resilient-power.org and at http://www.cesa.org/projects/energy-storage-technology-advancement-partnership/

Authors

Todd Olinsky-Paul serves as project director for both the Clean Energy Group and Clean Energy States Alliance (CESA). For Clean Energy Group, Todd works on the Resilient Power Project, which supports deployment of clean distributed technologies such as solar-plus-storage at critical facilities to enable the provision of essential services during grid outages. He also serves as a CESA project director for the Energy Storage and Technology Advancement Partnership (ESTAP), a federal-state funding and information sharing project that aims to accelerate the deployment of electrical energy storage technologies in the US.

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UK storage charges ahead

Markets | The UK government has placed energy storage at the forefront of its industrial strategy. David Pratt and Lauren Cook report on how this is creating the right conditions for what many believe will be a boom market in years to come

Energy storage has hit the mainstream in the UK this year after the government placed the technology at the forefront of its industrial strategy, laying out vast sums of money and accompanying rhetoric for the future of storage in the UK.

To back it up, regulatory progress has finally been made while transmission system operator National Grid is looking to build on last year's tenders, which showed a huge presence already in place.

Hype around the UK is growing as a result of progress like this. Utility Enel recently stated that the UK offers "one of the most advanced markets in the world" for utility-scale battery storage systems, while Navigant Research recently placed the UK within the five biggest markets for utility-scale storage.

Across residential, commercial and industrial (C&I) and utility-scale applications, 2017 has already proved to be an important year for energy storage and shows the UK is starting to meet the hype.

Credit: Anesco

"The best scale-up market in the world"

In a market where little more than 800,000 homes out of 27 million were convinced by the offering of solar panels and the attractive tariffs they once brought, UK residential storage has so far proved to be a tough nut to crack.

However, a key trend that has emerged this year is the sheer number of international and domestic companies that believe they are up to the task. Since December 2016, almost 10 battery storage manufacturers and suppliers have looked to create a foothold in the UK alongside those already present (see timeline).

From battery manufacturers selling directly to homes, or utilities looking to take advantage of their existing customers, UK residential storage is filling up with companies seeking to build a mass market, such as British manufacturer Moixa. The technology firm has deployed almost 1,000 systems across the UK, utilising partnerships with distributors to offer solar-plus- storage packages, deploy within social housing and new build, and work with utilities.

These partnerships are proving to be popular targets for storage firms looking to get their products into homes. Moixa CEO Simon Daniel expects around 80% of home storage to be deployed through these mass channels – no doubt a view also taken by E.On given its UK solar-plus-storage launch back in April (see timeline below). As he explains, past deployment of solar in the same way has shown the UK is ready for mass roll-out.

The UK's utility-scale storage pipeline has reached 3.5GW, placing it within the world's top five markets

"We're much more bullish on the potential for storage in the UK because while it is not the best early adopter for storage, it is probably the best scale-up market in the world because of the way organised, multi-thousand projects for solar and other technologies were deployed and funded historically," he says. "There are probably about 50,000-plus batteries deployed in Europe today, but

December 2016	February 2017	April 2017	July 2017	August 2017
Sonnen partners with distributor CCL to expand UK sales	Solarwatt begins trials of MyReserve home storage	Utility E.On launches its solar and storage offer	Nissan and Eaton begin shipping xStorage second life batteries	IKEA confirms it has begun offering LG Chem and Sonnen batteries
	Leclanche reiterates commitment to UK in preparation for new product	Mercedes Benz Energy Storage Home units enter UK	SolaX Power begins shipping LG Chem batteries	

Timeline of UK storage milestones since the end of 2016

we see pipelines in the UK that could exceed that and it's just a question of the economics and the process."

With this many units expected to be in place over such a short timescale, poor practices could grow as more disreputable members of the industry seek to take advantage of 'Solar 2.0' in much the same way some did during the golden age of feed-in tariffs.

Throughout 2016 the Renewable Energy Consumer Code (RECC), a consumer protection scheme for domestic renewables, received at least one complaint a week related to battery storage, half of which concerned mis-selling practices.

However, this could be set to change with the publication of the Code of Practice for Electrical Energy Storage Systems by The Institution of Engineering and Technology (IET). Formulated alongside the UK's rapidly evolving distribution network operators (DNOs) and others, the guidance on "safe, effective and competent application of electrical energy storage systems" provides "a timely shot in the arm" for the country's storage market according to Sonnen's UK director, Martin Allman.

"There's a real lack of guidance for installers to follow – and which consumers could use as well. The IET guide is going to be really important to fill that vacuum, to give some clear advice to installers about how they can go about installing and selling these systems, and making sure things are done in the right way," he says. "It's just part of a maturing market that these standards can come along and play an important role."

Another sign of growing maturity for UK storage is regulatory progress, and recent advances for home storage are typified by the government's decision to extend a tax break enjoyed by solar to energy storage.

In August the UK's Solar Trade Association announced it had secured a 5% VAT rate for battery storage instead of the standard 20% previously applied. With the stipulation that this would only be allowed if the battery unit is sold and installed with solar panels, the decision will no doubt further boost the attractiveness of a solar-plus-storage package, which could become the leading choice for homeowners, while discussions to extend this to retrofit storage continue.

With this initial decision as well as rapidly developing business models from major players in the market bent on making a success out of UK residential storage, Allman points out: "There is an exciting momentum to the UK battery storage market with various pieces of the jigsaw coming together over the last few months."

The C&I opportunity

Meanwhile commercial and industrial applications of energy storage are proving tricky for existing suppliers – surprising considering the ability of storage to reduce what are in the UK considerable electricity costs for businesses.

These systems can help large energy users avoid the peak times used to calculate a premium levied on electricity use by drawing down from the grid at cheaper periods to use later, without interrupting normal operations. For the thousands of commercial properties equipped with solar arrays, storage can help to further increase self-consumption and lower reliance on the grid while reducing exposure to unscheduled interruptions to business activity.

Despite these benefits, cost remains the presiding factor for any business when considering investment, and while batteries can cost a quarter of what they did six years ago, many are waiting for this price curve to continue downward.

A range of businesses models have therefore emerged to tempt early movement into the storage world. Much in the way that power purchase agreements emerged to overcome a similar issue in solar, businesses are now being offered free energy storage in the UK.

Omnio, set up under solar developer British Solar Renewables, has set out to address the "overlooked" market for small, distributed energy users. The company's engineering team work with host businesses to install batteries free of charge at proposed sites. These will then provide a peak shifting service and charge when energy prices are low before discharging when they are at their peak to generate savings across the business. Omnio uses the installs and an aggregator to provide ancillary services to the grid, prioritising the partner businesses' needs but creating revenue to fund the fleet of 50kW energy storage devices.

"Omnio is looking to help distributed energy users, companies who probably use just as much energy as those large companies but distributed over 50-100 sites. Large retail, hotels, restaurants, those sorts of things, who have a shorter site tenure of something like five to 10 years," founder and managing director Chris Curry explains.

In a similar vein, Siemens Financial Services has launched no-money-down options for the first time in the UK. The 'outcome-based' finance model is available to electricity users with on-site electricity demand profiles between 1MW and 100MW and allows customers to pay for Siestorage systems based on battery output

Head of sales in energy finance for Siemens Financial Services, Ian Tyrer, says that customers would be paying for "what the technology delivers rather than the technology itself". In the case of Siestorage, this again allows C&I electricity users to arbitrage their power purchases and defer them to non-peak periods, saving on bills and grid network costs.

For businesses, arbitrage is rapidly becoming the key draw of storage and, according to Scott McGregor, chief executive of flow machine company redT, could soon become the main economic case with which storage can be pitched.

"I've been very vocal up until now about how energy storage doesn't make economic sense in the UK. However we've spent months tentatively modelling how to get the revenues laid up for storage, grid services and solar and some arbitrage and we're getting an eight to 10-year payback now in the UK, which is pretty good for an infrastructure project. We believe it is now commercial in the UK, we've got the right price for the system so it's economic," he says.

The right direction of travel

Despite these advances in both residential and C&I, it is the recent activity and progress in grid-scale storage that is making the UK such an exciting market for the technology. As Lauren Cook, analyst with *PV Tech Power*'s publisher Solar Media's in-house research team, explains in the box to the right, the pipeline for utility electricity storage projects is growing and has now reaching over 3.5GW.

This pipeline and all the additions that are certain to join it have been waiting for a combination of factors to kick into gear, and these have finally emerged in the UK: government backing, regulatory change and a planned revolution of the power system.

Storage-friendly reforms in the UK

Removal of 'double charging': Owners of storage assets will no longer have to pay charges associated with the RO, CfDs, FiTs and Capacity Market auctions when charged electricity is dispatched. Electricity used to charge storage assets may also be exempt from Climate Change Levy costs under certain conditions.

Demand residual charged: Ofgem is considering removing these transmission and distribution charges as part of its Targeted Charging Review.

Definition of storage: The Electricity Act 1989 will be amended to include an explicit definition of electricity storage, specifically as a generation subset to allow Ofgem to consult on a modified generation licence intended for next summer.

Easier connections: Network operators will be expected to improve the connections process for storage, specifically the clarity and transparency regarding where to connect and better queue management.

Energy storage has been chosen as a key industry for the future of the UK, both in and out of the EU, and with that in mind the UK government launched a call for evidence alongside regulator Ofgem seeking views on what was needed to get this industry going.

Eight months after its launch, having been delayed by the UK's snap general election in May, the outcome set out 29 actions in response to a whole range of issues in need to tackling if storage is to take off (see box above for examples).

While these actions may not materialise until 2019 in some cases, the measures were widely welcomed by industry as a sign that the government was finally making progress on behalf of storage. Cyrille Brisson, European vice president at Eaton, says: "The proposed steps should help remove barriers to market and allow for a more flexible and responsive energy system.

"The direction of travel is therefore the right one from a regulatory perspective and has the potential to put the UK in a strong position as a global leader in the development of battery storage technology.

Greg Clark, the UK's business, energy and industrial strategy (BEIS) secretary, also announced that £246 million would be spent on the Faraday Challenge, designed to boost research and development and position the UK at the forefront of energy storage, predominantly for electric vehicles.

This will see the creation of a virtual 'Battery Institute' to address the key industrial challenges in developing battery storage technology in the UK. Its most promising work will be moved on to further development for commercial applications while a competition is already underway to find the best proposition for a new National Battery Manufacturing Development facility.

In isolation this looks good, however storage companies will need to be careful of plans released by BEIS to alter the derating factor of batteries competing in the capacity market. The changes, which could see the majority of storage assets lose their current 96% derating status, stem from the fact that most storage facilities normally deliver power for around 30 minutes to an hour. Traditional fossil fuel plants, on the other hand, run for longer periods to offer greater security of supply during an extended stress period.

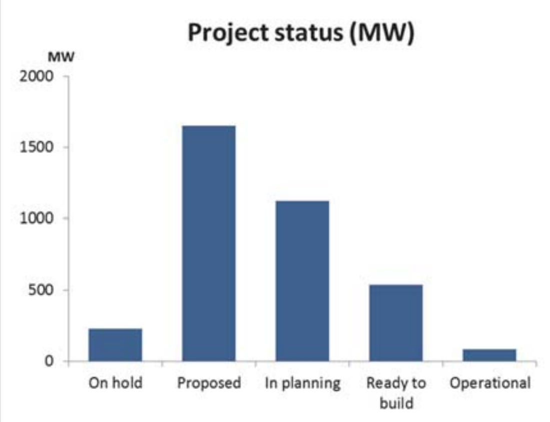
While capacity market payments often make up only a small proportion of the revenue for a storage project, they do offer a long-term income as part of a revenue stack often made up of shorter-term contracts. With upcoming changes to embedded benefits and National Grid's planned reforms to its products, it's unclear what revenues will look like for large-scale storage when the dust settles.

However, it is also likely to see rapid deployment alongside renewables as the UK moves into a post-subsidy phase of development. According to Solar Media's head of market research Finlay Colville, more than a quarter of the solar farms currently sitting in the UK's pipeline without subsidy are being planned to include energy storage units.

All of this across residential, commercial and utility-scale applications means the UK is more than meeting the hype around the developing market. Either through the sheer consistency of new additions to the market, new and innovative business models, or the regulatory progress and hunger for large-scale storage developments, it is sure to be a diverse and highly active sector for years to come. ■

The status of the UK utility storage pipeline

By Lauren Cook, analyst for Solar Media market research

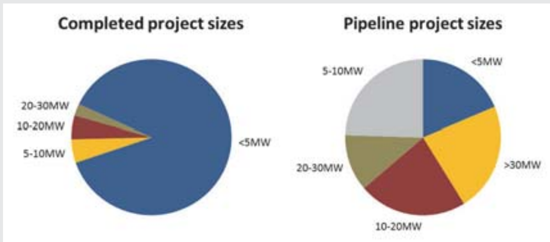


The UK's utility storage pipeline*

Operational projects have increased to over 80MW made up of around 40 projects. The average project size has been small to date – most under 1MW – with the four largest projects accounting for around 50MW.

The average project size looks set to increase with several 50MW projects in the ready-to-build category, where planning has been consented plus another indication of progress has been made, such as confirmed financing or a components supply contract. The average size of projects at this stage is 20MW, reflecting trends globally as grid-scale batteries become more widespread, and there are over 500MW of projects in this category that could be built over the next 12 months.

The proposed and in-planning categories show what is coming through the system next, with projects at the planning stage likely to be eyeing up the next capacity market auction and keeping a close watch on National Grid's decisions on how it will procure future frequency services.



The size of completed and pipeline utility storage projects in the UK*

The majority of completed projects are small, made up of demo and research projects between companies and DNOs, for example, or those co-located with renewables like solar farms. But with both 15 and 20MW battery storage systems built already this year we can see the shift towards larger projects is underway.

Going forward there is a lot more diversity in the pipeline, with projects typically anywhere in size up to 50MW. Standalone projects are typically larger and we can see a variety of project sizes in this group and even in individual developer's pipelines.

**Storage output has been measured in megawatts as this unit is more commonly used at the earlier stages of development, especially for planning purposes.*

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Grid-connected energy storage: implementation and risk management

Grid storage | The advent of grid-scale energy storage means a whole raft of new technical, safety and risk-mitigation requirements for the industry to understand. Martijn Huibers, PhD and Paul Raats, MSc of DNV GL report on guidance designed to help stakeholders get to grips with this fast-emerging sector

Credit: AES

GRIDSTOR is intended to support the growth of the grid-scale storage sector

The world of energy is changing at breakneck speed, whether you appreciate it or not. Even the most passionate climate change deniers cannot deny the simple facts of the energy transition. Obviously, the growth of photovoltaics has been exponential for the last decade, owing to technological progress and decreasing costs. Wind power, especially offshore wind, is thriving as well, with prices dropping decades faster than industry expert forecasts even a few years old.

With the shift in the energy mix towards variable renewable generation comes an increasing need for flexibility. Which combination of flexible resources is best suited for a particular (small- or large-scale) power system is strongly dependent on among other things the local generation and demand profiles as well as properties of the grid. Grid-scale energy storage is one booming option. It has been widely compared to where PV was 10 years ago, storming the market due to maturing technologies and steady cost reductions. Grid-connected storage systems can serve several applications in the power system, often simultaneously: primary reserve, peak shaving, arbitrage, black start capabilities, ramp rate control, grid investment deferral and more.

Utility-scale energy storage is catching the attention of power grid stakeholders. Utilities, where allowed by law, are now integrating them into their grids (or at least running demonstration projects), project developers are building them, investors are financing them, insurers are asked for policies, manufacturers and system integrators are ramping up production. And as energy storage has been around for at least a century (depending on the type), the technologies are considered matured and their risks are clear and well-mitigated. Or are they?

Risk mitigation

As with many other energy transition issues, things are not that simple; there are several complicating factors. Recent years have seen rapid technological advances, raising the possibility of risks and a lower system-level maturity. Even if only one component has evolved, the behaviour and risk profile of the entire system can be quite different. Furthermore, the scale of grid-connected storage systems being installed nowadays is quite different. Issues emerge for tens-of-megawatts systems that are not present or not relevant for (kilo-)watt-scale systems. For example, grid-scale lithium-ion batteries have different safety requirements (e.g. cooling, fire extinction) and different energy management systems than the lithium-ion cells that have been used in consumer electronics for years. Lastly, the grid-scale storage market itself is rather young. Experienced suppliers and end users exist, but a significant number of players have only comparatively recently moved into the field and are lacking knowledge to a certain extent. Consequently, designs and mitigation measures may not always be optimal, and conversely buyers are not always aware of what to ask for or pay attention to.

So why not rely on standards, the tried-and-tested way to mitigate risks, improve quality and prove compliance? Indeed, there is no shortage of standards, guidelines and other guidance documents out there – in fact, as many as 200 were identified worldwide that may apply to grid-scale energy storage components, systems or projects. It is understandable that stakeholders in an emerging market, including regulators and authorities, have trouble choosing which ones could, should or must be applied. Currently, there is no single comprehensive standard that covers all relevant aspects.

Enter GRIDSTOR. In 2015, the energy storage industry had realised the situation described above and a consortium of eight industry stakeholders (and 36 reviewing parties) cooperated in a joint industry project to resolve it. The product of their efforts was documented through "DNVGL-RP-0043; Safety, operation and performance of grid-connected energy storage systems", also referred to as GRIDSTOR. The document is a comprehensive recommended practice (RP) intended to be the one-stop go-to document for all stakeholders, issued by DNV GL and publicly available online [1]. It references existing standards and similar documents as much as possible, while adding additional or new recommendations in case topics are not or inadequately covered elsewhere. The general approach is technology-agnostic, with technology-specific content wherever needed, for example on safety issues like fire suppression and safe system design. All project phases are covered, from feasibility to decommissioning.

Market response to publication of the RP has been overwhelmingly positive, with industry players picking it up and using it as an independent risk mitigation tool. In 2016, a new consortium with 14 members formed to update and fine-tune GRIDSTOR and to add or expand upon topics such as micro-grids, cyber security, conformity assessment, warranties and decommissioning; publication is scheduled for this September.

All things to all people

The ways in which GRIDSTOR is supporting grid-connected energy storage business depend on who is using it. Every stakeholder has its own interests, expertise, risk focus and risk appetite. For example, utilities are using the document as a manual and as a guide for procurement. Investors value it as an independent and industry-supported foundation for due diligence. And last but not least, developers of solar-plus-storage projects can find support for technology selection, dimensioning and benefit stacking. These examples are examined in more detail below.

Utilities are generally experienced in implementing projects for their assets, but energy storage systems may be new to them. Therefore, in all phases they may not have an overview of key issues to investigate or address, and minor or major risks to mitigate. GRIDSTOR can then be used as a manual of sorts. By reading carefully through all applications, project phases, definitions, technology-specific issues etc. relevant to the project at hand, the utility is able to absorb the knowledge required for the project as it is being set up and run. For example, correct formulation of employer's requirements is facilitated, including key system and component specifications as well as carefully defined and relevant KPIs. Furthermore, standards with which compliance could or should be requested are easily selected and safety issues can already be discussed and incorporated early on in the project. During construction and installation, Factory Acceptance Testing (FAT) and Site Acceptance Testing (SAT) can be done in a more reliable way.

Investors are moving into the grid-connected energy storage market too. Some invest in stand-alone storage systems, other already have a portfolio of solar or


Credit: redT

wind projects to which storage is added. In all cases, the Recommended Practice is being used as a foundation for the due diligence process typically executed before investment decisions. If upon careful assessment the project or system(s) are found to be in line with GRIDSTOR recommendations, the investor can have confidence that risks are sufficiently identified and mitigated. If certain aspects are not compliant, the investor has an independent reference as a solid basis to convince the other party about the issues and how to address them.

System sizing

Developers of solar PV plants are more and more faced with challenging interconnection requirements, including for example conditions for maximum allowed power ramp rates and frequency control. These requirements can encourage the integration of storage into the PV plant, where the storage device is only used for a small portion of the 8,760 hours make up a full year. In such occasions the business case for the PV plant investment would improve when the storage capacity could be deployed for multiple applications, often referred to as 'benefit stacking'. The recommended practice provides insight in and guidance on the 20 fundamental applications of grid-connected energy storage in the power system.

Incorporating a storage device into a PV plant, whether by necessity or by choice, also implies selection of the correct storage technology and involves a sizing effort for the storage system. GRIDSTOR addresses electrical, electrochemical and mechanical storage technologies, and elaborates on the parameters essential for sizing storage devices to be connected to the grid.

For the consumer-oriented mass market of energy storage (photovoltaic storage, home energy storage etc.) rough sizing rules exist, mainly based on the size of the installed PV system and depending on the region the storage system will be installed in. For industrial applications, such rules do not exist yet. Although a general classification of the storage application is possible, the requirements resulting from the application of the storage device vary significantly depending on the properties of the grid where the device will operate. In many cases this hinders the transfer of a business case from one application to another with slightly different surrounding conditions, and thus requires running the dimensioning process for the new application.

The question whether actual risks have been identified and mitigated with the help of GRIDSTOR can be answered with a resounding 'yes':

- incorrect determination of battery degradation, leading to shorter lifetime and lower capacity than anticipated, as well as warranty disputes
- definitions of key parameters being unclear or not applicable to the project, leading to performance not matching application requirements
- business cases being based on another application
- unclear guarantees and unenforceable conditions for replacement
- inadequate or absent fire suppression systems

And the list goes on. Fortunately, in these and many more cases, the recommendations the industry itself is providing through GRIDSTOR have been able to prevent and/or resolve serious issues. With all industry stakeholders being able to rely on independent risk mitigation, the grid-scale energy storage market is accelerated, in turn further enabling other energy transition technologies – like photovoltaics, just to name one. ■

An updated and expanded version of GRIDSTOR is scheduled for publication by September 2017.

Authors


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References

[1] See the GRIDSTOR landing page at www.dnvgl.com/services/gridstor-recommended-practice-for-grid-connected-energy-storage-52177/ or the general site for all DNV GL service documents at www.dnvgl.com/rules-standards/.

10 OF THE BEST

Storage system integrators

Storage integration | Our team profile 10 of the leading global system integrators working in energy storage today. This is a handful of the names that are designing systems, solving problems, executing projects and shaping the industry around us. By: Andy Colthorpe and John Parnell with Tom Kenning, Danielle Ola, David Pratt and Liam Stoker

S&C Electric

Founded in Chicago in 1911, S&C Electric Company has a long history of providing system integration services across a range of electric power systems. It began working with energy storage more than a decade ago and now has 189MWh of battery storage projects worldwide.

Its three core products offer scalable energy storage products for a number of applications, including what is thought to have been the US' first and largest solar storage project to stack revenue streams and build the case for storage.

S&C's 7MW PureWave SMS Storage Management System was used to provide fully integrated storage management and power conversion for 3MWh of lithium-ion batteries, connected to Half Moon Ventures' (HMV) 4.2MW solar plant at the village of Minster in Ohio.

It allowed HMV to bid into the PJM frequency regulation market, providing grid reliability for more than 60 million customers, while Minster was able to defer US$350,000 of transmission and distribution costs. The award-winning project also provides backup power and shaves the peak demand of the village.

The company is also heavily involved in the development of micro-grids and off-grid technologies. Past projects. This includes upgrading Santa Rita Jail near San Francisco to a fully functioning micro-grid using on-site generation; an advanced micro-grid in Texas for utility Oncor and its 10 million Texan customers; and using the off-grid technologies to bring power to two schools in Zambia.

Last year S&C acquired all outstanding common shares of intelligent micro-grid control systems company IPERC to help it continue this work.

Engineers at S&C's Europe, Middle East, and Africa business unit are based locally in the UK, with vital system parts stored centrally. S&C says this helps it maintain system uptime of greater than 98% and deliver a high standard of service for its customers.

S&C PureWave storage and PV arrays

Renewable Energy Systems Group

With a history that stems back more than 25 years, Renewable Energy Systems Group – more commonly known as RES – lays claim to be the world's largest independent renewables company. With 12GW of renewable generation under its portfolio and offices in 15 countries, its stated aim is to lead the global transition towards clean power generation with an emphasis on wind, solar, storage and transmissions infrastructure. Revenues for the year ended 31 October 2015 amounted to £107.3 million, a staggering 131% year-on-year increase on the £46.4 million it recorded in 2014, however its operating loss also grew throughout the year as the group's cost of sale proved prohibitive.

RES completed its maiden UK-based utility-scale storage facility last year, deploying a 300kW/640kWh BYD-developed battery on the site of a 1.5MW solar park in Copley Wood, Butleigh, constructed by UK solar stalwarts British Solar Renewables. RES acted as the EPC on behalf of local grid operator Western Power Distribution, which used the battery and the solar farm with which it's co-located to deliver various ancillary services. It has been funded through the UK energy regulator Ofgem's Network Innovation Allowance to test the commercial feasibility of similar co-located projects.

RES also offers its 'RESolve' suite of operations and management tools to battery storage projects it develops, offering to optimise asset operation owing to particular performance parameters or revenue streams available. The software communicates with the battery via SCADA systems to optimise for separate load-shifting and frequency services, while also incorporating forecasted generation outputs when co-located with renewables.

To date, RES has developed more than 140MW/92MWh of battery storage projects in three countries including the UK, Germany and the US, which has seen the bulk of its storage deployment so far. The company has a further 200MW of battery storage in its pipeline, including several projects in the UK.

A RES project for frequency regulation near Chicago taken during construction

Nidec

Heavy industrial manufacturer and system integrator Nidec ASI functions across a range of sectors from petrochemicals to steel. The company was created when Japanese parent Nidec acquired the Italian firm Ansaldo Sistemi Industriali in 2012.

In November 2016, the company installed and commissioned what was then the largest utility-scale project in the world.

The West Burton project

Customer:	EDF Energy Rewewables
Location:	Co-located with the West Burton gas-fired power plant, Nottinghamshire, UK
Contract price:	£7 (US$8.77) per MW per EFR/h
Contract length:	15 years

The 90MW project was comprised of six 15MW Nidec systems using LG Chem batteries. The site provides frequency regulation and voltage control for the German utility Steag. The investment was rumoured to have topped US$100 million.

Its most eye-catching project win in the energy storage space in the UK came when it partnered with EDF Energy Renewables for the 49MW/34MWh system that the French utility won as part of the UK's enhanced frequency response (EFR) auctions. Nidec is providing the batteries and the power conversion system for the project in West Burton, Nottinghamshire (see box, above). The deal saw the company take its market share in the UK at the time to 33%.

The company has gained a reputation as a giant provider of giant battery energy storage systems and is surely in a strong position to continue reaping the rewards as energy storage tenders proliferate.

Nidec's project for Steag was the largest in Europe at the time of completion

Siemens

The German industrial giant has been active in the power electronics market for some time and its energy storage business has been accelerating at a rapid pace since 2014. Back then, the company established a partnership with battery manufacturer LG Chem. Siemens said at the time that it hoped the arrangement would enable the pair to "accelerate their dominance" in the energy storage market.

The company has been winning business in Italy, via a tie-up with utility firm Enel, the UK and of course in its native Germany. It has also delivered a smart-grid pilot for 20,000 homes in Rotterdam. While Siemens has enjoyed much success on its own, it is also about to become one half of a new entity that could be well placed to dominate.

In July, Siemens formed another partnership, this time with power distribution company and project developer AES. The two created a joint venture company, Fluence, which will offer hardware from both parties as well design, engineering and system integration. Between them they have completed almost 500MW of energy storage systems and will leverage the scale of Siemens to operate in 160 countries.

"As the energy storage market expands, customers face the challenge of finding a trusted technology partner with an appro-

Andrés Gluski, president and CEO of AES at the launch of Fluence

Siemens in-house hardware, the Siestorage system

priate portfolio and a profound knowledge of the power sector. Fluence will fill this major gap in the market," said Ralf Christian, CEO of Siemens' energy management division at the time of the launch.

Greensmith Energy

The US firm has installed almost 200MW of energy storage since its inception in 2008. The lion's share is in its domestic market with a handful over the border in neighbouring Canada and a double-digit number of installs in Australia.

Greensmith was among the firms to deliver projects at breakneck speed in response to the Aliso Canyon gas leak and the urgent tender that followed. The design, integration and installation of the 20MW/80MWh energy storage system took less than four months.

Of the more than 180MW installed by the company, 130MW was completed in 2016, an indication of the sector, and the company's current trajectory.

"There's no question 2016 was another record-setting year for Greensmith and the energy storage industry as a whole, particularly from a grid-scale perspective," said John Jung, president & CEO of Greensmith Energy. "As the industry begins to grow and expand, Greensmith has seen rapid transition from test systems and pilots to bankability and ROI over the past eight years. As perhaps the largest provider of energy storage software and turnkey systems to some of the largest power companies in the world, coupled with tier-one battery and PCS vendor relationships globally, Greensmith enjoys a holistic view of the entire market."

In July 2017, Finnish power company Wärtsilä completed a US$170 million acquisition of Greensmith.

Greensmith in numbers

16	The number of batteries the company has experience working with
14	The number of inverters the company has experience working with
1	The company's claimed market position
180MW	Greensmith's total installed capacity
1/3	The proportion of energy storage in the US delivered by Greensmith in 2014
4	The number of months needed to install a 20MW/80MWh system in California

NextEra Energy Resources

One of the US' biggest deliverers of energy storage systems is a subsidiary of Fortune 200 energy company NextEra Energy and sister to utility Florida Power & Light. Between them the latter two have PV pipelines to the end of 2018 of 403MW and 600MW respectively.

The company has also developed, constructed and operates energy infrastructure projects that include more than 90MW of energy storage.

Nearly all based in the US, with a couple of exceptions in Ontario, Canada, notable projects to date include a 20MW/10MWh installation serving the PJM service area's frequency regulation market completed in 2014 in Illinois.

Since then NextEra Energy Resources has developed or constructed multi-megawatt projects in Pennsylvania, Maine, Arizona, New Jersey and California. With the exception of the 14MW California project, all of these plants serve front-of-meter grid or network services markets.

In May it was announced that a 30MW/120MWh energy storage system coupled with a 100MW PV power plant being built by NextEra for utility Tucson Electric Power in Arizona could deliver energy at a historic low price. The utility will be able to source renewable power for less than three cents per kilowatt-hour from the combined installation for a 20-year period – although this discounts the cost of constructing the storage system itself. Another NextEra US project worth mentioning is a 5MW/40MWh system being built near Long Island, New York, to deliver stored energy to a substation close to a 90MW wind farm.

AES

Arlington, Virginia-based AES Energy Storage, a wholly-owned subsidiary of the Fortune 200 global AES Corporation Group, was responsible for the first ever grid-scale advanced battery storage solution in commercial operations in 2007. It has delivered several multi-megawatt projects based on its Advancion Li-Ion platform in the past couple of years, in countries including the Netherlands, Northern Ireland and the US.

AES has 476MW of interconnected energy storage deployed, under construction or in late-stage development. Company president John Zahurancik recently said it took AES nine years to reach 118MWh of projects, yet in just six months of 2016, AES Energy Storage was able to deliver 120MWh of energy storage.

Timeline of achievements:

- Indiana, 2008 – AES introduced the first grid-connected lithium-ion batteries
- PJM, 2008 – AES introduced the first grid battery compensated within a power market
- New York, 2009 – AES introduced the first battery qualified as a generator by the Federal Energy Regulatory Commission (FERC)
- West Virginia, 2011 – AES received the first storage private letter ruling to allow it to be paired with renewable generation under the ITC
- Chile, 2012 – AES was the vendor for the first lithium-ion battery project financed with a power station
- California, 2014 – AES secured the first long-term PPA for a grid battery, a 20-year PPA for Southern California Edison
- Philippines, 2015 – AES breaks ground on the country's first ever battery-based energy storage facility
- Northern Ireland, 2016 – AES completed the UK's biggest battery-based energy storage array
- California, 2017 - AES announced the financial close of a US$2 billion project in California combining more than 1GW of gas generation with 100MW of energy storage
- Global, 2017 – AES launched an energy storage tech and services JV with Siemens called Fluence

Younicos

From self-confessed origins as "solar hippies from Berlin" with the corporate slogan "Let the fossils rest in peace" and a sign at their headquarters informing visitors that they are "…leaving the CO2 producing sector of the world", Younicos is explicit in its intentions but has never let idealism prevent it from also being a serious business entity.

The company delivered Europe's first 'commercial battery park', a 14.5MWh grid-balancing system for WEMAG in Germany. In 2016, over 75MW of contracts were awarded to the US-German system integrator, including a 49MW battery storage system in the UK for utility giant Centrica. Younicos has installed over 200MW of systems and has a claimed 1.2GW pipeline over the next two years.

The company was bought out for US$40 million by power generation equipment hire company Aggreko earlier this year. We have yet to see what impact this will have, but Younicos has said that it enables the company to scale up its efforts, and quickly.

One of the earliest to recognise the importance of revenue stacking, using battery systems for multiple applications and therefore multiple value streams, Younicos has also been involved in a range of island grid projects, with perhaps the most celebrated among them a 'grid-forming' multi-megawatt installation on the Portugese territory of Graciosa that reduces the island population's reliance on diesel by two-thirds.

The company has also launched its own range of energy storage hardware, power converter unit and a standalone, easily deployable storage solution called the YCube.

NEC ES

As of the beginning of this year, the Massachusetts-headquartered energy storage development and manufacturing subsidiary of Japanese IT and network integration firm, NEC Corporation, had installed and commissioned around 120MW of grid-scale energy storage (GSS) installations delivering services such as peak shaving, renewables integration, frequency response, frequency regulation and voltage regulation across Europe, Asia and South America. In total, NEC Energy Solutions has in excess of 250MW of storage systems installed, under construction, or in the contracting phase around the world.

The company provided major utility Southern California Edison (SCE) with its first grid energy storage pilot system under a procurement programme established in 2015, while its largest installed system to date stands at 32MW/8MWh in Elkins, West Virginia.

The company has claimed some other big project wins this year, including a 48MW/50MWh system in Germany with Mitsubishi and Eneco, set to begin operation in December 2017 and a contract with UK developer Low Carbon for the construction of 50MW of projects supplying frequency response services.

"Some companies call us an energy storage EPC; that seems to fit fairly well," Roger Lin, NEC ES director of marketing said, comparing the company's role in integrating and procuring technologies and sites to an EPC's job in a "traditional generation plant".

"What we say is that we're an end-to-end solutions provider for energy storage systems for the electric grid."

LG CNS

The information services subsidiary of the South Korean mammoth LG Corporation is most active in the field of large-scale public infrastructure IT network implementation but is also involved in a dizzying array of other business sectors.

Along with solar, wind, fuel cell and smart city project development, one of those other areas is energy storage systems. Within its own domestic market, the company lists 85MW / 85MWh of projects completed to date. These include three substation projects in Nongong (36MW), Uiryeong (24MW / 8MWh) and Shin Youngin (8MW).

Also of significance are three commercial energy storage projects delivered to fellow LG Group company LG Chemicals in South Korea, designed to reduce grid energy usage and peak demand, including a 3MW/27MWh plant in Iksan and a 4.5MW/21.3MWh plant in Ochang.

As might be expected, LG CNS has a partnership agreement in place with LG Chem – which is a clearly separated part of the group – for battery supply. LG Chem is supplying 40MW of batteries for two systems LG CNS is developing and constructing, one of 24MW and the other 16MW, for frequency regulation and renewables integration respectively, on the US island territory of Guam, announced in May this year. The Guam systems will utilise LG CNS' energy management system (EMS) in conjunction with the lithium-ion batteries.

LG CNS appears to be looking to expand its footprint abroad, seeing the Guam project as a strategic opportunity to get closer to the US markets and Australia due to the island territory's geographical and political ties. ■

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Quick Review of PV Taiwan 2016

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Gigawatts of subsidy-free solar farms being planned for UK market rebound

UK | Solar Media's head of market research Finlay Colville delves back into the UK's vast network of planning portals to uncover the incredible scope of subsidy-free solar farms entering the planning phase, and discusses their build potential as UK solar enters its next phase

The UK solar industry is set to emerge as one of Europe's leading post-subsidy large-scale solar markets from 2018 onwards, with plans being scoped, submitted and approved in the past 12 months alone that comfortably exceed the gigawatt-level of new site deployment.

Sites are typically being planned now in the 20-50MW range, with the largest site going through full planning submission today with a potential capacity, when built, above 100MW in size.

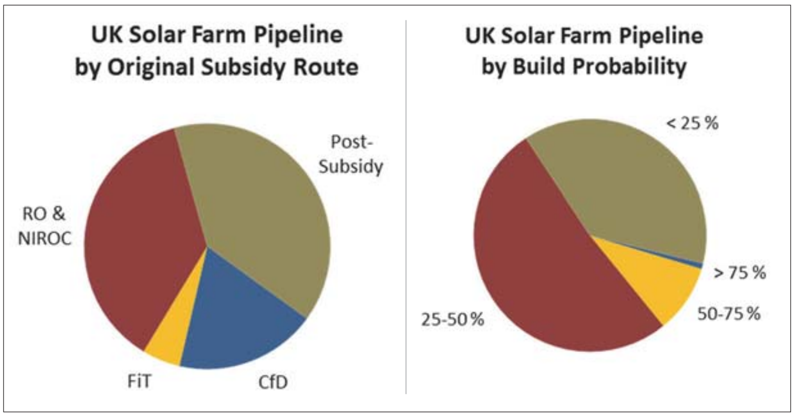
Over the past few years, there have been many claims from developers about starting large-scale solar farms, post-subsidy. However, as long as these plans remain absent from any planning process they are just plans and no more; every solar farm needs full planning application approval as a bare minimum, as the planning portal remains the leading marker for any future deployment prospects.

In this respect, we can also see clearly the sites that are a spill-over from development that had been done for Contracts for Difference submission in the past, or sites that were either partially done under Renewable Obligation Certificates (ROCs) or simply never got to shovel-ready stage to generate financing under 1.3 or 1.2 ROCs.

Removing these, we have the 'real' pipeline sites that were put into planning during 2016 and 2017. As such, it has to be inferred that subsidy-free operation of these is envisaged, or at a minimum using a different business model and revenue streams and carrying a different risk profile for investors.

Currently, the post-subsidy pipeline of large-scale solar farms in the UK exceeds 3GW, across more than 300 sites. Applying the timeline-based filter (as discussed in the section above), we can segment the pipeline now to see how much of the 3GW is arising from specific post-subsidy activity.

The most interesting segment of the left-hand pie-chart above relates to the post-subsidy part. These are new sites that have emerged in 2016 and so far in 2017. Approximately 95 sites fall into this category, adding up to more than 1.3GW. Incredibly, more than 25% of these (on 560MW worth of new solar farms) are being planned to include energy storage units.



Composition of the UK's post-subsidy pipelin (left) and by build probability (right)

Credit Solar Media

In terms of the size of projects within the full 3GW-plus of projects, most of the capacity falls into the 20-50MW site level – again confirmation of the intent to move these forward post-subsidy and applying economy-of-scale economics as a key driver for return-on-investment metrics.

Indeed, in the past few days, full planning documentation has been tracked by our in-house research team at Solar Media for the UK's first 100MW solar farm. Given the developer in question and the site location, we expect this site to be approved in the next few months, raising the prospects of a 100MW solar farm being constructed in 2018. What a start to subsidy-free deployment this would represent for the UK solar industry!

Forecasting build-out probability in the analysis

As with every pipeline of planning or scoping, it is essential to apply cautious forecasting, in terms of the probability of completion. Clearly, if a site is simply at screening and waiting to see if an environmental impact assessment is needed, the chances of final build-out are at the 10-20% level, depending on the developer in question and whether the company is using as a tentative placeholder or as a serious attempt to submit a full application.

Probably the most useful reference point in the history of the site applications comes down to the current developer/owner, and their track-record in UK solar farms and seeing through shovel-ready sites either through in-house EPC work or packaged into shovel-ready site bundles and sold to global developers that have the financial backing to take on large solar farm developments.

The right-hand pie chart shows a capacity-based segmentation based on adding up site-specific build-out probability factors. The key part to view is in the >50% segments that capture the most viable sites for the 2017-2018 time period. Many of the other sites will end up terminated or not seen through for a host of reasons, as is normal with any pipeline of applications. But a bunch of sites here will move to the >50% bands in the next 12 months, in addition to new applications yet to be lodged. This is expected to keep the hot prospect listing an ongoing research exercise and tracking these for prospective component suppliers (modules, inverters, mounting) and EPCs will be essential reading over the next 12-18 months. ■

The Solar & Storage Live event at the NEC in Birmingham, UK on 3-5 October will showcase the latest developments in subsidy-free UK solar. Further details are at http://uk.solarenergyevents.com/

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