PV TECH POWER

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THE SOLAR BRIEFING
Navigating the year ahead

MARKET WATCH
Where next for the UK's secondary solar market?

SYSTEM INTEGRATION
Hurdles to widespread bifacial adoption

DESIGN & BUILD
Crunching the numbers on floating solar

PLANT PERFORMANCE
Advances in self-cleaning module technologies

About LONGi Solar

A world leading mono-crystalline solar module manufacturer for achieving best LCOE (levelized cost of electricity) solutions.

LONGi Solar is a world leading manufacturer of high-efficiency mono-crystalline solar cells and modules. The Company, wholly owned by the LONGi Group (SH601012), has focused on p-mono for 18 years and is today the largest supplier of mono-crystalline wafers in the world, with total assets above $5.2 billion (2017). It has plans to reach 45 GW mono-crystalline wafer production capacity by 2020.

Enabled and powered by advanced technology and long-standing experience in mono-crystalline silicon, LONGi Solar shipped approximately 4.6GW of products in 2017, which is a 100% growth rate in three consecutive years. The Company has its headquarters in Xi' an, China and branches in Japan, Europe, North America, India, Malaysia, Australia and Africa.

With a strong focus on the R&D, production and sales & marketing of mono-crystalline silicon products, LONGi Solar is committed to providing better LCOE solutions and promoting the worldwide adoption of mono-crystalline technology.

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Introduction

The solar industry endured an eventful 2018 with the US establishing its trade tariffs on module imports and China hitting the brakes on deployment, yet, through sheer determination, everyone ended the year feeling fairly optimistic.

There is lots of cause for hope in 2019. Module prices are down for the timebeing, seeding subsidy-free markets. We are on the cusp of technological gains that can tilt that balance even further in solar's favour. Traction with energy storage is clearing up grid headaches and creating new sources of revenue. Our ultimate 2019 briefing (p.18) addresses all this and more, including what to expect in some of the key territories during the next 12 months.

One of those technological advancements is bifacial. It's become the archetypal chicken and egg situation with bankable projects scant despite the potential and enthusiasm. Jenya Meydbray of Cypress Creek Renewables discusses how the tech is viewed on the frontlines of procurement as the industry works out how best to take advantage of this promising new technology (p.64).

Another emerging technology, albeit slightly better developed, is floating solar. In early November, the World Bank grabbed some headlines when it published the first in-depth analysis of floating PV. Sara Verbruggen takes a deep dive, no pun intended, into the study and goes behind the 1GW installation figure that you may well have seen reported on PV Tech (p.46).

We also have an excellent technical paper from Fraunhofer ISE reviewing the host of purported self-cleaning module technologies on the market (p.78). Our Benban project briefing (p.76) includes a reminder of why developing such anti-soiling materials could prove so important.

A trio of market-focussed pieces take us across three continents. Liam Stoker looks at the UK's secondary solar market as ownership of the country's PV assets consolidates (p.36). Tom Kenning lifts the lid on the Vietnamese solar market, which could see a rush of activity as the feed-in tariff ends, assuming myriad problems can be solved (p.30). Finally, Norton Rose Fulbright discusses the impact that corporate solar demand as well as energy storage will have on driving the Middle East and North African market (p.34).

Our regular Storage and Smart Power section will include all its regulars as well as an in-depth look at California's vibrant market as decrees turn into deployment (p.102). Pason Power discusses how the modern generation of energy storage is using data and machine learning to draw out every drop of value (p.98).

Thanks as always for reading, stay tuned to PV-Tech.org for all your solar news as we navigate 2019!

John Parnell
Head of content

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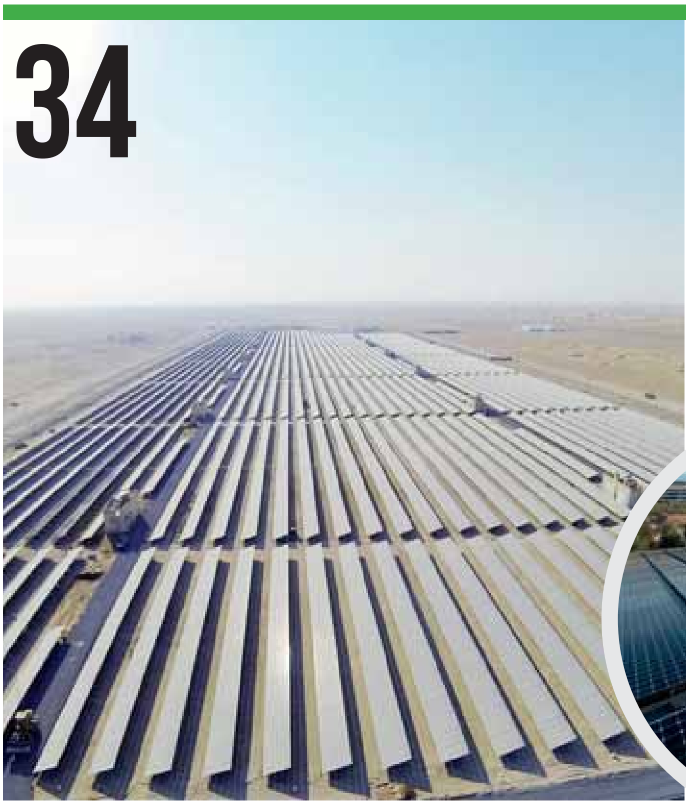

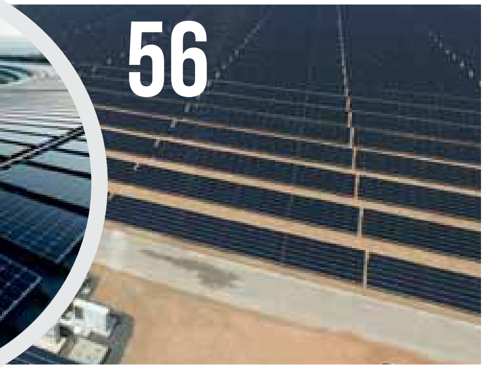


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EUROPE

Post-subsidy Europe

Grid parity promise makes European solar a 'sleeping giant'

The lifting of political and cost-based brakes on European solar is set to awaken a sleeping giant, with subsidy-free solar projects potentially the norm all across Europe in just a few years. A combination of more and more countries hitting grid parity, the ending of the Minimum Import Price (MIP) on Chinese imports as well as a temporary Chinese module oversupply means that the European solar market is on the cusp of booming, according to several developers and a major module supplier, who were speaking at the 'Solar and Storage Live 2018' conference in Birmingham, UK. Frank Niendorf, general manager Europe at China-based manufacturer, JinkoSolar, said that the MIP ending has led to a huge IRR boost for investors and developers since it has allowed global market module prices to be used in Europe. Lily Coles, commercial operations director, at UK-based developer Anesco, which has already built a subsidy-free solar-plus-storage plant in England, agreed: "Coming out of MIP then opens up a huge door for us and the panels have always been the most expensive part of it. We've spent a lot of time whittling down the other components and being cost competitive while maintaining the quality on the inverters, the cabling, the ground-mount system and everything else, but the panels have been out of our control, so it's going to make a massive difference and we can now see that pipeline really growing."

Frank Niendorf and Lily Coles speaking at the event in Birmingham, UK.

Spain

Solarcentury receives approval for 200MW of PV projects in Spain

Solarcentury received approval from the regional government in Andalucia to construct four PV projects in Alcala de Guadaira, Seville, Spain. The four projects, known as "Cerrado Cabrera", "El primo Alemán", "Hazas de los sesenta" and "Los Gonzalez", will generate enough energy to power 105,000 households once completed. Solarcentury holds a Spanish office in Valencia, with the company boasting a pipeline of projects in Andalusia amounting to approximately 500MW. These four projects are the first to reach the ready-to-build stage, with each featuring an installed generation capacity of 50MW. Solarcentury believes project construction is likely to begin in April 2019. The projects are being delivered through a partnership with Texla, a local engineering firm based in Seville.

Lightsource BP targets utility and corporate solar PPAs in Iberia

Lightsource BP moved into the Iberian energy market and plans to work with local partners to purchase and co-develop utility-scale ground-mount solar sites as well as to create a greenfield pipeline of solar projects across the Iberian Peninsula. From a base in Madrid, the British company aims to deliver electricity through power purchase agreements (PPAs) with both utility and corporate customers. Corporate PPAs are already booming in Spain in an era of grid parity. Lightsource BP already operates a 2GW solar portfolio across Europe in the UK, Ireland, the Netherlands and Italy.

Iberdrola signs PPA with northern Spain telecoms provider for 391MW solar project

Iberdrola signed a PPA with Basque Country-based telecoms provider Euskaltel to supply electricity from a 391MW solar project. The utility claimed it was the first such deal with a telecom firm as an offtaker. Iberdrola will build the Nuñez de Balboa solar plant in Usagre, in the Badajoz-Extremadura region. Iberdrola had already signed a 10-year PPA for the solar project with Grupo Kutxabank, in what it also claimed to be the first contract in the world of this kind to be signed between an energy company and a bank.

UK

Post-subsidy pipeline passes 3GW with 500MW slated for 2019

New research from PV Tech's market research arm has found that the UK now has a 3GW pipeline of subsidy-free projects. Around 500MW is set to be constructed in 2019. The findings are backed by the major development plans announced recently. In November, a project of up to 350MW submitted it planning application to the national authorities, a requirement triggered by its side. NextEnergy Solar Fund (NESF) also added 470MW of subsidy-free PV assets to its acquisition pipeline and Lightsource BP confirmed it had a pipeline of 300MW of PPA-backed utility-scale solar in the works.

Credit: Anesco

The Clayhill project was the first subsidy-free solar plant in the UK.

France

France to fall short of 2018 solar target

France installed 8,374MW of solar PV capacity as of 30 September 2018, but is set to miss its target of 10,200MW by the end of the year, according to data from Electricity Transmission Network (RTE). The country deployed 213MW of solar PV in Q3 2018, while 1,113MW was connected over the rolling year up to the same date. RTE said that the transmission and distribution networks continue to evolve to allow the integration of renewable electricity generation with an eye on the target of a 20% share of renewables in the electricity mix by 2030.

Trina Solar supplies 17MW of dual-glass mono PERC modules to Europe's 'largest' floating PV project

Trina Solar has supplied 17MW of PV modules to what is said to be the largest floating PV plant in Europe, developed by French IPP

Akuo Energy. The O'MEGA 1 project, located in Piolenc, a commune in the Vaucluse department in the Provence-Alpes-Côte d'Azur region in south-eastern France, was awarded in France's CRE4.1 tender, which stipulates the use of low carbon footprint modules. Trina has now supplied 46,000 units of its TSM-DEG14.20(II) dual-glass monocrystalline PERC modules in its low carbon footprint version. The dual-glass structure is made to protect solar cells from strong humidity over lifetime, preventing energy loss from potential induced degradation (PID), a key risk in floating solar projects due to their deployment on top of water bodies.

AMERICAS

Midcontinent US

Capital Dynamics signs deal with Tenaska to develop 2GW of solar projects in US

Independent global private asset management firm Capital Dynamics' Clean Energy Infrastructure (CEI) business has signed off on a deal with Tenaska to develop a portfolio of greenfield PV projects in the Midwestern United States. In total, the transaction includes 14 PV projects with approximately 2,000MW in the Midcontinent Independent System Operator (MISO) market. The portfolio includes all solar projects currently in the MISO North interconnection queue, with projects in Michigan, Missouri, Illinois, Wisconsin, Indiana and Minnesota. Benoit Allehaut, director of Capital Dynamics' Clean Energy Infrastructure team, said: "This agreement was a unique opportunity for us to acquire a meaningful pipeline of solar capacity in an efficient project development structure within a market poised for growth.

Credit: Tenaska

Tenaska's Imperial Solar Energy Center South near El Centro, California.

Corporate

EDF, Shell sign PPA for 100MW PV project in California

EDF Renewables North America and Shell Energy North America have signed off on a 15-year power purchase agreement for the 100MW tranche of the Palen Solar project called the Maverick 4 Solar Project. The installation, located in Riverside County, California, expects to start providing clean energy by the end of 2020. The site will be developed on 1,270 hectares of federal lands within a Solar Energy Zone (SEZ) and Development Focus Area, managed by the U.S. Bureau of Land Management (BLM).

Dominion Energy tests the corporate PPA demand ahead of 3GW renewables tender

Dominion Energy sampled the appetite for corporate power purchase agreements (PPAs) before it launches a 3GW tender in Virginia. The company circulated a survey asking companies the scale of solar or wind power they would be interested in, whether they would consider siting solar on their own property and how long a contract they would consider signing. Virginia has mandated for 3GW of wind and solar to be connected or in development by 2022.

First Solar using Series 6 modules in 58MW plant for Facebook

Leading CdTe thin-film module manufacturer First Solar is building a 58MW (AC) PV power plant using its next-generation large-area Series 6 modules and single-axis trackers for Facebook's Prineville Data Center located in Oregon. The Cove Mountain Solar Project is expected to begin construction in late 2019, with commissioning due in late 2020. First Solar Energy Services is expected to provide Operations and Maintenance (O&M) services which will support the Facebook data centre with 100% renewable energy.

The new larger format Series 6 modules will be used at the plant in Oregon.

Brazil

Scatec and Equinor complete 162MW solar project in Ceará, Brazil

Scatec Solar and its partners Equinor and Apodi Par grid-connected the 162MW Apodi Solar plant in Ceará, Brazil, Scatec's first PV project in the South American country. The Apodi Solar project was awarded in the auction process held by ANEEL, the Brazilian Electricity Regulatory Agency, in November 2015. The project holds a 20-year power purchase agreement (PPA) with CCEE, the Brazilian Power Commercialization Chamber. The Apodi Solar plant is owned 43.75% by Scatec Solar, 43.75% by Equinor and 12.5% by the holding company Apodi Participações formed by the Brazilian companies Z2 Power, Pacto Energia and Kroma Energia.

Enel Green Power starts construction of 475MW PV project in Brazil

The Enel Group's Brazilian renewable energy subsidiary Enel Green Power Brasil Participações started construction of the 475MW São Gonçalo solar park in São Gonçalo do Gurguéia, located in the Brazil's northeastern state of Piauí. The PV installation, which is expected to begin operations in 2020, is the largest PV facility currently under construction in South America. The Enel Group will invest approximately US$390 million in the development of the project.

Mexico

Enel completes largest solar project in Mexico, connects 1,089MW to the grid

Enel Green Power México (EGPM), a subsidiary of Italian power giant Enel, connected around 1,089MW of solar energy to the grid in Mexico, including the largest solar project in the country. The new capacity includes the Villanueva solar park, which has now been extended to around 828MW capacity from its original 754MW tabbing, in the State of Coahuila. The second project is the 260MW Don José solar park – extended from its original 238MW – located in the State of Guanajuato. Both projects' sizes were increased from their original billing after implementing a 10% capacity extension option included in their power purchase agreements (PPAs). Investment in the construction of the two projects amounted to approximately US$950 million.

Trade friction

Inverter tariffs unlikely to impact US deployment

The trade tariffs placed on Chinese solar inverters are unlikely to create major procurement challenges. Tariffs of 10% have been applied to Chinese-made inverters as of 24 September, rising to 25% for 2019. Scott Moskowitz, senior analyst, at Wood Mackenzie Power & Renewables, formerly GTM Research, expects the impact to be modest. "There won't be a supply crunch of inverters in the US, but folks will certainly rush to beat the tariff, and it certainly will affect pricing for inverters across the board in the US," he told PV Tech. "Overall, it is mostly another headache for developers and installers who have had to deal with a barrage of tariffs over the past year on modules, steel, and other componentry."

MIDDLE EAST & AFRICA

North Africa

Algeria tenders 150MW of solar

Algeria's Regulatory Commission for Electricity and Gas (CREG) issued a tender for 150MW of solar projects, made up of 10MW-sized individual projects. Meanwhile, a pair of oil and gas giants, Algerian state-run company Sonatrach and Italy-based firm Eni, have inaugurated a 10MW solar PV project to power an oil field in Bir Rebaa North (BRN) in Algeria. Eni and Sonatrach have also signed an agreement to implement the construction of a research and development (R&D) laboratory at the BRN site to test solar and hybrid technologies in a desert environment.

IRENA plots roadmap to make Egypt a multi-GW solar market

Credit: Gamesa Electric

The Benban Solar Park in Aswan, Egypt, one of the world's largest.

Streamlining red tape, ditching subsidies for bill payers and improving investment conditions could see Egypt become a multi-GW market for solar, according to a report by the International Renewable Energy Agency (IRENA). The Renewable Energy Outlook: Egypt report sets an ambitious path, beyond the government's goal to source 42% of its electricity from renewables by 2035. IRENA forecasts that this figure could reach 53% by 2030, under the right conditions. Egypt has 3.7GW of renewables installed at present including 0.9GW of solar.

Gulf

Dubai adds 250MW of PV at 2.4 cents tariff to CSP deal with ACWA Power consortium

Dubai Electricity and Water Authority (DEWA) added 250MW of solar PV to its agreement with a consortium led by Saudi-based developer ACWA Power for capacity in the fourth phase of the Mohammed bin Rashid Al Maktoum Solar Park, which is already one of the world's largest Concentrated Solar Power (CSP) developments. DEWA has signed an amendment to the power purchase agreement (PPA) with the consortium, which includes China's Shanghai Electric, for the new 250MW of PV to be supplied at a price of just US$0.024/kWh, amongst the world's lowest utility-scale solar tariffs. The total capacity of the fourth phase of the solar park will rise from 700MW to 950MW, however, the original fourth phase was made up of 600MW from a parabolic basin complex and 100MW from a solar tower and is said to have the lowest Levelised Cost of Electricity (LCOE) of US$0.073/kWh for CSP technology.

Credit: First Solar

The Mohammed bin Rashid Al Maktoum Solar Park in Seih Al Dahal, Dubai.

Sub-Saharan Africa

Mali gold mine to halve energy costs with 40MW solar-storage-HFO plant

Australian firm Resolute Mining signed an agreement with Africa-focused power developer Ignite Energy to set up a 40MW hybrid solar, battery and heavy fuel oil (HFO) plant at its Syama Gold Mine in Mali. This will replace an existing 28MW diesel-fired power plant at Syama. The new project, which is expected to be operational by the end of 2020, could become the world's largest off-grid hybrid power plant for a stand-alone mining operation and will offer around 40% energy cost savings at Resolute's gold mine.

ENGIE signs 25-year PPA for Senegalese Scaling Solar projects

French energy giant ENGIE signed power purchase agreements for two solar power plants in Senegal. The projects, with a combined capacity of 60MW, were developed as part of the International Finance Corporation's Scaling Solar Programme. ENGIE will be responsible for the construction and operation of the plants in Kahone and Kaël.

Soventix to build 22MW solar plant in Zimbabwe with community ownership scheme

A subsidiary of German developer Soventix bagged a contract to build one of the largest solar PV projects in Zimbabwe standing at 22MW. Soventix South Africa will start constructing the Harava project across 40 hectares of land in the Bwoni Village, Seke Rural

District which is located South West of the city of Harare. The project is being funded by Botswana-based clean energy investor and IPP Invest Solar Africa. Local villagers will own 10% of the project through a Community Development Share Ownership Trust.

PPA signed for 60MW solar project in Malawi

JCM Matswani Solar Corp, backed by InfraCo Africa, Canadian private equity firm JCM Power and South Africa-based Matswani Capital, signed a 20-year power purchase agreement (PPA) with Malawian national utility Electricity Supply Corporation of Malawi Limited (ESCOM) for a 60MW solar plant. InfraCo Africa has committed US$2.6 million to the development of Salima Solar and has leveraged US$320,000 in grant funding from its sister Private Infrastructure Development Group (PIDG) company and the Technical Assistance Facility (TAF) to acquire the project site.

Middle East

Oman reveals bidders in 500MW solar tender

Oman Power and Water Procurement Company (OPWP) revealed the three consortia who have submitted bids for its 500MW solar tender. The bidders were 1) Abu Dhabi Future Energy (Masdar), Total Solar, and Jinko Power. 2) ACWA Power, Gulf Investment Corporation (GIC), and Alternative Energy Projects Company (AEPC). 3) Marubeni, Oman Gas Company (OGC), Nebras Power, and Bahwan Renewable Energy Company. The evaluation of bids is currently underway and OPWP expects to finalise the award by early next year. The project is planned to achieve commercial operation by June 2021.

Marubeni consortium bags 100MW solar project from Oman's oil major

A consortium led by Japanese conglomerate Marubeni Corporation was awarded a 100MW solar PV project in southern Oman by state-owned oil and gas major Petroleum Development Oman (PDO) in a competitive bidding process. With PDO as its sole offtaker, the project in Amin is said to be the world's first utility-scale PV project to have an oil and gas company as the sole wholesale buyer of power.

EDF completes 101MW of solar projects in Israel

EDF Renewables commissioned five solar PV projects in Israel with a combined capacity of 101MW, including four projects with what are said to be the lowest-ever tariffs agreed in Israel. The five plants are all located in the Negev desert. Four of the projects were won in a mid-2017 tender and generate electricity at €47/MWh (US$53.41). Meanwhile, EDF acquired the 60MW Mashabei Sadeh solar power plant at the project stage in a separate deal last year.

Kuwait oil company launches tender for 1.5GW of solar

The Kuwait National Petroleum Company (KNPC) launched a tender for up to 1.5GW of solar. The company is looking to develop five blocks of up to 300MW to form the Dabdaba Solar Park. Bidders will also be asked to take on a 25-year O&M contract. The deadline for bids is 16 December 2018, with work to commence in 2019. The site is based in the Al-Shagaya Renewable Energy Park.

ACWA Power secures financing for 300MW Saudi Arabia solar project

A consortium of Saudi-based developer ACWA Power and contractor AlGihaz closed financing of the SAR1.2 billion (US$319 million) Sakaka solar project standing at 300MW in Al Jouf, Saudi Arabia, a project that attracted headlines across the world last year after the government chose ACWA Power despite Masdar putting in the lowest ever solar bid. The project has a tariff of just 8.781 halalas/kWh (US$2.3417/kWh), is financed by Natixis and Arab National Bank.

ASIA-PACIFIC

India

Unique Indian solar tenders draw little interest

Solar Energy Corporation of India's (SECI) 10GW solar tender combined with 3GW of manufacturing once again received a poor response from the industry with only local developer Azure Power submitting a bid. Azure Power's bid was for a 2GW project on a single site as well as 600MW of manufacturing capacity. Meanwhile, SECI's 1.2GW hybrid solar and wind auction, the first in the country, drew bid submissions from heavyweight players Adani and Softbank, but was still undersubscribed by 150MW. In this case, Adani bid for 600MW and Softbank's unit SB Energy bid for 450MW. At the time of writing, reports suggested that SECI would hold an auction. NTPC has also tendered for another 1.2GW of solar and a hybrid 60MW/130MW wind and solar project in Karnataka.

Indian solar deployment to decrease by 55% in 2018/19, but rooftop PV shines

India is expected to deploy just 4.1GW of solar in FY2018/19, down 55% year-on-year and roughly a quarter of the government's annual target of 16GW, according to the 'India Solar Compass Q3 2018' from consultancy firm Bridge to India. India added 1.2GW of utility-scale solar capacity in Q3 2018, and 1.9GW in the first half of FY2018-19, down 43% and 44% over respective periods last year. India's total PV capacity has now reached 27.4 GW as of 30 September, with 23.2GW of utility-scale, 3.4GW of rooftop solar and 0.8GW off-grid solar.

Malaysia

Malaysia to announce 500MW LSS 3 solar tender in January

The third round of Malaysia's Large-Scale Solar (LSS) tenders will be for another 500MW of capacity and details will be announced in January, according to energy minister Yeo Bee Yin. The value of the projects could be as much as RM2 billion (US$477 million). Although many developers have enjoyed the steady pace of Malaysia's market with a clear road of 500MW auctions on a regular basis, many were hoping for the capacity level in LSS 3 to be far more generous.

Malaysia moves on solar highway, PV monitoring, insurance and foreign support

Credit: Flickr: Simon_sees

Malaysian oil and gas giant Petronas is even considering solar power through a new unit.

South Korea

South Korea plans 3GW solar-wind-storage hub on reclaimed land

South Korea's government is planning for nearly 3GW of solar PV alongside smaller capacities of wind and batteries on reclaimed land in Saemangeum, which is an estuarine tidal flat on the coast of the Yellow Sea. The Saemangeum Development and Investment Agency (SDIA) will oversee 2.6GW of projects. This will include 2.4GW of solar, 100MW of wind and 100MW of battery storage power. Meanwhile, the Ministry of Agriculture, Food and Rural Affairs (MAFRA) will oversee 400MW of solar PV. There will also be a 1GW offshore wind project. The projects would be located on reclaimed land at Saemangeum, which the Korean Government is hoping to turn into a global business hub and free trade hub of Northeast Asia, after a major damming operation known as the Saemangeum Seawall Project, completed in 2010, said to be the largest dyke in the world.

Credit: Wikimedia commons

Saemangeum Seawall built in 2010 for reclaimed land.

Malaysia plans to install solar along a major highway and has introduced both the first solar insurance scheme and monitoring system. Firstly, TNB Energy Services (TNBES), a subsidiary of Malaysia power giant TNB, has signed a memorandum of understanding (MoU) to add solar panels along a highway in Johor, a state in southern Malay Peninsula. Meanwhile, Sustainable Energy Development Authority (SEDA) Malaysia has launched the country's first-of-its-kind Solar PV insurance, a product by insurance firm Allianz Malaysia Bhd via Anora Agency Sdn Bhd in collaboration with the Malaysian Photovoltaic Industry Association (MPIA). SEDA has also launched the first national solar PV monitoring system (PVMS), a single platform that allows real-time data to be disseminated to the industry.

Philippines

Philippines utility aims to become 'major player' in renewable energy

The Manila Electric Company (Meralco), the major utility of the Philippines, plans to set up 1GW of solar and wind projects in the medium term. The plans are for the projects to supply power to the Luzon grid and for 500MW-1GW of solar to be set up within 2-3 years. The key challenges remain in securing land and transmission. Over the last year, large-scale clean energy projects in the Southeast Asian country have been held up by major regulatory challenges and delays, however this has been the case for the entire domestic power sector at large.

Vietnam

B.Grimm signs PPA for 257MW solar project in Vietnam

Thai firm B.Grimm Power has signed a power purchase agreement (PPA) with Vietnamese utility EVN for a 257MW solar project. The Hoa Hoi project in Phu Yen Province, southeast Vietnam, will receive a feed-in tariff (FiT) at US$9.35 cents per kWh for a period of 20 years. The scheduled commissioning date of the project is expected to be before 30 June 2019. Back in September, B.Grimm Power also signed a PPA with EVN for its 420MW solar project in Tay Ninh, Vietnam.

Thailand

Thailand utility eyes 1GW of floating solar on hydro dams, pilots energy storage

Credit: Flickr: 193days

Thailand utility EGAT is looking at floating solar and storage.

State-run utility Electricity Generating Authority of Thailand (EGAT) is planning to facilitate 1GW of hybrid floating solar-hydro projects across eight dams throughout the country. The first two projects, located in the Northeast, are already in the development phase, including 45MW(AC) of contracted capacity at Sirindhorn Dam, with a commercial operation date expected in 2020. A second 24MW(AC) project at Ubol Ratana Dam is due to come into commercial operation in 2023.

Australia

Neoen completes Australia's largest solar project

French renewable energy firm Neoen started commercial operation at its 189MW Coleambally Solar Farm in New South Wales, Australia. The project is producing the highest energy output of any solar farm in the country's National Electricity Market at present. The project will soon be surpassed by the 275MW Bungala solar farm in South Australia that is owned by a joint venture between Enel Green Power and Dutch Infrastructure Fund.

Australia's Snowy Hydro contracts 888MW of wind and solar

Australian utility Snowy Hydro contracted eight wind and solar projects totalling 888MW in capacity across New South Wales and Victoria to reduce its exposure to high wholesale power prices, due to its current inability to supply power to all its customers via its own power generation. Snowy Hydro aims for the new clean energy projects to help power half a million households, without being impacted by high prices on the National Energy Market (NEM).

Kazakhstan

Kazakhstan awards 170MW of solar in first auction

Kazakhstan awarded 170MW of PV in its first solar auction with winning prices ranging between KZT 18.6-22.9 (US$0.051-0.063)/kWh. A total of 20 companies submitted 28 applications for projects of capacity between 10-100MW. The ceiling price for the auction was KZT 32/kWh. JSC Hydroenergy, Avelar Solar, and Shell Kazakhstan were all winners.

Product reviews

Mounting | Esdec provides a lightweight and 'clickable' solar mounting system for flat roofs

Product Outline: Solar rooftop mounting solutions provider Esdec has launched its first product into the US market, offering its 'FlatFix' system, a lightweight, clickable solar mounting system for flat roofs. FlatFix's innovative design enables rapid assembly, allowing commercial installers to significantly reduce installation times.

Problem: Maximising PV systems on commercial and industrial flat roof space can be problematic due to limitations in orientation through to mounting system design. A flexible ballasted non-penetrating system that can be oriented in a traditional south-facing direction or in a dual-tilt orientation is often required.

Solution: The FlatFix system is said to guarantee the use all common solar panels on any flat roof. The lightweight system exerts less of a load on the roof, is quick to mount thanks to the click-fit connectors, and has a unique thermal decoupling. FlatFix's racking components, including bonding straps, are assembled by snapping into a locked position without the need for tools. The rails click together easily and quickly to form an interconnected, solid structure. Complete module installation requires just one tool and minimal parts, while power optimisers can be attached via snap-on clips in a matter of seconds.

Applications: Flat roof commercial and industrial.

Platform: Using self-levelling baseplates, FlatFix is available with ballasted and hybrid attachment options. The flexible system can be oriented in a traditional south-facing direction or in a dual-tilt orientation. FlatFix's materials and design compensate for thermal effects, reducing potential heat-induced degradation of the PV modules and protecting the integrity of the roof. The system comes with a 20-year warranty and UL certification.

Availability: Available in the US since September 2018.

Inverter | GoodWe ET Series three-phase high voltage energy storage inverter has UPS function

Product Outline: GoodWe has recently launched its new ET Series three-phase high-voltage energy storage inverter for both households and small commercial applications. It offers maximum efficiency of 98.3% and is equipped with uninterruptible power supply (UPS) function, backup overloading, AC charging functions and open-protocol EMS communication system.

Problem: With the growing demand for storage solutions in both domestic and small commercial properties, a three-phase high voltage energy storage inverter is necessary for high-power electrical appliances and devices that enables enhanced energy independence and maximises self-consumption. When compared with existing EPS (Emergency Power Supply) functions on the market, UPS function is favourable to inductive loads such as air conditioners or refrigerators with an automatic switchover time of less than 10 milliseconds, providing security when it is down or compromised.

Solution: Covering a power range of 5kW, 8kW and 10kW, the ET Series allows 30% DC oversizing to fully maximise yield during extreme hot and cold weather, and features a wide battery voltage range of 180-550V to ensure compatibility with different type of lithium battery. When installing ET Series, battery will not be damaged by accidental swap of the positive and negative polarity which help to ensures safety battery installation.

Applications: Residential and small commercial rooftop applications.

Platform: GoodWe ET Series storage inverter is manufactured to be very compact, with dimensions of 415x516x160mm, and lightweight (25kgr. Natural convection cooling offer greater reliability, quiet operation (<30dB) and a long lifespan. It is also equipped with an AC charging function meaning it is able to charge the battery even when the inverter has not met its maximum performance.

Availability: November 2018 onwards.

Products in Brief

Ginlong's commercial three-phase product line has been upgraded for quicker install times

Ginlong has updated its North American commercial three-phase product line for 2018-2020. The 50-66kW inverter family now features a separate wire box design that results in quick installation times and reduced O&M costs. By staging the inverter installation process, wire box first, then inverter power train, significant cost savings can be realized, the company claims. In addition to saving money, the two-part staged installation process is safer, reducing on-site injuries related to the weight of the inverter and handling on uneven terrain. The 25-4 kW inverter family is also moving to a separate wire box design and installers will enjoy the same savings and benefits as they do with the 50-66kW family.

GoodWe DS3 Series string inverter handles bifacial double-glass PV modules

The new GoodWe DS3 Series is the first single-phase, on-grid inverter in the market compatible with bifacial double-glass modules, the company claims. The DS3 Series inverter is also 30% lighter for easier installation both indoors and outdoors. DC oversizing of up to 35% and AC overloading of 10% is allowed. Thanks to its reliable performance, the DS3 Series can reach a highest efficiency of up to 98.6%.

Tracker | JinkoSolar and Edisun Microgrids offer C&I PV systems with trackers for lower LCOE

Product Outline: JinkoSolar and Edisun Microgrids have teamed to develop the 'Eagle PowerTrack', a performance bundle for commercial and industrial (C&I) rooftops that includes high-efficiency 'Eagle G2' solar modules in combination with Edisun's 'PV Booster' rooftop tracking technology.

Problem: The U.S. National Renewable Energy Laboratory's (NREL) PV cost analysis study in 2017 calculated that a single-axis tracker used in a utility-scale PV system cost US$1.11/W, while the cost increased to US$1.85/W for a commercial rooftop system. C&I rooftops therefore remain a challenging market, often requiring self-consumption economics to be lower than well-designed PV systems can provide. Rooftop tracking technology has the potential to provide significantly higher module yields to provide lowest levelised cost of electricity (LCOE).

Solution: The performance bundle leverages JinkoSolar's Eagle G2 modules, which feature the company's 'Diamond' cell technology, a new high-efficiency mono PERC cell that allows 72-cell Eagle G2 modules to reach up to 400Wp. Edisun's PV Booster rooftop tracker offers contractors a flexible system design, more energy harvested per panel and real-time data for predictive operations and maintenance. When combined, the Eagle PowerTrack performance bundle is claimed to yield up to 30% more energy per panel, resulting in notably lower LCOE and significantly increasing return on investment over traditional C&I systems.

Applications: Commercial and industrial rooftops.

Platform: Eagle PowerTrack is designed to be a low-cost tracker moving individual modules (60-72-cell).

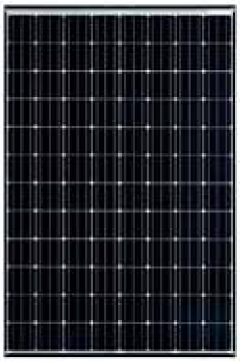
Availability: The new performance bundle will be available for sale during the fourth quarter of 2018.

Module | Panasonic and SolarEdge team on optimised high-performance 'smart module'

Product Outline: Panasonic Eco Solutions of North America and SolarEdge Technologies have team to offer the Panasonic 'HIT' (heterojunction with intrinsic thin layer) 'S Series' PV module, using power optimisers that offer greater design flexibility for higher power efficiency, lower installation costs and a higher ROI.

Problem: The US residential PV market is rapidly shifting to high-performance modules to reduce system costs and cater for high-consumption, as electric vehicles and energy storage become increasingly popular and utility companies change policies to partial and full self-consumption.

Solution: With advanced electronics built in, module-level maximum power point tracker (MPPT) allows each module to individually generate maximum energy output. Strings of up to 6kWp in residential systems can be deployed for increased design flexibility on complex roofs. Individual MPPT allows panels on multiple roof facets, orientations, and tilts, meaning more panels and higher power output per system. Power loss from shading and module mismatch is also reduced, helping generate even more power output from each panel.



Applications: US residential rooftops.

Platform: Panasonic solar panels are backed by a performance warranty that guarantees minimum power output of 90.76% after 25 years. SolarEdge's power optimiser warranty is for 25 years and its inverter warranty is for 12 years, extendable to 20 or 25 years. The module is engineered for faster installation times, resulting in lower labour costs. In addition, panel-level performance monitoring and remote maintenance means fewer site visits and higher uptime.

Availability: From early 2019 in the USA.

Sungrow's 1,500V central inverter SG3150U-MV tailored for the North American market

Sungrow Power Supply Co has updated its 1,500V central inverter, 'SG3150U-MV', to tailor it for the North American market and position it as a more comprehensive solution for utility-scale PV plants. Given its high efficiency and energy conservation characteristics, the 3.15MW inverter enables stable operations in severe environment while its maximum efficiency can still reach 98.8%. Equipped with an MV transformer and an LV auxiliary power supply in a 20-foot container, SG3150U-MV enables a lower initial investment and easy O&M as a complete 20-foot container solution.

Canadian Solar's BiHiKu' series module offers 400+ Watt output

Canadian Solar has introduced its 'BiHiKu' series module, combining three solar PV technologies in one new 400+ Watt module, which includes the latest black silicon, multicrystalline PERC and bifacial cell technologies. Merging these technologies enables Canadian Solar to produce the BiHiKu module, a HiKu module with bifaciality up to 75% and up to 30% additional power generation from the back side, dramatically increasing system yield and reducing the levelised cost of electricity. The product will be available in 2019 and pre-production orders are being accepted now.

Product reviews

Module | REC Group offers first n-type mono PV module with 'Twin Design'

Product Outline: REC Group has introduced the world's first n-type mono PV module with its 'Twin Design', which combines n-type mono half-cut cells with a twin-panel design and offers power of 330Wp and notable resistance to light-induced degradation.

Problem: The loss of power generation capacity experienced by a standard solar panel on its first exposure to light is known as light-induced degradation (LID). This is a result of the combination of boron and oxygen inside a cell and causes a permanent drop in a standard panel's maximum power.

Solution: The REC N-Peak Series (310-330Wp) panels come in a 60-cell format. The panel features the 'Twin' cell layout design, where the panel is split into two twin sections, also enabling continued energy production, even when partially shaded. As the combination of boron and oxygen inside a cell and causes a permanent drop in a standard panel's maximum power, n-type crystalline wafers in REC's N-Peak cells stops these two elements from mixing at any level, thereby fully preventing any occurrence of LID, according to the company.

Applications: Residential rooftop.

Platform: The REC N-Peak Series has extra support bars across the rear of the panel, boosting its strength and durability, and allowing loads of up to 7,000 Pa. Combined with a 30mm frame height, this frame design enables flexible installation options, making overcoming every obstacle easier during system design.

Availability: Available since August 2018.

Module | Seraphim Solar integrates 'NEP PV-Guard' to modules for rapid shutdown requirements in US

Product Outline: Seraphim Solar System Co (Seraphim) has introduced a new smart solar module that has a DC module integrated with "NEP PV-Guard", a module rapid-shutdown device made by Northern Electric and Power (NEP). This product is designed specifically for the residential and C&I rooftop markets in North America, and will bring solar projects installed after 1 January 2019 into compliance with NEC 2017 module-level rapid shutdown.

Problem: The US 2017 National Electric Code (NEC) changes the requirements for "Rapid Shutdown of PV Systems on Buildings". PV systems are required to include a rapid shutdown function to reduce shock hazard for emergency services, which need to shut down the PV system safely.

Solution: When compared to traditional modules, Seraphim's integrated rapid-shutdown modules with NEP PV-Guard help optimise the safety and performance of any given PV array. Smart modules offer customers' real-time monitoring at the module level to enable proactive maintenance, reducing losses, plus providing zero power clipping, flexible array design, and compatibility with leading inverters.

Applications: Residential and C&I rooftop markets in North America

Platform: The NEP PV-Guard has two options for PV systems. One, the NEP PVG-B, is a junction box-integrated rapid shutdown function, replacing the traditional junction box in order to meet module-level shutdown compliance without external boxes. The second is the NEP PVG-R, a retrofit rapid shutdown solution. It is installed on the system separate from the modules. The NEP PV-Guard has been tested and verified by leading string inverter manufacturers.

Availability: Available since September 2018.

Products in Brief

Hanwha Q CELLS reveals solar module products to be assembled in the US

Hanwha Q CELLS has revealed its 'Made in America' product strategy to address utility, residential and commercial solar markets in the US with module assembly operations starting in 2019 at a 1.6GW-plus plant in Whitfield County, Georgia. Key US assembled modules will include its Q.PEAK DUO BLK-G6 series, a follow-on development from the recently launched Q.PEAK DUO-G5 series, which won an Intersolar Award 2018. The US made module will use p-type monocrystalline half-cut cells with at least six busbars on its proprietary 'Q.ANTUM' PERC technology.

3megawatt makes major reporting upgrades to BluePoint asset management software

3megawatt has made key reporting upgrades to its BluePoint 5 asset management software for utility-scale PV power plants. BluePoint's solution provides owners and operators of renewable energy assets with a 360degree view of their portfolios, while streamline the reporting. BluePoint 5 users will be able to use drag and drop editors to easily edit content, change designs, add charts and tables and modify page layouts, while personalising reports using smart data selection tools. 3megawatt is also announcing enterprise-level updates including advanced user analytics, audit logs, separation of duties and advanced access control settings.

Inverter | SMA Solar's Sunny Central UP inverter is the 'most powerful' in the central inverter class

Product Outline: SMA Solar Technologies has launched the new 'Sunny Central UP' with a capacity of 4.6MW, which allows a reduction in the number of inverters in large PV projects with 1,500 volts DC voltage.

Problem: Utility-scale EPC companies, operators and investors require higher energy yields, more project realisation flexibility and significantly lower operating costs as the drive to fossil-fuel grid parity continues and the demand for integrated solutions for the coupling of AC-bonded storage systems increases.

Solution: With an output of up to 4,600kVA and system voltages of 1,500V DC, the SMA central inverter allows for more efficient system design and a reduction in specific costs for PV power plants. A separate voltage supply and additional space are available for the installation of customer equipment. With a capacity of 4.6MW, the Sunny Central UP is the largest central inverter on the market. It implements particularly high design flexibility for PV power plants of the megawatt class with integrated solutions for the coupling of AC-bonded storage systems as well as for the coupling of DC-side battery storage systems.

Applications: Utility-scale PV projects.

Platform: The Sunny Central UP is said to be the first central inverter to offer a fully integrated hardware and software solution for connecting storage solutions so that DC-side battery storage systems can be easily connected without additional components. True 1,500 V technology and the intelligent cooling system OptiCool ensure smooth operation even in extreme ambient temperature as well as a long service life of 25 years.

Availability: Available since September 2018.

O&M | SunSniffer's Digital Twin adopts NASA technology to offer STC values during PV power plant operation

Product Outline: By adopting and modifying technology initially developed by NASA, SunSniffer is able to provide STC (Stanadard Test Conditions) values of each individual module, on a constant basis during PV power plant operation.

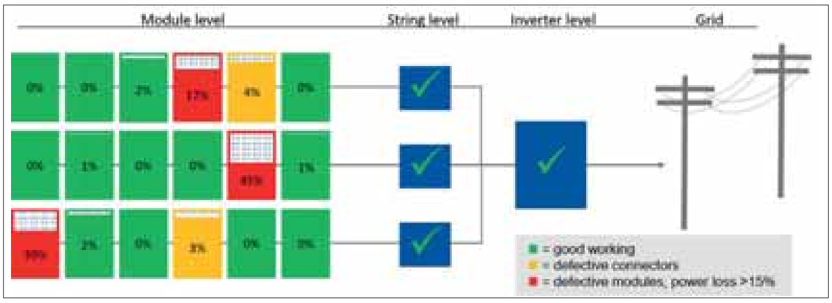
Problem: Typcially, the standard way to determine the performance of PV modules in the field is to make inspections of module arrays through thermal imaging IR (Infrared) to detect and locate any potential performance and degredation issues. The process, in which the faulty modules are demounted, taken to a laboratory for further qualified testing, transported back to the plant for reinstallation, is time consuming and expensive.

Solution: With its adapted NASA technology, that whole process can be reduced to the push of one button, according to SunSniffer. With a dataset collected for just one week of field operations, coupled with SunSniffer's 'virtual flasher', the Digital Twin can provide the final exact STC values of each module within the dataset chosen. Shadings, soilings or defective modules are recognized beside STC values and classified. Cleaning, repair or exchange services can be coordinated depending on the respective cost efficiencies. This is made possible by an integrated sensor which costs less than 1 Cent per Wp.

Application: PV power plants of all sizes, unlimited scalability.

Platform: Condition-based plant analysis by SunSniffer Digital Twin is part of the SunSniffer PV plant analytics technology, which measures and analyses PV plants of all sizes, providing precise condition reports and clear solution proposals in case of failures.

Availability: From December 2018.



Sunpreme teams with Honeywell for smart connectivity offerings for C&I installations

PV module manufacturer Sunpreme has formed a strategic partnership with Honeywell Process Solutions (HPS), a division of Honeywell Inc. The alliance will integrate Sunpreme products with HPS smart connectivity offerings for C&I installations. Sunpreme's Bifacial Smart solar modules provide both high power and high energy yield which are important for space-constrained applications. They will be coupled with Honeywell's solar power plant management hardware and software offerings in order to provide C&I customers with higher returns on their investment over the project lifetime.

SnapNrack's 'Ultra Rail System' offers a lightweight rail solution for residential rooftops

SnapNrack has launched its all new 'Ultra Rail System', which is claimed to reduce solar installation times and costs for residential rooftop arrays. Ultra Rail, a lighter rail profile, is a more economical solution for projects in more average load conditions, especially when attachment spacing is already dictated by the existing roof structure and more mounts are needed to disperse the weight of the system. Ultra Rail is said to be a more cost-effective solution for customers installing on a mix of roof surfaces. The entire system uses new Ultra Rail Mounts that include snap-in brackets for attaching rails.

The 2019 briefing

Technology & markets | After weathering some major upheavals in 2018, the global solar industry looks in decent shape to take on the year ahead. Our team of reporters scope out the big themes for 2019, exploring the technology and market trends that will set the agenda over the next 12 months and beyond

Welcome to our comprehensive scene setter for 2019. With a succession of disruptive events behind it, the solar industry largely knows the parameters it will be working under – for a change. Questions remain about how China will proceed following the sudden cap on deployment it announced in May. The early signs are that the country wants to continue deploying solar at a comparable scale to previous years, but only on the right terms.

The US is a little more predictable heading into 2019 than it was this time last year. The industry did fantastic work to finish the year feeling optimistic. That was largely through the hard work and ingenuity that kept projects viable, as well as a little luck from falling global module prices. A slew of new US states are now clearing the final obstacles for greenfield solar development, offering more sustainable business conditions.

Europe meanwhile is entering a new era of subsidy-free projects from Spain to the UK after a solid but unremarkable 2018.

Of the major markets India arguably has the most clouds hanging over it but the demand for electricity and the political will at the very highest level would suggest obstructive bureaucracy will be swept aside.

All of this positivity running into 2019 is bolstered by the benefits of emerging technologies. We could see bifacial modules secure sufficient backing to attain bankable status. The full impact of First Solar's Series 6 panels on project economics will become clearer as installations begin in earnest. Also, look out for trackers chipping away at the levelised cost of energy in some markets where their use has not previously been the norm.

Storage technology will bring another new route for post-subsidy deployment by providing new revenue streams in those markets where the regulators have enabled them. The past 12 months have seen a number of utility-scale projects in Europe, the US and Australia demonstrate the value that can be added under the correct conditions.

Making predictions is difficult, especially when they are about the future, to paraphrase the physicist Niels Bohr. With that in mind we have steered clear of issuing forecasts and instead present the key issues that will set the agenda for the year ahead.

John Parnell

CONTENTS

MODULE TECHNOLOGY The agony of choice

Choices, choices and more choices; this is the reality facing anyone hoping to procure solar modules in 2019 and subsequent years as the PV industry looks beyond its traditional trappings of 60- or 72-cell aluminium back-surface field (Al-BSF) based cell technologies. As if the array of new module offerings were not already bewildering to developers, EPCs and investors, the chances are it will be even more so in 12 months' time as yet more innovations are presented to the sector, according to Finlay Colville, head of research at PV Tech and Solar Media. That is unless independent engineers (IEs) and third-party labs manage to reach consensus quickly not just on how to evaluate the latest technologies, such as bifacial or half-cut cells, PERC, HJT and n-type, to name a few, but also how they perform in specific conditions and on different mounting systems such as trackers.

It was with this atmosphere of excitement mixed with uncertainty that PV ModuleTech kicked off for its second year, this time in Penang, Malaysia, with the whole value chain of the industry trying to come to terms with the newest module products. Traditional technologies look set to stay in play for a while longer, however, wherever cost or wafer supply remain constrictive to the spread of newer modules. Moreover, one key question was whether a standard 72-cell p-type multicrystalline module is at present the only truly bankable module in the world, being the only relevant product to have had 20-plus years in the field.

Nonetheless, it wasn't all rosy for the tried and tested technologies, with some shocking statistics presented about variability in solar panel supply. For example, Michelle McCann, partner at test lab, PV-Lab Australia, showed that when manufacturers knew their product coming into Australia would be examined, tests showed modules performing generally at or above nameplate power. However, when manufacturers did not know their product would be tested, deviation from nameplate power was far more variable, with up to 12% less power than billed in the worst case.

"We do get good product in Australia; we just don't always," added McCann. "Manufacturers can and do choose where to ship certain product."

It seems the trick is no longer just about what you buy, but also the way you buy.

Indeed, Lawrence McIntosh, another partner at PV-Lab Australia, showed evidence that product from the same tier-one supplier going to two different customers in the same country can often have significant variation in performance tests. The findings harked back to this time last year when we covered the inaugural PV ModuleTech 2017 conference in Kuala Lumpur; from which the takeaway phrase was 'all modules are not created equal'.

A bewildering array of new module technologies is available to project developers and EPCs

Credit: Wuxi Suntuh

Scrutinising bifacial

However, the overriding focus of this year's event was on how to grapple with the whirlwind of new technologies going into 2019 and beyond. One of the major questions facing the industry is how, when and whether to adopt bifacial modules, because if bifacial were to become the industry norm it would force all EPCs and plant designers to completely rework their assumptions about how to optimise site yields over 20-30 years. Many procedures that are standard to monofacial module installations are turned upside down by the bifacial concept, given its ability to generate power from albedo on the ground on the backside of a sun-facing module. A whole new game in terms of balance of system (BOS) would need to be played.

IEs and certification bodies all showed their work on bifacial testing so far, but it seems that a benchmark test for bifacial has eluded the industry and as one delegate put it "the industry is really excited but confused about bifacial technology". While there is puzzlement and risk aversion, there are also early adopters taking the sector into uncharted territory. Offering one of the more bullish forecasts on where bifacial will be in 12 months' time, Paul Wormser, VP of Clean Energy Associates, reminded us in the final panel session that some players are starting to invest in and install hundreds of megawatts of bifacial modules already.

"We are going to see not just the data coming from the test labs and the pilot sites, but we're going to empirically see really big projects going in the ground now," said Wormser. "It's going to accelerate and so we're at the tipping point and I think when we come back here next year it's going to be the normal thing to do."

This suggests that some players have done their due diligence and fully trust this technology, having moved on from the pilot phase. Of course, only time will tell us how performance will be out in the field.

Colville noted a tendency in the solar industry for innovations to either vanish or become almost universal very quickly and this is why everyone in the sector needs to watch closely to see if bifacial starts catching on.

Another suggestion that bifacial technology simply cannot be ignored came from Helen Zhou, module technical director at China-headquartered manufacturer JA Solar, who said the firm would soon start only producing bifacial cells and even putting them in monofacial modules due to the prices coming down so far on bifacial cells.

Ralph Romero, senior managing director, Black & Veatch Management Consulting, which plans to introduce the industry's first bifacial module rankings through tests in the Nevada desert, said: "In the US, there is a lot of excitement about bifacial modules, but the reality is there is still a lot of uncertainty with regards to module availability and module quality and first and foremost is the lack of a widely accepted energy forecasting tool for bifacial module performance. That's probably the single most significant limitation today that I see in the US market for deployment of bifacial technology. There are still hurdles to be overcome – it's not that everybody is now going crazy about bifacial modules; there's still a lot of hesitation."

Romero said that B&V's bifacial tests show on average a 5% module efficiency gain over mono, which is significantly less gain than the 15%+ gains that many manufacturers have touted. He added that the large variability in bifacial forecasts across the industry means that they need to be taken with a grain of salt. Regardless of that, the conference still heard of some developers considering sites of up to 300MW capacity using bifacial modules.

Nonetheless, Romero added: "The reality is that most manufacturers have bifacial products, but not very many actually have high volume commercial production of them."

Multi not dead…yet

The issue of multi versus mono is still a huge question given that these technologies account for roughly 90% of the market still.

The rise of mono-PERC modules has been undeniable, perhaps symbolised by some players in the aggressively price-obsessed Indian market starting to come to terms with it.

For Colville the global market is utterly dependent on wafer supply now and he went as far as to suggest that if there was enough mono wafer availability to supply the whole market today, then "multi is dead". However, wafer supply constraints mean multi should still be supplying multiple-gigawatts over the next three years and can still utterly dominate specific markets, with some Indian players, for example, likely to be procuring multi right up until the last standard polycrystalline module comes off the production line for an extremely low price in a few years' time.

In his analysis of the event, Vinay Rustagi, managing director of consultancy firm Bridge to India, aptly wrote: "There has been a common perception in India that the solar industry is highly commoditised, with multi-crystalline modules accounting for over 98% market share. But these modules are turning obsolete – worldwide share has already fallen from over 70% in 2015 to less than 50% now.

"As for the developers, there seemed to be a feeling that their job is becoming difficult in trying to evaluate different technologies and picking the right one. Some developers mentioned that they have to run as many as 30 different project design combinations before settling on a final plan."

What and when to pick

Indeed, Frank Faller, VP technology at 8Minutenergy Renewables, one of the largest solar IPPs in the US, said that not only is p-type multi "disappearing" but there are easily 15-plus technology options for modules and the trend is increasing. This dramatically increases the number of modelling iterations the company has to run to optimise its projects. This has made predicting the LCOE of a project more complicated and performing due diligence both more difficult and strenuous.

Faller also said that from a general developers' point of view, degradation modes on panels are still not fully understood, particularly as "degradation modes depend on the BOM [bill of materials] and components, and are unique for each single PV module brand and mode". He also described the finding that quality varies even between different workshops of the same manufacturer as "quite disturbing".

A major difficulty is how to instil confidence in developers that in six months' time the frontrunner technology won't completely change again, added Colville. The speed of technological progress means a newer, better module could be around the corner just three months into a project that takes 18 months to build, so how does one factor that into LCOE calculations?

"Everyone thinks it's great that there are all these higher performing modules and all this extra capability, but actually that's a problem if you are trying to develop something and have a fixed plan that you are giving to investors and demonstrating what the returns are going to be for 20 years," he said.

Besides the wafer supply issue, downstream growth will also play a key role in deciding the future of p-type multicrystalline. Colville said that if the market suddenly needed an extra 40GW next year, it is multi that would supply that demand, simply because there is not enough mono.

However, he added the caveat: "In a world of low-cost mono you have got the sky in terms of what might happen next. You have to deal with change quickly because in 12 months' time or in 18 months or two years there could be a rapid transition to tens of gigawatts of heterojunction (n-type) and then everything changes again. So maybe this is actually a warning time in the industry that it's just different now, that the industry and the cell processing have moved and we've got low-cost, high-purity wafers coming through for the first time."

Bouncing back from 531

China's policy upheaval in May this year, which significantly cut the leading solar market's projected growth, sent shockwaves through the industry; however, early November saw news emerge that the Asian giant may be considering enlarging its overall solar target to a huge 250-270GW by 2022. This will be sure to affect the rising demand from the rest of the world across Southeast Asia, Latin America and the Middle East, which have been absorbing the surplus capacity in China caused by the 531 announcement.

The resulting decline in ASPs has caused the whole industry to squeeze. Colville said this decline is entirely due to the supply of polysilicon and wafers, which is controlling both technology and pricing – adding: "The pricing of modules in the last few years has been held relatively high, you'll be disappointed to hear if you're a manufacturer."

Price and quality

Declining ASPs of course puts pressure on manufacturers to increase energy yield while also decreasing costs.

"The gap between the ASP and module cost is quite small and this is a huge pain for all of us in the industry, which means nobody is really earning money," said Mirko Meyer, head of product management at major equipment supplier Meyer Burger. "So then the question is how can we overcome this? Of course we can reduce module costs but this is hard without suffering on quality. The whole industry is squeezing and quality becomes a pain."

To make matters harder, Colville also added that a rebound on prices is very unlikely anytime soon.

"There's not a lot of margin in module manufacturing especially after China 531," said Tristan Erion-Lorico, head of PV module business, laboratory services, at quality assurance and risk management company, DNV-GL. "People are getting squeezed, but for the most part they are surviving. But if they are not getting a healthy margin to survive then cutting corners is an inevitable thing to turn to rather than closing the company down."

Quality was indeed a major feature of PV ModuleTech and we heard throughout the conference a long list of problems including underperforming modules, poor quality backsheet choices, replacement of modules after only a few years, and micro-cracks, to name a few.

For example, due to many first-time Indian developers entering the market during the "gold rush" of 2014/15, Vinay Rustagi said: "There is a big problem in India that many projects don't have the necessary amount of quality focus that they should have had. Many projects we know are underperforming very badly. There is high module degradation, there are warranty problems being reported etc."

However, besides emphasis on price, many delegates noted the importance of third-party labs and IEs having a strong voice for the industry to rely on.

Lou Trippel, vice president of product management at US-based thin-film solar manufacturer and developer, First Solar, said: "In terms of energy prediction – these things are hard enough without even considering some of the biases that may be present. We end up with a bit of an arm wrestling match here and we luckily have some referees that can jump in. As an industry we need to recognise the importance that these independent roles play in trying to drive toward that level of unbiased and absolute correctness."

Tom Kenning

MOUNTING Trackers go to the poles

The tracker market's progress can be plotted on a map emanating from the equator and spreading towards the poles. Barring a few outliers (a double-axis tracker was fitted at 65°N by a Swedish energy company in 2011) the mass markets for solar trackers have been rooted in hot desert-like environments. As with so much progress in the industry, the double win of improved technology and better project economics has opened the door for a host of new markets.

Steve Daniel is the VP of sales at Solar FlexRack, which makes both fixed and tracker mounting systems. He says the shift to trackers is exemplified by his company's own sales record: from selling next to no trackers two years ago the company is now approaching a 50:50 split.

"We're seeing a lot of fixed-tilt in the Midwest and Northeast (of the US) and we're seeing a lot of trackers in the south west and south east but it is creeping up the eastern border. We're going further and further north," he says. "It's all in the economics. We've got some good proof points that we've done in Montana, Minnesota, Ohio, Michigan and Oregon, which are showing that trackers are viable in cold weather climates in general; it's been a very positive year for us."

In the US, as markets develop beyond the deserts of the south, so too will the opportunities for trackers.

That level of ubiquity that has been achieved in California and other states could be repeated elsewhere. Trina Solar is providing its TrinaPro system to one of the new wave of subsidy-free projects in Spain. The package includes a tracker and it seems hard to believe that Europe won't repeat the same 'creep' northwards that has been experienced in the US.

As bifacial modules find bankability the argument for trackers will be bolstered further, blowing open the door to markets like India where the economics have not been favourable.

Jim Fusaro, CEO of Array Technologies, is eyeing strong growth in the market but not at any cost, leaving some markets such as India out of reach.

"We're certainly looking at all opportunities. The market is going to continue to grow, we're looking at more than 10% growth in the tracker industry over five years and there is scope for more than that. There is business out there that will be good for our competitors. We just simply won't take it at those margins," he adds.

Maturity is not only improving the end product it is also increasing competition and creating consolidation in the tracker market. This healthy fat trimming is only likely to improve the cost per extra kWh that trackers can deliver for the market. New opportunities, a healthier ecosystem, more complementary module technology and an ever stronger economic case suggest the poleward march of the tracker shall continue in 2019.

John Parnell

The market for trackers is maturing, technology is improving and the addressable market is growing.

Credit: Array Technologies

STORAGE Several steps closer to ubiquity

Like water slowly filling a maze, energy storage is spreading through the power and energy sector via niches and targeted opportunities, until the levee breaks and batteries and other storage media play a ubiquitous and integral role in managing power and energy flows all over the world.

That is to say, analysis of the sector is not taking in the whole picture if we are to narrow our focus too much. While front-of-meter, grid-scale storage deployment may have levelled off in Western Europe and parts of the US, the fact that last year saw record-breaking deployments in the behind-the-meter (BTM) segment in both territories shows that where one avenue in the maze begins to fill up, the market travels in new directions. The BTM segment is likely to grow further this year in many territories, not just in Australia or the southern US where the economics of solar self-consumption make a compelling case for batteries, but also through changes in market design in regions including the US and Europe. These changes will enable or encourage increased participation of aggregated distributed resources such as behind-the-meter energy storage in wholesale markets or to provide grid services, meaning that the lines between the transmission & distribution (T&D) and customer sides of the meter will begin to blur.

The biggest macro trend we are likely to see is the push further away from long-term contracts, particularly for grid services provided by front-of-meter energy storage. Again, the good news behind that trend appears to be that in addition to the increased value of BTM storage, high commercial electricity costs and corporate decarbonisation goals will be a contributing factor to total deployments in 2019. Peak demand reduction will be a big market driver, but in a broader sense so will the aspect of "merchant risk" involved in energy storage projects at the bigger end of the scale.

Fair market design and stable policy conditions will be important to success and there will also be regulatory and policy developments to follow closely throughout the year, providing many unknowns. If one could be crass enough to draw a general trend, it appears that as network operators begin to understand the value of storage, so too do policy makers and regulators, and we can only hope that this is how things will play out in general in 2019. This year we saw California elect to introduce a 100% renewable retail electricity by 2045 target and again we can only hope that other governments, be they state or national, will follow.

Of course, those are the 'saturated' or 'mature' markets. Other countries and their grid operators are still in the process of deploying large-scale storage and many of those, which include Italy, much of Asia and Latin America, can learn from those early adopters. While mentioning Asia, it cannot be denied that of course South Korea, Japan and most significantly China will continue to exert influence on global markets as well as shaping their own. All three are home to leading technology providers and manufacturers, and China and Korea are deploying huge projects including solar-plus-storage and energy storage in combination with other technologies over the next few years. South Korea is incentivising solar-plus-storage with Renewable Energy Credit certificates, while China has created a National Energy Storage Mission which includes plans for flow batteries of multiple hundreds of megawatt-hours.

Microgrids will continue to grow in both individual project size and relevance to the overall market. While a vast amount of that will be in emerging markets such as rural parts of Africa, Southeast Asia and India, bringing energy access to remote communities or islands, the very definition of microgrid is ever-evolving. In 2019 we are likely to see big megawatt-scale systems for communities and industries, including remote mining operations and instances where the microgrid is even in a grid-connected area, it just doesn't need to run from the grid.

We can also expect further exploration of technologies besides lithium-ion. It still reigns supreme, but 2018 was also quietly a good year for flow batteries and to a lesser extent for ultracapacitors not to mention even earlier stage technologies such as liquid air energy storage (LAES) and various combinations of hybrid systems.

We will also see energy storage in competition with natural gas, whether that will mean the retirement of existing peaker plants as batteries take their place, or even cases where energy storage is deployed at natural gas plants to increase their efficiency and reduce their carbon footprint. The relationship between batteries and natural gas is being very closely looked at.

Andy Colthorpe

Storage is making headway towards becoming an indispensable part of the modern energy system

Credit: Nuon/Jorrit Lousberg

INDIA Solar tender flurry overshadowed by policy hiatus

Credit: Welspun

A policy hiatus in the run-up to elections could slow down solar deployment in India in 2019

Indian solar is facing its toughest period so far since the launch of its 100GW solar target and its current slowdown has the potential to turn sourer if a major tax issue is not resolved. Despite the government's best attempts to issue innovative tenders and then shape them to the desires of developers, recent tenders have also persistently been undersubscribed or not subscribed to at all. While hybrid wind and solar, and manufacturing-linked tenders both come with their own set of concerns, the sentiment is that several wider market factors mean that the tariffs that the government is looking for are not viable at the present time.

"There are a huge amount of tenders coming out, but because of the ceiling cap on the tenders people are not bidding for them," says Anmol Singh Jaggi, co-founder of India-based solar advisory, EPC and O&M firm Gensol Group, which has provided services on multiple gigawatts of projects across India.

For Singh Jaggi, there are four factors that are holding back the sector right now, and it's not just the two-year safeguard duty imposed on cell and module imports from China, Malaysia and developed countries.

"One is of course the safeguard duty," he says. "But the other is the Goods and Services Tax (GST), which lacks clarity on whether it is at 5% or 18% for solar.

That's a big overhang. It's an even bigger issue than the safeguard duty today. The third is the Indian currency has gone from 68 rupees per dollar to 74. Of course it's now come back to about 71, but still it has increased the project costs. Fourthly, interest rates over the globe have hardened by about 150 basis points in the last six months."

As a result of these factors, tariffs of 2.50-2.60 rupees per unit are no longer viable, adds Singh Jaggi, who does not expect interest rates to soften in the next year or so.

More importantly the Ministry of Finance needs to come out with a paper clarifying the GST rate for solar, because if it comes out at 18%, the industry can be expected to slow down "much more significantly", says Singh Jaggi.

To make matters trickier, 2019 is an election year, so with just six months to go before people hit the polls, the GST rate for solar is not expected to be the top priority of any politician. Moreover, investments in India tend to stall two months either side of an election.

However, Vinay Rustagi, managing director of consultancy firm Bridge to India, expects a big pick up in 2019 for solar deployment because of the various tender timelines from 2017, with 10.9-11GW of projects due to come online. Rustagi agrees there will most probably be a hiatus on the policy front, particularly either side of the election, but also notes that a council meeting on the GST is due to be held shortly where there are expectations that the issue could finally be resolved.

Ups and downs of 2019

Expecting 2019 to be anything but a peak year for Indian solar, Singh Jaggi says he would be happy if the market hits 7-7.5GW, a far cry for the more than 10GW of capacity installed back in 2017 or what may well be achieved in 2018.

On the flip side, rooftop solar is the main success story in India right now and Jaggi expects this segment to see 1GW+ installations in 2019. Bridge to India also expects rooftop to grow very robustly by adding 1.5-2GW every year mainly driven by the commercial and industrial segment.

On another positive note for PV, Jaggi believes that next year individual states will start realising that they will be facing a power deficit in 2021 and 2022, given that India is growing at 7% GDP per year, and will need roughly 14-15GW of new capacity added each year. That comes on top of the fact that almost no new major coal plants have been added in India in the last two years. Solar has the advantage of being installed in just over a year, unlike coal, hydro and nuclear, which can take 3-10 years, so he expects states to come out with lots of tenders in the second half of 2019 or in early 2020.

"Power demand has definitely picked up in 2018 especially in the last six months faster than anytime in last three to four years," adds Rustagi – noting that exchange power prices have increased due to some hydro plants running at much lower plant load factors (PLFs) and poor availability of coal and railway links for thermal power plants.

On the other hand, India still has excess installed thermal capacity and some plants will be coming online again soon after resolving bankruptcy proceedings, which could absorb some the need for more solar generation.

Nonetheless if the manufacturing-linked solar tenders do not work out, there will be renewed impetus on the issuance of pure solar tenders, says Rustagi, since government is under pressure to take some positive steps. The Ministry of New and Renewable Energy (MNRE), for example, has already directed the Solar Energy Corporation of India (SECI) to issue a 1GW tender every month for four months up to March 2019.

There is also talk of the government reviving plans for 12GW of solar capacity for public bodies (PSUs) with a mandate to use domestically produced modules, given that both the safeguard duty and the manufacturing-linked tender have so far failed to encourage expansion of PV manufacturing capacity in India in the manner envisaged.

Tom Kenning

POST-SUBSIDY EUROPE MIP ending and grid parity promise make European solar a 'sleeping giant'

The lifting of political and cost-based brakes on European solar in 2018 is set to awaken a sleeping giant, with subsidy-free solar projects potentially the norm all across Europe in just a few years.

A combination of more and more countries hitting grid parity, the ending of the Minimum Import Price (MIP) on Chinese imports as well as a temporary Chinese module oversupply means that the European solar market is on the cusp of booming, according to several developers and module suppliers.

"The MIP ending has led to a huge IRR boost for investors and developers since it has allowed global market module prices to be used in Europe," says Frank Niendorf, general manager Europe, at China-based manufacturer, JinkoSolar.

Lily Coles, commercial operations director at UK-based developer Anesco, which has already built a subsidy-free solar-plus-storage plant in England, agrees: "Coming out of MIP then opens up a huge door for us and the panels have always been the most expensive part of it. We've spent a lot of time whittling down the other components and being cost competitive while maintaining the quality on the inverters, the cabling, the ground-mount system and everything else, but the panels have been sort of out of our control, so it's going to make a massive difference and we can now see that pipeline really growing."

Other developers have also celebrated the effects of the MIP ending combined with China's subsidy removals. Dale Barnard, senior project engineer at Denmark-based developer, European Energy, cites an IHS Markit report on prices dropping 30% across the board, with panels in Europe bottoming out at €0.20/W.

He describes these as "insanely cheap prices" that could only have been dreamed of last year – adding: "It almost opens up the entire European market for subsidy-free, perhaps with exceptions for some of the very northernmost countries."

When the MIP ended the prices dropped overnight, adds Andrew Witkin, sales director at module manufacturer Seraphim Solar System. Manufacturers had huge amounts of stock and the prices have carried on dropping to point where there are rumours of stock nearly running out in Europe, with potentially even a shortage from now into Q1 2019. Witkin also believes that much of the highest efficiency stock such as bifacial and mono PERC modules is being soaked up by China's Top Runner programme, leaving less for Europe. Thus availability of product could be an issue at a time when Germany is increasing deployment, Italy is rebounding and the US market is growing again.

In any case, Niendorf cites several countries where post-subsidy projects are already proliferating or are set to kick-start merchant PV in the coming year, including Spain, Portugal, Italy, the UK and the Netherlands.

"From 2020/21 onwards it will be all over the place,' he adds. "No matter which country and we will have reached a system cost level that will allow the installation of projects without any kind of support."

In the short-term, Niendorf stresses that while he expects prices to come down further to some extent, the overcapacity in China is a temporary phenomenon, and prices coming down 30% in such a short period of time raises questions over how sustainable those levels are. However, an industry that is not dictated by the politics of feed-in tariff (FiT) support also means that future module price fluctuations will be far less severe than in the past.

"Becoming independent from those subsidies will actually lead to a more stable supply and demand, which we have in other industries as well, so PV will get there," he says.

Furthermore, both developers agree that post-subsidy solar will drive both better quality and competition in projects. Investors become far more interested in technology when project margins and returns are predicated on the performance of the technology used rather than the comfort of a FiT subsidy. Anesco's Coles says this means developers have to demonstrate their technology's capabilities far more to investors whilst also focusing heavily on re-engineering plant designs.

European solar has faced a tough five years held back by what Niendorf describes as "artificial brakes" while other geographies boomed. Now most of those brakes have disappeared, but there is the major looming problem of grid integration.

Nevertheless, he adds: "I think this parity is a sleeping giant, and most players are not aware of what potential also in Europe that parity has.

"We can see so much development activity all across Europe, which scares the commercial conservative utilities like hell. It's a great chance for Europe as well to become finally more [energy] independent, so we are extremely bullish

THE EUROPEAN MARKETS HUNGRY FOR MODULES

Frank Niendorf, general manager Europe at manufacturer JinkoSolar, gives his forecasts for European market demand

"For sure Spain will become the biggest European PV market again in 2019 and probably also 2020/21, for the next three years (see separate box). There is a lot of activity developing projects on a pure merchant basis and that's a pretty impressive development. At some point in time, in particular in Spain, probably 2-3 years we will reach a point when there are so many more installations and gigawatts that actually the spot market price level will come down and then it might become an interesting question what parity finally is.

"Italy is showing very interesting signs now on parity projects. France is now starting with its first parity projects to be installed at the end of next year as well and in Germany there are activities from big utilities who are starting to acquire big lands because they plan to do projects on a pure merchant/parity basis. In the UK we think we will see the first 200MW of installations during next year without any kind of subsidies.

"The Netherlands – you still have a certain regulation which makes PV installations extremely attractive but then I would say from 2020/21 onwards it will be all over the place, no matter which country and we will have reached a system cost level that will allow the installation of projects without any kind [of support]. Portugal also has a reasonably hospitable regulatory environment with great irradiation."

Credit: Anesco

Clay Hill Solar Farm in the UK is one of a growing number of unsubsidised solar plants emerging in Europe

for the European market and in general as well because this momentum cannot be stopped now.

"We have reached a cost level which is unbeatable. It's the cheapest electricity energy source in the world and we have not finished that yet – it's going down further."

European Energy's Barnard agrees: "Solar has got a raft of positives from ease of installation to low cost to low maintenance. […] The only thing that was holding it back was the high cost of procurement versus the power prices that you can achieve and once we hit parity that problem disappears, you're no longer tied to political issues, you're completely divorced from that process and you can rely on the market to drive things forward, so it's incredibly exciting."

The industry is equally excited by the new technologies and efficiencies as they are about low prices with module power ratings now in the range of 270-400Wp after significant R&D efforts by the upstream sector. Moreover, Coles says that even high street banks are beginning to see revenue streams in solar and investors are becoming more comfortable with the words "merchant risk".

Tom Kenning

NEW ROUTES TO MARKET

As Europe's solar markets move into a post-subsidy scenario, two new business models – merchant solar and corporate PPAs – are coming to the fore as key routes to market. Merchant power plants sell power on the wholesale spot market, while under private PPAs, developers sell power directly to off-takers as a means for the latter to hedge against rising energy bills and cut emissions.

Spain's solar resurgence is a prime example of this new world, driven as it is by a huge merchant and power purchase agreement opportunity that far outstrips the size of recent government tenders. The country now has a pipeline of 29GW, according to the national solar trade group, UNEF, of which only 3.9GW has been tendered by the government.

"The market has realised that they can expect very little from the government and they aren't going to wait around for a new support scheme," says Jose Donoso, the head of UNEF. "With the degree of competitiveness that solar has, we can go straight to the market on a merchant basis or we can look for PPAs, without any need for input from the government.

"At this moment in Spain, there are 29GW of solar projects in the planning process. One year ago we had no PPAs and now we have a PPA signed every week with big companies. All the major off-takers are in talks with different developers," added Donoso.

Trade body SolarPower Europe acknowledged the growing importance of the merchant and PPA markets in its most recent 'Global Solar Outlook' report. According to recent SPE figures, corporate solar accounted for 1.7GW of new capacity in 2017, while a further 2GW has been contracted this year.

SPE's deputy CEO, Bruce Douglas, highlights the recent financial close by developer Baywa of the 174MWp Don Rodrigo PV power plant near Seville, Spain, as a sign of things to come. The plant is unsubsidised, instead trading off a 15-year PPA with the Norwegian energy group Statkraft. "That's an example of what's coming, and coming fast," Douglas says.

SPE is more circumspect about the growth of the merchant power market for solar, as this comes with considerable price risks for developers. According to SPE's head of market intelligence, Michael Schmela, although some companies are trying merchant projects "here and there", financing such projects remains a barrier. As such, Schmela says the full adoption of the European Commission's so-called clean energy package, which sets the EU's legislative framework for clean energy going forward, will be a key step forward for growth in the merchant market.

"We have to wait – the market design of the clean energy package is in its final stages, and it's really still here the questions around balancing responsibilities, on priority dispatch… [that] need to be clarified to make sure what you can do and what you can't do so that the financing institutions will be able to make decisions on [financing projects]."

John Parnell and Ben Willis

USA The uniting states of solar

Credit: Conti Solar

California has long been the 800lb gorilla of the US solar market. According to data from the Solar Energy Industries Association and Wood Mackenze, it has installed more solar than the next largest eight states combined. It's clearly a special case. Of those next eight, only Arizona and North Carolina have installed more than 3GW. If you move further down the rankings it becomes quite thin indeed. For that reason, even modest improvements across the board could yield a fairly positive result for overall US deployment. The good news is that appears to be very much the case.

Looking ahead into 2019, there is scope for progress in a huge variety of US states. Despite this, the industry is understandably wary about making predictions.

"The only that has ever been true is that whatever we expect to happen, will definitely not happen," says Joe Song, vice president of project operations, Sol Systems. "We went into 2017 thinking all these projects were going to happen and then [Section] 201 [solar tariffs] came around and it paralysed the industry. Everyone went into this year thinking no projects were going to happen and then come July the China market pivoted and it opened up a whole lot of opportunities.

New state markets are beginning to open up in the US, driven by new policy and financing developments

"In terms of where I believe we are now, excluding any disruptive events, we, like most other developers, are heavy in Massachusetts, and so is everyone else, we've also been paralysed there waiting to see if we have a good or a bad project," Song says. Massachusetts launched its new 1.6GW solar programme which will see projects of up to 5MW entered into an online approval process. Developers that have invested time and effort into predevelopment work

CHINA If the cap fits

If 2018 taught us anything about the Chinese market it was to expect the unexpected. May's cap on solar deployment caught many cold. The scale and swiftness of the actions were indeed a surprise but runaway manufacturing expansions and a desire to avoid a severe overcapacity issue might have been a warning sign that something had to change.

At the time of writing, Beijing was still planning for 2019. A meeting in early November with a variety of stakeholders offered no definitive answers. What we do know is that the National Energy Administration (NEA) is well aware that some of the same companies working on FiT dependent projects are delivering eye-wateringly low-cost subsidy free projects in other parts of the world. We also know that grid issues that have plagued renewable plants in recent years are receiving renewed attention. The NEA has said it will support local governments who wish to offer their own incentives to plants on the proviso that they make sense, that is to say, that the grid will not curtail the electricity at some of the painfully high rates seen in China's North West.

At the meeting in November, the idea of ramping up the country's solar target was floated. A figure of 200GW by 2020 was circulated but PV Tech Power understands that one major module supplier is pushing for a higher figure of as much as 270GW. Current installed capacity is 165GW.

A willingness to press ahead with that higher goal may be as dependent on grid improvements as it is on Chinese module manufacturers' ability to prove there is sufficient global demand for the product of new factories.

Five years ago this latter objective was a harder task. California and a volatile European market were the only multi-gigawatt games in town. Today India, a more predictable Europe, a patchwork of US states plus South East Asia and Latin America offer outlets. The diversity of the global solar industry is broadening and on parcels of 5MW, have no idea how much capacity they will ultimately build.

"Illinois is similar with a lot of community energy as well as adjacent markets to Illinois, where again, people are waiting until they can enter the block programme. We're tracking policy changes that are in the works whether it's in New Jersey, Maryland or DC that will enable the incentives to be better or at least longer term. We're also keeping an eye on emerging markets like Idaho, we've been doing a project in Nebraska for a couple of years. Some people view Alabama and Kentucky as being the next Georgia so we'll keep working down there buying land and putting in interconnections."

EPC and developer Conti Solar has a similar outlook with Illinois ranking high but not alone in offering fresh opportunities.

"Broadly, the entire south east region is largely an untapped market," says Eric Millard, CCO, Conti Solar. "We're starting to see some indicative feelers from developers in Alabama and Kentucky looking for pricing guidance. The Carolinas – I know North Carolina is already a prevalent market – and Virginia will see a lot more activity from the Duke and Dominion procurement rounds. Dominion is aggressively building out and will do so for a while."

In October 2018, Virginia issued a mandate for 3GW of solar and wind.

"Then there are states like Florida, Tennessee and Midwest states like Indiana and Ohio which are on our watch list as well. Historically there has not been a lot of build but now, on the utility-scale side of things, there is a bit of a queue," says Millard.

The policy challenge

For a lot of states, large and small, the issue is one of unpicking incumbent legislation that chokes solar deployment. James Owen is executive director of the advocacy group Renew Missouri, which has been advocating for all renewables since 2006. Missouri recently passed Senate Bill 564, which as Owen explains, is often referred to as the grid modernisation bill. Solar forms a key component. In the case of Missouri, coal remains a dominant force and part of Renew's work, in conjunction with the Natural Resources Defence Council, is to find affordable ways to retire coal plants early.

"We're working with the NRDC on legislation to promote the concept of securitisation, which would open a market place for those depreciated assets which would allow the utilities to shut down those coal assets early and we think that will contribute to the concerns about solar adding to that bottleneck," says Owen. "Michigan has done this with a lot of success. Consumer groups like it, the utilities like it and environmental groups very much like it. We can close down plants with 10-15 years left in them."

The refinancing uses bonds with interest rates in the order of 3% versus the project finance rate, which could easily be double. The savings can allow the plant to be mothballed early without creating a stranded asset. The technique was also used when Florida's Crystal River nuclear plant closed after it was found to have structural problems.

Missouri's largest utility, Ameren, is targeting emissions reductions of 80% by 2050.

"By 2025 they want to add 50MW of solar generation and plan to add 100MW by 2027. This is nine years but I would expect this to be frontloaded because we have the tax incentives expiring in 2021. I suspect that will come sooner," says Owen. New legislation will also clear the path for microgrid developments such as those favoured by military bases.

The emergence of new solar markets across the breadth of the US means even new entrants have to look beyond California and New Jersey.

Dutch mounting manufacturer Esdec, which specialises in rooftop systems, launched its US operations in September. Its approach signals the growth of non-utility solar beyond the usual suspects.

"If you look at the research reports the top 10 are in the south west and north east but we need to be aware of what is going on in the other states," says Esdec CEO, Stijn Vos. "We want to make sure we are present there as well. "We are building a team of solar veterans to cover the established states but we need to be able to cover the up and coming solar states as well."

John Parnell

just as in nature's ecosystems, everybody wins in that scenario, barring any external interference.

If China is to decouple deployment from centralised support schemes and devolve this to local governments, then the Chinese market is only going to be more complicated in 2019. The diversity of creating 34 provincial Chinese solar markets could well see it evolve into something more sustainable.

John Parnell

Some in the industry want to see annual deployment remain at similar levels as we have seen recently

Credit: United PV

Global markets: where's hot and where's not

Interview | Vikas Bansal, head of business development, solar international, at one of the world's largest solar EPC firms, Sterling & Wilson, talks to Tom Kenning about which geographies show the most promise for solar development going into 2019 and beyond. India, Western Europe and China are covered separately in this feature

Asia

"This year Vietnam has been a fantastic market. We were all expecting last year that Vietnam would open up but finally, it has. We are constructing roughly 300MW of plants in Vietnam and even next year Vietnam is going to remain very active in PV (see p.30 for separate analysis of Vietnam). Bangladesh will pick up. This market has been dormant for the last three years. There have been lots of things happening at the government level, but finally this year they will be able to roll out a few solar PV plants on the ground and next year will even be bigger for this market so we are very focused on Bangladesh.

Markets like Malaysia are doing lower volumes, but they seem to be doing a small volume every year so they are more consistent.

Indonesia has been one market which personally for me has been a bit of a disappointment. Two years back when we started getting into Indonesia, we invested, we had people and offices there and we all thought that Indonesia would finally open up, but unfortunately, it didn't happen. There are a lot of grey areas in terms of local content requirements, and in terms of feed-in tariff (FiT) applicability, so that is one market which has been a dampener to say the least.

There are other sporadic markets like Myanmar, Cambodia, where action will happen but as of now we don't see them as long-term markets because they do not have long-term policies to promote renewable energy.

Australia

Australia has been one market which has absolutely boomed in the last two years and we feel the market will continue to boom although there are some policy-level issues which have been happening in the past few months, for example, The National Energy Guarantee (NEG).

Nevertheless, the way we see the market is that in Australia the merchant power plants are still making sense. We are also working on several large opportunities there including some of the large plants which are going under construction in the next three to six months.

So overall, from our perspective, even though the policies are a bit fuzzy as of now we still feel the market has all the right macro indicators and will continue to grow for the next three to five years.

Central Asia and Eastern Europe

Kazakhstan has shown some signs of movement. That is one market which we think this year will be small – they really want to take a step-by-step approach, which we appreciate, but the overall long-term plan seems to be there so that is a market to watch out for. If not this year, next year that market is going to open up for large-scale investment on the PV side.

There are markets like Ukraine which have been dormant for the last many years. Even now we do not have much visibility on the way the market will shape up, although there were a few issues on the bankability of the PPA, which have been partially addressed. We still feel the market will take another six to nine months more for things to become clearer.

Middle East

The Middle East is like one large tender driven market. You've had tender announcements in almost all the major countries in the gulf, while Abu Dhabi has indicated that it will come out again for another 1.5GW tender for solar PV. They want to bring about 5-6GW in the next two to five years so there is a high possibility that they will come out with a large tender in the next six to nine months, but obviously, that still remains a possibility. These UAE programmes are all evolving.

In Saudi Arabia, where things have still not gone the way they were planned, finally, they were able to come out with more structured and long-term solar programmes. It's another country where we all know it has a lot of potential when the macros are all in place. It's a matter of [the] right policies and right implementation.

They have taken the first step with the execution of the 300MW Sakaka plant and we are very confident that moving forward they will come out with more structured RfPs for the solar PV domain. Sterling & Wilson invested in that market many years back. We have a full-fledged presence in Saudi Arabia and that speaks volumes about our focus and interest in this market.

Egypt has done a lot of megawatts and they have been able to allocate more megawatts recently, but moving forward after this year we have little visibility about Egypt for 2019.

We are not clear whether they will be looking for more capacity but overall we always evaluate the market from a very macro level perspective. We still feel Egypt is a large country with large requirements and they can still absorb power [on] their grid. However, the policies are still as of now not clear in terms of implementation and what kind of targets they are aiming at.

Other markets in the Middle East are more sporadic. Some countries will come out with a tender, but will they go through it in a long-term process? Countries like Oman are now very active in solar after a three-year break, but strategically planning for such countries can be difficult.

Credit: Wirsol

Australia is among the global solar markets S&W's Vikas Bansal expects to continue growing

Africa

A few pick countries are likely to be very active. One would be Kenya, which we feel has finally woken up to the fact that some amount of solar on their grid would be useful. It will help them in creating more jobs and Kenya has already allocated a few PPAs and as per our understanding they will be allocating more PPAs in the next 3-6 months, so that's one market which is going to be important.

Then everybody knows South Africa has made a comeback. It took a break for two years and now it's suddenly coming back on the block.

A lot of other markets have [the IFC's] Scaling Solar programmes, but from a strategic level these markets will remain sporadic. They will come out with a few tenders and then they will go back to their normal route.

Even if you look at some of the countries which adopted the Scaling Solar programme things have been rather slow. They have been able to implement only a few hundred megawatts under the programme and the programme started almost two years ago. These countries obviously need a lot of baseload generation but they do not have any solar on the grid so all of these countries can very easily absorb a few hundred megawatts of solar in their grids and they can kick-start their industry.

In the last four to five years a lot of countries have done one or two projects, for example Mozambique, around 50-100MW, Zambia around 100MW, Namibia around 50MW, and Kenya till now not much, 20-50MW. So they have done one or two projects but the large-scale adoption has not happened and from our perspective we don't think a lot of African countries will adopt large-scale solar at least this year, but maybe next year once the prices of solar further go down they may again start looking at solar in a more active way.

But all these countries have the right intent and I'm very sure it's only a matter of time before they start adopting solar on a larger scale.

Latin America

Latin America has been very active. Although Argentina has had some issues on the banking and credit side of the market, we feel it will become an important player moving forward.

Chile has traditionally been a very proactive solar market, but it had a break in the last couple of years. However, now that the north and south parts of the country are linked with transmission lines, it will again see a third wave of solarisation and 2019 and 2020 are going to be important for the Chile market.

Mexico is another country that started solar about 3-3.5 years back and is again keen to do around 1-2GW every year and they will continue to play an important role.

Colombia has had a government policy announced and although there are a lot of regulatory challenges in the market, we think in the next one to two years Colombia will become an important market from a scale perspective. We think even their solar programme will be 500MW-1GW, which is a good enough scale for anybody to start investing and thinking seriously about any country.

Brazil has been an on and off market. They have done more than 1GW to date. Even now we are not very clear which way the market will go, so from a strategic perspective we are not sure whether we should focus on Brazil now or wait and watch.

North America

We very strongly feel that the US will remain an important market despite the tariff imposition on modules. We still feel the market will remain healthy although the volumes have gone down. But even at a level of 5-7GW it's a big enough market. The policies are very structured and a lot of states are still interested to go for solar.

We also feel that US is one market wherein you will see a lot of integration of solar and storage because it's a developed market. There are a lot of possibilities of combining storage and solar and then offering more dispatchable power to grid operators. Sterling & Wilson understood this a couple of years back and we are right now implementing a 30MW solar project in US and very soon we will be starting a 70-80MW construction.

Vietnam's mysterious solar market builds momentum

Southeast Asia | Concerns over Vietnam's power purchase agreement have not prevented a huge number of project deals being signed. Tom Kenning weighs up what progress is being made in putting one of Southeast Asia's most promising solar markets on the map

Credit: Prince Roy/Flickr

Few global solar markets are harder to get a consensus view on than Vietnam. One only needs to talk to a handful of people to realise that players looking seriously at this market have highly conflicting views about its current and future progress, what PPAs have and haven't been signed and who's trying to exit them, how many projects are getting financed and, most importantly, the level of risk involved in this fledgling market.

If one were to only take heed of the enormous number of EPC contract, power purchase agreement (PPA) and module supply deal signings being announced in recent months, one could easily infer that the Southeast Asian country's PV industry is flying. Though issues around the PPA have been called "a storm in a tea cup" by Eddie O'Connor, executive chairman of wind and solar developer Mainstream Renewable Energy, with a PPA as controversial as Vietnam's has been, gauging the health of the market may not be as simple as just counting project announcements.

The seed of this discussion dates back to the Ministry of Industry and Trade's (MOIT) introduction of a solar feed-in tariff (FiT) of US$0.0935/kWh last year. The market immediately garnered a huge level of interest that saw multiple gigawatts of project applications and potentially billions of dollars ready to be invested before the FiT deadline of June 2019. However, as the draft PPA was circulated, many potential investors started to think again. The Vietnam Business Forum (VBF), an umbrella group for all international Chambers of Commerce, went as far as to openly declare the PPA as "non-bankable".

Ultimately it comes down to an international developer's appetite for risk. Whether the frontrunners are industry leaders, players with deep pockets, or straight up cowboys, reports of the number of PPA signings suggest that its shortcomings have not completely knocked the market on its head.

Debate has raged over whether Vietnam's PPA will act as a deterrent to solar developers

Oliver Massmann, general director at law firm Duane Morris, declared at the ASEAN Solar + Storage Congress, in Manila, the Philippines, in November, that 35 solar PPAs have been signed in Vietnam as of September 2018, accounting for 2,271MW of capacity. Although *PV Tech Power* was unable to get MOIT to confirm the numbers, other developers said it was reasonable to believe that the correct figure is around this level.

However, progress at the next step of raising financing is even more opaque and it's not clear which players are successfully raising finance and with whom – particularly as international banks see so many risks in the PPA as it stands. Another important insight from several industry insiders is that some players are actually trying to get out of their PPAs. Yet it's important to note that this worrying situation, if true, comes against a backdrop of enormous optimism from a host of players – many of them heavyweights in the industry who are at very late stages of developing their projects. Renowned Singapore-based developer Sunseap Group, for example, has already started constructing a 168MW project in Ninh Thuan Province and this should give comfort to others.

Crystal ball

"It's a bit of an unknown future, you need a crystal ball to figure out what exactly will happen, but what we can see now is that a similar trend is happening in Vietnam to what happened in the Philippines for example," says Milan Koev, vice-president, international business development, at Sunseap. "The government did a great job by coming up with an attractive FiT and they've got more project applications than what they expected. We are seeing a short-term boom and I think going forward things will change, with either a lower FiT or an auctioning system and this will cool down a lot of investment aspirations for the country."

In spite of the long lines of naysayers, some developers, including Sunseap's Koev, believe Vietnam will be the biggest solar market in Southeast Asia and they have been impressed by government policy in recent months, having initially been taken aback by the PPA issues. Views from the one of the world's largest PV module suppliers alongside perhaps the world's largest solar EPC go someway to backing up this claim.

Firstly, Ku Jun-Heong, senior sales director Asia Pacific and Middle East, at Chinese PV manufacturer, Trina Solar, says: "For Asia Pacific, the higher demand we are seeing is coming from Vietnam right now, and Vietnam also has a sudden target of volume commissioning of projects by end of June 2019, so we are actually getting big volumes from customers."

However, the challenge for Vietnam is that it has not done any utility-scale PV projects before, says Jun-Heong, and so the test of implementing its first few hundreds of megawatts of projects is that the typical local developer has no experience and there are difficulties with financing, as discussed later in this article.

Echoing Trina's sentiment, Vikas Bansal, head of business development, solar international, at Indian EPC firm, Sterling & Wilson, says: "This year Vietnam has been a fantastic market. We were all expecting last year that Vietnam would open up but, finally, it has. We are constructing roughly 300MW of plants in Vietnam and even next year Vietnam is going to remain very active in PV."

Credit: Sunseap

Sunseap CEO, Frank Phaun, and Vietnam prime minister Nguyen Xuan Phuc, shake hands over Sunseap's 168MW PV power plant in Vietnam

PPA prang

The debate about the PPA has been raging for more than 18 months now, with fears circulating around curtailment and compensation, dispute resolution without international arbitration and a lack of clarity over 'take or pay' agreements, to name a few. However, initial dislike of the parameters of the solar PPA has tempered somewhat, as investors come to terms with the fact that 2GW of PPAs for hydroelectric power in Vietnam have been signed under almost exactly the same terms as the solar PPA over several years. Moreover, the state-run monopoly utility, Electricity Vietnam (EVN), has never defaulted on a PPA involving foreign invested IPPs, and Vietnam, one of the fastest growing economies in the world, is facing an energy crisis with demand projected to go up by 11.4% between 2016 and 2020. This means it is not in EVN's interest to curtail power, although grid challenges are already surfacing.

"There are a lot of developers who are struggling with financing for Vietnam, but I'm not sure whether this is down to their ability to finance projects or if it is a country-specific issue"

The prime minister is intimately involved in the future of electricity in Vietnam, says Eddie O'Connor, which is a positive sign.

Nonetheless, the termination clause, under which EVN could unilaterally terminate the PPA without paying any compensation, is "a big one to swallow for bankers", says Olivier Duguet, CEO of Singapore-based wind and solar developer Blue Circle. He describes the PPA as the "elephant in the room", but given the 2GW of hydro signed under the same terms, the Vietnam government does not see a need to update the PPA, he says, while there is also consideration in supporting local developers over foreign ones at this early stage of the market and this is partly why the lawmakers lack urgency in amending the PPA.

Financing

"From an international bank point of view there's a lot missing from the PPA," says Raphael Chabrolle, senior vice president, Sumitomo Mitsui Banking Corporation (SMBC). "No compensation for grid curtailment means banks need to do big grid studies."

Local banks are more relaxed and really the go-to option for financing, while foreign financiers, for whom investment is more challenging, are looking at ways to share their risk before diving in, adds Chabrolle.

Thus, besides the PPA, financing is yet another hurdle.

"There are a lot of developers who are struggling with financing for Vietnam, but I'm not sure whether this is down to their ability to finance projects or if it is a country-specific issue," says Sunseap's Koev. "It is a very thin border between investment risk-taking appetite and developers' ability to convince those investors that projects are indeed bankable. Everyone knows the current PPA is troublesome, but there are a lot more other specific items on the agenda for every investor to look into during the project due diligence, and above all I believe the relationship with EVN and MOIT is what really matters beyond the numbers."

Trina's Jun-Heong says that it takes players a long time to get financing, and contrary to others' claims, he believes local banks do not see solar projects as having a good return on investment.

Big Vietnamese conglomerates like TTC group and Thai giants like B.Grimm Power are dominating development on the larger projects, but there's less visibility at the smaller scale.

Unlike Koev, who says market will be much smaller post 2020, Jun-Heong compares Vietnam to Thailand in its early days of 2011/12 when there was a steep learning curve for EPCs. After this round of project construction and commissioning by the end of June 2019, he expects that there will be a sizeable group of developers and EPC companies who will pick up the necessary experience and capabilities over this time to continue that momentum.

Patrice Clausse, COO and head of international business, at growing Filipino firm AC Energy, believes that the government has handled the industry well so far and that the unfortunate lack of international financing appetite may only hit market deployment by hundreds of megawatts rather than gigawatts.

The hot provinces

For now though, much of the planned PV projects have been centred around just two provinces, Binh Thuan and Ninh Thuan, the latter of which has been granted a lengthy extension for its FiT up to December 2020. Binh Tuan has also called for an extension, according to local reports. These provinces have benefitted from having explicit PPA policies and a significant chunk of development progress has been down to individual province policies rather than just central government incentives.

However, some steps of approval are opaque especially at provincial level and even just for doing a survey on the land, says Pranab Kumar Samah, CEO, UPC Solar Asia Pacific.

"If those things can be standardised, some of the development cost will be reduced significantly," he says. "So from there until to the time you get construction permit, if everything can be done through a single window system - some other countries are doing that - that will practically sort out a lot of the development cost."

Samah also claims that central and local governments are not working coherently and there are many arguments ongoing between them

Grid trouble

Clustering of projects is a big problem in Vietnam, nowhere more so than in Ninh Thuan province, which has a 2GW pipeline of solar projects but an existing grid capacity of just 650MW.

"Binh Thuan and Ninh Thuan are the main hotspots and this has created a huge issue of grid access," says Duguet. "Wind and solar are already fighting each other for access to grid, which is key to the FiT deadline."

He advises other developers not to put their eggs all in one basket and to consider developing projects in other provinces even if they have lower irradiation.

However, Eric Liu, GM of Vietnam, at China-based PV manufacturer and developer, Risen Energy is more upbeat: "Of course, there will always be problems, but there will always be solutions. Now the power grid capacity is not enough to support so many projects, so the key is to upgrade the EVN's power grid."

Post-FiT

The industry is watching closely and preparing for the next step, with much speculation on whether the FiT will be extended for more provinces than just Ninh Thuan, as well as whether the FiT will be reduced or if an auction system might be brought in.

"In my opinion I think the extension will only be for Ninh Thuan province because this is the poorest of the provinces in Vietnam and there's no other industry or any sectors that can be developed in this area – just only the energy," says Mai Van Trun, business development director at Vietnamese firm, SolarBK. "After June 2019 of course I think the FiT will decrease and anyone who misses deadline will have a lower FiT."

Corporate PPA and storage

A direct corporate PPA is being worked on for Q1 2019, says Massmann, and once that PPA comes in, it will be a huge opportunity, since commercial and industrial (C&I) projects are seen as more bankable in this climate.

Massmann says the government is working on a pilot programme for such a corporate PPA, but it is still at the research and study stage. There have been no final decisions on capacity, licensing process, participants, location, wheeling fee and contractual terms, he adds.

On the energy storage side, Samah notes that there have been some suggestions that upcoming projects should have a certain percentage of their capacity supported by intermittency storage requirements.

Both corporate PPAs and storage would be a boost for the country's clean energy goals, but with 120 solar projects approved by MOIT with a total capacity of more than 4.7GW, large-scale solar remains the dominant focus and the global sector will be watching closely to see how many projects are actually built on time as the potentially lucrative FiT hits its deadline midway through 2019. ■

The EPC challenges of building in Vietnam

Eric Liu, general manager for Vietnam at China-based PV manufacturer and developer, Risen Energy, which has bagged several hundred megawatts of EPC contracts in Vietnam in recent months, discusses the unique considerations of constructing a solar project in Vietnam.

What challenges are there for setting up in Vietnam's climate?
Eric Liu: Wind pressure, high temperate and high humidity needs to be taken into account. The salt and alkali resistance also needs to be considered.

What O&M challenges do you expect there to be?
The operation and maintenance period mainly relies on reasonable operation and maintenance plan and experienced human resources. Furthermore, the operators in Vietnam need to be trained to learn and experience more about PV station operation.

Do you see any module choice trends or expectations of which module technologies work best in this country?
Now the polycrystalline PV module is popular in Vietnam. However, because of the shortage of the land, high performance PV modules will be used in Vietnam more and more.

Falling costs help solar thrive in the desert

Dubai's Mohammed Bin Rashid Solar Park. Most countries in the MENA region are now looking to solar to meet future energy needs

MENA | Solar in the Middle East and North Africa continues to flourish, with utility projects leading the way. As Paul Mansouri and Angela Croker of Norton Rose Fulbright write, the development of battery storage technology and a growing interest among large corporates in solar as an energy source will help the market to continue growing

Solar energy continues its success story in the Middle East. Falling costs, healthy competition, fluctuating oil prices and an ever-increasing demand for capacity are all factors helping the continued, impressive growth of solar energy in the region. Some reports indicate that the Middle East is expected to more than triple its share of renewable energy from 5.6% in 2016 to 20.6% in 2035 with solar energy making up the majority of this figure. Meeting such targets will necessitate significant capital investment in renewable energy projects in the region, with all forecasts indicating that the renewable energy sector, and in particular solar, will continue to grow for the foreseeable future.

The UAE and Saudi Arabia remain at the forefront of the large utility- scale solar projects with neighbouring countries following closely at their heels. The majority of countries in the Middle East now have their own ambitious national renewable energy targets that they are working hard to meet.

In the UAE, Abu Dhabi's Sweihan PV power project is currently under construction and will have a capacity of nearly 1.2GW when it is commissioned in April 2019. Upon completion it is expected to become the world's biggest solar PV plant and should generate power sufficient to supply nearly 200,000 homes. With a plan to have around 5.7GW of renewable energy capacity installed by 2026, the Abu Dhabi government is pushing on with increasing its solar energy capacity and is leading the region's drive towards renewables.

Dubai, with the Mohammed Bin Rashid Solar Park, now has the largest single-site solar park in the world with a planned capacity of 1GW by 2020 and 5GW by 2030 and is well on its way to meeting its commitment to 7% clean energy by 2020 and in turn, 25% by 2030. Whilst the majority of renewable energy capacity installed by 2030 will be generated at the Mohammed Bin Rashid Solar Park development, Dubai has set itself a further goal to produce 75% of its energy from clean sources by 2050. The successful implementation of its ambitious Shams rooftop solar programme, which allows DEWA customers to install solar panels on their rooftops connected to the grid under a net-metering agreement, will also be critical to the achievement of these targets.

In the Kingdom of Saudi Arabia, whilst the future of Saudi Arabia's US$200 billion SoftBank solar project announced earlier this year may be uncertain, there is no doubt that there is still a significant focus on renewable energy to free up oil exports. Saudi Arabia has set an ambitious target to add 9.5GW of renewable energy by 2023 and is expected to tender 3.25GW of solar capacity in the next year. The 300MW Sakaka PV solar project in Al Jouf reached financial close in the middle of November, marking REPDO's first ever utility-scale project tendered under the National Renewable Energy Programme.

Oman aims to reach a 10% renewable energy share by 2025 and recently announced its second solar power project with a capacity of 500MW-1GW. This follows on from the 500MW Ibri PV project tendered earlier this year which is expected to commence operations by 2021. Bahrain is also making strides in the renewable energy space, with project proposals for the development of a 100MW solar PV plant at Askar landfill site expected as this publciation went to press. New projects are also coming online in Kuwait with the Kuwait National Petroleum Company launching a tender for the installation of up to 1.5GW of solar as part of Kuwait's plans to produce 15% of power from renewable energy by 2030.

Egypt remains an active market, following on from its success with approximately 1.5GW of solar PV projects reaching financial close in the Benban area at the end of 2017 as part of the Round 2 solar feed-in tariff programme. Egypt has now moved away from the feed-in tariff structure in favour of competitive tenders with a view to driving down the cost of clean energy. Late last year, Egypt issued a competitive auction to build a 600MW plant in the West Nile Region for which it has recently set a maximum price of US$/c 2.5 per kWh. This follows on from the Kom Ombo 200MW project where the lowest offer submitted in August by ACWA Power was US$/c2.752 per kWh.

With the cost of solar energy projects already at an all-time low, and competitive tenders producing ever reducing tariffs, the region is clearly enjoying a renewable energy boom. Whilst large-scale utility projects dominate the renewable energy space in the region, companies operating in the Middle East are looking for ways to reduce their electricity costs as governments in the region shift away from fossil fuel subsidies. In addition, large numbers of corporations have set their own ambitious targets for emissions reductions or renewable energy sourcing either independently or under global initiatives such as the global RE100 initiative, under which companies pledge to source 100% of their electricity from renewables; this is expected to increasingly impact the Middle East and the way large corporates purchase power. With solar pricing on government tenders continuing to hit record lows, raising some questions around long-term market sustainability, some developers are looking to secure deals with corporate off-takers directly. Factors such as these are expected to significantly accelerate the adoption of corporate PPA contracts in the Middle East and North Africa and we are likely see increasingly significant activity in this area in the near future.

> "With the cost of solar energy projects already at an all-time low, and competitive tenders producing ever reducing tariffs, the region is clearly enjoying a renewable energy boom"

Demand for storage

Finally, with the increasing prevalence of renewable energy production in the region, the question of energy storage is also becoming increasingly relevant. Whilst solar production halts when the sun does not shine, demand for energy does not significantly fluctuate. If the goal of the region is to become permanently independent of fossil fuels, much more investment in safe, reliable and efficient energy storage will be required. The World Bank Group announced in September that it was committing US$1 billion for a new global programme to accelerate investments in battery storage for energy systems in developing and middle-income countries. In addition to committing this US$1 billion, it will fundraise another US$1 billion in concessional climate funds and the programme is expected to raise an additional US$3 billion from public and private funds and investors. The potential in this market is immense.

Costs of battery storage have declined significantly with market analysts estimating a drop in cost of nearly 80% between 2010 and 2016, and predicting further price declines to come. This, coupled with the constant improvement in performance and reliability of utility-scale batteries, is attracting increased levels of investment in battery storage projects. In the Middle East however, battery storage projects are still at early stages and utilities are looking to trial and test the technology before fully embracing it, in particular given the extreme ambient conditions that the batteries need to withstand.

For example, in Dubai, DEWA is trialling large-scale battery storage in the Mohammed Bin Rashid Solar Park. Batteries are being installed in Phase 1 of the solar park, a 13MW PV plant built by First Solar in 2013. The batteries will have an aggregate storage capacity of 7.2MWh. The success of this trial will certainly influence the development of larger scale battery storage installations in the UAE. Jordan, which has a target of securing 10% of energy from renewable energy sources by 2020, has seen the number of renewable energy projects skyrocket in recent years. As a next step Jordan is pressing ahead with a 30MW electrical storage project located in the Maan development zone to further bolster its expansion in solar generation.

There is significant momentum in the transition to a more sustainable future in the Middle East. With its abundant sunlight and vast desert expanses, the natural advantages of the Middle East are finally being harnessed. Battery storage will play its part in maintaining this momentum and contributing to further growth. ■

Authors

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To read more about the construction of Egypt's Benban solar park, turn to p.76

The seller's market

Secondary market | Following years of frantic consolidation, the UK's secondary solar market has begun to slow. Liam Stoker analyses what the future holds in store for the once-thriving market, and what's next for long-term asset holders

Credit: WeLink.

The 72MW Shotton Solar Park, pictured, is currently the UK's largest and was quickly snapped up by Foresight Solar

With more than 8GW of utility-scale solar having been built in the UK, it was only a matter of time until the secondary market took off.

What followed the country's hugely successful Renewables Obligation build-out period was akin to solar's own Black Friday. Investors, lured to the market with predictable and economically viable returns, rushed in with deep pockets and even deeper shopping trollies, flinging in asset after asset.

That spree created UK solar's own 'Big Four', namely Octopus Energy Investments, Foresight Group, NextEnergy Capital and Bluefield. Between them, they own more than one-third of the built utility-scale solar market in the UK, and that share is continuing to grow. Kareen Boutonnat, COO at prolific solar developer Lightsource BP, describes the market as being dominated by "a few very big players and a very long tail". *PV Tech Power* publisher Solar Media's in-house market research team puts the top 20 asset owners as holding in excess of 70% of the market, helped by readily available assets and willing money.

But after a strong few years of purchaser power, aided by a subsidy programme that unwittingly created a boom-and-bust model, the UK secondary market has undoubtedly swung in favour of the seller.

A seller's market

"It's a good market right now if you own an asset and you want to sell it," Ricardo Pineiro, partner at Foresight Group, one of the UK's largest holders of solar assets, concludes. Across various funds, Foresight Group has amassed a portfolio of operational solar farms with a capacity of almost 1GW, almost entirely purchased during a time when supply far outstripped demand. Foresight was joined by a handful of other listed funds and a few other investors as early adopters of UK solar.

As a result, prices were relatively stable and, as Pineiro says, comfortably within the parameters of what its listed fund was able to pay. But as the sector has consolidated and assets become less available, prices have trended upwards to such an extent that Foresight has found itself occasionally priced out.

"We have a very strict pricing methodology because our fund is listed. We noticed that for the wider tenders – the ones we knew were widely circulated in the market – we went from being selected for the second rounds and being a shortlisted bidder, to on some occasions being told our pricing was more than 10% off," he says.

Rather than just a fleeting occurrence, this would appear to be happening with increasing regularity, particularly on those portfolios shopped around the market. Prime examples of this can be found in the sale of both the Terraform and Canadian Solar portfolios, which garnered considerable interest before being sold during auction processes to Vortex and Greencoat Capital respectively.

Other investors have bemoaned similar circumstances. Kevin Lyon, chairman at NextEnergy Solar Fund (NESF), another of the UK's top five solar investors, says that competition in the secondary solar market is now "substantial". While NESF is continuing to make investments in the secondary market, it's doing so amidst other interests too. And last year Bluefield Solar Income Fund said it was looking beyond the Renewables Obligation era to embark on an "asset management journey" to optimise the portfolio it has amassed.

"That's what we're seeing in the market at the moment. There is more pressure on returns if you're buying assets, and there's a more limited pool of assets as we've already seen a significant amount of consolidation," Pineiro adds.

Problem pricing

So what constitutes a fair price these days? It's difficult to say, with a range of moving factors contributing towards the going price for any asset on the market today, least of all the level of subsidy and build quality of the actual assets in question.

There has also been a considerable movement towards more institutional money flowing into renewables, which in itself has had an impact on asset prices. For some time the main investors in UK solar were listed funds and a handful of others, but there has since been a trend towards a new breed of investment, especially pensions funds. Cubico, the asset owner which purchased many of British Solar Renewables' assets, is backed by Ontario Teachers' Pension Plan, while more recently HSBC's UK Pension Scheme division handed Greencoat Capital some £250 million to invest in UK solar and wind farms. Lightsource has partnered with BlackRock, the world's largest asset manager, to invest £1 billion into UK solar.

The phenomenon of investors with a perceived lower cost of capital flooding the market has, according to Pineiro, "created a shift" in the market in terms of how much assets can change hands for.

Asset prices can also vary widely based on the debt structure used to acquire them, with the level of gearing – or indeed the use of an equity-based strategy to offset that altogether – affecting the level of returns, and therefore the price a potential buyer is willing to pay, achievable on any given portfolio.

As a result of all these moving cogs, it is again difficult to determine what constitutes a fair price and what's overpriced, but nevertheless there is almost certainly a trend upwards as the available pool of assets on the market has shrunk and appetite for infrastructure investments, solar and renewables in particular, has accelerated. Pineiro says that some assets that have exchanged hands recently are clearly outliers, remarking that even withstanding some uncertainty over their bid structure, it has been "difficult to understand" how particular prices have been reached.

This has led Foresight to pursue bilateral deals with vendors who want a quick, simple sale that doesn't drag out over the course of a six- to nine-month auction process. Such prolonged sales inherently involve more costs from an advisory perspective, with some vendors simply wanting a more streamlined, easy-to-navigate process.

But such sales are now harder to come by, and the market in itself is far more fragmented than it was before, when sizeable portfolios were sold in one transaction. Now, according to Pineiro, you'll be lucky to find a portfolio on the market that's 50 or 60MW in size, with NESF also bemoaning this fact. The likes of Foresight, NESF and Bluefield have all guided towards far slower growth in portfolio size in the future.

Boutonnat says that Lightsource BP is continuing to do due diligence on new deals, with the firm's chief executive Nick Boyle describing the process as more of a "drip" than a flood, despite retaining an interest in sizeable portfolios. "There will continue to be some sales in that market, but it's not a huge consolidation with big, big platforms selling," Boutonnat adds.

In the event of slow growth, high prices and a consolidated and richly competitive market, what is the future for built UK assets and indeed, potential new entrants?

The next steps

"There's a question mark over what's next," Pineiro says, indicating his belief that while the market will still retain a fair amount of liquidity and churn, appetite for renewables infrastructure is only growing within investor circles. In that respect, the boom and bust cycle that has often befallen many international solar markets – the UK included – has occurred at precisely the wrong time. "[It] always seems to be in the wrong cycle between investor demand and the availability of new assets," Pineiro says.

NextEnergy Solar Fund's most recent results disclosure, published in November 2018, revealed very much its direction of travel. Secondary market assets would remain of interest but on a smaller scale than before and further down the priority list. Instead, NESF's outlook guides towards increasing opportunities in bolstering the technical and operating performance of its existing assets, and optimising the revenues it derives from them.

"There is more pressure on returns if you're buying assets, and there's a more limited pool of assets as we've already seen a significant amount of consolidation"

Asset holders are indeed becoming far more sophisticated with how the power they generate is sold, taking into account short- and mid-term power price curves to determine what the best course of action is. Recently, many investors have sought to arrange short-term power purchase agreements (PPAs) for a larger proportion of their asset base, hoping to achieve a more stable, non-ROC revenue stream given the relative volatility of the spot market.

Repowering, too, is on the cards. Pineiro says Foresight has examined the potential for repowering old(er) assets with new(er) panels to eke every last drop out of an asset's grid connection – an activity which the repeal of the European minimum import price (MIP) could render more financially viable – but this remains very much a watching brief. The UK government is also mindful of the repowering equation and this summer consulted on proposals to effectively cap an asset's subsidy-eligible capacity at that which was originally applied for.

Then there's the battery storage question, one which occurs on almost every investor's radar. Nearly all of the major investors in UK solar have either made their first forays into battery storage or insisted the technology remains under consideration but, as yet, barely any ROC-accredited sites have had storage retrofitted. This, Pineiro says, is due to complications with the overall operation of the site and how the grid connection is utilised, meaning that storage is "not a straight forward investment proposition".

But if the question is 'what to do when built assets are running dry?', the more established asset holders are increasingly landing on the same answer: just build some more.

Sans subsidy

The RO closed for good on 31 March 2017 and, since then, deployment of ground-mount, utility-scale solar farms has been all but stymied. Save for a few corporate PPA-backed projects and the first glimpses of subsidy-free developments, there's been little coming down the pipeline.

That all looks set to change in 2019, when the market looks set to burst back into life. *PV Tech Power* publisher Solar Media's in-house market research division is guiding for around 500MW of utility-scale to be deployed next year, triggered at least in part, ironically, by the funds who've made hay while the sun has shone in the secondary market.

NESF is to break ground on its first tranche of subsidy-free solar projects in the UK early next year and aims to deploy some 172MW. A host of other developers are busily getting their ducks in a row, bolstered by the MIP's repeal and mid- to long-term power price forecasts shooting skyward.

Pineiro insists the unsubsidised market in the UK remains "quite speculative" – "It will happen in the UK, but not quite yet," he says – but there are ample developers who do not share quite such a pessimistic view. Twenty-nineteen looks set, for some at least, to be the year subsidy-free solar becomes a reality. The impact of that reality on the secondary market is uncertain. There will almost certainly be more available assets in the coming years, but those backed by ROCs will retain their appeal over those whose returns are at the whim of the merchant market.

Investors in the UK market have ridden the peaks and troughs of activity just as much as the developers that have fuelled them over the course of the last five years but their paths look now more intertwined than ever. ■

Renewables 2.0: Opportunities in renewables in a post-subsidy world

Business models | Substantial flows of investment into renewables have brought about significant reductions in the cost of delivered energy, while simultaneously increasing the penetration of renewables in most markets. These developments herald the rise of Renewables '2.0', a post-subsidy world for investment in renewable energy. Duncan Ritchie and Kornelia Stycz of Apricum explore the opportunities in corporate PPAs and hybrid renewable energy systems in the context of the Renewables 2.0 energy transition


Credit: Apple

Corporate PPAs, such as those used by tech giant Apple, are part of the of post-subsidy 'Renewbles 2.0' world

Over the last decade, renewable energy has benefited from significant capital allocations, elevating renewables to a *bona fide* investment class. The rise of renewables has been underpinned by the 'Renewables 1.0' paradigm—state-sponsored off-take agreements and revenue certainty (price and volume)—providing capital with relatively stable returns.

The expansion of investment in renewable energy has enabled the renewables supply chain to achieve economies of scale and brought down the cost of capital for renewable energy projects. This has translated into substantial declines in the delivered cost of energy, making renewables increasingly competitive compared to conventional energy sources in many markets.

While state-sponsored procurement of renewable energy capacity still plays a major role in many markets, the falling cost of renewables has prompted some governments to question the merits of state intervention. Simultaneously, the private sector is proactively responding to the shifting landscape, seeking new revenue models that do not rely on traditional state subsidies and state-sponsored off-take agreements.

At the same time, the increasing penetration of renewable energy on electricity grids brings into focus the challenges of managing a higher proportion of variable renewable energy supply. It also highlights the shortcomings of the traditional energy supply system, premised on large-scale centralised generation with extensive networks of 'poles and wires' to transmit and distribute electricity. This is especially relevant in markets where inadequate and out-dated infrastructure requires significant capital investment; even more so where that transmission and distribution (T&D) infrastructure does not yet exist.

Renewables 2.0

Against this backdrop, we see the rise of "Renewables 2.0", a post-subsidy world for investment in renewables, ushered in by economics that increasingly favour renewable energy and a global call for energy sustainability and climate action.

This energy transition demands new revenue models, which, in turn, requires new and innovative investment and financing solutions. The transition will also bring greater technical complexity, creating opportunities for investment in smarter, more flexible grid systems that are able to manage and mitigate the impact of variable and bi-directional energy flows as well as in distributed energy solutions that bring energy supply closer to users.

The migration to corporate PPAs

In recent years, corporate power purchase agreements (PPAs) have become a popular model for companies seeking to take a more proactive approach in managing their energy supply, especially with the goal of replacing conventional energy supply with renewables—principally from solar and wind energy. The main drivers for corporates to enter into PPAs are two-fold: first, to meet environmental and sustainability commitments, including commitments to reduce their carbon footprint; and, second, to manage their long-term energy costs. The growth in corporate PPAs has been dramatic in recent years. The United States (US) market has a leading position, with US corporates signing renewable PPAs for 4.8GW in 2018 to date (versus 2.8GW in

2017). Although corporate PPA activity has been slower to gain traction in Europe, we are seeing increased activity in the past couple of years, especially in the Scandinavian market and in the United Kingdom (UK). Mexico has also been an active market for corporate PPAs with over 1GW of PPAs signed with wind farms up to 2018.

Companies in the Asia-Pacific, Africa, and Middle East regions have been slower to adopt corporate PPAs but there are undoubtedly untapped opportunities in these markets, especially for corporate PPAs focused on off-grid solutions.

The RE100 club

Underpinning the growth of the corporate PPA market for the foreseeable future are sustainability commitments that companies are making to migrate energy procurement to renewable energy supply. Some 154 companies have signed up to the Climate Group's RE100 initiative, committing to source 100% of their energy needs from renewable sources. Some well-known RE100 members from the tech sector, such as Apple, Microsoft and Google, who were pioneers in the use of corporate PPAs, have already achieved this goal.

Since 2015, however, a much broader spectrum of large international companies has joined the RE100 commitment, including companies in banking (Bank of America, Citi, HSBC, ING), brewing/drinks manufacturing (AB InBev, Carlsberg, CocaCola), car manufacturing (BMW, GM), Pharmaceuticals (AstraZeneca, Johnson & Johnson) and telecoms (Telefonica, Vodafone). Although many of the RE100 have longer-range targets to achieve the goal to source 100% of their energy from renewable sources, all of them have ambitious milestones within the next 10-15 years.

Rising costs of grid infrastructure

The incentive to transition to renewable energy corporate PPAs is also supported by the prognosis that conventional energy prices and, therefore, the on-grid cost of energy may rise and become more volatile in the future. Renewable PPAs allow companies to hedge their long-term energy supply costs and reduce their exposure to the inherent uncertainty of future energy costs.

In developed countries with ageing grid infrastructure, the cost of investing in and maintaining grid infrastructure will likely push energy supply costs up, as the cost of T&D contributes increasingly to the cost of electricity supply. This is likely to be exacerbated in markets where an increasing number of corporate users procure energy directly from local suppliers via distributed energy solutions. The effect will be to reduce the energy flows across the T&D infrastructure, increasing the cost burden on the remaining grid-connected customers.

"While state-sponsored procurement of renewable energy capacity still plays a major role in many markets, the falling cost of renewables has prompted some governments to question the merits of state intervention"

In less developed countries, poor grid infrastructure and unstable energy supply provide additional incentives for companies to procure renewable energy directly through corporate PPAs via off-grid solutions.

Corporate PPAs supporting project development

From the perspective of project developers, corporate PPAs become increasingly relevant as state support for renewable energy is reduced or withdrawn. The stable revenue stream offered by a corporate PPA provides a substitute for the traditional state-sponsored off-take agreement, enabling developers to switch to a new revenue model.

The corporate PPA may not provide 100% off-take of the project's generation, leaving some residual merchant risk for part of the project's output or a 'merchant tail' in the post-PPA period.

Nevertheless, the corporate PPA will reduce a project's exposure to merchant risk and enable it to attract more competitive financing.

Conversely, projects falling out of subsidy schemes may be available to enter into competitive corporate PPAs over the coming years as an alternative to entering wholesale merchant markets. For example, about 16GW of early onshore wind farms will fall out of Germany's 20-year feed-in tariff scheme between 2020 and 2025. This will provide impetus to the German corporate PPA market.

Hybrid energy systems

Electricity from renewable sources (excluding hydro) has the disadvantage of being variable in nature and, therefore, not dependable for baseload or uninterrupted power supply. To date, power with renewable energy certificates or conventional generation has been used to fill the gaps between consumption patterns and renewable energy production of PPA suppliers. Hybrid energy systems offer the potential to bridge these gaps.

In this context, a hybrid energy system means a combination of renewable energy supply (e.g. solar or wind) with one or more of:

- Renewable energy from a different supply source, e.g., solar coupled with wind;
- Energy storage system(s), e.g., battery storage, pumped hydro;
- Conventional energy generation supply.

These solutions aim to reduce the variability of electricity production from renewable energy sources to provide more dependable supply and/or to reduce the cost and risk of filling the gaps between consumption and supply patterns. Such solutions are especially interesting in areas where (i) grid infrastructure is weak, (ii) an 'island grid' exists or (iii) the customer is off-grid and, consequently, the reliance on the supply is elevated.

Solar and wind hybrids

While the intermittent nature of supply from solar and wind rarely levels out during a day, it does so well across a year in many moderate-to-cold climate zones: the summer peak load is provided by solar generation, the winter peak load by wind generation. Both systems can share the same grid interconnection and it may also be possible to use the wind turbine's converter as the inverter for the photovoltaic (PV) modules. This will reduce the capital and operating cost compared to separate solar and wind power plants.

Solar and hydro hybrids

The combination of solar PV and pumped hydropower plants provides an interesting energy storage solution. Relatively cheap and abundant daytime solar generation may be utilised to pump

Credit: David Clarke/Flickr

Tesla's 100MW battery co-located with the Hornsdale windfarm has helped Australia become a world leader for with energy storage hybrid projects

water from one storage reservoir into another elevated reservoir, allowing the hydropower plant to be used to shift generation across time to meet peak demand and to smooth the PV electricity generation. Such systems make the most sense where the PV plant can be added to an existing hydropower plant with a grid connection. The economics of these projects rely on a significant differential between the peak and off-peak electricity price.

Another possibility for a hybrid solar-hydropower project is the use of the reservoir surface area of a hydro project for a floating PV (FPV) solar plant. FPV projects have the benefit of saving space in densely populated regions (Japan has been an early adopter of FPV) and/or reducing land use for energy generation. (For more on floating PV, turn to p.46.)

Renewables and energy storage hybrids

Until 2017, hybrid projects coupling solar and/or wind with battery storage were perceived to be constrained by the relatively high cost of battery capacity. This perception shifted dramatically when Tesla delivered its 100MW/129MWh lithium-ion battery to be co-located with the 315MW Hornsdale windfarm to resolve South Australia's energy crisis in 2017. This has spurred investment in energy storage hybrid projects, helping to make Australia one of the fastest growing markets for these projects.

The cost of battery storage continues to place energy storage hybrid projects at the margin of economic viability. Projects often rely on multiple 'stacked' revenue streams and require rigorous analysis to make the economic case. However, expected reductions in the cost of battery storage will bring energy storage hybrid projects into the mainstream in the coming years. This is especially exciting news for corporates seeking to secure firm power for off-grid use cases.

Renewable, energy storage and conventional hybrids

Renewables with and without energy storage, in combination with conventional energy (especially diesel, heavy fuel oil, and gas generation), also offer opportunities for integrated hybrid systems. Such hybrid systems are particularly suited to off-grid, behind-the-meter and 'island grid' use cases. For example, the addition of solar and energy storage capacity to supplement existing diesel generation capacity can bring down generation costs by using solar to offset the high operating cost of diesel generation during the day and storage to smooth the solar generation profile to avoid having diesel generators operating as spinning reserve.

Outlook

Renewables 2.0 will see a gradual shift away from state-sponsored procurement of renewable energy capacity, with the private sector taking a more prominent role in future renewables capacity additions. This shift will be underpinned by a significant expansion of corporate PPAs both in traditional markets as well as in new markets as companies seek to achieve the dual objectives of sustainable and economic energy supply. This will be welcomed by project developers seeking to secure viable revenue models to support their projects.

Energy supply will become increasingly distributed, moving closer to end-users. Grid infrastructure investment will need to focus on smart, flexible grid systems in addition to traditional 'poles and wires' to support the Renewables 2.0 era.

Energy storage costs will continue to fall, supporting an expansion of hybrid projects for both on- and off-grid solutions. New peer-to-peer trading models have emerged that make use of smart grids, energy storage and, in some cases, artificial intelligence to enable energy trading among traditional utility customers.

Utility companies will need to respond to these challenges and opportunities. So too will regulators. Regulation developed to support the traditional centralised generation and T&D paradigm has lagged behind the fast-changing energy landscape. It will need to catch up, adapt and enable the Renewables 2.0 energy transition. ■

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Quantifying the impact of R&D on PV project financing costs

Finance | For PV to continue competing with alternative energy sources, the cost of financing solar projects must fall. David Feldman, Rebecca Jones-Albertus and Robert Margolis of the US National Renewable Energy Laboratory explore ways in which research and development can boost PV competitiveness

Although R&D has helped make PV-generated electricity cost-competitive with traditional forms of generation in many markets, studies have shown that PV electricity costs must continue to decline if it is to keep gaining market share [1, 2, 3]. Financing costs currently represent a significant portion of total PV electricity costs. We explore ways in which R&D can influence PV financing costs by removing real and perceived risks from PV projects, and we use financial models to estimate R&D's full impact on PV financing costs and levelised cost of energy (LCOE) via reduced risks [4].

Improved module testing is among the R&D activities that can help drive PV financing costs

Credit: Hanwha Q CELLS

How R&D affects financing

The cost of financing comes from debt and equity investors who fund PV project construction and operation to make returns on their investments. The return rate each investor desires—and thus the cost of capital—is impacted by a variety of factors. Supply and demand dynamics [5] and the underlying interest rate the US government charges banks play an important role in determining the required rate of return. In addition, the underlying risk of the cash flow a project receives and the risk of changes in perceived value of the asset play critical roles in determining investors' required rate of return, particularly in the long run. In general, investors require a higher rate of return to make investments that are perceived as riskier, and vice versa. Finance theory typically includes a measurement of risk (i.e., volatility) when calculating the expected rate of return for equity and debt investors in a project or company.

When financiers build financial models, they estimate their risk exposure by examining the sensitivity of returns to various risk factors. For example, financiers may look at expected project cash flows assuming an average level of production (or P50) and a production level that the project has a 99% chance of exceeding (or P99). Narrowing the gap between the P50 and P99 scenarios lowers a project's overall perceived risk.

Risks affect different sources of capital differently. Equity investors own assets or a portion of assets. They enjoy the benefits of any appreciation in asset value, but they are also exposed to any reduction in asset value. Debt investors lend money that is paid back later, and they are compensated by interest payments on a set schedule. Because of the need for cash flow certainty, the inability to benefit from asset appreciation and the exposure to risk of asset depreciation, debt investors are more exposed to cash flow and asset value volatility over the term of the loan. However, debt investors, as well as tax-equity investors, are less exposed to long-term risk than are long-term equity investors.

Based on this information, we divide the sources of PV financing costs into four categories, emphasised below in bold:

- Costs required to pay back the sources of capital (the **"cost of debt"** and the **"cost of equity"**) for providing project funds, plus profit—summing their weighted contributions to the "cost of capital."
- The amount of debt or **"leverage"** on a project; because receiving a larger fraction of funds from a cheaper source such as debt can lower the weighted average cost of capital (WACC), generally the higher the leverage, the lower the costs.
- Upfront costs or **"transaction fees"** associated with arranging funds.

R&D reduces these costs primarily by reducing risks related to uncertainty and volatility, such as by lowering the uncertainty of PV system electricity production. Reducing PV project risks can directly lower the required rate of return/cost of

R&D activity	Effect on financing cost: Lower risk premium	Increased leverage	Reduced upfront costs	Reduced time to close financing
Technology R&D				
Durability	√	√	√	√
Reliability	√	√	√	√
Certainty of production over time	√	√	√	√
Improved module testing	√	√	√	√
Lower system price			√	
Integration R&D				
Improved production forecasting	√	√	√	√
Advanced inverter designs	√	√	√	√
Improved communications	√	√	√	√
More integrated technology and systems design	√	√	√	√
Business practices analysis and standardisation activities				
Aggregated system performance and payment history	√		√	√
Expanded new sources of capital	√			
Lower O&M costs		√	√	
Increased available customer base			√	√
Streamlined processes, standardised procedures and documentation			√	√

Table 1. Summary of R&D, analysis and standardisation impacts on PV financing cost

capital, in accordance with finance theory [6, 7, 8]. Reduced risk can also make more investors comfortable with investing in an industry or asset class, which increases marketplace competition and thus lowers the cost of capital—and this reduction in risk has occurred for PV with the help of R&D-related policy. Ten years ago, only 5-10 institutions provided financial instruments for PV projects, but now there are 30 [4]. Finally, increasing cash flow certainty can lower WACC by increasing a project's leverage. Debt typically protects itself with a buffer of extra cash flow to account for cash flow volatility, as calculated in a project's debt service coverage ratio (DSCR); reduced risk can lower the DSCR, allowing for greater debt and a lower WACC [9].

Many R&D advances have reduced PV technology-related risks. Improvements in product design and manufacturing have decreased module failure and degradation rates [10, 11, 12], reduced power electronics failure rates within PV systems [13] and increased PV system lifetimes [14], allowing PV module companies to offer longer warranties [15] and creating more confidence in investors to make long-term investments. The PV industry now has much better tools, data, and practices than it did 10 years ago to estimate solar irradiance and PV system electricity production. R&D that results in standardised PV testing and improved due-diligence processes also has reduced financing costs by reducing the time and expense associated with closing a financial transaction.

Table 1 summarises various R&D, analysis and standardisation activities that could affect PV financing costs by reducing perceived risks, increasing competition, or making business practices more efficient.

Estimating the impacts of R&D on financing costs

We estimate the effects of R&D on financing costs differently for each of our four

R&D activities that can reduce PV project cash flow volatility	Sources of project cash flow volatility	Estimated standard deviation: Current	Low risk	High risk
Reducing technology risk by improving the durability, reliability, O&M, and testing of PV products **Reducing solar-resource risk through improved production forecasting**	PV system electricity production [16]	8.9% [18]	6%	14%
Reducing electricity value risk through improved grid integration	Regulatory uncertainty [19] Value of competing electricity (e.g., fuel costs, retail rates) [20, 21] Customer credit [22]	2% 17% 7%	1% 9% 3.5%	4% 43% 14%
Reducing electricity off-taker risk and energy production risk by improving data transparency related to system performance and payment history	Customer credit PV system electric production	Standard deviations already given above.		

Table 2. R&D that can reduce PV project cash flow volatility matched with sources of volatility

	Volatility by Scenario		
	Current	**Low Risk**	**High Risk**
Equity returns	20%	10%	50%
Asset value	20%	10%	50%
Debt payments (for DSCR)	10%	5%	20%

Table 3. Volatility of equity returns, asset value and debt payments for PV systems

	Current	Low Risk	High Risk
Cost of equity	10.9%	6.9%	21.5%
Risk premium	1.0%	0.1%	6.1%
Swap spread	2.3%	2.3%	2.3%
LIBOR	1.0%	1.0%	1.0%
Cost of debt	4.3%	3.3%	9.4%
DSCR	1.30	1.13	1.87
Utility-scale PV transaction costs ($/W)	$0.01	$0.00	$0.07
Residential PV transaction costs ($/W)	$0.03	$0.00	$0.19
Leverage	56.8%	58.2%	50.9%

Table 4. Calculated financing costs in current, low-risk and high-risk scenarios

cost categories. For transaction fees, we simply estimate the change in upfront costs. To estimate the cost of equity, we use the capital asset pricing model (CAPM), varying risk by the volatility of equity returns. To estimate the cost of debt, we use the Merton Model (a derivation from the Black-Scholes option pricing model), varying risk by the volatility in asset value. To estimate leverage, we adjust the required DSCRs for P99 and P50, varying risk by the volatility in debt payments.

Before we measure the change in PV system risks, we must quantify those risks. In Table 2, we map the R&D activities that can reduce PV project cash flow volatility with measurable sources of cash flow volatility. We also provide very basic estimates of current volatilities as well as volatilities in a "low risk" scenario (in which R&D successfully removes risks) and "high risk" scenario (in which R&D is not performed or is unsuccessful in preventing the introduction of additional risk). Additional research to improve the accuracy of PV volatility estimates would be valuable.

Assuming the sources of volatility are not correlated, we can combine them by squaring the standard deviations, summing those products, and taking the square root of the sum. This results in a total current PV project volatility of around 20%. We assume that total project volatility would apply to the volatility of equity returns and asset values, but volatility associated with debt payments does not include residual value risk. Because the value of competing electricity is most applicable to residual value (i.e., value after the electric contract), we remove this risk, lowering debt payment volatility to 10%. Table 3 summarises the current, low-risk, and high-risk volatilities, rounded to the nearest 5% value in part because the estimated volatilities in Table 2 are based on limited data and are not comprehensive.

We use the National Renewable Energy Laboratory's System Advisor Model (SAM) and assumptions listed in our report [4] to calculate the impact that a change in inherent risk and transaction costs could have on PV LCOE via a change in equity and debt risk premiums, project leverage and upfront financing costs. Because leverage is an important factor in CAPM and Merton Model calculations, we iterated the models collectively until all leverage values in SAM were consistent with those used to calculate the cost of debt and equity.

Results

For each scenario and U.S. PV sector (utility-scale and residential), Table 4 summarises our estimated financing costs. Figure 1 summarises the resulting unsubsidised LCOEs for utility-scale systems. As shown in the figure, R&D-driven changes to financing costs could lower LCOE about 20% in the low-risk scenario, or prevent an LCOE increase of about 90% due to the high-risk scenario.

Our calculations for the cost of

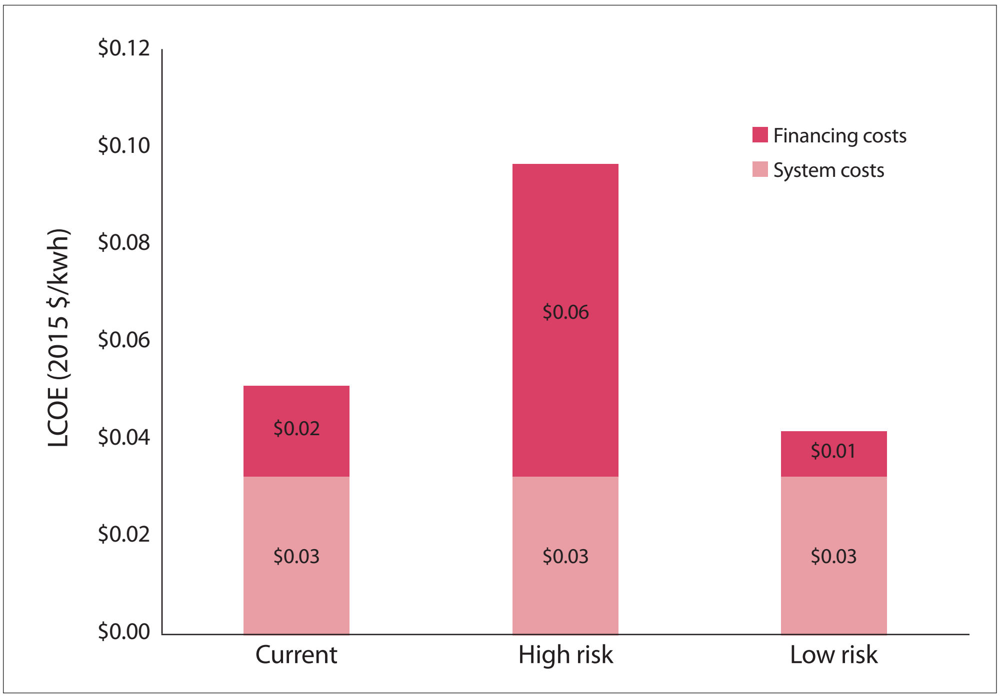

Figure 1. LCOE of a 2015 utility-scale PV system under current, high-risk, and low-risk financing scenarios

financing for current, low-risk, and high-risk scenarios are relatively consistent with comparable industries. The current values are fairly consistent with those reported in the National Renewable Energy Laboratory's 2016 PV project finance benchmark report [23, 24]. The low-risk WACC of 4.1%, calculated from the values in Table 4 (and a tax rate of 35%), is fairly consistent with the average WACC for other industries with low risk profiles, such as real estate (4.5%), transportation (5.9%), and utilities (3.5%) [25]. The high-risk WACC of 13.7% is fairly consistent with other higher-risk investments coming exclusively from private sectors, such as mezzanine debt (10-24% cost of capital) and private equity (20-28% cost of capital) [26].

Our assumptions about uncertainty and volatility are based on limited data, and future data-collection and analysis efforts would strengthen the results. That said, our research clearly shows that R&D activities can help reduce and remove many of the risks and procedures that currently exist for PV investments. Financing costs are fundamentally driven by expectations about risk and return as well as the friction necessary to complete a financing transaction. The more certain financiers are of receiving cash flows from projects—and the less variability is expected—the lower the cost of financing. R&D focused on improvements in technology, system integration, and business practices can create more certainty and reduce expected variability in energy production and the resulting cash flow for the life of PV projects. Further, R&D activity that adds to or sustains the consumer and grid value of PV assets could result in higher investor returns with less expected risk—and thus lower PV financing costs. ■

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[24] These calculations are based on an unsubsidised cost of electricity and do not include the 30% federal investment tax credit, so the amount of leverage in the current scenario (55%) is higher than what we see in the marketplace. If we include the 30% federal tax credit in our model, the amount of debt drops to 35%—consistent with market values reported in [22].

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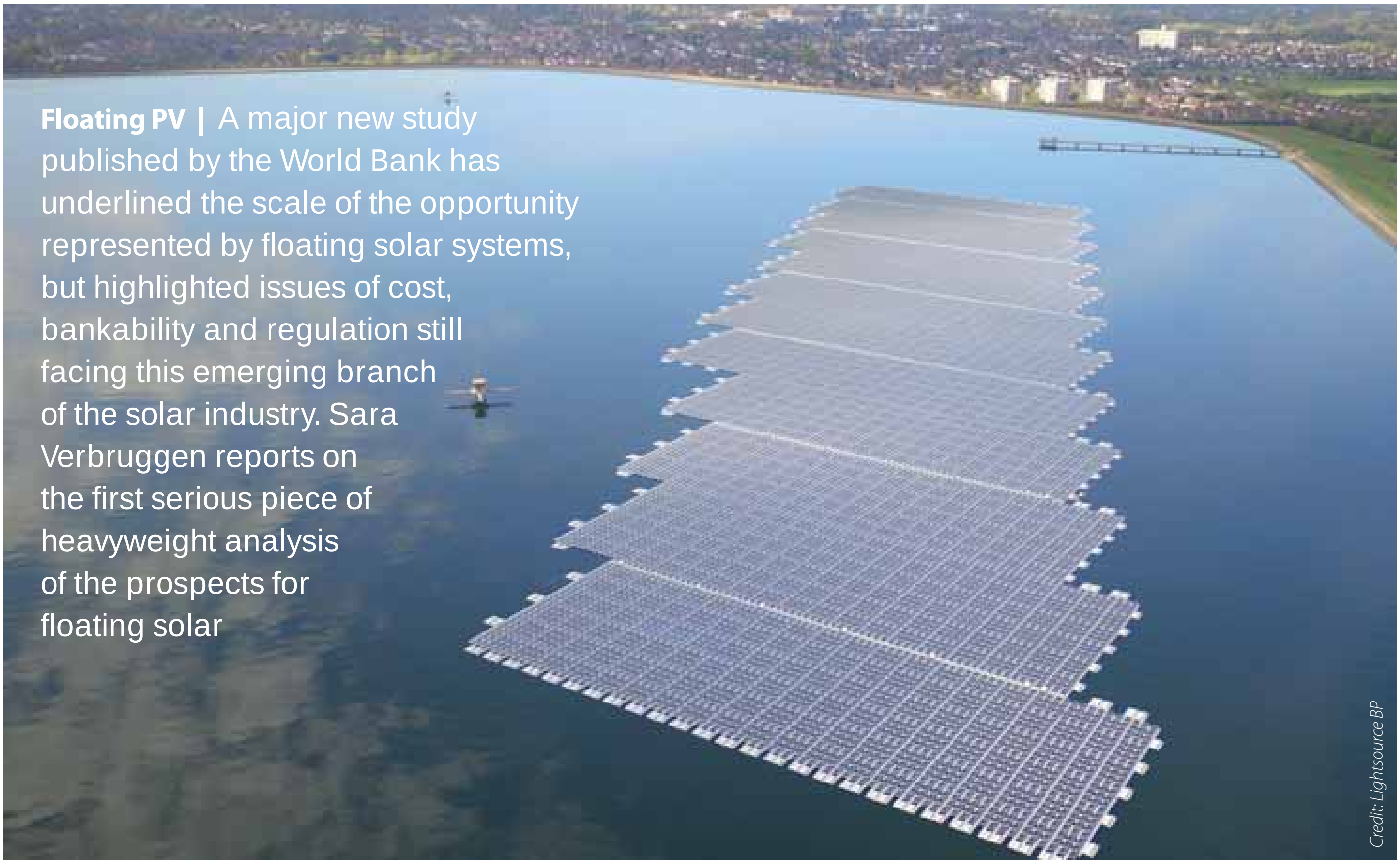
[26] Everett, C. 2017. 2017 *Capital Markets Report: Pepperdine Private Capital Markets Project*. Malibu, CA: Pepperdine University Graziadio School of Business and Management.

Crunching the numbers on floating solar



Floating PV | A major new study published by the World Bank has underlined the scale of the opportunity represented by floating solar systems, but highlighted issues of cost, bankability and regulation still facing this emerging branch of the solar industry. Sara Verbruggen reports on the first serious piece of heavyweight analysis of the prospects for floating solar

Credit: Lightsource BP

Floating solar has global potential, with cumulative installations exceeding 1GW today, according to an upcoming floating solar market report, 'Where Sun Meets Water', written by the Solar Energy Research Institute of Singapore (SERIS) at the National University of Singapore and published by the World Bank and the International Finance Corporation.

That said, investment costs are about US$0.10 per watt higher for floating solar projects, compared with equivalent ground-mounted plants, providing opportunities for collaboration between the solar industry and other sectors in order to bring down costs and deliver large-scale projects.

Demand outlook

According to the report,, a summary of which was published in early November as the first in a series planned by the World Bank and SERIS, a conservative estimate puts floating solar's overall global potential, based on available man-made water surfaces, in excess of 400GW. Since the first floating PV system was built in 2007 in Aichi, Japan, the market has grown with projects increasing in size and more countries installing these types of renewable energy plants.

Around 500MW was installed in 2017 and 2018, much of it in China by making use of flooded mine sites. Many floating solar projects are being developed or under feasibility studies in many different parts of the world.

SERIS' senior financial advisor Celine Paton says: "If they all materialise, then yes we could see such annual growth of 400-500MW taking place. However, the development and realisation of these projects also depends on many factors, which are not always controlled by the owners/developers: politics, environmental aspects, but also appetite from banks. Therefore, this annual figure may not materialise immediately in 2018 or 2019, but is likely thereafter."

Floating solar capacity now exceeds 1GW worldwide, but has significantly greater potential if issues around cost and bankability can be surmounted

Costs and project structuring

Calculated on a pre-tax basis, the levelised cost of electricity (LCOE) for a generic 50MW floating PV system does not differ significantly from that of a ground-mounted system.

The higher initial capital expenditures of the floating system are balanced by a higher expected energy yield, from the cooling effects of the close proximity of cold water. This is conservatively estimated at 5%, but potentially could be as high as 10-15% in hot climates.

Capital expenditure (capex)

The main difference in investment costs when comparing floating PV with a ground-mounted PV plant of similar size is in the floating structure and the related

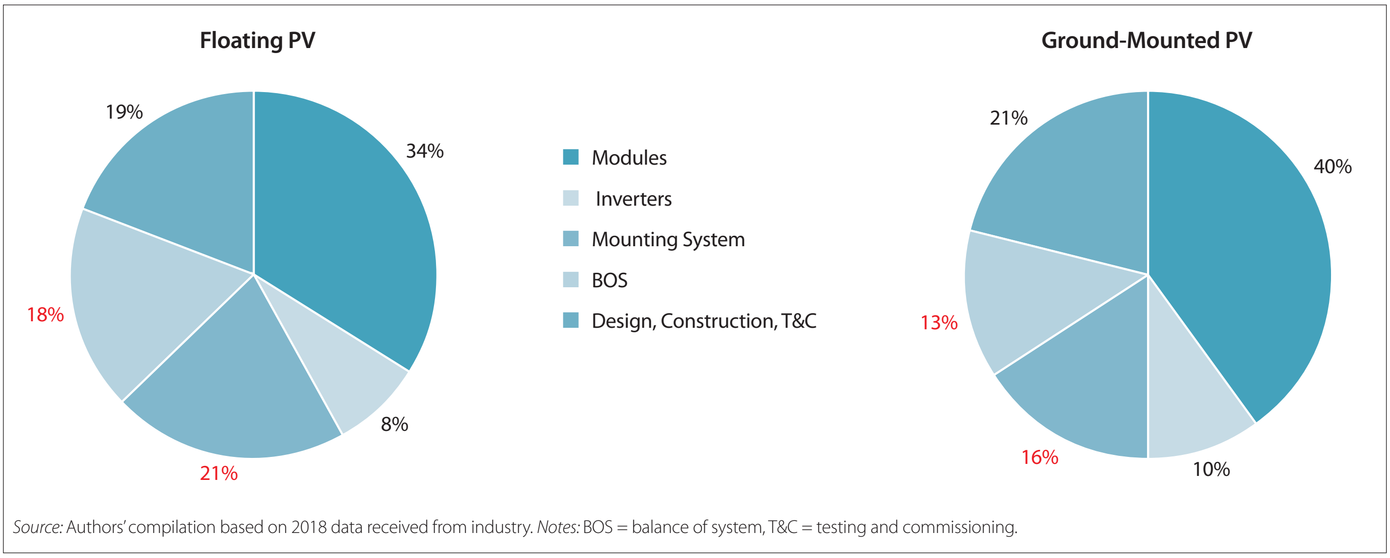


Figure 1: Floating versus ground-mounted 50MW PV investment cost breakdown (numbers indicative only)

anchoring and mooring system. These are highly site-specific, according to the report's authors. At this early stage in the market's development, lack of experience as well as available data makes it very difficult to provide an "average" cost figure with confidence.

Cables, a balance of plant (BoP) element and cost for all types of PV installations, differ for floating solar projects. Using direct current (DC) – in some cases submarine – electric cables with additional insulation and shielding properties to protect against moisture degradation, potentially adds a premium to the capex of a floating solar plant compared with a ground-mounted PV system.

In capex cost modelling, the report's authors have tried to make reasonable assumptions in terms of crunching the numbers on the main average cost per component for a hypothetical 50MW floating PV system on a freshwater reservoir, based inland. In addition, the theoretical site presents no particular complexity. For instance, the maximum depth level is 10m and there is minimal water level variation.

The cost component assumptions used in the report's chapter on cost analysis are based on SERIS' experience, investigations and guidance from solar PV equipment suppliers, engineering, procurement and construction contractors and developers.

The authors stress the figures represent estimations and need to be adjusted once the design and location of a specific floating PV project is determined and as more cost figures become available from the completion of more and more large-scale floating PV systems across the world.

A breakdown of the main capex cost components assumed for a hypothetical 50MW solar PV installation, comparing floating to ground-mounted systems, both of which are fixed tilt, at the same location is shown in Figure 1.

Standard module and inverter costs are assumed identical for both technologies. Mounting system, including floating structure, anchoring and mooring for floating PV and BoP costs are significantly higher for floating solar projects as opposed to ground-mounted.

On a per watt-peak basis, industry experience has shown that floating PV capital expenditure to date tends to remain US$0.10 higher than ground-mounted PV projects under similar conditions.

Improved economies of scale and competition between vendors will begin to

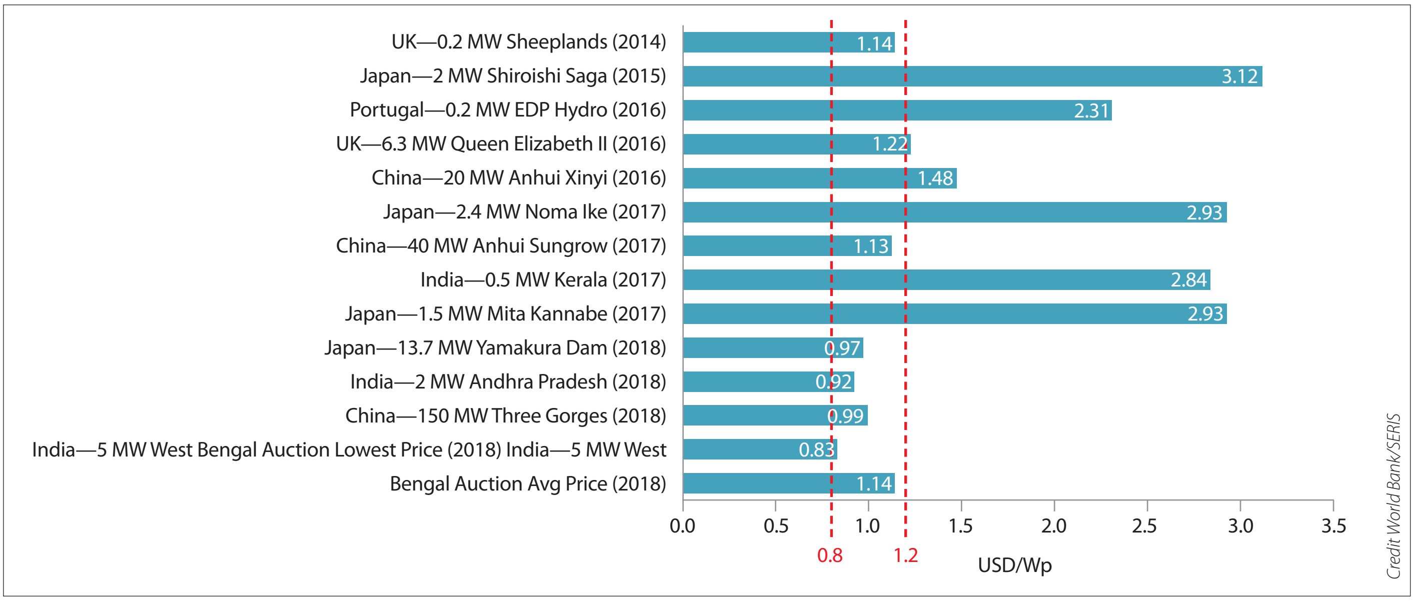


Figure 2. Investment costs of floating PV in 2014–2018 (realised and auction results)

Seaflex®

Floating solar industry turns to Seaflex for its mooring expertise

Many investors, project managers, engineers, and product manufacturers are concerned with the longevity of individual components of floating PV systems. The LCOE generally revolves around a lifespan of 20-25 years for such floating PV projects. How does Seaflex tackle the challenge of longevity and make ownership cost effective?

Our approach to a 20-year-plus longevity for our mooring systems comes from several factors. First being that we have a 20-year warranty on our products and mooring solutions. We can offer this because we have over 30 years' experience designing and building marinas using the Seaflex mooring systems. We currently have Seaflex in marinas that are over 30 years old, so we know from real-life experience that our products, materials and designs last a long time.

We have adapted our range of Seaflex products and mooring designs to be utilised in the floating solar segment. We have numerous different mooring designs and products that can handle a wide variety of environmental factors such as water levels from zero meters to hundreds of meters deep. We also have existing floating solar projects that have survived typhoons without failure. So, we can say from real-world experience that Seaflex, installed on floating solar applications, can also withstand extreme wind conditions as well. Additionally, our mooring products are compatible with every floating solar panel float, which allows for seamless integration and helps to increase the lifespan of the floats and solar panels.

Since Seaflex products only require routine inspections and do not require maintenance, we provide a much lower cost of ownership over the lifespan of our applications.

What should designers and engineers be careful to consider when looking at mooring solutions for floating solar applications?

One misconception that many designers and engineers have when considering the mooring aspect of the floating solar application is the correlation between the size (in megawatts) of the system and how much in terms of cost and quantity of mooring is needed. Unfortunately, the relationship is not linear and is somewhat complex to describe.

There are many factors which can change the quantity, composition of materials and design of the mooring system. For example, different environmental conditions like water levels and wind from two identical 2.5 MW facilities can have very different designs and costs associated with the mooring. Another factor can be the proximity of the solar panels and floats to the shores of the water source. A system located in the middle of a body of water is moored differently than one where all four sides are close to the shores.

Factors such as these are why we caution designers and engineers not to guess about the mooring solution based on sizes or designs of other seemingly similar floating solar applications.

Why is using Seaflex versus other mooring technologies beneficial for floating solar applications?

The use of metal cable and chain in mooring floating solar projects is one type of solution that comes with many drawbacks and potential devastating failures. We have seen such real-life failures and therefore can comment on the design and material inadequacies.

Seaflex offers an elastic solution that unlike metal cable and chain provides a dampening effect that neutralises shocks (or peak load effect) to both the floats and solar panels from wave and wind forces. This is beneficial from both a safety and durability standpoint in that the possibility of potential damage over a 20-year period is minimised, saving material replacement and labour costs. It should also be said that the usage of piles as a mooring solution has the same risks as cables in that shocks and peak loads are not at all dampened and therefore can also create a total failure in storm conditions.

Additionally, Seaflex products utilise very little metal and even offer a titanium hybrid option to drastically limit corrosion and material degradation. Another benefit of our elastic mooring solution is that Seaflex can handle water level variations from very small to very large (+50 meters!) This would not be possible using the metal cable, chain or pile solutions.

If you have questions about this article or other questions regarding floating solar applications, please do not hesitate to contact us at info@seaflex.net

For information on Seaflex products, services and reference material please visit our website at www.seaflex.net

Anchoring innovative **floating applications is our passion!**

SEAFLEX is the flexible mooring solution that has been securing floating applications world-wide since 1981. The system can be used regardless of water depth, while handling large water level variations, strong currents and storm conditions.

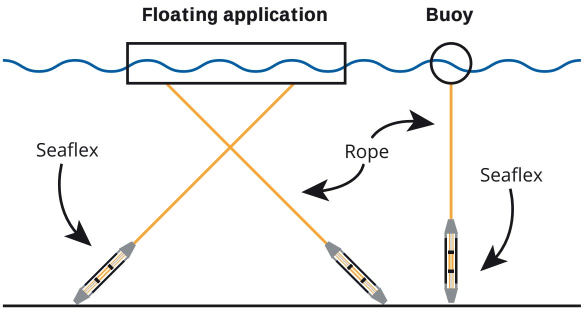
We are thrilled to follow the development in the groundbreaking floating renewable energy sector. Anchoring such innovative applications couldn't be a better fit for us, since achieving longevity while taking environmental responsibility have always been cornerstones in the creation and development of the SEAFLEX mooring system.

GEUMJEON, KOREA, Nemoeng Co.

This pictured 2MW floating solar power plant produces electricity that can be used by 660 households at the same time. SEAFLEX is used to secure both 110 x 100 m platforms.

KERALA, INDIA
Adtech Systems Limited
Shown above is a 0.5 MW floating solar park in India, the SEAFLEX holding it in place manages their 20+ meter water level variation.

How Seaflex mooring works



SEAFLEX is used whenever there is a need to anchor something floating, such as commercial marinas, wave attenuators, floating solar parks or wave energy converters. The system expands and retracts with each tide and wave, taking on and dampening the forces year after year.

Contact us
info@seaflex.net

See more at
www.seaflex.net

	Ground-mounted PV (fixed tilt)	Floating PV (fixed tilt)
Electricity produced (first year), GWh *Increase in performance from ground-mounted fixed tilt*	75.8	79.6 *5%*
LCOE (U.S. cents/kWh)		
at 7% discount rate (base case)	5.0	5.6
at 8% discount rate	5.2	5.7
at 10% discount rate	5.4	6.0

Source: Authors' compilation.
Note: GWh = gigawatt-hour; kWh = kilowatt-hour; LCOE = levelized cost of electricity; MWp = megawatt-peak; PV = photovoltaic

Credit: World Bank/SERIS

Comparing the levelised cost of electricity from a 50MWp floating with that from a ground-based PV system

System size (MWp)	Business model	Ownership	Financing structure
≤ 5	Self-generation	Commercial and industrial companies	Pure equity and/or corporate financing (or "on balance sheet" financing). Owner would typically be an energy-intensive commercial or industrial company with ponds, lakes, or reservoirs on its premises and willing to install a floating solar system for its own use.
>5	Power sold to the grid	Independent power producers and public utilities	Mix of debt and equity (typically 80:20); on balance sheet or non-recourse project finance. The latter is still rare, however, because such project finance structures make sense only for projects of a certain size (generally larger than 10 MWp). Future large projects will likely have financing structures similar to the ones used for utility-scale ground-mounted PV projects.

Source: Authors' compilation.

Credit World Bank/SERIS

Financing structure versus size of floating solar system

drive down float costs, lowering capex.

Module costs are a slightly smaller proportion of overall investment costs for a 50MW floating PV project, at 34%, versus 40% for a 50MW ground-mounted solar plant.

Design and construction costs and inverter costs see little variation, though are proportionally slightly less for a floating PV farm than for a ground-mount PV installation.

Together, mounting system, which include floats, and BoP costs are higher as a proportion of capex for a floating solar project, compared with a ground-mounted one. For floating PV, BoP and mounting system costs account for 39% of total capex investment, compared with 29% for ground-mounted PV.

Regionally floating PV capex varies just as it does for ground-mounted PV, market by market. As reflected in Figure 2, Japan remains a region with relatively high system prices, while China and India achieve much lower prices, a trend reflected in these countries' ground-mounted and rooftop solar system prices, in the context of the global average.

Levelised cost of energy (LCOE)

Data from across the world shows that floating PV systems have a higher energy yield compared with ground-mounted PV systems under similar conditions.

Irradiance level and ambient temperatures relating to the climate where a project is located are an even more sensitive variable for calculating the energy yield and, therefore, the LCOE of floating solar plants.

Preliminary results show that in hotter climates the energy yield gain of a floating PV plant when compared to ground-mounted technology is higher than in temperate climates thanks to the cooling effect on PV modules, improving their efficiency.

However, the authors advise that more studies should be done to verify this assertion and to more accurately quantify the correlation between energy yield gains and various climates.

In the report, representative 'average' P50 global horizontal irradiance and performance ratio figures for ground-mounted PV have been estimated for each climate zone. The performance ratio (PR) of floating PV systems under similar conditions is estimated to increase by 5% in the conservative scenario and 10% in the optimistic scenario.

In the conservative scenario (+5% PR), the LCoE of a floating PV system is 8-9% higher than the LCOE of a ground-mounted PV system. In the optimistic scenario (+10% PR), the floating PV LCOE is only 3-4% higher than the LCOE of a ground-mounted PV system.

In time, say the report's authors, this difference is likely to reduce, become zero, or may even reverse with an increasing installed base and anticipated cost reductions for floating PV installations as volumes go up. The installed capacity today is much smaller in relation to ground-mounted PV systems across the world.

Bankability

According to the report, from an investor's perspective, more traction needs to be gained in terms of bankability of floating solar systems, which will come over time, when durability and reliability have been proven in real-world installations.

In this early phase of the market, floating solar PV plants are deemed to have more risks than conventional land-based installations. They include a lack of experience with long-term reliability of system components, particularly modules, cables and inverters, under permanent high-humidity conditions. Paton says: "This remains one of the main barriers at this stage."

According to the report's authors, when banks are considering investing in projects, they are looking at the creditworthiness of every counterparty. This will stand in the favour of big, established solar developers and EPC companies. In many cases these types of businesses also have the funds for on-balance sheet financing that characterises how projects have tended to be financed and funded in the initial stages of the conventional, land-based, solar PV market's development.

"That said, we are seeing a mix of models at this stage, especially when systems are not too large and funded with equity or corporate – balance sheet – financing, or a mix of both, from the owner," Paton says.

Traditional solar developers with experience of developing large rooftop and ground-mounted PV projects are diversifying into floating PV. Examples include Lightsource BP, Canadian Solar, Sunseap and Cleantech Solar. Some of them are doing the EPC themselves or are outsourcing it to other companies.

According to Paton: "Most of the time the company providing the float structure will be involved in overall plant design, EPC and operations and maintenance (O&M) support; thereby 'training' the developer to gain skills in floating PV. The float supplier therefore has a key role to play in the development and construction of these plants."

In certain jurisdictions float suppliers are forming partnerships with developers, such as Ciel & Terre, a French company that has commercialised a floating PV mounting system and is working with developers and EPCs in France, the UK, the US, Columbia and other markets.

The market has also provided opportunities for new developers, which are defining their business or service as a one-stop shop floating PV solution provider. "This is in the case of maritime companies looking to bring their skills to floating offshore solar projects in marine or nearshore environments, which are more complicated to do than floating solar systems on reservoirs," Paton says.

According to the report, in order to design, build, commission and operate floating solar PV plants that are bankable and are able to produce competitive, clean electricity, collaboration is needed that aims to bring together relevant skillsets from a range of companies.

The adapted supply chain needed to deliver floating solar will span developers and EPCs experienced at developing, building and operating large-scale conventional solar plants, float manufacturers, such as chemicals producers, companies experienced in designing and developing floats for maritime applications, providers of mooring and anchoring equipment and hydropower plant operators.

Market support

Policy and regulatory framework needs to be adapted in some markets, the report adds. "As an example, in certain jurisdictions like in the Netherlands, the ownership of an asset, in this case a floating solar system, constructed above an immovable site owned by another party, in this case, a reservoir, can complicate how to enforce certain lenders' securities over the assets," says Paton.

On the other hand, floating solar projects can pose fewer development headaches, especially during the early permitting stages.

Oliver Knight at the World Bank's Energy Sector Management Assistance Programme (ESMAP) division says: "Floating solar is more straightforward to develop in many cases, since large bodies of manmade water tend to be under public or government ownership, such as hydropower dam reservoirs, for example. If you have one owner then the project is simpler to develop rather than dealing with several. In many cases the owners want these assets to be used."

> "Floating solar is more straightforward to develop in many cases, since large bodies of manmade water tend to be under public or government ownership. If you have one owner then the project is simpler rather than dealing with several"

Both Paton and Knight agree that subsidy regimes for floating solar – though they do exist in some markets – are not usually necessary, as solar costs have already come down significantly.

Countries with subsidies for the technology include Taiwan, which has a specific feed-in tariff (FiT), and the US, where Massachusetts has a location-based compensation rate adder. A renewable energy certificate (REC) mechanism has also been implemented in South Korea, which favours floating solar over ground-mounted plants. In countries in Southeast Asia, such as Vietnam, floating PV projects benefit from the same FiT as ground-mounted PV, which was also the case in Japan, though FiTs have been removed for large projects.

What is needed, say the report's authors, are more empirical studies to determine the exact advantages of floating PV systems in various climates or how to create beneficial hybrid business models, with hydropower plants, for example.

"Floating PV is still a new application and there will be a need to address it specifically through regulations and policies, especially with regards to permitting, licensing and eventually minimum quality standards," says Paton.

Knight adds: "There may be a need for enhanced monitoring for a country's first few floating solar projects, particularly in terms of gathering evidence of the environmental impacts of such projects on fish and other aquatic life. This would be a good candidate for concessional or grant financing, for example using climate finance."

As the market is at an early stage the authors are cautious in their expectations. However, in future, in some locations and depending on the specifics of projects, such as design complexity and floating structure, the LCOE of floating PV installations could reduce to below that of ground-mounted PV, making them the cheapest form of solar generation.

Hybrid approach – hydropower and floating solar

The potential for building solar farms on hydropower water bodies could have unique advantages over other sites. Potentially capex costs could be streamlined as solar installations can piggyback on a hydropower plant's under-used grid connection.

Hybrid clean generation plants are being commercialised in all flavours, such as solar+wind, solar+wind+storage, around the world. In the case of floating solar PV and hydropower, especially in dry regions, the two resources are highly complementary. Installing solar can reduce over-reliance on hydropower for electricity generation. "Hosting floating solar farms that feed into the same grid connection means that in summer months solar takes care of demand for electricity that hydropower generation would usually supply, preserving the water resource during dry seasons and spells," says the World Bank's Oliver Knight.

Some hydropower resources have such large bodies of water that a solar array would only need to cover 1-2% to double their existing installed power capacity.

Some Asian countries are particularly interested in floating solar on hydropower reservoirs, including Vietnam, which has a lot of dams but limited available land. "Myanmar has initiated a floating solar study and there is similar interest in India also," says Knight.

In West Africa, where ESMAP is funding a number of studies on solar, floating PV plants on hydropower dams can bring different benefits as in many areas where grids are weak, hydro can firm up solar output, according to Knight.

Countries with floating solar on hydropower resources projects include Indonesia, with 200MW under development, Vietnam with 47.5MW under development, Thailand with a 45MW and 24MW project under development, Brazil and India with large-scale projects in development. Lithuania has a pilot project underway. According to SERIS there are likely to be others underway that they are not aware of.

Game changers: the rise and rise of 1,500V technology

System architecture | Two years ago, 1,500 volt PV systems were predicted to become the industry standard in the utility-scale segment. Patrick Fetzer of 1,500V pioneer GE looks at how far the technology has come and what further innovations could lie around the corner

Credit: GE Power Conversion

The cost of solar power has plummeted so fast – solar LCOE has come down by some 70% since 2010 [1] – that solar power has already achieved grid parity in many parts of the world. This price pressure is reason enough to fuel innovations across solar plants, such as a shift to higher voltage architecture for achieving system-level cost reduction. And this is indeed what we have seen played out across the market.

When GE launched the world's first 1,500V central inverter in 2012, it was a natural next step for the utility-scale solar market to benefit from the significant cost benefits a voltage increase can bring – just as it had from the previous voltage increase from 600V to 1,000V.

Adopting 1,500V technology for utility-scale solar farms reduces the number of components needed to produce the same power at 1,500V as 1,000V, resulting in a reduction of up to 5% on capex. Supplementary economic savings on operating and maintenance expenditure can also be realised thanks to fewer labour hours needed to maintain fewer inverter units and associated balance-of-system (BOS) components, ultimately bringing value from a long-term opex perspective.

What was once the new kid on the block has rapidly become the industry standard, with 1,000V consigned largely to history for utility-scale solar PV power plants. In 2018 we anticipate more than half of the new central inverter installations for utility-scale projects will be based on 1,500V technology, effecting a tipping point for this now proven technology.

The solar industry has adopted 1,500V as the *de facto* standard system architecture for utility projects

The 1,500V system is already the *de facto* standard system for utility-scale solar projects around the globe, regardless of emerging or mature markets. At GE, we've not only pioneered the technology, we've also been the first to bring it to a range of markets such as the US, India, Japan, Vietnam, Egypt, and Brazil (where we were also the first to obtain BNDES [2] accreditation for 1,500V solar inverters). Today, our global installed base has exceeded 5GW.

Making the shift

We need to remember that new technology cannot thrive in a vacuum – it requires the right infrastructure and environment to support it. So while cost pressures have been a key driver in this recent shift, several other factors also come into play.

Increased plant size

Around a decade ago, the largest size for new plants was 20 to 50 megawatts. This has since increased to the point where it is common to see large utility-scale solar PV projects of over 100MW. This trend towards larger project sizes has enabled the EPCs and developers to capture the full value of the savings on the complete system capex and opex, thanks to the shift to 1,500V systems.

Regulatory changes

A flexible regulatory environment has also been crucial. Over the years, North America's National Electric Code (NEC) has evolved in solar's favour, shifting away from rigid rules to an approach that focuses more on experience and practical application. This flexibility has given companies the freedom to innovate and build game-changing projects – on the condition the finished plant is fully viable. This more flexible regulatory approach has been important for GE, since it effectively lowered the perceived risk of investing in something as yet untested in the field.

> "What was once the new kid on the block has rapidly become the industry standard, with 1,000V consigned largely to history for utility-scale solar PV power plants"

Relevant expertise brings iterative innovation

While 1,500V inverters have been a step change for the solar market, from GE's perspective, this 'new technology' was not, in fact, new. The LV5 1,500V inverters use the same design topology as applied in our proven MV drives – we also leveraged our experience of upgrading LV drives to higher voltages (from 690V to 900V) for the wind market. Bringing proven technology and relevant experience to new applications has allowed us to harness this new technology with less risk.

Technical challenges

While 1,500V technology is hot on the heels of the solar industry, this did not take place overnight.

PID

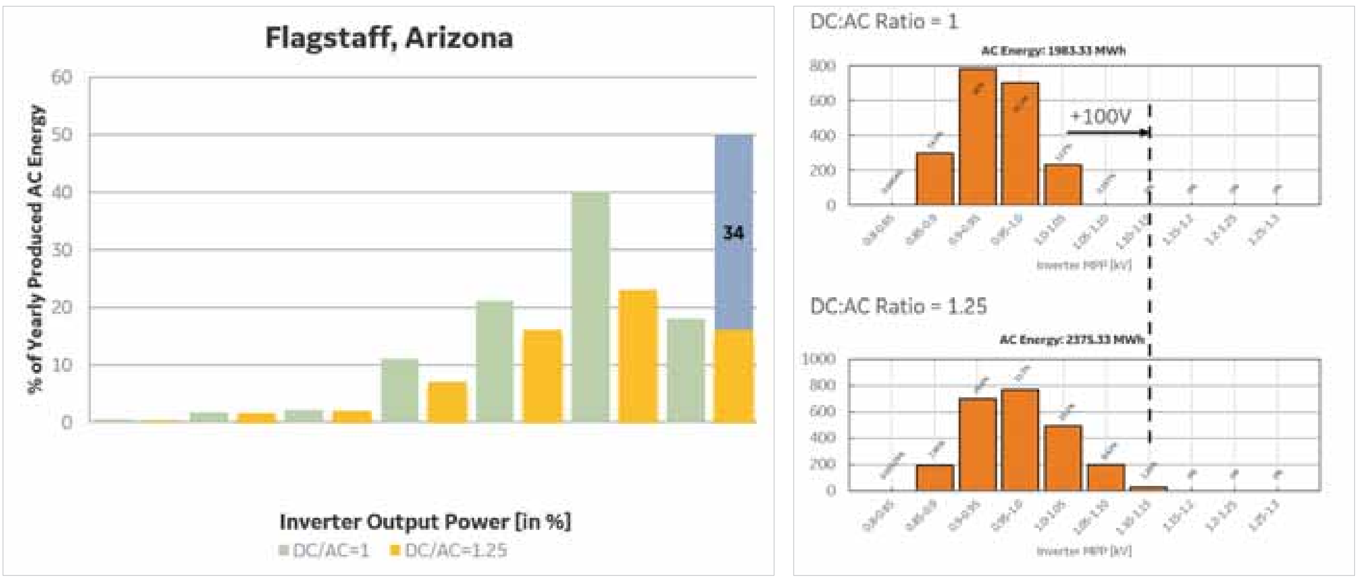
While the industry was becoming increasingly convinced that the shift to 1,500V was one worth making, concerns remained – for example, around the risk of potential-induced degradation (PID). PID is a phenomenon that can affect PV panels and cause up to 80% in power losses. Since PID can be triggered by high voltages, panel manufacturers were naturally wary of 1,500V systems.

However, the availability of anti-PID modules has reassured the industry that, in terms of 1,500V systems, PID is not a cause for concern. Similarly, comprehensive tests have demonstrated that it's possible to reverse the effects of PID during the night using charge equalisers that apply an opposite bias to the inactive panel which cancels out reversible PID.

Inverter performance under high voltage

As costs of panels plummet, plant developers have oversized the PV array to maximise the annual energy production per inverter station, thus DC/AC ratios are on the rise – from 1.1 about five years ago to what will be the highest ratio of 1.7 in 2019.

A DC/AC ratio is the measure of PV power versus that of the inverter – a DC/AC ratio of 1.5 means there is 50% more power available from the array than the inverter can convert into the grid. Higher DC/AC ratios also push inverters to operate at significantly different conditions compared to what they were



Both figures showcase the simulation of a PV plan in Flagstaff, AZ, with a DC/AC ration of just 1.25 compared to a plant with a DC/AC ratio of just 1 in the same location. The figure on the left shows the AC energy produced in percent; the figure on the right shows the AC energy produced in absolute terms.

designed for between five and 10 years ago, when DC/AC ratios were around 1. This results in additional stress to inverters as they are now operating at higher power levels and at full capacity for longer portions of the day.

The increased DC/AC ratio forces inverters to operate away from the Maximum Power Point (MPP) of the array. Instead, inverters move the DC voltage operating point higher to effectively 'clip' the extra energy provided by the PV array. This issue exists in both 1,000V and 1,500V systems, which have higher DC/AC ratios. Since inverters' switching losses are directly proportional to voltage, higher voltage levels result in greater losses and technically lower efficiency than if an inverter were operating at the lower DC voltages of PV plants with smaller DC/AC ratios.

A simulation of a PV plant in Flagstaff, Arizona, with a DC/AC ratio of just 1.25 – compared to a plant with a DC/AC ratio of just 1 in the same location – resulted in higher DC operating voltages (100V), and inverters operating at 100% power while 'clipping' extra energy for 34% of the operating hours in a year.

However, some may argue that if the inverter is at 100% capacity and is in fact clipping extra power, then an inverter's efficiency at 100% power is no longer important. This may be true from an Annual Energy Production (AEP) standpoint. But as the inverter is delivering all the power it can, efficiency still plays an essential role when we examine the wear-out mechanisms of an inverter.

The CEC (California Energy Commission) efficiency weighing factors predominantly favour the 75% loading point – which is weighted with 53% of the final CEC efficiency value we commonly see on inverter datasheets today – while the efficiency at 100% inverter loading only receives 5% weighting. This made sense back in the day when oversizing the PV plant beyond what the inverter could handle was prohibitive due to the high PV module cost, so DC/AC ratios were generally around 1.

Indeed, this CEC weighting was also justified, as when we look back at our Flagstaff, AZ simulation with a DC/AC ratio of 1, 40% of AEP was produced with the inverter loaded around 75% of its full capacity, so naturally the efficiency at that point would be very important to extract maximum value of the PV plant. With a DC/AC ratio of just 1.25, the amount of AEP generated with the inverter at 75% drops from 40% to over 25%, while the percentage of AEP delivered with the inverter near or at 100% capacity jumps from just under 20% to a whopping 50% of all the energy produced in a year.

While it goes without saying that inverter efficiency is still a very important metric, our focus at GE has evolved to the point at which the inverter is performing near or at full-power capacity – and at higher DC voltages due to the clipping effects of higher DC/AC ratios. What's more, it is effectively generating 50% or more of the year's energy under those conditions, compared to just 18% or less a few years ago. Therefore, inverter thermal cycles and the overall higher losses and subsequent generated heat and temperature increases are at the core of our requirements to ensure a more reliable and lasting solar inverter for our customers.

Although higher DC/AC ratios are pushing the boundaries of 1,500V inverter performance to new levels, the advent of DC-coupled energy storage architectures could very well have a reversing effect. As the industry sets its sights on capturing the otherwise clipped energy of high DC/AC ratio PV power plants with energy storage systems connected in parallel to conventional solar inverters, the coordinated operation of solar inverters and battery DC/DC converters will bring the DC voltage operating point back down to the MPP, effectively returning solar to its roots and extracting the maximum available energy from the solar plant.

Upgrade the supply chain

In fact, the main challenge of shifting to this particular innovation wasn't the technology per se, but rather market forces.

For a 1,500V inverter to capture the full benefits of the new technology, you need 1,500V modules and BOS components to support it. Gaining buy-in from the entire supply chain was crucial, so it was gratifying to see tier-1 module manufacturers come on board very quickly, gaining certification and manufacturing 1,500V modules on a commercial scale. In terms of upgrading BOS system components, these have been relatively easy to develop and bring to market.

However, upgrading the ratings takes time and naturally requires industry investment. So while adopting 1,500V technology does eventually offer a capex advantage, the costs of developing the technology when it was initially launched were relatively high. This explains why, in highly price-sensitive markets where capex counts for more than opex, there has been a slow initial take-up. India is one example of this – however, the latest trend for large solar parks has seen the market shifting to 1,500 volts.

Partnership for proof-of-concept

The difference between ideas that thrive long term and those that fall short comes down to the reliability and credibility of the technology when applied to projects in the field and at scale. Fostering partnerships throughout the chain – from developers to end users – was essential for getting the pilot project off the ground. The ultimate goal however, was to unleash this technology at scale – and for that we needed to win the support of technology consultants, certification bodies and investors.

Multiple inverter players were forced to exit the market during the solar industry's rise, and left gigawatts worth of stranded assets. As choosing a lesser-known partner could leave a project with potentially bigger problems down the road, solar companies are also looking at a potential partner's corporate profitability and bankability as well as the sound technical solution they can provide.

GE's century-long history in the energy sector has played a key role in convincing partners to embrace the new technology and co-launch our 1,500V pilot project in the US. This became our proof of concept that demonstrated the cost-effectiveness and overall value that 1,500V technology could bring.

Again, cost

The solar industry's unique cost pressures meant that for 1,500V systems to be viable, they needed to deliver lower cost from day one, which is always a challenge when going up against the de facto standard that already enjoyed a dominant large volume in the market. We saw this as one of our biggest challenges to 1,500V adoption.

Inverter costs are 90% related to the supply chain, so at GE we focus on increasingly standardising our multiple inverter and converter product offering with common building blocks. This delivers a double benefit: first, it drives volume into fewer components, allowing our suppliers to focus manufacturing efficiencies into a reduced component portfolio, thereby reducing supply chain costs. Second, it further streamlines our engineering focus onto fewer components and building blocks which are in turn used in a wider application set. This accelerates continuous improvement as various industrial segments benefit from learnings and enhancements developed from other application areas.

In short, by shifting to the 1,500V standard, the main challenges revolved around commercial availability of the components, long-term reliability and potential technology risks. As we have seen, these uncertainties have been addressed, but also continue to evolve as the industry develops. Nevertheless, there have not been any persistent issues that would be considered a long-term concern.

While the debate over central versus string inverters goes on, GE's product development strategy continues to be focused on reliable, efficient, cost-effective central inverters. That is not to say that there isn't a place for string inverters. However, for large PV plants, we believe that central inverters are more cost effective during the construction and commissioning phase in terms of capex and deliver a better return on investment over the lifetime of the project in terms of opex. What's more, we've been observing a growing trend to both centralise the physical location of string inverters, and increase their nominal power rating. In doing so, the industry is reinforcing that DC power collection is more cost effective than AC power collection – and, that a larger string inverter is potentially more cost effective and delivers better performance than a smaller equivalent unit.

As we look to the future of solar energy, we continue to evaluate higher voltage systems, novel materials, disruptive new power collection systems and opportunities to deliver more value to our customers – with intelligent features that will drive down capex and opex alike.

Is another voltage upgrade on the cards?

There will always be a demand for lower cost of energy, and even higher voltage systems may be one way of achieving this – the history of the solar industry thus far is testament to that. So how high could the voltage go? Developers are already considering the possibilities of moving to over 1,500V systems – essentially combining DC-DC string inverters with a single medium voltage converter – which would deliver an upgrade to 2 to 2.5kV. The attraction is clear: a reduction in losses, higher power single inverters, reduced BOS components and costs – basically all the same advantages that the shift to 1,500V gave. However, this would no longer be classified as 'low voltage' so this MVDC concept may present additional challenges.

Yet while a MVDC configuration would be a more efficient, cost-effective system, there are some significant barriers to upgrading beyond 1,500V configurations. Regulation is one of them. In Europe, rollouts would be limited by the low-voltage limit, which is currently set by the IEC at 1,500Vdc. Going beyond this to 2,000 or 2,500 volts would be classified as medium voltage. This would then subject the technology to an entirely different set of standards, which would significantly increase the cost of development. Moreover, an upgrade to MVDC would trigger the same supply chain constraints experienced in the shift from 1,000 volts to 1,500 volts. In other words, the industry would need to address the challenge of upgrading both modules and BOS components cost effectively and to scale.

There's every possibility that a strong demand for higher voltages would trigger regulatory changes. However, in the short term, 1,500V remains the most enticing prospect and an obvious choice for new solar projects. It all comes down to cost: what is viable is whatever can drive the cost down fast – and a shift to MVDC may not drive this cost down fast enough.

To be sure, the challenge of providing higher and higher value at lower cost is something the industry must continue to overcome. But I believe there are many ways to drive costs down:

Increase inverter size

Across the industry, inverter sizes are getting bigger. While the industry standard sits at around 2 to 2.MW, we're now regularly seeing sizes of 3.5 to 5MW. There are also instances of combining two or more inverters and one transformer together to create a 5 to 10MW megawatt or even larger central solar power conversion stations.

However, there's a limit as to how big these inverter configurations can become. Bear in mind that, so far, the number of panels does not change. So there will come a point when the distance the cabling has to cover to reach the inverter is so great that the resulting power loss eliminates the cost benefit of using a large inverter block. However, we continue to be amazed by the ingenuity of our customers as they continue to push up the centralised inverter megawatt rating from single-digit into double-digit territory, and thanks to our modular LV5+ inverter building block, we're able to deliver on any requested rating.

Improve inverter efficiency

If we do hit a size limit, the next step will be to redirect efforts into pushing the efficiency levels of the inverter itself. This could be achieved through better cooling mechanisms or by developing better semi-conductors, for example. Using new materials is another possibility. Silicon carbide (SiC) takes the best features of diamond, one of the toughest materials in the world, and combines them with the properties of silicon, which is inside every computer and smartphone. Based on the inverter demo tested in the field, it has achieved 99% weighted EU power conversion efficiency – a rating that is unrivalled in the solar industry.

Although introducing disruptive technology like SiC takes time, I'm excited about the prospects this technology will bring once the SiC manufacturing industry scales up to enable a cost-competitive position at commercial scale.

Opex optimisation

While higher plant voltages can improve capex and overall LCOE, additional efforts can be taken to reduce a PV plant's opex when a plant is in operation. For example, by leveraging GE's low-maintenance air-filtration technology developed for our high-efficiency gas turbines, to also reduce or sometimes eliminate air-filtration maintenance in our air-cooled solar inverters.

As a matter of fact, opportunities also exist after sunset. During the night, inverter transformers are normally connected to the grid and consume 'no-load' power from the power grid – which typically costs more than the low PPA rates a site receives today for its PV power generation. These power losses add up to costs over the lifetime of the PV plant.

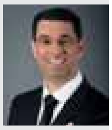
That is why we have come up with the night-time disconnect feature for the medium voltage step-up transformers in our LV5+ Solar Power Stations. Thanks to the integrated solution with smart controls borrowed from our wind converter experience, the LV5+ Solar Power Station can intelligently connect and disconnect the transformer from the grid during periods without solar power (i.e. during night-time periods). This feature, based on GE's estimates, can save a couple of kilowatts each night per solar power station, ultimately saving up to 15GWh for a 100MW solar plant [3] over its lifespan.

Emerging new tech

Two new developments are transforming the profitability of solar plants right now. The first is in energy storage, with the latest innovations enabling better energy management that increases the plant's operational efficiency. The second is in digitisation – and here's where the effects are potentially far-reaching. Unplanned downtime is hugely costly, and ever-increasing plant sizes are making it harder to locate and identify faulty equipment. Digitalising a plant makes it possible to automatically identify equipment issues before they affect overall performance. As a result, plants can shift to a predictive maintenance model, minimising downtime and reducing maintenance costs in the process. Asset performance management (APM) systems have also made it possible to monitor plants remotely – and run analytics that allow operators to fine-tune assets for optimal performance. The result is higher productivity and lower costs overall.

I strongly believe all of these innovations will happen before any shift to using MVDC system configurations in particular. The potential for these innovations to continue lowering LCOE is great – so great, in fact, that I would question whether there's any chance of MVDC system configurations ever taking off at all. But with clarity on the regulatory requirements for 2 to 2.5kVdc systems and availability of PV modules at these higher ratings, MVDC central inverters could be the next technology shift to contribute in lowering the LCOE of solar. ■

Author



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References and notes

[1] International Energy Agency, 2017, 'World Energy Outlook 2017', https://www.iea.org/Textbase/npsum/weo2017SUM.pdf
[2] The Brazilian Development Bank (BNDES) is the main financing agent for development in Brazil. The Bank offers several financial support mechanisms and enables investments in all economic sectors.
[3] Based on a 100-megawatt plant for 25 years in southern USA.

A case for accuracy: Pyranometer or satellite irradiance data?

Irradiance data | Accurate irradiance data is key for assessing the feasibility, profitability, and performance of solar energy assets. 3E and Kipp & Zonen investigate the benefits of combining pyranometer and satellite-based irradiance data for optimal planning and operation of PV plants

Policy makers, project developers, investors, asset managers, owners and O&M contractors base their daily operations and decision-making on accurate solar resource information. Developers, lenders, and investors need assurances when evaluating the feasibility, the financial profitability and the risk of a project. If the system does not produce the predicted energy, large financial penalties that require expensive risk mitigation measures may apply. Precise solar irradiance data is essential to produce robust PV energy yield predictions. Moreover, the quantification of uncertainty in the solar resource and the resulting PV energy yield is especially important for evaluating the financial risk of PV investments. An error of just a few per cent in irradiance measurements, together with small and unnoticed plant under-performance, can easily result in lost annual revenues ranging from tens of thousands of Euros for a 5MW installation up to a million Euros for a 250MW plant.

During the operational phase, owners, asset managers and O&M contractors need unambiguous KPIs for an efficient and profitable operation of their portfolios. Adequate monitoring of a PV plant is crucial to evaluate its performance and improve the operation and maintenance of it. Irradiance data is the most important environmental factor determining the production of the solar array. Accurate irradiance measurement is essential for determining the overall performance of a solar park, since the energy provided by sunlight on earth (irradiation) has a relevant variability, both in space and time. As shown in Figure 1 on the following page, (irradiation data from 32 meteorological stations spread throughout the Netherlands), there is a considerable spatial and temporal variation, even over a relatively small and geographically uniform area such as the Netherlands. Figure 1 particularly highlights the yearly variability compared to the yellow line that shows the 10-year moving average.

A combination of satellite and pyranometer irradiance data is preferable when planning and operating PV power plants

Improving bankability of PV projects during the design phase

Reliable and independent historical solar irradiance data is required for the assessment of the long-term forecasted solar resource and PV plant yield. Increased solar data accuracy informs the financing of solar projects and accelerates investments. High accuracy historical irradiance data covering a period of more than 10 years and clear information on uncertainty is required to produce bankable reports.

The effect of the accuracy of the solar data source and its impact on the bankability of a project is shown in Figure 2 on the following page. For illustrative purposes, a comparison of two data sources with different accuracies is presented. A simplification is made using a normal distribution assumption to allow an easier comparison of the effect of different accuracies and their impact on indicators like, for example, P90 (90% probability of exceedance). In the example, an uncertainty of ±3% is considered for a state-of-the-art satellite-

Irradiance data

In this article, we focus on the two most common sources of data for Global Horizontal Irradiance (GHI):

1. On-site ground measured data
2. Data derived from satellite instruments measurements

The local irradiance is usually measured by a pyranometer and is very accurate (low uncertainty, if the equipment is well installed and maintained). When averaged and/or integrated over relatively short periods from as little as a minute to an hour, a pyranometer is the most accurate solution. But data derived from satellite imaging comes close to the on-site measurement uncertainty over longer time periods such as several days, months and years. Best practice is to use both on-site pyranometers and satellite data services to obtain accurate irradiance data for solar plant performance monitoring over both short and long time-scales.

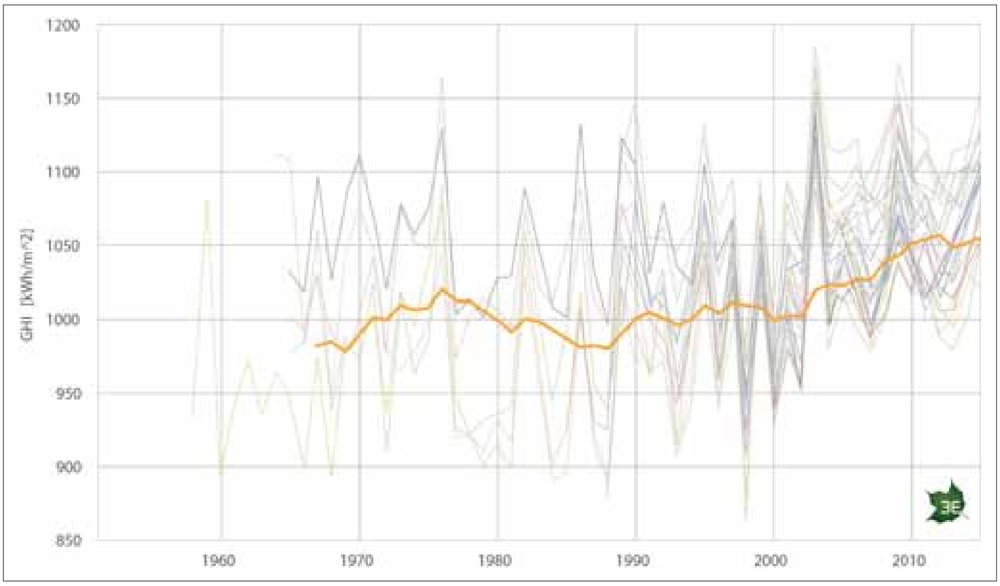

Figure 1. Annual GHI from 32 meteorological stations from KNMI in the Netherlands (orange line = mean 10-year moving average irradiation). An example of well-collected data with irradiation differences between years and up to 4% off the average (orange line)

based irradiance data provider (which can be even lower as shown in [1–3]) and an uncertainty of ±5% is considered for the other data source to highlight the effect of only ±2% difference in accuracy.

The effect of the propagation of this uncertainty into the final expected yield (kWh/kWp) for both a P50 and a P90 scenario is shown in the example (Figure 2), where using a data source with lower accuracy (red line) results in a much lower P90 value impacting the bankability of the project. A higher P90 value resulting from the use of a higher quality solar data source like 3E's satellite-based solar irradiance data results in higher debt leverage for the investor since the Debt Service Coverage Ratio (DSCR) is not limited by a lower yield (EBITDA) from the project. The higher the yield, the less equity the developer must invest, resulting in more attractive financial indicators.

For example, for a typical 5MW European solar power plant, and considering a DSCR of 1.2, a 2% difference in P90 when using a higher quality solar irradiance data source such as 3E's satellite-based solar data [3, 4] results in higher lending capacity and thus ca. 9% less equity for the investor. Or, to put it another way, the investor can increase his return on equity (ROE) by 10% compared to a situation where medium quality data has been used.

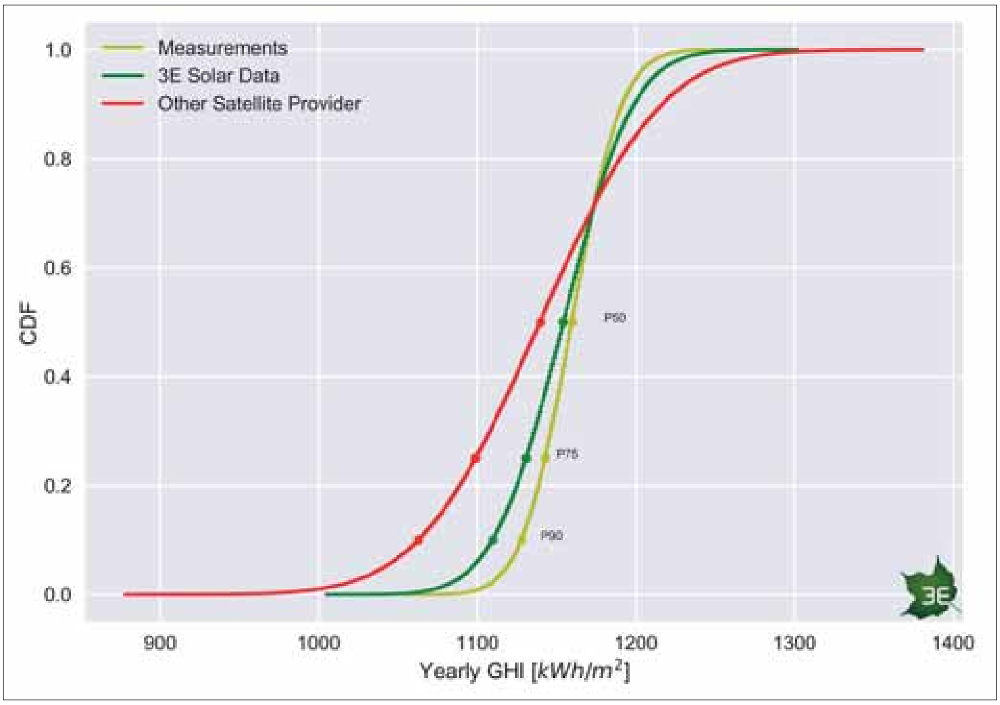

Figure 2: The importance of accurate long-term irradiance data when calculating indicators such as P50/P90 for the bankability of a PV project

Detecting underperformances during operation

Undetected under-performance can easily cause the performance ratio of PV assets to drop below a contracted value, resulting in financial penalties. Investment in good quality irradiance measurement equipment usually pays back within one to two years. During the O&M of a PV asset, having a second independent solar irradiance data source is crucial for revenue and yield reporting, considering that many local sensors may be faulty or that there is often missing data. The solar irradiance data is key for the calculation of production losses, optimisation of maintenance interventions and contractual reimbursement in case of underperformance.

The importance of accurate irradiance data is shown in Figure 3, opposite, for a degrading 5MWp PV plant: the contractual performance ratio is plotted in orange (taking a small, predicted degradation into account). There is a badly maintained, low-quality, degrading on-site sensor (dashed lines for monthly and six months PR) and high-quality irradiance data (solid lines for both monthly and six months PR) available. The figure indicates that in this case the contractual performance ratio threshold would get triggered nine months later due to bad irradiance sensing.

The value of irradiance data to solar plant stakeholders

As an example, let us consider a typical 5MW European solar power plant: it produces 1,200kWh/kWp, the electricity is sold at €120/MWh, expected annual revenues are €700,000 and contracted annual O&M costs are €50,000 [1]. In Table 1 (facing) the value of accurate irradiance data is quantified for each of the different stakeholders involved in the asset operations.

On-site measured irradiance data

On-site irradiance data is collected by sensors placed at well-chosen locations in a solar park and they must be able to reliably measure irradiance differences of a few per cent over long time periods, as shown in the annual irradiation chart

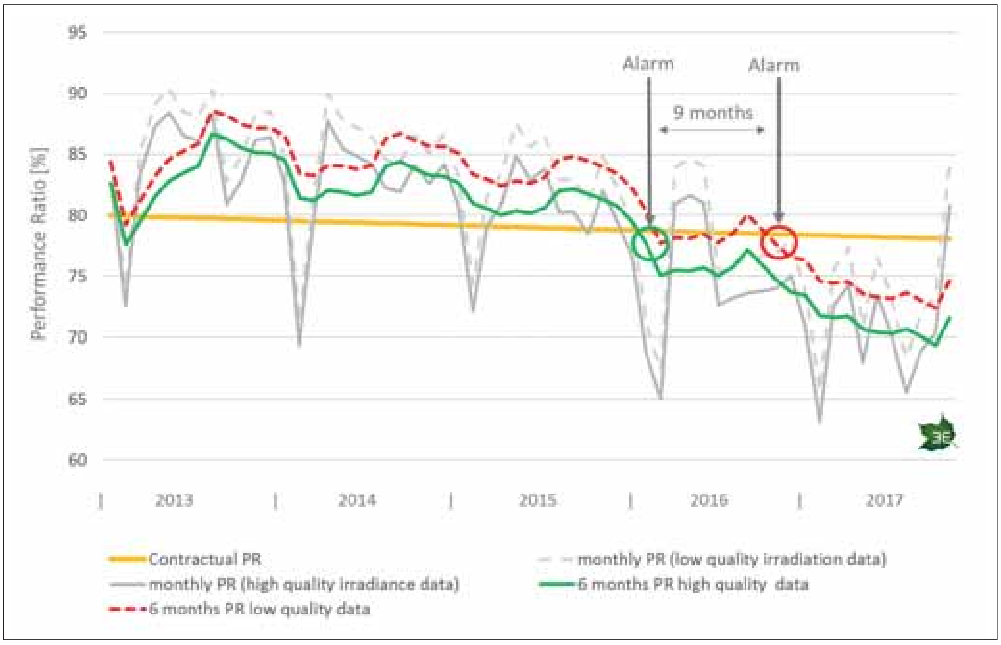

Figure 3. The importance of accurate irradiance data when detecting operational underperformances

for the Netherlands. By specification, ISO 9060:2018 Class A and ISO 9060:1990 secondary standard pyranometers (e.g. Kipp & Zonen CMP10 or SMP10 [5]) are most suited for the job. Their modest price, compared to the multi-million euro investments in a solar project, and their role in plant performance monitoring and fault and degradation analysis, imply that the business case for installing these instruments is very positive.

Figure 4: Kipp & Zonen CMP10 or SMP10 pyranometer

On-site data is needed for real-time and short-term performance monitoring for analysis of solar plant issues (e.g. panel or system degradation) and for maintenance and repair decisions. It is also used to fine-tune the satellite data for the local conditions.

Two separate local solar irradiance measurements are necessary:

1. Irradiance in the horizontal plane - Global Horizontal Irradiance (GHI)
2. Irradiance at the same tilt and orientation as the solar panels, often called Plane of Array (POA) or Global Tilted Irradiance (GTI)

On-site POA measurements are most important, since this parameter is a major input for monitoring the expected yield and performance of the solar plant. Unlike GHI, POA takes into account radiation reflected from plant structures and the ground that are in the view of the PV panels and of the tilted pyranometer. For example, the reflection of white sand is much higher than that of black soil (Figure 5, following page).

To collect high-quality on-site irradiance data, the pyranometers must be installed precisely and maintained well, with regular dome cleaning, alignment checks and recalibration. On larger plants,

EPC	O&M contractor	Asset manager/owner	Debt finance/investor
When developing, designing and building a utility-scale solar energy power plant, the most cost-effective irradiance measurement solution that is compliant with the specifications brought forward will normally be chosen. However, during the various stages of acceptance testing, irradiation measurements become critical to justifying the plant performance.	As an O&M contractor on a large portfolio of solar assets, it is important to have adequate, cost-effective, reliable and indisputable irradiation monitoring.	Managing solar assets is about contracts and performance, including guarantees and indemnities for underperformance. Without reliable data, particularly for irradiance, Performance Ratio calculations are meaningless, degradation becomes undetectable and availability cannot be calculated.	Short-term performance issues of the assets are not very relevant. However, in order to assess Debt Coverage Ratio (DCR) versus the business plan, medium-term to long-term plant performance issues should be distinguished from irradiation differences.
A clear irradiation monitoring approach, with a well designed and implemented measurement chain, is therefore key to avoiding lengthy performance and availability discussions that delay payments. Expensive on-site corrective interventions due to mounting, cabling, calibration, communication or placement issues can be avoided.	High-quality on-site measurements of performance parameters with remote analysis (including irradiance) lead to efficient problem solving (with or without a site visit) and contribute to the margin on the contracted O&M fee.	Data integrity, maintenance and the re-calibration of on-site pyranometers (and other measurement equipment) should be part of the contract with the O&M contractor.	A reliable source of site-specific irradiation data is key to being forewarned of up-coming debt finance issues.
Example case: *Typical outstanding payment at the Provisional Acceptance Certificate (PAC) stage on a 5MWp project is in the order of €200,000. Delayed payment hinders the cash position and therefore investments in new project developments. At the Intermediate Acceptance Certificate (IAC) and Final Acceptance Certificate (FAC) stages, poor irradiation policies can result in significant liquidated damages for the EPC. Typically, for a 5MWp plant, if 2% under-performance is suspected, the penalties at stake could also be in the order of €200,000.*	***Example case:*** *Typical O&M fee on a 5MWp project is in the order of €50,000 per year, while annual revenues amount to €700,000. The cost of going on-site differs per location (determined by travel costs and wages) but one day on-site for in-depth local investigation and fault analysis typically costs €500-1,000.*	***Example case:*** *An undetected performance degradation of 2% over five years can result in a revenue loss of €70,000.*	***Example case:*** *Working with high probability (P90) scenarios for solar assets requires high quality, validated irradiance data as an input and the asset manager should be able to report degradation figures. As previously mentioned, an undetected performance drop of 2% over five years could result in a loss of €70,000.*

Table 1. The value of accurate irradiance data for each of the different stakeholders involved in the asset operations

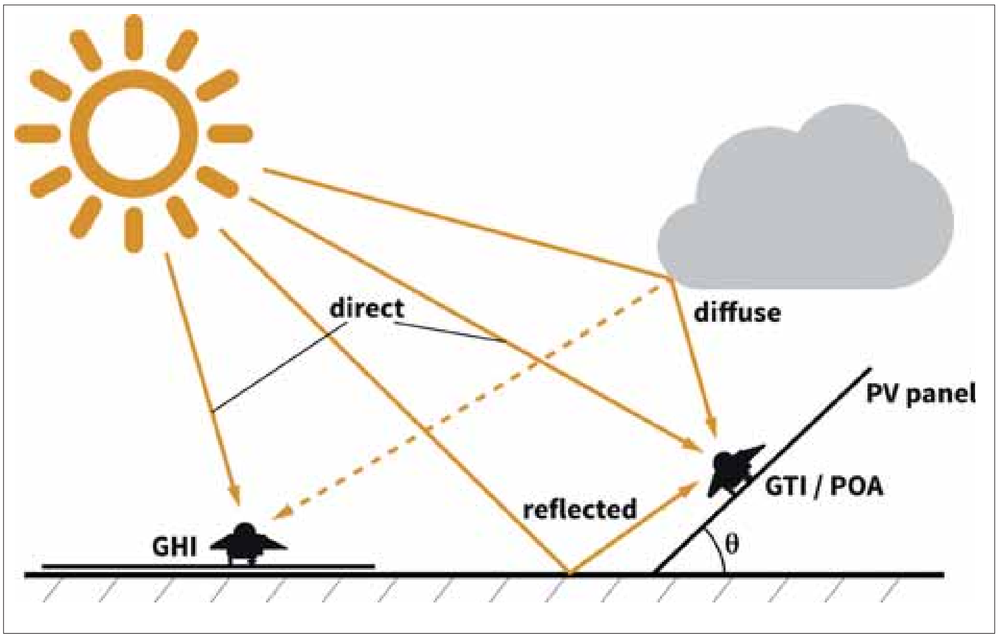

Figure 5: Global horizontal irradiance (GHI) and plane of array irradiance (POA) measurements

measurement at multiple points is necessary to increase measurement accuracy as clouds transit the site and where panel arrays are installed at different angles (for example on a hillside).

Additional pyranometers are advisable for redundancy and for backup during recalibration. If one pyranometer mounting becomes distorted, for example by a mowing lorry or a cleaning robot, a second pyranometer nearby will indicate that something is wrong. This happens more often than you might think! Intercomparison with additional pyranometers and/or satellite data will tell you where the problem is.

How many pyranometers?

The number of pyranometers, and their placement on a solar plant, is a subject of discussion in the utility-scale solar power market. Internationally accepted guidelines, such as the Project Developer's Guide, Utility-Scale Solar Photovoltaic Power Plants (IFC 2015) and the recent standard IEC 61724-1:2017 Photovoltaic System Performance Monitoring, provide recommended minimum numbers of pyranometers for different plant capacities.

However, these minimum numbers do not take into account:

- Differing environmental conditions across a large solar park, such as near or far shading effects, surface reflections, micro-climates, cloud transit times and dust accumulation (soiling);
- Plant design division into subsystems: strings, MPPs, inverters and differences in panel orientation & tilt;
- Redundancy: continuous measurement during service and calibration of pyranometers and backup in case of faults.

In general, substantial (environmental or design) deviations within a solar park need to be covered by separate, representatively positioned, pyranometers.

Maintenance

Pyranometers require some maintenance to ensure accurate measurements and this should be incorporated into every O&M planning schedule. In particular, the dome needs regular cleaning and the alignment (horizontal or plane of array) must be checked after cleaning. Recalibration is generally recommended every two years.

PV plant size	Minimum number of Class A/Secondary Standard pyranometers	
	Horizontal	Plane of array
<5MW	1	2
5-40MW	2	4
40-100MW	3	6
100-200MW	4	8

Table 2. Recommended minimum number or pyranometers for a solar park of uniform layout and topography

Irradiance measurement chain

Just fitting a high quality pyranometer is not enough, the entire data collection and analysis process must be robust and secure:

- Use Class A or Secondary Standard pyranometers for low measurement uncertainty.
- Sampling and logging intervals of the irradiation data:
  - o Sample every 1-3 seconds
  - o Log the average of the samples every minute
- Use a good quality scientific data logger for unamplified pyranometers (CMP10).
- Record the Modbus® digital data of Smart pyranometers (SMP10).
- Use statistically sound data analysis in the plant monitoring software, such as in SynaptiQ [6].

High-quality, site-specific solar irradiance data is the key to meaningful plant monitoring.

Satellite-based irradiance data

Satellite irradiance data is increasingly being used in both, utility-scale solar parks and in smaller installations since it is easy to acquire. A simple subscription to a service provides high availability of data with good time resolution and spatial coverage. Furthermore, for most locations on earth, in addition to near real-time data, satellite data is available going back at least 10 years providing a useful historical database for site prospecting and for optimising the site-specific design of solar power plants. Therefore, this source of irradiance data is often used as an input for long-term yield assessment and to calculate a reference yield for monitoring and business reporting.

Satellite irradiance data is retrieved using models to derive cloud, precipitation, and other parameters from measurements by optical instruments on board satellites. State-of-the-art satellite irradiance data providers such as, for example, 3E's Solar Resource Data Service [4] use advanced cloud physical properties (CPP) models. The use of CPP models has increased significantly the accuracy of satellite-based irradiance data throughout the day and under complex cloudy conditions.

How accurate is satellite-based irradiance data?

Satellite-based irradiance data can be extremely useful when available at high temporal and geographical resolution.

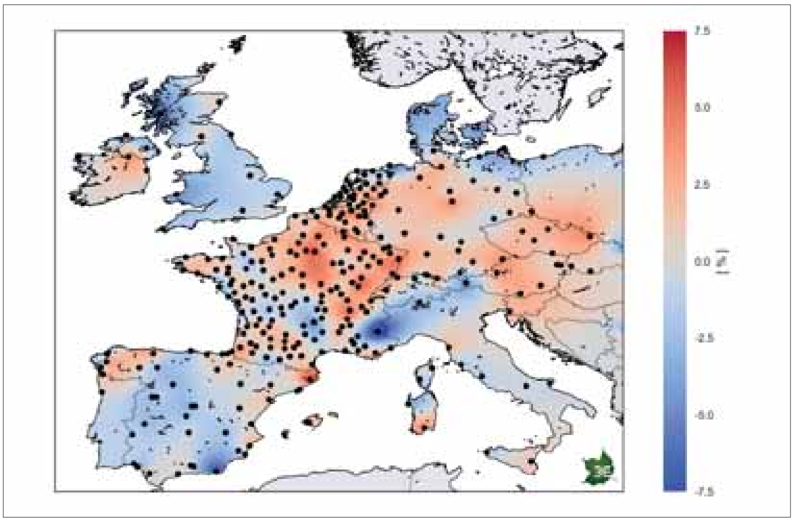

Figure 6: Percentage difference between 3E Solar Data and ground station data measured over one year with high-quality pyranometers maintained by the national public weather services in Europe

State-of-the-art satellite irradiance data providers are constantly evaluating their models against the reference data from the measurement stations ensuring their high quality. A recently published independent validation study performed by TÜV Rheinland shows that the percentage difference (bias) between 3E's satellite-based solar irradiation data [4] and the on-site measured data is in the order of ±2.5% even for moderate-climate regions like Germany [3]. The study analysed data over 35 meteorological stations in Germany using over 215 complete years (1-14 years per stations between 2005 and 2017) of high quality data.

Over 300 high-quality meteorological stations spread across Europe and Africa are used within 3E's Solar Data validation framework, participating in the continuous improvement of the models. Results of these extensive validations are presented in [2] and validated by [3].

Satellite-based solar irradiance data is evaluated against the reference data from the measurement stations. Hourly, daily, and monthly irradiation for all sites are evaluated by their root mean square error (RMSE), the standard deviation of the error (SDE) and the systematic part of the error (bias).

An overview of the geographical distribution of the error (bias) is shown in Figure 6 and Figure 7 for Europe and South Africa respectively. These validation maps show the yearly difference (bias) between 3E's Solar Data derived from satellite images using advanced CPP models and on-site measured data using high-quality pyranometer measurements collected and maintained by the national weather services of several countries.

As shown in Figure 6, the yearly percentage difference (bias) between 3E's satellite-based solar irradiation data and the on-site measured data is in the order of ±2.5% for many places in Europe. This yearly percentage difference is even lower in some regions across Europe. Results over South Africa show that the yearly percentage difference (bias) between 3E's

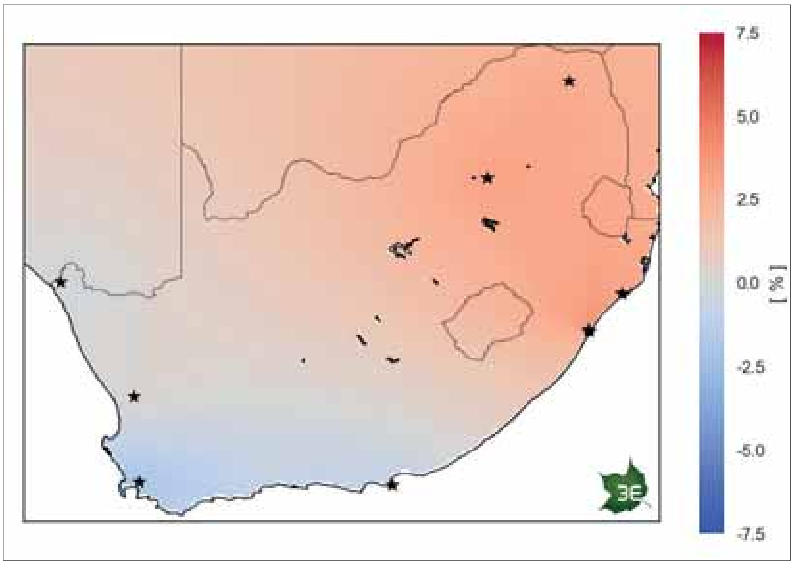

Figure 7: Percentage difference between 3E Solar Data and ground station data measured over one year with high-quality pyranometers maintained by the national public weather services in South Africa

satellite-based solar irradiation data and the on-site measured data is lower in this region of Africa than for many places in Europe, being often around ±2% for the region (Figure 7).

In practice, when computing irradiation by integrating irradiance over long times, random errors are averaged out, decreasing the standard deviation of the error (SDE) while the bias remains the same. As shown in Figure 6 and Figure 7, the systematic component of the error (bias), is on average 2.5%.

Results of the extensive validation show that the random component of the error (SDE) is 10% for daily resolution and 4% for monthly resolution in Europe. Results for South Africa, where hourly data is also available, show that the SDE is around 12%, 6% and 3% for hourly, daily and monthly resolution respectively, showing the clear improvements with other non-physical models. Extended results over multiple years, including hourly, daily and monthly resolution, are presented in [2].

Best practice: combining pyranometer and satellite irradiance data

The strengths of on-site pyranometers and satellite-derived irradiance data sets can be perfectly combined to reduce the uncertainty in both long-term forecasted PV plant yield during the design phase and to detect underperformances during the operational phase. These two data sources are highly complementary and should be used together to obtain redundancy and cross-checks for the most accurate data.

The bankability of a PV project during the design phase can be improved by combining the data of a short period of record, but with site-specific seasonal and diurnal characteristics measured by an on-site pyranometer, with a satellite-based data set having a long period of record, but not necessarily with site-specific characteristics. Upon completion of the measurement campaign (typically around one year), different methodologies can be applied to correlate the measured data at the target site, spanning a relatively short period, and the satellite data, spanning a much longer period. The complete record of satellite data is then used in this relationship to predict the long-term solar resource at the target site. Assuming a strong correlation, the strengths of both data sets are captured and the uncertainty in the long-term estimate can be reduced [7].

Combining pyranometer and satellite-based irradiance data during the operational phase of a PV plant enables robust and advanced statistical analysis in state-of-the-art solar PV plant monitoring software like SynaptiQ [6], which combines both on-site pyranometer and 3E's satellite-derived measurements into validated and precise irradiance data for a specific plant.

Reasons to combine data pyranometer and satellite irradiance data:

- Satellites and pyranometers are fully independent sources of irradiance data that can be compared, analysed and correlated to determine reliable site data.
- For monthly to annual reporting of the overall plant performance by O&M contractors and asset managers, satellite-based data are a reliable source that can be validated by comparison with on-site pyranometer data.
- For long-term yield estimates as computed by investors, installers and consultants, satellite-derived data are a valuable source. Data from a well-maintained on-site solar irradiance monitoring station can be used to further improve the accuracy of the calculations.
- Fault detection and analysis by an O&M contractor requires hourly or even sub-hourly on-site irradiance data. High-quality and well maintained pyranometers are the first choice; satellite data may be used as back-up if the instruments fail or appear to be badly maintained.
- Satellite data may also serve to validate the proper calibration and configuration of pyranometers in case of doubt. For large deviations, cleaning needs or shadowed sensors, satellite data analysis may spare the O&M operator a site visit.

The best practice is to use both on-site pyranometers and satellite data services to obtain accurate irradiance data for solar plant design and performance monitoring over both short and long time-scales. ■

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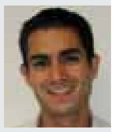


Mauricio Richter manages product innovation at 3E and has worked in 3E's R&D team as photovoltaic expert since 2012. Mauricio is currently the product manager of 3E's data services. The scope of his work covers topics in solar photovoltaics, with a focus on solar resource assessments, forecasting, long-term yield estimates and performance analysis of PV systems. Mauricio is focussed on bringing R&D innovations into financially effective products and services for 3E.

Clive Lee has been with Kipp & Zonen since 1998, involved with all aspects of solar radiation measurement in meteorology, climatology and renewable energy. He is currently the technical sales and services manager, advising on all aspects of Kipp & Zonen products and their applications. He has a degree in geophysics and initially worked in the field of flammable and toxic gas detection and monitoring, before joining Siemens Environmental Systems in the UK as senior technical specialist for the air quality monitoring division.

Hurdles to widespread bifacial PV adoption

Bifacial | Bifacial technology is seen by many as the shape of things to come for the solar industry. But how is it regarded by those on the frontline of choosing equipment that will result in the most profitable projects? Jenya Meydbray, VP of solar technology at Cypress Creek Renewables, offers an insider's view

Ten years ago, nobody batted an eye when the output of a photovoltaic (PV) system exceeded estimates from the best available performance modelling software by a healthy margin. Back then, overperformance gave project owners cause to praise the quality of their systems, while highlighting that they delivered all the energy expected by the end customer, and then some.

The rules of the game have changed.

Today, if a project developer proposes to build a PV system, all future energy generation must be captured in the third-party energy model to result in a profitable and financeable project. There's simply no more fat left in PV systems at power purchase agreement (PPA) rates in the mid- to low-single digit USD cent range. That's because, in the past several years, yield estimates for systems with standard monofacial crystalline silicon (c-Si) modules have become very precise. Using the simulation software PVsyst, a popular tool for analysing system design configurations and evaluating results, investors and system owners have come to expect that actual output will be in a range of ±1% of what they expected, after normalising for weather. Why take the risk on a project or technology that may give you plus or minus 10% when many projects using standard technology minimise risk so effectively?

The predictable nature of c-Si technology has helped scale up project finance for the solar industry, where investors tend to apply a lower debt-service coverage ratio than in the wind industry. But by the same token, it presents challenges for the adoption of alternative PV design concepts, such as systems using bifacial modules.

Bifacial PV technology is generating great interest in the solar industry despite a paucity of data on its bankability

A bifacial module uses glass or transparent backsheet behind the c-Si solar cells instead of an opaque white or black backsheet, allowing light to pass through it and onto the module's back side to generate more energy. Bifacial solar cells are also c-Si but are processed to allow light in from both sides. Everybody likes the idea of generating more energy, in principle. The problem is there's not enough data to tell investors how much of a performance boost they can expect from replacing standard monofacial c-Si modules with bifacial modules. At this moment, yield estimates for systems with bifacial modules are too imprecise. Anytime we try to simulate their performance, it's like stepping into a time machine and going back 10 years to an age of low predictability in solar project output. Although there is reason to believe that bifacial modules will increase net present value for many solar projects, developers today are seeing increased risk in the performance model, which often leads to unnecessary conservatism.

With funding from the US Department of Energy, Cypress Creek Renewables is launching a project to generate data and analysis on the variables affecting bifacial solar output, accounting for obstructions on the module back side, tracking algorithms, module degradation, snow shedding and much more. The research will include the deployment of bifacial test stations, instrumenting of commercial systems in the field and computer modelling. The goal is to characterise bifacial technology behaviour and to further develop and validate performance models that investors and independent engineers can utilise to accurately quantify the performance boost from bifacial solar technology and ultimately to reduce the solar levelised cost of electricity (LCOE).

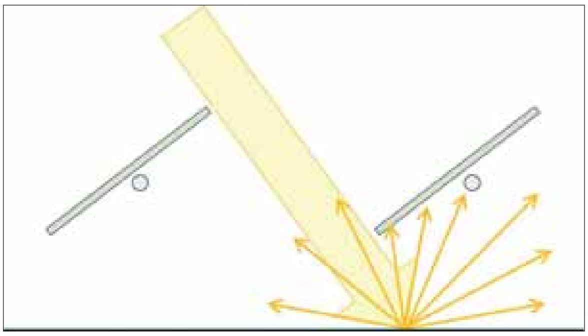
How bifacial technology impacts NPV

Investors develop their own criteria to measure a solar project against any other investment opportunity. As one important benchmark, many investors use net present value (NPV), a measure of profitability that combines cost of capital-adjusted payments and receipts. Whether an investor is seeking projects that yield NPV of 10 cents per watt or some other threshold, electricity sales are an important part of the projected cash inflows needed to show that a project should qualify for financing.

Bifacial PV technology has the potential to drive up NPV. According to researchers at the International Solar Energy Research Center in Konstanz, Germany, bifacial solar projects have reported energy gains of up to 20%. The best results thus far come from the 1.25MW Asahikawa Hokuto Solar Power Plant in Japan that has been operating since November 2013. Results vary at other sites, such as Yingli Solar's 100MW Top Runner project, where an initial 50MW section of the project has reported about 17% energy gain, and a 2MW project in Saarland by the developer Ökostrom Saar that is reporting a 10% gain. Other industry players confidentially report 5-7% gains. However, the industry has not yet produced seminal research to establish how bifacial modules affect system yield in various system configurations and locations.

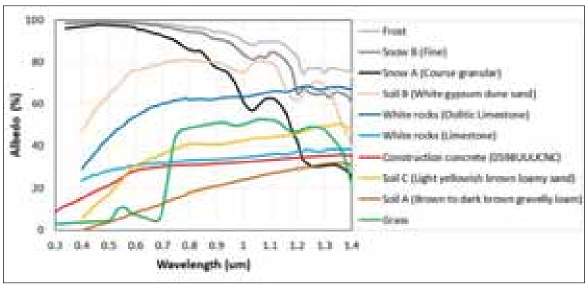
Projects can see a marginal upfront cost increase associated with bifacial modules. Module assembly isn't altogether different. Bifacial modules use the same cell technologies, front-side glass, encapsulant and wiring as c-Si modules. Module cost on a per-Watt basis may go up a little by replacing the backsheet with a second layer of glass, thereby potentially reducing front-side performance by a few watts. Mounting system costs could go up a little too, because they must be redesigned to avoid covering the module back side. Balance of system cost also could see a modest increase to account for a slightly higher series fuse rating. Altogether, expect to spend a couple cents more at the system level in the near term and less over time as the industry gains experience and production volume for bifacial-specific parts.

A wide variety of factors affect system output, for better or worse. This article is not intended to thoroughly cover all the factors but rather to briefly describe some of the leading factors and demonstrate why the industry must understand their impacts on system output to accelerate bifacial solar deployment.



Credit: PV Lighthouse

Figure 1. Light reflecting off of the ground (albedo) onto the back of PV modules



Credit: PV Lighthouse

Figure 2. Spectral content of albedo for various ground types

Albedo

This is the percentage of sunlight reflected by the ground back up onto the PV modules. The value depends heavily on what lies beneath the modules and can change hourly, daily and seasonally. Fresh snow provides a higher value than grass, for example. Albedo has the strongest impact of all bifacial-specific system design considerations that didn't impact standard monofacial c-Si PV modules.

Spectrum of albedo

As light passes through the atmosphere, certain colours (i.e., wavelengths) of light are absorbed more than others, thereby resulting in some spectrum of intensity as a function of wavelength. Different ground types can vary greatly in the spectrum they reflect. Solar cell efficiency is a function of wavelength, so this phenomenon will impact back-side efficiency. Light that hits the cell surface but fails to produce electricity is wasted as heat.

Incidence angle modifier (IAM) on back side

This refers to the amount of light that fails to reach the solar cell due to reflection off the glass and the encapsulant. When incident light hits the front glass at a sharp angle, the reflection is higher. When light comes in perpendicular to the module surface, reflection is lower. IAM describes the reflective losses at different angles. This is implemented in energy modelling of the front-side performance but will impact back-side performance as well.

Obstructions

Objects on the back side of the module—junction boxes, cables, mounting system components—that have no effect on traditional c-Si solar output can interfere with potential energy gain in a bifacial solar system. To optimise bifacial system output, modules should use a shallow junction box that does not obstruct solar cells on the back side, and systems should employ design configurations that keep balance of system components from blocking reflected light from below.

View factor

This describes the energy transfer from one surface (e.g., the sun) to another

Figure 3. PV module junction box installed directly over the back of two bifacial cells

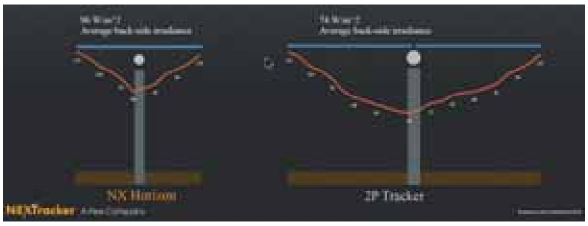


Figure 4. Diagram illustrating reduction of back side light intensity as the module table gets larger for the same height tracker. Source: NexTracker

(e.g., the back of the PV module). In solar, view factor is a function of the height and width of a module array. A tracker that is one module high lets more light around to the ground below the modules than a tracker that is two modules high. The diagram below from NEXTracker illustrates this effect for trackers that are the same height. It's important to note that trackers with two modules in portrait will be taller.

Mismatch

Like anything manufactured in volume, solar cells are not all identical. However, when wired in series they must have the same electrical current flowing through each one. Electrical current is approximately linear with light intensity. In other words, if you double the light intensity incident on the solar cell, you'll double the current. Non-uniform light intensity on the back side of the PV module and non-identical cells all contribute to mismatch losses.

Portrait versus landscape orientation

Bypass diodes, used to mitigate the effects of non-uniform shading on a solar module, operate based on module orientation relative to shade geometry. Neither configuration, portrait nor landscape, necessarily yields more energy in all cases. However, the non-uniformity of back-side illumination is typically in the dimension perpendicular to the ground or the tracker torque tube.

Snow shedding

Modelling for systems in locations that experience winter snowfall includes energy losses due to shading from snow. For standard monofacial c-Si systems, the range of loss estimates from various independent engineering (IE) firms can be 10% or more. To what extent does absorption of light on the back side cause the module to heat up faster and accelerate snow shedding? Does snow shedding cause soiling on the back side? Additional testing is needed to introduce real-world behaviour into engineering estimates.

Module degradation

Due to a combination of factors, including prolonged exposure to temperature swings, moisture and ultraviolet light, c-Si modules tend to see a gradual decline in efficiency over time. With two layers of glass instead a glass-backsheet combination and with increased overall light absorption, degradation may occur at a different pace in bifacial modules. It's feasible that degradation can be lower if outgassing and delamination can be avoided.

> "Yield estimates for systems with bifacial modules are too imprecise. Anytime we try to simulate their performance, it's like going back 10 years to an age of low predictability in solar project output"

Light-induced degradation (LID) / Light- and elevated temperature-induced degradation (LeTID)

All c-Si modules built with p-type wafers experience light-induced degradation (LID) caused by oxygen and other impurities in the silicon. Light- and elevated temperature-induced degradation (LeTID) can occur in passivated-emitter rear contact (PERC) cells. Depending on how the cells are processed, the magnitude of these behaviours can vary for a cell's front side and back side.

Tracking algorithms

Systems with single-axis or dual-axis trackers use algorithms to evaluate various tradeoffs to maximise overall system output. According to discussions with two leading tracker manufacturers about how bifacial PV modules may affect tracking algorithms compared to standard monofacial c-Si modules, completely differing perspectives are present today.

Module-to-module spacing / Row-to-row spacing

Adding spacing between modules and between rows will allow more light to hit the ground under the modules and reflect onto the module back side. However, this adds potential cost to the land, racking, wiring and other electrical and mechanical balance of system.

Tilt angle for fixed-tilt systems

With standard c-Si modules, system designers tend to orient modules south facing at latitude tilt with a steeper tilt for systems located furthest from the Equator. With bifacial PV modules, maybe systems perform better at a slightly flatter angle. Maybe not.

Torque tube shape and size

When an opaque backsheet covers the back of a solar module, it makes no difference whether a tracker's torque tube, the part that controls module orientation, has a circle or a square cross-sectional shape. Shape doesn't affect monofacial system output, nor does torque tube size. In systems with bifacial modules, the torque tube shape and size can both introduce obstructions on the module's back side and impact reflection from the torque tube. Generally, you want the shape, size and placement of the torque tube to minimise back-side shading, if possible.

Electrical stringing

Details about the available land, such as shape, wetlands and waterways and topography, are just some considerations affecting the choice between going one module high or two modules high on a tracker. With bifacial PV modules one must also consider how electrical stringing affects module mismatch. In systems that go two modules high, one row is closer to the ground than the other, and the two rows capture different amounts of reflected light from the ground. Stringing the two rows together in series will increase mismatch losses.

In time, we may come to realise that impacts from some of the above-mentioned factors are trivial. That's ok. Incremental progress is the way that the

solar industry has driven down module costs by over 90% in less than a decade. Meanwhile, through the course of study, other as-yet-unidentified considerations may materialise. Even if all the impacts from bifacial solar add up to a modest 2% energy gain at the system level, that would be the equivalent of a roughly 3 cents per Wp cost reduction, according to the National Renewable Energy Laboratory's (NREL) recent cost modelling presented at the 2018 Bifacial Conference in Colorado. If bifacial PV systems could increase output by 10% or more in a way that is predictable and widely adopted by the financial community, it would improve NPV and help many more projects get built.

How investors model bifacial technology today

Until the necessary research on bifacial PV modules is available, investors will most likely continue to associate the technology with a higher degree of risk and uncertainty relative to standard monofacial modules, particularly the cash investors who provide sponsor equity. Why? These are the people taking long-term risk, the ones who make money only after debts have been repaid and tax equity investors have cashed out. The financial community as a whole bases assumptions about a project's financial performance around the idea that cash flows are a known quantity. But since financiers are experts in risk management, not electrical engineering, they rely on IE firms to estimate energy output in one system design configuration or another.

IE analysis can be detailed at times and fairly high level at others. Sometimes the analysis is completed without a site visit, similar to a home appraisal in a real estate transaction. In addition, IEs don't provide a single firm number when predicting solar energy output. Instead, they provide figures based on the probability that output will exceed an estimate. If they say a project has a P50 value of 100,000 kilowatt-hours (kWh), for example, the investor understands that the project has a 50% chance of meeting or exceeding 100,000kWh. A P90 value says a project has a 90% chance of exceeding that estimate. If a project has a P50 value of 100,000kWh, the P90 will be lower than this. The more the uncertainty, the further apart the P90 is from the P50. The P75 or P90 values matter because often banks will lend on these lower-risk estimates. If you ask three IEs to estimate the energy output for a system with bifacial modules, you're likely to get three different answers.

Years ago, there was enough margin in solar project development that nobody was bothered if a project could outperform its yield estimate by 5-6%. Everybody was making money. Today, leading developers are signing power purchase agreements in the US for 3c per kWh. Margins are thin and there's no room for uncertainty. This is how solar projects are competing with (and beating) fossil fuels. Higher confidence reduces the cost of capital and increases deployment. Lower confidence kills deals.

> "Years ago, there was enough margin in solar project development that nobody was bothered if a project could outperform its yield estimate by 5-6%. Today... margins are thin and there's no room for uncertainty. This is how projects are competing with (and beating) fossil fuels"

Department of Energy project and goals

In October 2018, the US Department of Energy's Solar Energy Technologies Office announced funding for 53 projects supporting research and development for PV and concentrating solar power, and workforce development initiatives. Among 12 projects aimed at increasing PV affordability and reliability, Cypress Creek Renewables has committed to a multiyear process that will help the solar industry capture the full benefit of bifacial PV technology.

To quantify yield under varying conditions, the project will include a combination of bifacial test stations and megawatt-scale commercially operating systems in different climate zones around the country. It aims to evaluate project yield sensitivity to a variety of design characteristics discussed earlier, including different cell technologies.

Using test results and commercial system output, the project will provide the necessary input to improve (as needed) and validate modelling of leading simulation software programs, including PVsyst and NREL's System Advisory Model (SAM). Two to three years from now, when a bifacial project lands on an IE's desk, modelling tools and best practices should be able to provide a more accurate estimate of system output with higher confidence.

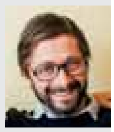
A central goal of the project is industry outreach and stakeholder engagement. Systems with bifacial modules can achieve a levelised cost below 3¢ per kWh. The only way to get there, however, is to increase investor and IE familiarity with bifacial technology.

Seeking project participants

For the past several years, industry analysts have been predicting that solar will become a primary source of electricity by 2040, outpacing coal and nuclear and, under the most optimistic scenarios, natural gas. Bloomberg New Energy Finance forecasts 6,700GW of solar capacity to be installed globally in 2050, up from about 500GW in 2018. The solar technologies that can reliably demonstrate improved project economics in the market today will be deployed in far greater volumes in the future. We're just getting started.

If you are an investor or an independent engineer with more than 200MWs per year of solar project participation and have interest in bifacial technology, please contact me to become a project participant and contribute to the industry's adoption of bifacial PV technology. ■

Author



Jenya Meydbray is the VP of solar technology for Cypress Creek Renewables. Previously he was the VP of strategy and business development for DNV GL's Laboratory Services group, which acquired PV Evolution Labs (PVEL), where Jenya was founder and CEO. At PVEL Jenya successfully ramped and sold the first solar laboratory business in the US focused on supporting the financial community. Prior to founding PVEL, Jenya was the senior quality and reliability engineer at SunPower, where he developed accelerated test methods for high-efficiency solar cells and modules. Jenya began his career at NASA Ames Research Center's hyper-gravity facilities. Jenya received an MS and BS at Boston University and UC Santa Cruz, respectively, and holds two photovoltaic-related patents.

Analysis of bifacial PV systems in the Middle East

Bifacial | PV systems incorporating bifacial modules require careful design and integration to maximise the additional yield they offer. Drawing on extensive field studies, researchers from LONGi Solar describe the optimum design of bifacial systems in the desert conditions of the Middle East, to which bifacial technology is especially well suited

To meet the demand of reducing the levelised cost of energy (LCOE) of PV power plants, the evolution of solar cells and modules is moving towards higher efficiencies. High-efficiency solar cells, abbreviated as PERX (i.e. PERC, PERT and PERL), HIT (heterojunction with intrinsic thin layer) and IBC (interdigitated back contact), are becoming more and more sophisticated under the impetus of drastically increasing demand. Such solar cells have excellent rear passivation so that the aluminum layer at the rear side of the BSF cell can be removed. At this point, the rear of the cell can absorb incident light and form an equivalent cell parallel to the front. After encapsulation, 60/72 bifacial cells become a bifacial module [1].

Due to the higher yield they offer, high-efficiency bifacial modules are gaining more popularity and becoming a new favourite in the PV industry. Although many PV industry insiders believe that 2018 will witness the beginning of the era of bifacial modules in the Middle East area, they still wonder how bifacial modules work, what extra yield bifacial modules will result in and how to use bifacial modules properly. In this paper, we explore the key questions relating to bifacial modules and systems in the Middle East.

Fundamental and extra yield of bifacial modules

As is shown in Figure 1, since the rear side is transparent, the bifacial module can absorb not only the incident light at the front side, but also light at the rear, which is generally composed of diffusive light from the sky, reflective light from the ground and sometimes beams that can arrive at the rear in the summer evening. This indicates that the bifacial modules receive and then absorb more light. Therefore the features of bifacial modules are:

1) Higher current
2) Higher power
3) Almost the same voltage,

Which should be remembered for designation.

To evaluate the extra yield of bifacial modules (versus conventional poly-Si modules), one should take into consideration the following two aspects. One is the improvement from poly-Si to PERX, which is composed by the better spectral response and lower power loss at high temperature. As a result, PERX modules generally have 3% more yield than conventional poly-Si modules, which is currently unable to be simulated by PVsyst. The other is the extra yield stemming from the incident light at the rear side, which can be approximately simulated by PVsyst [2-7].

For a typical utility-scale plant in Middle East, a common system choice is a north-south horizontal tracker. Here, by employing PVsyst, the extra yield of bifacial modules is estimated for Dubai, UAE, with poly-Si as a reference, as is shown in Figures 2a-2c. The capacity of the PV system is 25.6kW and 25.2kW for a conventional poly-Si system and a bifacial system, respectively. The modules are 320W for poly-Si and 360W for bifacial, with a bifaciality of 75%. The ground used in the simulation is yellow sand, common in the Dubai area. The DC/AC ratio is set to about the optimal value for Dubai. The height of the module in the system is defined as the distance between the ground and the tracker axis. The ground coverage ratio is defined as the module width/system pitch.

It is found that the poly-Si fixed-tilt system could yield 1,761.53kWh/kWp per year in Dubai, according to databases provided by MeteoNorm Station. The poly modules in the tracker system could produce more energy due to the sun-tracking effect; the yearly energy yield gain could be about 117.6%, as is shown in Figure 2d. It is found that the energy yield gain reaches the peak point in June, and then falls back in the winter. This is reasonable because the incidence angle modifier loss of the horizontal tracker in winter is much more than that in summer. However if bifacial modules are used in the tracking system, the energy yield performance in the winter would be improved. It is shown that the bifacial tracking system would have

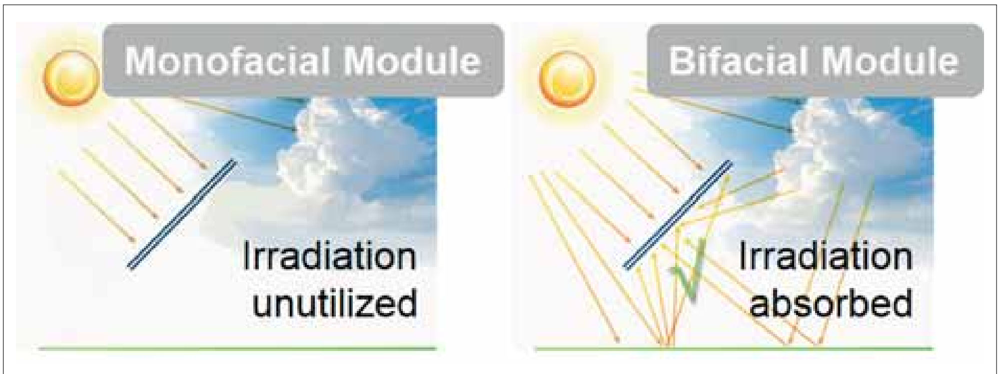


Figure 1. Working mechanism of bifacial modules

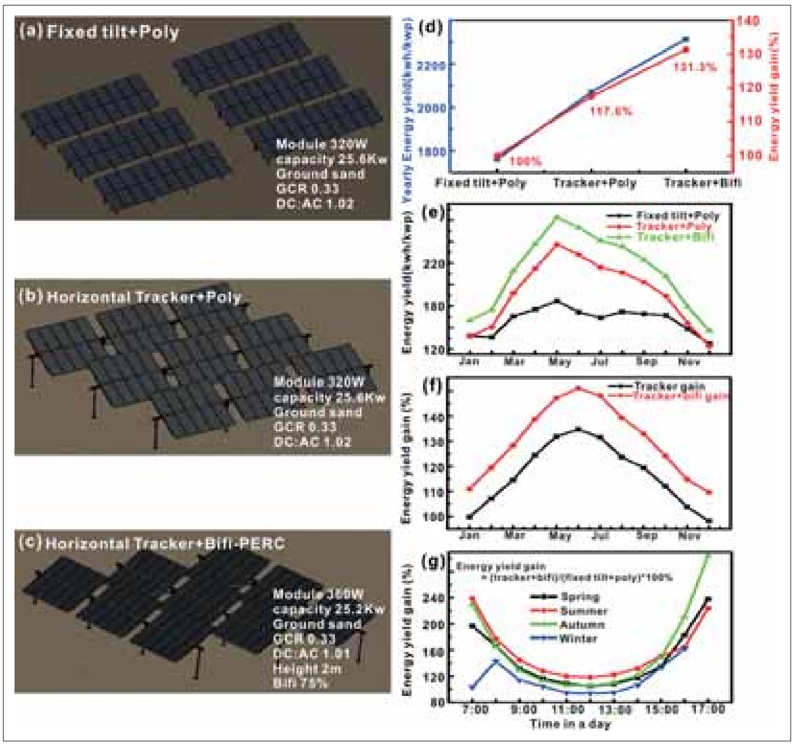


Figure 2. The energy yield of a poly-Si fixed-tilt system, a poly-Si horizontal tracker system and a bifacial-horizontal tracker system, and the energy yield gain of different systems at different times compared to the poly fixed-tilt system

a yearly energy gain of about 131.3% compared to the poly fixed-tilt system. It is about 11.6% higher than the poly-tracking system, but the cost could be just only a little higher.

Figure 2e shows the energy yield of different systems in different months. It seems that the highest energy yield appears in May. However Figure 2f shows that the highest energy yield gain of the tracking system appears in June, little different from the energy yield data. The bifacial tracking system energy yield gain differs from different months, but the bifacial module gain is very stable. Figure 2g shows the energy yield gain of the bifacial system in a day, this is very important for the inverter capacity design. It is obviously that the energy yield gain of the bifacial-tracking system mainly came in the morning and evening; irradiation at this time is not very high. The highest energy yield gain could reach 304% in the autumn evening. The energy yield gain from 11:00 to 13:00 should be paid more attention; the highest irradiation in a day often happens at this time and output often reaches the inverter capacity limit at this time. It is less than 100% in winter from 11:00 to 13:00; in autumn and spring, it is between 106% and 110%; in the summer, it is the highest, appearing from 120% to 122%.

Therefore, a preliminary conclusion is that on trackers, the bifacial modules can produce 14.6% (11.6% from more light absorbed at the rear and 3% from the benefit of the PERX technology) more yield than poly-Si modules with the bifacial gain varying across the seasons in one year and according to the time of day.

How to design bifacial systems with better yield

Since the light absorbed by the rear side is one important part for bifacial modules, more factors will have an influence on the output of bifacial modules than conventional poly-Si module, which means more attention should be paid to the design of bifacial systems, on both the DC and AC sides.

DC design

In our research, the extra yield ascribed to the incident light at the rear can be strongly associated to the albedo of the ground, the latitude of the project location, the diffusive light ratio in the plant, the tilt of the module, the ground coverage ratio (GCR) and the rack height. For a typical scenario in the Middle East, the ground is in general covered by yellow sand, which has an albedo of 30-40%. The latitude of the project location and the diffusive light ratio in the plant are fixed for a given area. Therefore, the design of a tracking system should pay special attention to the GCR and the height.

Figure 3 mainly shows the effect of the module height and GCR on the system output. In Figure 3b, the module height in the bifacial-tracking system indeed has an influence on the energy yield. This is because the tilt angle of the module in the tracking system varies with time; especially in the morning, the scattering light proportion in the sunlight reaches the highest so the tilt angle is the largest to catch the diffuse light. This also means the energy yield gain in morning could reach more than 300%. So increasing the height of the tracking system can increase energy yield gain, but it would have a higher system cost. Therefore, there should be a tradeoff between yield and cost.

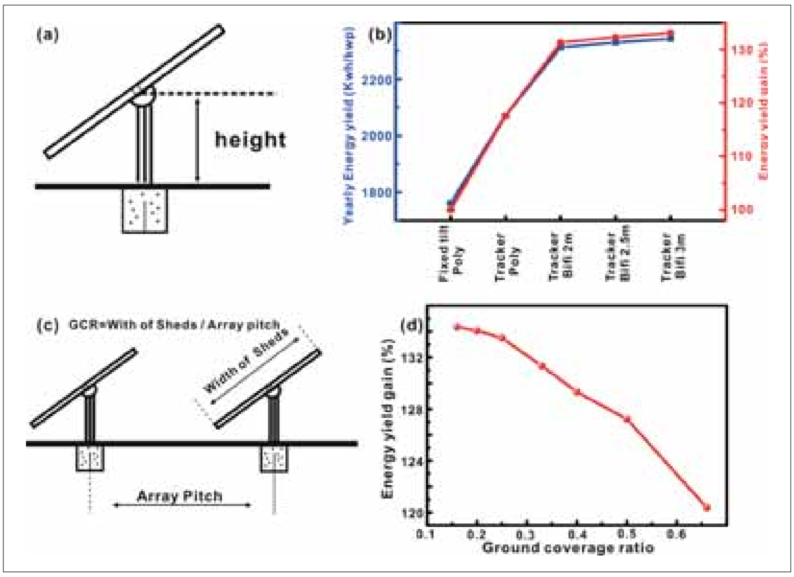


Figure 3. The energy yield gain of bifacial-tracking system varies with the module height and the ground coverage ratio

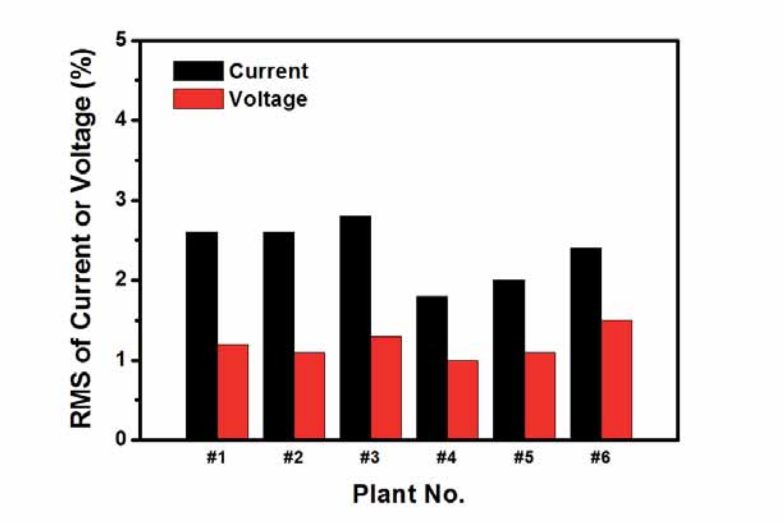


Figure 4. RMS of current of voltage in the plants

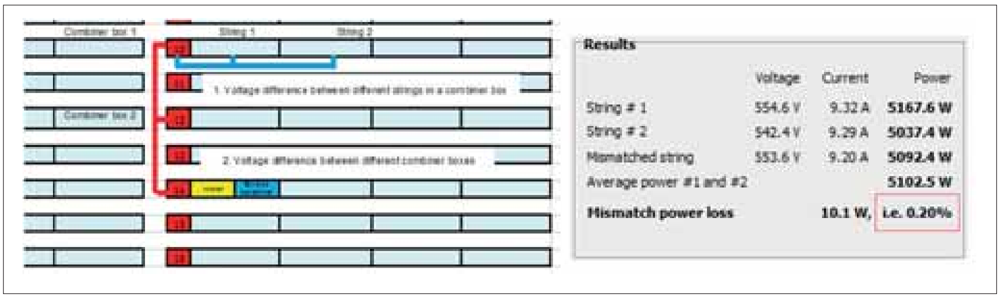


Figure 5. Mismatch loss caused by the different wire lengths

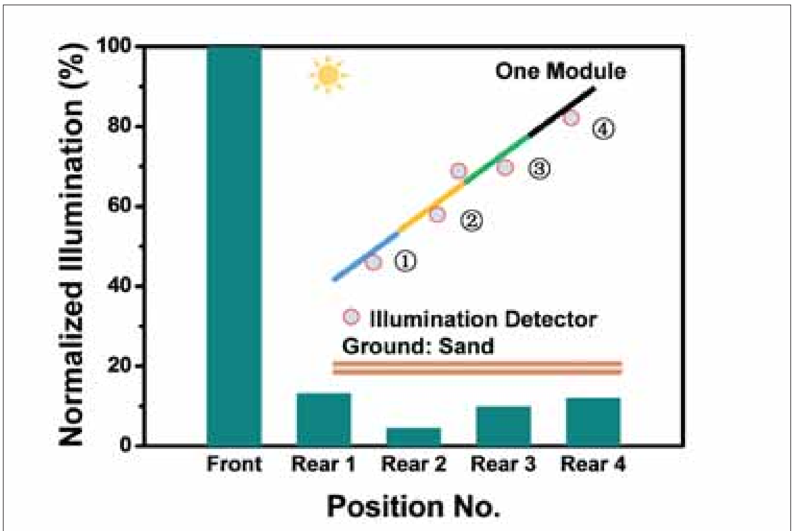


Figure 6. Measured irradiation at different heights of the rear side. The values were measured at the same moment

Figure 3d shows that the energy yield gain of the bifacial-tracking system increases as the GCR decreases. It is evident that decreasing the GCR could increase the ground area available to scatter light, which would increase the diffuse light on the backside of the module. It can be seen that the energy yield gain increases almost linearly from GCR 0.5 to 0.25; it increases very slowly from GCR 0.25 to 0.1, suggesting that the increase in scattered light from decreased GCR at this range results in only a small portion reaching the backside of the module. However, the reduction of GCR may increase the land cost, the wire cost and the power loss on wire. Therefore, a good design of bifacial systems should balance the cost related to GCR and the yield. In the Middle East, the land cost is generally very low, so it is recommend a smaller GCR be adopted for a better investment return rate.

Design of AC side

When the rear side is taken into consideration, a big challenge is the heavier mismatch among bifacial modules and strings, which is one of the most important factors for AC side design. The possible causes of mismatch are as follows:

1) Inconsistency of modules. Through the tests on some PV modules shown in Figure 4, it is found that the current RMS of common PV modules in the first year is 2%, and the voltage RMS is 1-1.5%.

Electrical performance inconsistency can be further aggravated by non-uniform degradation of PV modules over their entire lifetime. According to the industry consensus, the degradation of a bifacial module is 2% in the first year, and 0.5% per year for the following years. However, the degradation of each PV module is inconsistent, which increases the mismatch loss of the PV string.

2) As is shown in Figure 5, since the cable length and thus ohmic loss are different for each string, the voltage of PV strings is different. Generally, the voltage mismatch loss caused by wire length inconsistency is about 0.2% of the total yield.

3) Bifacial modules also withstand the mismatch loss caused by non-uniform incident illumination on the backside. When a PV module is installed on the bracket, there would be height difference inside the module, and the radiation intensity received by the module on the backside varies with different positions.

Figure 6 shows the measured irradiation on the front side of a PV module and the measured irradiance at different heights on the backside (Golmud, yellow sand background, fixed rack with tilt of 36 degrees, minimum height above ground: 50 cm, and rear irradiation normalised by the front value). It can be found that the radiation received at different heights on the backside of the module is different, which results in mismatch. According to the test data shown in Figure 6, RMS caused by the heights difference on the backside

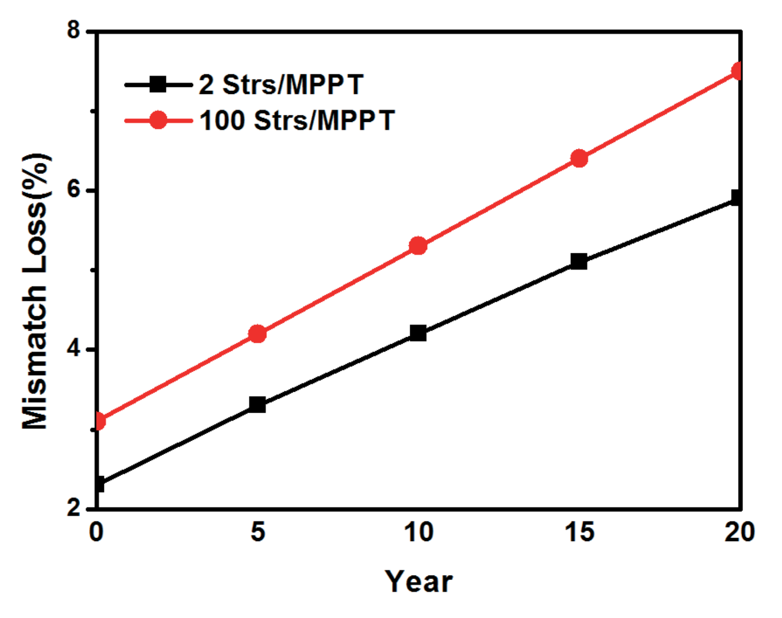


Figure 7. Mismatch loss evaluated by Monte Carlo method, with different densities of MPPTs

increases by about 3%. Combined by the RMS of the module itself, the current dispersion rate of the PV module is 5%. Even if the voltage dispersion rate of the bifacial PV module is consistent with that of the common PV module, the yield loss caused by the voltage and current mismatch is much larger than that of the common PV module. In addition, it should be mentioned here that this mismatch is existing mainly inside the bifacial module, so it is not so effective to eliminate the mismatch when optimisers are applied.

One of the most effective methods to reduce mismatch for PV plants is higher inverter MPPT density. For the bifacial module with a heavier mismatch, this is more effective. Since there are few methods to measure the mismatch, the mismatch loss under different MPPT density is calculated using the Monte Carlo statistical simulation, as shown in Figure 7 (boundary condition: current dispersion rate 5%, voltage dispersion rate 1.5%, annual RMS increase 0.1%, first-year power degradation 2%, and degradation every year after the first year 0.5% during the entire lifetime).

It can be seen that at the beginning, the gap of mismatch loss between two strings per MPPT and 100 strings per MPPT is about 0.8%. It indicates that compared to 100 strings per MPPT, two strings per MPPT will lead the yield by 0.8% in the first year.

Due to non-uniform degradation of modules over the years, the mismatch loss increases over time and the gap is simultaneously increasing. When viewing the entire lifetime mismatch loss, it can also be found that the weighted average mismatch loss over 20 years is up to 4.9% for 100 strings per MPPT solution, while only 3.8% for two strings per MPPT solution. This indicates that for a bifacial system, two strings per MPPT will lead to 1.1% more yield and the plant needs more MPPTs to guarantee the maximal output of bifacial modules [8-10].

Therefore, to exploit the energy yield of a bifacial module system as much as possible, a better choice is employing more MPPTs, which can effectively minimise the mismatch caused by bifacial modules and help fully realise the value of the bifacial modules.

Conclusions

To conclude, the performance of bifacial modules in the Middle East has been investigated. It is revealed that bifacial modules can improve the yield of 14.6% in a typical Middle East area, compared to conventional poly-Si modules. More importantly, the system design for bifacial modules requires greater effort for an optimal performance. On the DC side, greater height and smaller GCR are helpful for increasing yield, while on the AC side, solutions with more MPPTs should be adopted since bifacial systems have a higher mismatch. Based on this analysis, we believe a promising future of bifacial system in Middle East.

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Project briefing

BUILDING BENBAN: INSIDE EGYPT'S 1.6GW SOLAR PARK

Project name: Infinity 50
Location: Aswan, Egypt
Project size: 64.1MWp

Credit: ib vogt

Amid reports of logistical and bureaucratic difficulties, Germany's IB Vogt earlier this year became the first company to complete and energise one of the multiple projects that will eventually make up Benban, Egypt's gargantuan solar park in the western desert governorate of Aswan.

The contract to build the 64MWp Infinity 50 project was awarded to ib vogt under the first round of Egypt's feed-in tariff programme, which offered a relatively generous 14.34c per kilowatt hour. The company endured searing desert heat, sandstorms and water shortages to bring the project to fruition, in the end taking a little over a year between starting on site to commissioning in February 2018.

Tough going

Goncalo Aleixo, who oversaw the project's execution, describes how by being at the forefront of the first wave of large-scale solar development Egypt had ever seen, ib vogt and its joint-venture partner had to work from the bottom upwards, putting in place everything needed to make the project work from scratch.

"By developing the first project in Benban, we were the pioneers, with our local partner Infinity Solar, to develop a solar market in Egypt," Aleixo says. "We had to work with the Egyptian authorities to create new procedures in, for example, logistics, also for coding the equipment that the power plants require at customs. We worked together with Egyptian authorities on the necessary documentation we would need to create in order to have all the projects at the Benban site bankable for international lenders and international legal due diligence assessments."

Added to this, adds Joachiam Altpeter, ib vogt's executive director for the Middle East and North Africa, were the realities of executing a large and complex project in the extreme environment of the Egyptian desert. "They were really rough conditions," he says. "In the summertime we have temperatures up to 50 degrees and no shade. So it's unbelievable what people are doing under these harsh conditions. We actually had to start with construction in the morning at 4 o'clock and end around noon because it was getting too hot. We had to organise around Ramadan because this was also a challenge for four weeks, to obey the religious laws there. This was new to our company and also the Egyptians because they'd never built such large power plants in the middle of the desert. We had something like 1,000 people working on the construction side. And these all had to be managed."

"We actually had to start with construction in the morning at 4 o'clock and end around noon because it was getting too hot"

Developer collaboration

Of course, IB Vogt has not been alone in facing the range of challenges thrown up by the project; the developers working on Benban's other projects have it seems found the going similarly demanding, to the extent that earlier this year it emerged that they had formed a joint body – the Benban Solar Developers Association – to represent their collective interests to the various relevant Egyptian authorities.

"This organisation is to represent all the developers constructing projects in Benban," explains Aleixo. "It aims to have a common message between all the developers, Egyptian authorities and lenders. This is crucial because we have 25 projects all with different timeframes of construction…so the association aligns all the developers for the benefit and success of the full Benban complex. It was a necessity that developers had to create this. It took some time to set up this organisation, but now it is in place and we are seeing the benefits."

The main benefit, says Aleixo, is that any communication from the association carries the full weight of the collective group of developers, helping galvanise a speedier response: "For example in case an Egyptian authority receives 25 different opinions about one specific topic, they would challenge some developers and just not react or take more time to react. And in the construction of an infrastructure like solar, time is the essence of the project."

One area in which the association has so far proved beneficial is traffic management, having worked with the facility management company to optimise the site traffic plan and ensure the necessary transportation to carry workers from several local villages to the site.

As the first developer to complete a project at Benban, ib vogt has found itself in the position of being an unofficial mentor to developers building projects in the second round. "We need to learn with each other, especially we need to share knowledge and

By Ben Willis

Credit: ib vogt

we are happy to do so from our experience in round one. For round two the projects are financed by a few banks, which means there is a portfolio that is designed with the same counterparties, so in a way we exchange this information for the benefit of all projects."

Equipment choices

Clearly, given the harsh conditions at the Benban site, equipment had to be carefully chosen – modules able to withstand dust and day and night-time temperature fluctuations and inverters able stay cool even when ambient temperatures are hitting 50 degrees Celsius being two obvious examples. This required substantial quality control through monitoring of production facilities and testing of equipment.

But even then, says Aleixo, since Infinity 50 went into operation, unexpected situations have arisen. For example, a higher than projected instance of heavy sandstorms meant the dry cleaning system used on the project was wearing out its brushes faster than anticipated.

"Due to the occurrence of more sand storms than expected in 2018, we had to adapt our cleaning methodology. We ended up not having enough brushes on site, the spares were held in the customs due to non availability of all shipping documentation, which consequently didn't allow us to reduce the soiling losses for several weeks. The cleaning technology is very good, but the point is that you can never predict accurately beforehand the site conditions you will have. You can only plan… You need to construct and operate such a machine to understand exactly how it will react with such natural conditions," Aleixo says.

Credit: ib vogt

The benefit of experience

Building and operating Benban's first project has clearly been challenging experience but one that will ultimately provide ib vogt with a huge amount of knowhow to draw on as it moves on to fresh challenges. The company is working on three further separate plants in Benban under the second round of Egypt's FiT programme – the 64.1MW Phoenix 50, the 64.3MW BSEP 50 and the 38MWp MMID 30 projects. All are under construction and slated to begin commercial operation in the first quarter of 2019.

And beyond Benban, Altpeter says the company is on the hunt for further opportunities in the MENA region and beyond, more of which are emerging as solar becomes still more competitive with fossil fuels.

"We're very active in the region, we're constantly looking for new opportunities," he says. "Solar energy is becoming more competitive, it can be deployed quickly and costs keep falling, especially in the MENA region where we have a lot of sun, and it makes sense from an ecological and also economic perspective. So we're currently looking very intensively at Morocco, Algeria, Tunisia and Saudi Arabia. Also West Africa is in our focus for utlity-scale PV projects."

Aside from utility-scale projects, Altpeter foresees a growing role in these emerging markets for commercial and industrial solar projects to provide power to industry and agriculture in the face of rising electricity prices and falling subsidies for fossil fuels: "We are already competitive with a lot of energy sources, and I think it will be a booming industry for these countries, especially as we are not only delivering energy, we're also delivering jobs for the locals. That's very important." ■

Advances in self-cleaning PV module technologies – a review

Module performance | Technologies purporting to alleviate performance losses in PV modules due to soiling from dust and other airborne particles are becoming more widely available. But do they work? Elisabeth Klimm and Karl-Anders Weiß of Fraunhofer ISE investigate

Soiling impact on PV module performance

A reduction of light transmission through the glazing of a PV module by solid airborne particles settling and forming a layer, can cause up to an 80% performance loss within four months [1] if relevant climatic effects, e.g. dry surrounding with wind, humidity and salt, are combined in a negative way at one position (Figure 1). In addition, it has been shown that soiling layers can also support additional degradation such as corrosion or potential-induced degradation (PID) of sensitive module types [2].

The soiling effect and its severity are extremely location dependent and can differ even within some 100 metres or some kilometres. Some general terms relevant for the soiling phenomena are deposition, accumulation, soiling loss, soiling ratio and soiling rate. *Deposition* describes the amount of sedimentation onto a surface in a time and *accumulation* describes the sediment that remains at a surface. Figure 2 shows the processes of dust uptake, transport and deposition. The three mechanisms by which the particles are deposited are I) random Brownian movement II) turbulent deposition or inertia and III) sedimentation by gravitational forces. The random Brownian movement is induced by the constant interaction of dust particles with the surrounding molecules of the air thus also being the predominant deposition mechanism for small particles of <1µm in diameter [3]. Turbulent deposition occurs when the particle has enough energy to trespass into the laminar boundary layer. The deposition of larger particles (>100 µm) is forced by sedimentation. After deposition, particles may adhere to the surface and accumulate as an effect of the following adhesion forces acting on the particle I) Van der Waals II) capillary forces and III) electrostatic forces. The capillary forces become only of importance when water molecules in significant amount disconnect the dust particle from the solar glass surface. Until then the short range Van der Waals and electrostatic forces are the dominant forces for the particle-surface interaction [4].

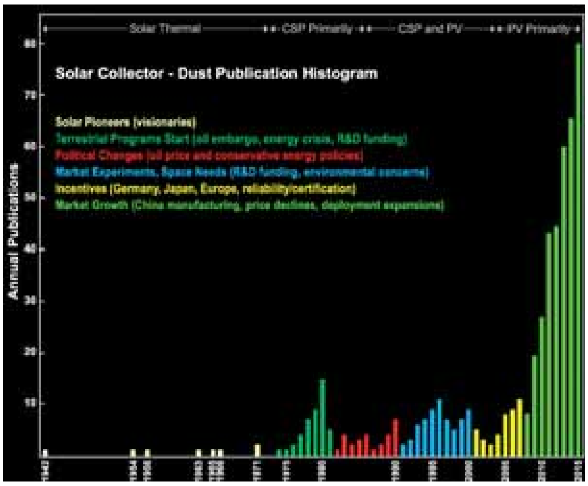


Figure 3. Overview of soiling studies [7]

Other important terms are the *soiling loss*, which describes the yield loss of PV modules due to particle accumulation. Again, this is location dependent and can account for 0 up to 2% per day [5]. Kipp & Zonen B.V. reported on power losses within one week of >10%. The last terms to be defined are the *soiling ratio*, which is the measured ratio of dirty to clean at a given point, and the *soiling rate*, which describes the average soiling loss per unit period of time. Research of the soiling phenomenon also requires the understanding of the dust sources, transport and sinks.

Although the topic has been getting lots of attention during recent years by the remarkable number of researchers active in this field (see Figure 3), further research has to be carried out, taking into account site-specific impacts and multiple variables in order to provide suitable mitigation approaches.

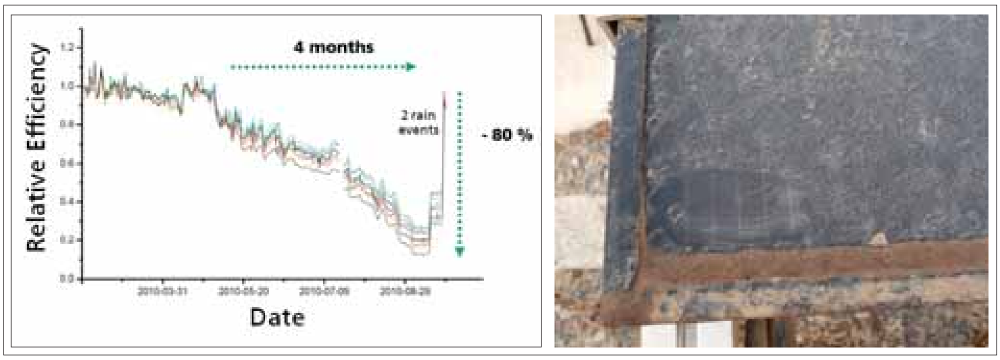


Figure 1. Efficiency loss of 80 % within four months after outdoor exposure of test modules at the ITC test site in Gran Canaria, Spain

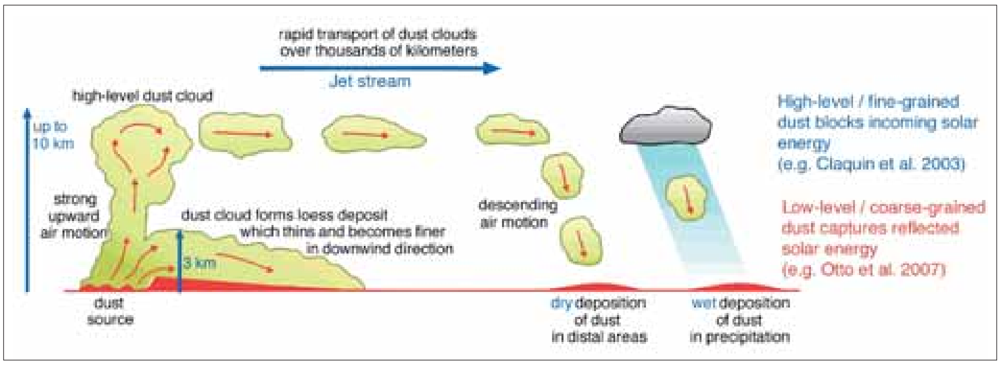


Figure 2. Schematic diagram showing different dust transport mechanisms in the high and low level atmosphere (Stuut and Prins, 2014, redrawn from Pye and Zhou, 1989)

Soiling effects

Degradation of PV power plants is mainly induced extrinsically by exposure to local atmospheric and climatic conditions. This situation is of special severity in arid zones due to the usually high irradiance, big temperature cycles and high peak temperatures. In addition one major location-dependent factor reducing the efficiency of PV power plants is soiling. Soiling is defined as the deposition and accumulation of contaminants in general particulate matter on surfaces, in arid zones mainly mineral dust (< 63 µm) and sand grains, of the PV modules [6]. The relationship between the loss of efficiency and soiling depends on the characteristics of the dust particles and the dust layer on top of the module surface. The physical and chemical characteristics include the particle size distribution, the particle shape, the chemical composition, the particle-surface interaction and the soiling rate itself. These factors are influenced by the climate and location around the power plant, but also by the installation itself – for example, tilt angle – and can be altered by the exposed PV module surface, (Fig. 4)

A correlation of the soiling layer mass and the transmittance loss, which is dependent on the type of dust, is found [7]. It varies with the location because different types of dust have different effects on the transmittance loss (Graph 1), what we call the soiling effectivity of dust. Finer dust particles induce larger losses because of the higher layer density with larger effective superficial area. The particle shape, colour and chemical composition also influence the light absorption or scattering at the surface. In certain conditions the soiling mass even relates in a linear way with the power loss of the PV modules. For the soiling layer in dry conditions sigmoidal growth up to a certain threshold has also been found experimentally, whereas a layer under humid conditions can grow thicker and more packed, lowering the transmittance further.

The soiling phenomenon is governed by the interaction of several forces – gravity force, drag force and adhesion forces – where drag and adhesion forces determine the total amount of initial dust deposition. Hence the characteristics of the soiling effect and the effort to clean the surface are set by dry deposition and ambient conditions and also influence the plant specific levelised costs of electricity (LCOE) significantly.

In the last decade, PV module prices have fallen from about €2.7/WP to about €0.6/WP, and accordingly, the global PV market has grown significantly. In 2016, the increase was over 30% and cumulatively one third of a terawatt of PV capacity was installed globally by the end of 2016. PV is booming and will continue to grow rapidly [8]. Just recently it was announced that the Kingdom of Saudi Arabia will install 41GWP of solar systems in the next 20 years. There are more renewable energy projects in the Gulf states at the planning and installation stages, such as Kuwait's Shagaya Multi-Renewable Energy Park Project with 10MWP PV or Dubai's Clean Energy Initiative with 4GWP of PV, and the "Shams Dubai" Programme being the largest solar project in Middle East, planning to install solar PV on every rooftop by 2030. The Middle East and North Africa (MENA) region has high solar potential and the spatial capability, but the extreme climate conditions make it difficult to adapt the technology. Soiling research is of interest for all solar technologies targeting dry and arid, sunny regions with the key themes on: I) performance with harsh soiling II) dust and adhesion mechanism III) standards and coatings IV) soiling loss measurements and predictive modelling and V) cleaning and robots and O&M in general.

Adapting solar technology to dry and hot desert climates is a key factor, since the location of a solar system plays a significant role in the reliability and soiling mitigation. Often sites with high solar radiation are characterised by low humidity and rare rain events [9] as well as the influence of sand and sandstorms. Studies tend to compare soiling losses from different climates, especially tropical versus arid regions, despite the fact that in different climates, different soiling mechanisms are present and different mitigation measures are most likely to be taken. Green solar surfaces caused by biological soiling films, combined with biomass and black carbon, are found in tropical areas with rural or

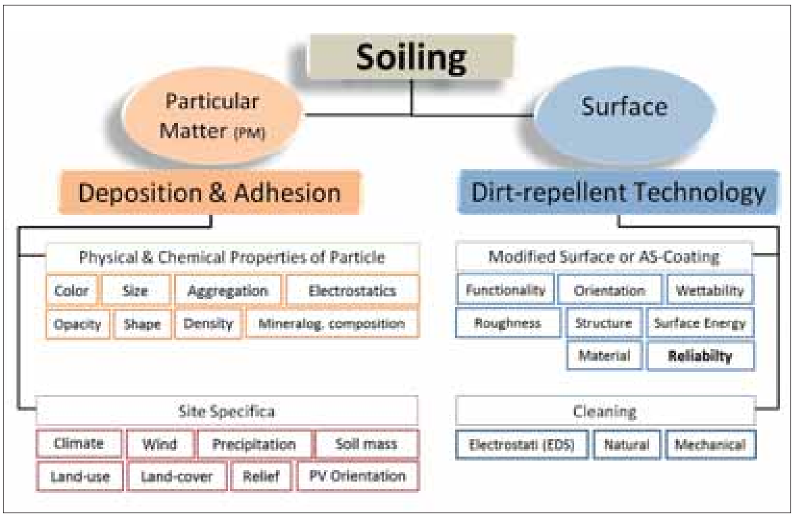
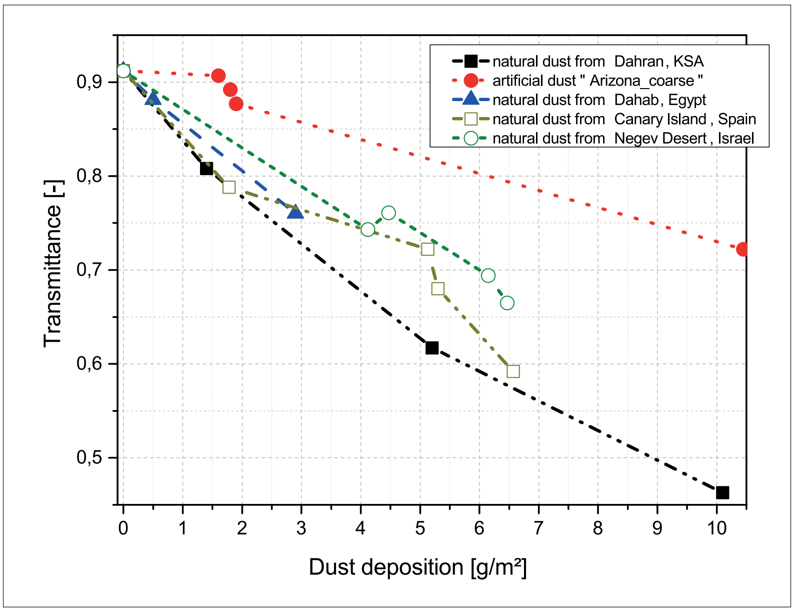


Figure 4. Factors influencing soiling



Graph 1. Correlation of soiling layer mass and transmittance, in dependency of dust type, Klimm et al., 2015, Proceedings of IEEE 42th PV SC

urban land use. Whereas in dry regions, with an arid climate or arid with maritime conditions, the deposition consists mainly of mineral dust, possibly combined with salts.

In scientific publications case studies describe the soiling loss in % per day only within the own climatic conditions, e.g. tropical climate. A summary of eight recent cases of solar systems in tropical climates gives an average loss of 0.39% per day; but also up to 1% loss per day. Meanwhile, 31 recent case studies on solar systems in arid climates show an average loss of 0.46% per day and up to 1.1% per day. Both climates are of course more affected by soiling than regions with a moderate climate. Not many publications have focused on the yield loss by surface coverage from snow and ice in the cold climate so far. There are many studies on soiling effects presented currently, but few can be compared in detail because of different boundary conditions. Since factors such as precipitation intensity and wind speed vary with the change of seasons, soiling-related power loss is inhomogeneous within one year. In general, the performance degradation is higher during the dry seasons (e.g. dry summer in the MENA region) and consequently lower during the wet or rainy seasons (arid and tropic climate).

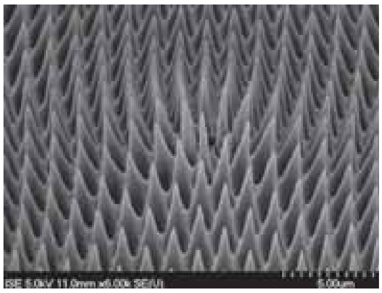
Self-cleaning methods and technologies for PV panels

Soiling mitigation or anti-soiling methods exist to reduce the impact of deposited dust and cementation, the worst case of soiling. Basically there are two distinct concepts for the dust resistant glazing: self-cleaning surfaces and active cleaning by electric fields, Fig. 5, [10].

To clarify, there are no known surfaces and coatings to completely prevent dust deposition or adhesion. So-called "self-cleaning" coatings are available to help the natural processes without the use of external water, brushes or power to remove soil particles, but do not yet do the cleaning on their own. This means that "self-cleaning" is usually a marketing term but not a reality (yet). To help these self-cleaners there are some R&D approaches to cleaning, including the heating of PV modules or cooling the PV modules to prevent or induce dew formation. Dew has been shown to accelerate or worsen soiling (cementation) and makes cleaning more difficult, but can also aid cleaning depending on the amount of dew and properties of the dust particles. Now artificially inducing dew and making it work will require energy, which reduces the "self-cleaning" capabilities of the coatings and also their economic and ecologic attractiveness. Meanwhile water, in terms of stronger natural rain or active cleaning with water and brushes, has also been shown to wash off the soiling layer. Wind has also shown to clean the modules, if strong enough, so that the aerodynamic force and dynamic torque of the wind exceed the adhesion forces to the surface and detach the particle from the surface [11].On other hand dew, water and wind are loads for the functional dirt-repellent coating, which can stress it in terms of corrosion and abrasion.

In general, mitigation and cleaning techniques are targeted in a passive or active way. The active cleaning methods can be supported by passive functional "self-cleaning" surfaces, received i.e. by surface modification, by varying the structures or the surface energy. To help remove the soiling layer functional coatings may be applied. The basic principle of these "anti-soiling" (AS) coatings is to lower or increase the surface energy of the solar glass by applying hydrophilic or hydrophobic structures, Fig. 5. Superhydrophobic structures are known from the "lotus effect" based on nano-structures preventing the wetting of surfaces. Water will form droplets on the surface, which pick up dust when they roll down an inclined module. Furthermore, the contact area of the water but also of the dust particles is minimised if the surface patterning is below the mean dust particle size. Thereby, adhesion of the particles is decreased. Hydrophobic surfaces can be achieved either by chemical modification to minimise surface energy or by the use of micro- or nano-structures. Moreover, these structured surfaces act as an anti-reflection cover and thus enhance the light transmission of the module glazing. However, in this application abrasion resistance as well as optical properties of this texture have to be considered.

Figure 6. SEM Image of a super-hydrophobic surface [15]



Hydrophilic coatings, meanwhile, have been successfully used for decades in self-cleaning architectural glass. Superhydrohilic coatings ensure an excellent wetting and contaminants can be easily rinsed off. However, also in the absence of rain a self-cleaning effect was reported. Hydrophobic coatings are mainly made of inorganic TiOx or SiOx and hydrophillic coatings are mainly made of silicones or fluoropolymers. TiOx has an additional advantage of being photocatalytic, using the incident light to decompose organics, but on the other side decreases the overall transmittance of the solar glazing. Newer developments include a combination of hydrophilic and hydrophobic structures, promising advantages of both technologies. Of course the other properties such as good adherence to the substrate, easy and cost-efficient application, high transparency in the relevant range of solar glass (≥92% transmittance) as well as long-term stability against UV and other environmental degradation factors, as well as abrasion due to sand and cleaning, are to be considered.

Another interesting technology development, albeit one not yet proven on full-sized PV modules, is the so-called electrodynamic screen (EDS), which cleans the solar panel with electrostatic forces. This active, energy-consuming, mitigation technique removes the soiling particle by using the charge of particles. Parallel electrode embedded in the substrate – i.e. solar glass, in the case of modules – can move soiling particles towards the edge of the PV module [12]. It can also support the natural cleaning because once the particles come loose and start hopping, air drag will enhance the cleaning effect. Challenges are right now the transmittance loss due to the electrodes themselves and the design of the parallel electrodes. A fundamental requirement for the electrodes spacing derives from the particle size. Efficient cleaning has been shown for particles

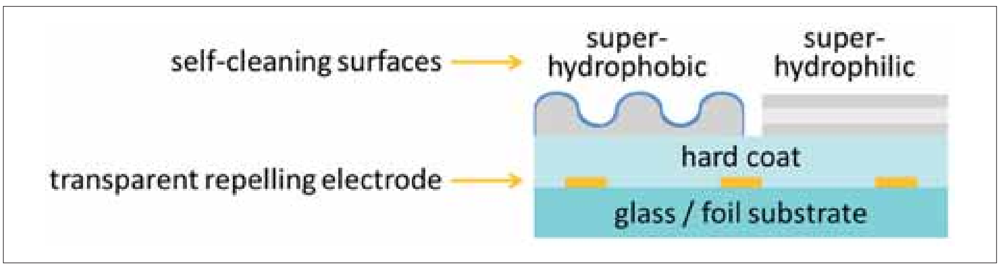


Figure 5. Schematic drawing of the two concepts for dust-resistant glazing with a dust-repelling electrode and the self-cleaning top layers

diameters in the range of the electrode spacing. For larger dust particle diameters, the accelerating force drops rapidly. Therefore, the electrode spacing should be chosen wisely to encompass the major part of the dust particle distribution. From existing literature, the maximum size of dust particles found in desert regions is typically between 50-200 µm [Sarv13]. The exact electrode spacing has to be adjusted according to the selected PV module exposure site. The ambient humidity is not to be neglected, because humid air can short-circuit the electrodes faster and increase the adhesion of particles.

Following crucial issues are that existing EDS require high voltages (up to 1-3 kV and higher) [Sarv13], which might have a negative impact on the stability of the PV module materials. Required high voltage generators and cabling drive up the system cost in the field.

In short: there are different approaches to reduce the effort to keep PV modules clean but none of them can really be called "self-cleaning" and many of them have issues with reliability up to now. Approaches are to combine passive methods with active soiling mitigation technologies, such as different cleaning technologies, for example low-water-consuming robots or dry cleaning equipment. Still unclear is the effect of abrasion, especially with tightly attached soiling coverage. It is expected that for the cleaning process of concentrated collector surfaces, which are basically also glass surfaces and so comparable to PV modules, a reduction of 25% of the previous water consumption seems achievable [12]. For the abrasion issues due to cleaning, there are approaches to design and standardise abrasion tests to benchmark and qualify the functional surfaces, for example with linear or a rotary abrasion tests. In terms of design, the tests are derived from a miniaturised car wash test standard. Of course the geometries, contact force or the force of the brush against the sample are to be specified and validated. But so far there are no scientifically validated abrasion testers. Working with dry dust simulates the worst case and in the MENA region, as representative for locations with water shortage, no or little water is used for cleaning, but the PV modules may be cleaned up to every day. Complementary methodologies for cost reduction are also under investigation, such as the reuse and treatment of cleaning water for reduction of water consumption and the improvement of monitoring in the solar fields by soiling sensors or mathematical tools to optimise cleaning cycles.

Qualification of coatings and reliability testing

The materials and surface functionality have to be qualified with real dust with a reliable and meaningful soiling tool and reproducible results. Until now, and out of lack of a standardised and meaningful artificial dust, many researchers use the artificial Arizona test dust (fine or coarse) for soiling simulation. Its use is also given in different standards e.g. in the standard for blowing dust tests for testing electronics under operation, e.g. according to MIL-STD-810G 510.5. In principle the Arizona test dust is specially designed as finer fractioned dust to identify small gaps in electronics packaging and their resistance against fine particle ingress, which can be tracked easily because of the red dust colour and the extreme stickiness, but it is not designed to measure soiling mitigation measures! Tests show that these tests with standardised dust do not correlate with one of the "real soil" samples we used so all the tests done on coatings are meaningless for specific plant sites if the soil is not comparable with the soil used for the tests. The test should include the physical and chemical properties of the different dust types and as well consider the different prevalent climate conditions affecting the adherence of dust to the surface. One important condition could be condensation on the PV module surface occurring during the morning hours when the modules faces and adapts to the clear night sky temperatures while the ambient relative humidity increases up to 90%.

To qualify the surface and particle analytically there are various possibilities. The surface roughness and structures can e.g. be measured in a high resolution nm-range with an atomic force microscope. For a full physical and chemical characterization of the dust are different methods suitable. Microscopic analysis methods are used to determine the particle shape – for example, by scanning electron microscope or with optical microscopy or laser scanning microscope. The latter can also be used to define particle size distribution, which also can be checked with a laser diffraction particle size analyser. The chemical composition can be investigated by applying energy-dispersive X-ray spectroscopy (EDS) just to mention some analytic possibilities. For the reliability tests, climatic chambers are available to qualify the surfaces for long-term stability of their functionality. Limits in reliability can be found with damp-heat testing with 85°C and 85% relative humidity (r.h.) for some hundreds of hours or even more harsh the humidity freeze test with cycling between minus 40°C to plus 80°C and 85% r.h. At some locations temperatures in the minus range are possible to occur even in the desert, e.g. the Atacama Desert in Chile. Moisture between nanostructures or in porous surfaces is found to be delicate in combination with freezing temperatures and harsh on the functionality. Accelerated ageing tests in general have to be carefully chosen to deliver meaningful results. The test design has to include the sensitivities of materials, such as UV for organic coatings for example, as well as location-specific conditions such as salty atmosphere or specific – for example, abrasive – properties of the dust itself.

Effects of mitigation technologies on module performance

Our opinion on the various approaches described is that the additional cost of coatings or EDS must pay off and the technology should be well chosen to fit to the environmental conditions with regard to functionality and reliability. In order to maintain the reliability of such methods and technologies in the most harsh environments, mainly dry deserts with high UV irradiation and little rain, knowledge about the prevalent soil, humidity and dew points should be taken into account. Mapping and global soiling models are not yet sufficient for PV power plant planning due to difference of conditions even within some kilometres. There are interesting approaches with soiling monitoring by sensors (e.g. by Moroni&Partners, UKC DDSolar, Atonometrics, Campbell or Kipp&Zonen), which are supposed to support optimised O&M of PV power plants and enable calculation models to define cleaning cycles. Since the deposition of soil as well as snow on PV modules is mainly non-uniform because of local conditions such as wind and sun and humidity/rains, spatial soiling rates have to be analysed for a well-considered selection of soiling mitigation approaches. A local variability in PV soiling rates is proven.

Right now there is a large community within the PV Quality Assurance Task Force (PV QAT) Task Group 12 with four subgroups analysing and exchanging information on TG 12-1 sensors and monitoring of soiling, TG 12-2 on solutions for cleaning, TG 12-3 antireflective and/or

WFES SOLAR 2019 – Your Gateway to over 76 GW of Solar Projects in the Middle East

WFES Solar is the largest marketplace in the MENA region for solar stakeholders, mandated to facilitate the development of solar energy projects by uniting investors, developers, regulators and innovators under one roof. Held as part of the World Future Energy Summit (WFES) in Abu Dhabi from January 14th – 17th, WFES Solar is a great platform that connects the largest producers of solar innovation with one of the fastest growing markets in the world.

The four day event will feature forums, workshops, an innovation showcase, expo and thought leadership debates that aim to help the Middle East and North Africa (MENA) region achieve energy independence. Solar power is changing how the world generates, stores and uses energy.

According to MESIA's annual solar outlook report, 2018 is expected to be a massive year for solar transition in the MENA region with over 11.86 GW of photovoltaic solar projects in the pipeline and a projected target of 76 GW by 2020. In addition to the large scale solar projects, there has been a steady growth in the commercial and industrial rooftop projects across the region with Saudi Arabia and UAE expected to take the lead.

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. WFES Solar 2019 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.

WFES, part of Abu Dhabi Sustainability Week and hosted by Masdar, is the world's largest sustainability gathering that will explore new ideas, exponential technological innovations, infrastructure challenges, industry insights and digital platforms driving the future of sustainability. WFES is a great platform for businesses to forge new partnerships, to build successful relationships and help solve global sustainability challenges within the energy, solar, water, mobility and eco-waste sectors. For more information, visit **www.wfes.ae**.

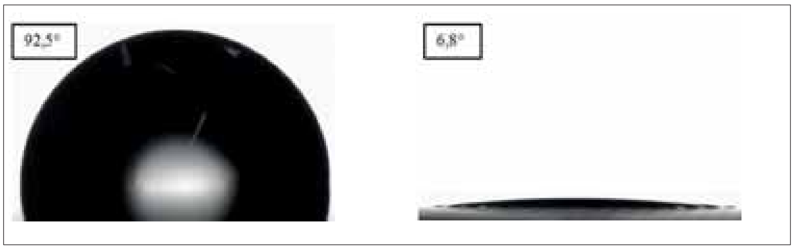


Figure 7. Results of an actual drop contour analysis and the according water contact angle with (left) water droplet on hydrophobic solar glass surface and (right) water layer on hydrophilic solar glass surface [13]

anti-soiling coatings and the TG 12-4 on modelling/analysis of the effects of soiling on PV systems.

Adoption of self-cleaning technologies by the PV industry and future trends

Actual AS hybrid surfaces show an improved cleaning efficiency, but are not self-cleaning and not yet proven to be reliable in the long term. Soiling mechanisms are in our view not yet or never to be standardised, due to the dominating influence of very local conditions and variability even within one PV power plant. In addition soiling affects different PV technologies differently, since soiling induces higher attenuation at shorter wavelengths and a red-shift of the spectral irradiance reaching the active semiconductor.

Newest research insights

In 2018, work at Fraunhofer ISE has been investigating the effect of soiling on the performance of solar systems and evaluating hydrophobic and hydrophilic anti-soiling coatings on solar glass, Fig. 7.

An experimental investigation of the functionality of anti-soiling coatings has been performed, characterising several coated and non-coated glass samples through contact angle measurement and artificial dust deposition. Based on the measurement results, a selection of promising samples has been made for further investigation. The transmittance was measured via FT-IR-spectroscopy before and after soiling the surfaces with artificial test dust. With the goal to develop and optimise a method of quantifying the soiling losses, the soiled glass samples and a clean reference sample were mounted on single-cell PV-modules in the roof top test field in Freiburg, Germany, (Fig. 8) and the modules' power output and backside temperature were constantly monitored. The photovoltaic current is directly related to the transmittance and therefore is used as a sensor to determine transmittance losses. This sensor set up showed satisfying results on the soiling loss and soiling ratio calculations. During the exposure time, several rain events occurred; proving previous findings [14] that rain events with little precipitation (<5 mm, in this case 1mm) are negative for the performance, showing a very inhomogeneous soiling layer. A second rain event (7mm) cleaned off most of the applied dust and recovered the yield.

After leaving each glass sample in the test field for several days, the transmittance was measured again, showing that all the glass samples recovered almost to their initial transmittance. In this study, the glass sample with hydrophobic coating showed the best results in transmittance, followed by the sample with hydrophilic coating. The lowest transmittance was presented by the non-coated glass sample, proving the positive effect of the dirt-repellent coatings.

Furthermore, the cost effectiveness has been calculated, with the payback time surpassing the life expectancy not only of the coatings but also of the modules. It must be noted, however, that the estimated coating prices might be decreasing with increasing market availability of the coatings, leading to a shorter payback time then the calculated or by producers given one. It is also worth noting, that the application might be more cost effective in arid regions, with higher maintenance and cleaning as well as larger effect of soiling losses [13].

We do not want to state that the AS coatings are not helpful but one has to be extremely careful when selecting a coating for a specific site with regard to the local soil and the reliability. The coatings have the potential to significantly reduce the cleaning effort when selected well but can even worsen the situation when selected incorrectly. ■

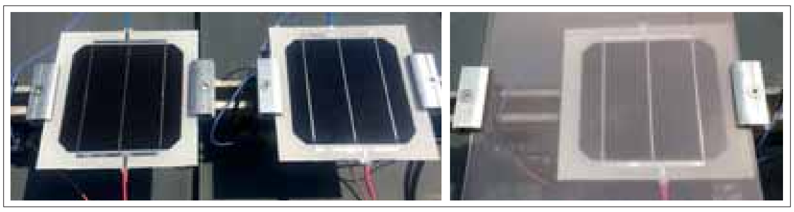


Figure 8. PV mini module as a soiling-sensor with reference module for the investigation of the impact of dust accumulation on PV performance with monitoring of current, backside temperature, solar radiation; on the right the mini module with the artificial soiled anti-soiling coated glass [13]

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Authors

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Karl-Anders Weiß studied physics and economics and holds a PhD in physics from the University of Ulm. He is head of the group "Service Life Analysis" at Fraunhofer ISE and leads various international R&D projects with a focus on material testing and development. His main focus is materials for solar applications, non-destructive testing and environmental loads.

Evolution of pre-cracked PV modules

Module performance | Cell cracks have been identified as a major cause of defects in PV modules, but their effect on performance is less well understood. Researchers Claudia Buerhop-Lutz, Thilo Winkler, Jens Hauch, Christian Camus and Christoph J. Brabec describe the results of ongoing investigations into how the electrical power of PV modules is impacted by cracking

High quality solar cells and modules are essential for an efficient operation and a high energy production over a 20-year lifetime or longer. During recent years there has been a large emphasis on seeking and identifying faulty and underperforming PV modules on site. Cell cracks and cell fractures have been identified as one of the major module defects [1]. The availability of mature electroluminescence (EL) imaging systems has enabled the visualisation of cell cracks and breakages [2] in PV modules. Many research projects around the world have studied the reasons for crack initiation – for example, manufacturing processes, handling, transport or installation. Nowadays, EL imaging can be carried out on site at the PV installation. That is advantageous because handling, demounting, transportation and reinstallation are avoided. Thus, on-site EL imaging directly shows the quality of installed PV modules, e. g. in terms of number of cracked cells. Therefore, it is easy to know or to determine how many modules with cracked cells are present in a solar park, for example before and after a severe storm event or a hailstorm. Consistent documentation allows for the detection of changes and identification of new faults; it states the current situation. However, it is still unknown what the identified faults mean for future performance.

The interesting questions are, firstly, how do these cracked and pre-cracked modules perform, what is the remaining/residual power output, and, secondly, how will these pre-cracked PV modules perform under operating conditions with temperature cycles, wind and snow loads in the future.

In order to study the performance before and after a special event, we designed a special setup [3], so that we could monitor the changes with an EL camera directly and if necessary in real time. In order to sensitise the PV community to the stresses induced in PV modules by mechanical loading, we mimicked the manual cleaning process. This is of importance because locally severe loads occur when persons walk across the modules. For the experiment we used a pre-cracked, polycrystalline PV module (module with existing cracked cells) which was approximately two years in operation. Figure 1 illustrates the change of the EL image of the pre-cracked module before, during and after the manual cleaning process. The left image shows the initial EL image of the module, 10 cells in total have cracks. Of these, five already exhibit open cracks, recognisable by the grey areas. The centre image illustrates the situation when somebody sets foot on the module. The changes are clearly visible (see also [4]). The previously grey cell areas turn black, more cells show open, grey areas, and further cracks are initiated in previously good cells. According to the local stress distribution in the module, mainly cells in the centre fail. After walking across the module, what remains are 19 cracked cells, eight with open cracks (see right image in Figure 1). The resulting electrical performance reveals that the measured power using a sun simulator varied about 1%, which is within the measurement accuracy.

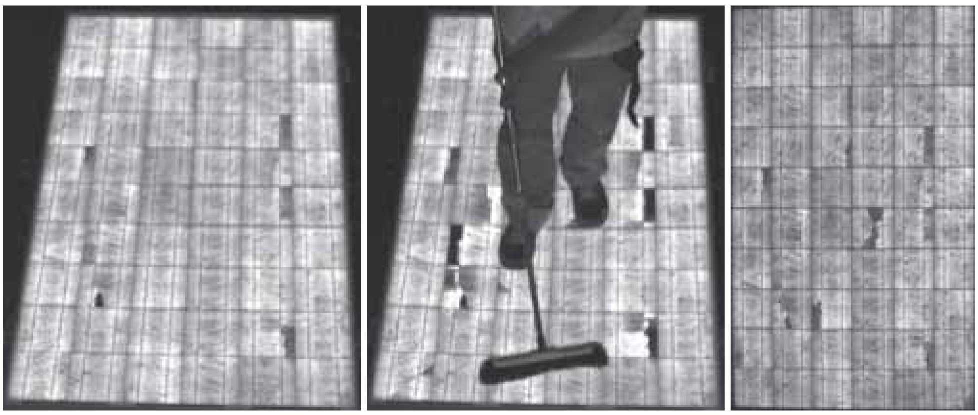

Figure 1. EL-image of pre-cracked PV-module, left: before stepping on the module, middle: while setting foot on the module e.g. for manual cleaning, right: after walking on the module [6]

These results give a first insight into the importance of interpretation of EL images. High loads can cause cracks and fractures which look dramatically deteriorated in the EL-image because of their fairly black appearance. However, unloading the module, the cracks remain but they close. The pattern of cells with grey, fractured cells changes as well as the EL-intensity distribution (dark areas are less dark). Open cracks (recognised by a darker, grey to black cell part) can influence the power output according to their remaining electric contact with the main, current-conducting cell parts. Cells with open cracks can be a risk for power reduction [5]. Closed cracks do not impact the power output. The direct correlation between EL image and module power highlight that a quick, superficial view at an EL image of a module with broken cells shows the mechanical condition of the module, whereas it is not sufficient to deduce the power output.

Mechanical load testing

Answering the question, how this module may perform under real outdoor operating conditions, an accelerated mechanical load test mimicking the weather conditions at a fictitious site of interest was carried out.

A new test facility was designed and built to simulate mechanical loads and give insights into crack initiation and growth in solar cells. The newly developed mechanical load test setup applies uniform homogeneous pressure to the module by applying under-pressure from the backside of the module. The pressure is controlled and varied by gauges. Simultaneously, the IV-curves, respectively the module power at maximum power point, and EL images are recorded. Changes in the crack structures are detected and correlated directly with electrical data [3, 7]. In comparison to standardised tests [8], which consider temperature and humidity cycles, we focus on mechanical loading in order to mimic realistic wind and snow loads during operating.

For the test scenario we consider a fictitious PV system installed in Central Europe with moderate continental climate. The ambient temperature reaches from -20°C in winter up to 35°C in summer. Therefore, the PV modules are exposed to daily temperature differences of up to 65K. Especially on hot summer days and clear nights, high module temperatures in the daytime and fairly low temperatures at nighttime occur. Snow heights of relevant static pressure causing cracks were neglected. However, wind gusts were studied. As a first approach, we analysed the distribution of the maximum daily wind speed over one year. At the fictitious PV site, e. g. in Bavaria in Germany, there were two hurricane events (v > 120km/h), several stormy days (90km/h < v < 120km/h), many windy days (50km/h < v < 90km/h) within the year. On most days the maximum wind speed was more or less a gentle breeze (v = 24km/h). According to the standard DIN 1179, "Eurocode 1: Actions on structures - Part 1-4: General actions - wind loads, 2010", the resulting pressure on the modules was calculated. The wind pressure distribution reveals that up to 90% of the wind loads are less than p = 200Pa (corresponding to v = 56km/h), 5% between 200Pa and 400Pa (corresponding to v = 80km/h), and rarely p = 1,000Pa (corresponding to v = 120km/h), and p = 1,200Pa (corresponding to v = 140km/h). For simplifying the experimental procedure we grouped the identical cycles between same load levels (e. g. 200Pa to 0 Pa, or 1,000Pa to 0 Pa (which simulates the unloaded, normal state)). Low load cycles were carried out much more often within one run than high load cycles. High load runs (Δp > 200Pa) were always followed by a low load run (Δp = 200 Pa). At the end of the cycling test procedure 22,360 cycles or 34 runs were applied to the module (see Figure 3). In more detail, throughout the test procedure almost 20,000 times low load cycles were done, 250 times high load cycles (Δp = 1,000Pa) as well as 10 times very high load cycles (Δp = 1,500 Pa). After each run EL-images as well as power measurements were recorded.

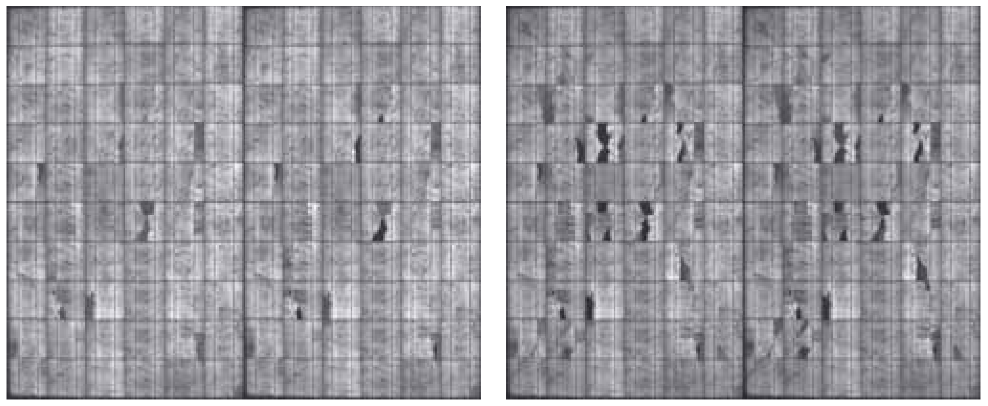

Figure 2. Sequence of EL images of PV module undergoing mechanical loading with an increasing number of cycles and extra heavy loading (p = 5,000Pa) at run 28, from left to right: run 0 (initial stage), run 27 (before heavy loading), run 29 (after heavy loading), run 34 (end of cycle)

Figure 2 shows the EL images of the "manually" cleaned PV module, on which somebody set foot, before and after simulating alternating wind loads in the lab. The images are always recorded at the unloaded state. The test cycle is divided in two phases, first, before high loading with 5,000 Pa, second, after high loading.

Through the first 16,000 cycles (Figure 2, run 27) no significant changes took place, the EL-image shows the same 19 cells with open and closed cracks. Just the intensity distribution modified a little. Surprisingly, cell fragments of broken cells in the centre show a better electrical connection, lighter in the EL image, than at the beginning. Obvious changes due to heavy loading in run 28 are exhibited in the EL image of run 29. The load of 5,000 Pa was so high that 12 previously good cells, especially in the corner and the centre, show new cracks. An increased number of cracked cells with grey to dark cell areas is visible. Throughout the following 6,000 cycles until the end no further obvious changes can be detected in the EL image. The number of cells with open and closed cracks remains constant.

The findings in the EL images are reflected in the power data. The relative power output drops from 99.8% to 99.4% through the first part of the cycle test. The power reduction is rather small since only two cells with extremely black areas are present in the module. They potentially impact the module's electric performance. The other grey-black cell fragments are of minor importance. Then, due to the high loading a power drop of roughly 1% is measured: 31 cells are cracked, 12 cells with pitch-black areas cause the reduction. Continuing the cycling test, the power loss is in the range of 1.1%. No changes in the cell structure are detectable. Thus, a total power reduction of 2.5% results (see Figure 3).

The judgement of experience points out that the performance between moderate, uniform loads on PV modules and exceptional loads differ. There is a creeping power loss between 0.8% and 1.4% for other modules tested with the same procedure except the extra high loading. On the other hand a spontaneous power loss of roughly 1% was measured for extra high loading events. The power does not decrease continuously, as shown in Figure 3. It rather alternates. This may be explained by the quality of the electric contact of the crack faces and respectively the cell fragments. In accordance with the power fluctuation the appearance of the EL image changes. Electrically unconnected cell fragments are black in EL because they do not emit luminescence. The better the fragments are electrically connected, the lighter they appear. During the loading and unloading cycles the fragments might be moved and shifted a little bit. That can have a significant impact on the electric contact and accordingly on the power output. Thus, careful evaluation and comparison of EL images and electrical data of modules with cracked cells is recommended. The rearrangement of cell fragments does not only happen during cycling, it is also is possible during other procedures, e.g. handling, installation or transport.

For relating the cycling test to a time period at real operating conditions, as a first guess, 10 to 20 wind gusts in average per day are estimated. Then, 22,360 cycles equal roughly 3-6 years. A worst case scenario potentially yields 1.4% degradation of pre-cracked PV-modules in three years. Published field studies of the performance of pre-cracked PV modules at real operating conditions present similar data [9, 10]. However, the investigation periods of field exposure are still rather short and the measured power changes over time are within the measurement accuracy for field measured IV-curves.

In summary, the investigated pre-cracked polycrystalline PV modules seem to degrade rather benignly at mimicked wind loads at moderate European climate for the first years. For more reliable long-term conclusions, more scenarios have to be studied for longer periods of time. The appearance of the EL images changes, cracks open and close, the electrical contact of the crack faces varies during the cycling test. New cracks in good cells occur quite rarely at moderate weather conditions. In contrast, high and local loads may cause cell breakage and be a risk for spontaneous power reduction. The power loss of modules with cracked cells is estimated of about 0.5% per year for moderate weather conditions.

In order to deepen the understanding of the degradation and performance of good and pre-cracked modules at real operating conditions, the study will be intensified in the future. The focus will be on testing modules of different technologies, analysing PV sites where the modules are exposed to higher stresses, and studying different failure modes, e. g. hail damage. Cooperation with interested parties is very welcome and essential for further progress.

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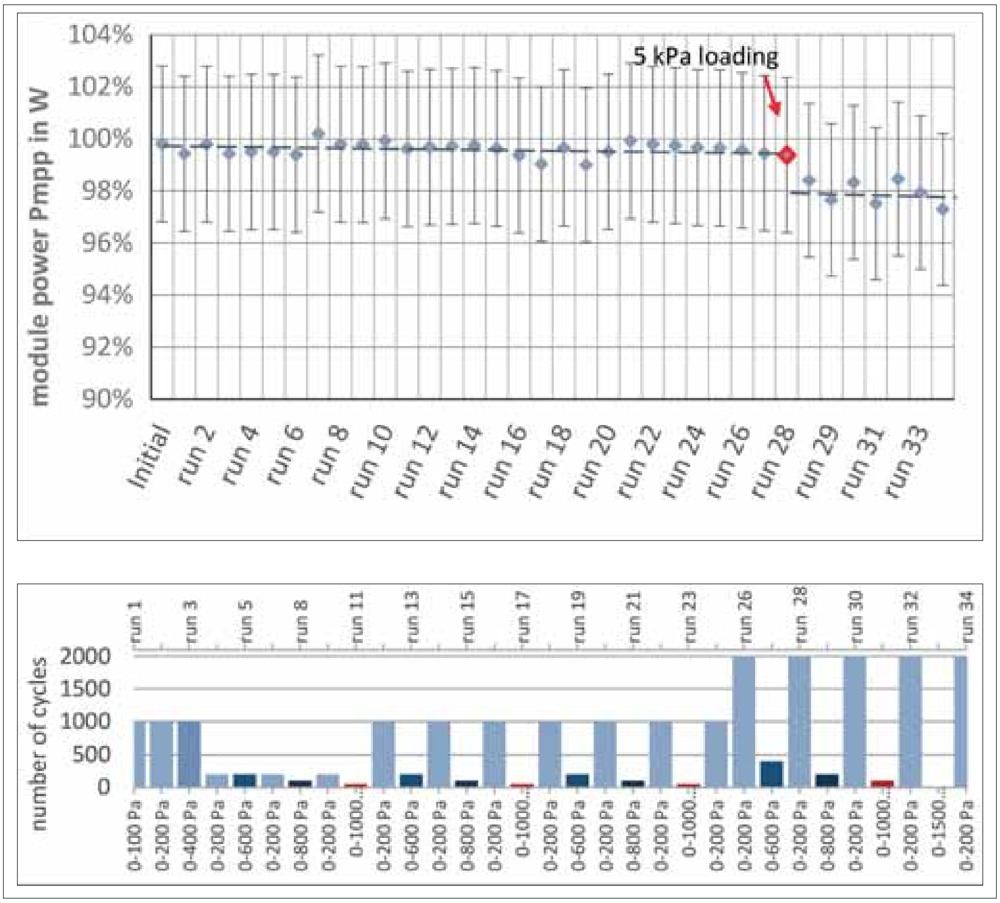

Figure 3: Cycling test, top: measured module power after cycling test with pressure p = 200 Pa simulating wind speeds of v_{wind} = 56 m/s, bottom: cycling procedure of the 34 runs

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Authors

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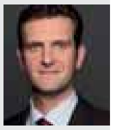

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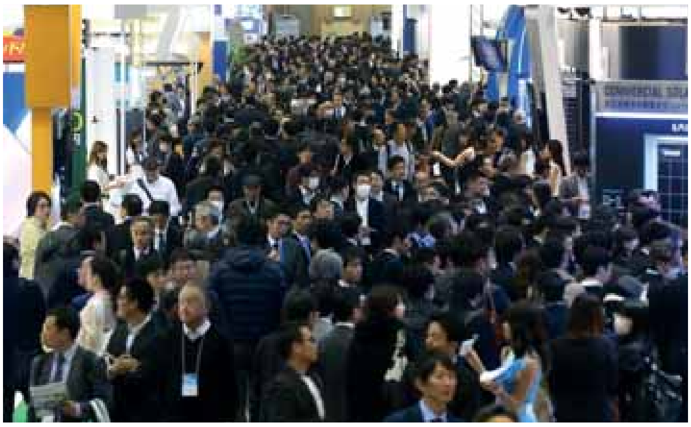
Japan's business continues to look bright at PV EXPO & PV SYSTEM EXPO 2019



Japan's largest PV industry shows, PV EXPO 2019-12th Int'l Photovoltaic Power Generation Expo and PV SYSTEM EXPO 2019-10th Int'l Photovoltaic Power Generation System Expo, will be held from Feb. 27– Mar. 1, 2019 at Tokyo Big Sight, Japan. Organised by Reed Exhibitions Japan, Japan's largest exhibition organiser, the events will cover both upstream and downstream business alongside a Technical Conference. Including concurrent shows, PV EXPO and PV SYSTEM EXPO are expected to attract 400 exhibitors, including 90 newcomers, and 70,000 trade visitors from 75 countries to source the latest PV technologies and products.

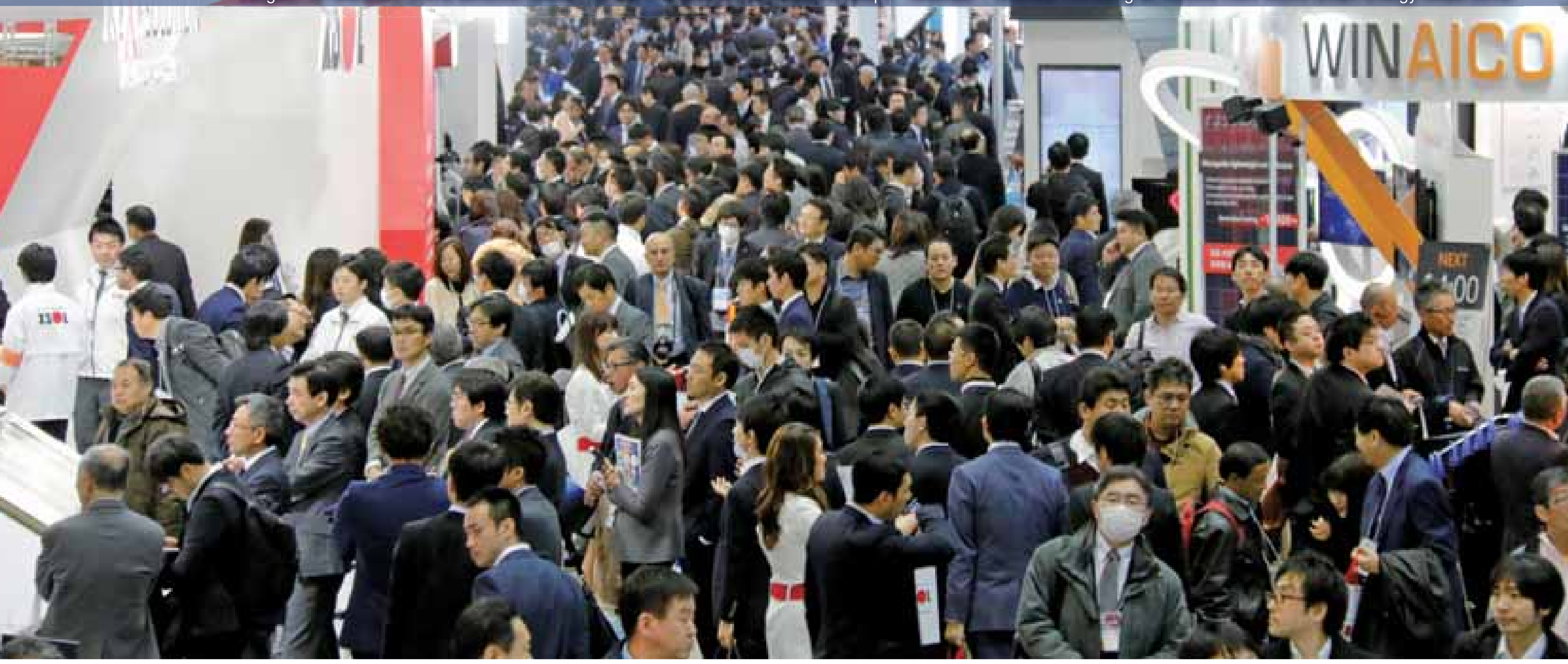
Photovoltaic power generation has become the top priority in Japan since the Great East Japan Earthquake in 2011. Since then, Japan's PV power generation capacity was calculated to be 49GW by 2017, according to the New Energy and Industrial Technology Development Organization (NEDO). The market will maintain its stable growth in 2019 with new opportunities for market players. PV EXPO and PV SYSTEM EXPO 2019 will also play a significant role in the market's new challenges and development with three highlights as follows:

Firstly, maintenance and management of PV power plants has become mandatory in Japan and the market size is predicted to be 1.2 billion USD by 2030. One of the major highlights of PV SYSTEM EXPO 2019 is also O&M and a wide range of related technologies and services will be comprehensively showcased at the event.

Secondly, there is also an industry-wide shift from utility sales to self-consumption of power generation for residential PV systems, as the first batch of residential FIT recipients will see their purchase period under the FIT ending in 2019 and will move into self-consumption of the surplus power. With the new business model, the development of EV and power storage technology is essential, hence cutting-edge technologies and services will be widely exhibited at PV EXPO/PV SYSTEM EXPO 2019, alongside its concurrent shows.

Lastly, most of the major global PV manufacturers, such as Jinko Solar, Trina Solar, Canadian Solar, Hanwha Q CELLS, JA Solar, LONGi Solar, Yingli Green Energy and Panasonic have already confirmed their participation as exhibitors once again this year. These companies will showcase their high quality modules, as well as new services and products for a total solution.

With the continuous development of PV power generation in Japan, PV EXPO and PV SYSTEM EXPO 2019 continues to offer the best platform for sourcing the latest leading-edge technologies and products, catching the trends, and finding new business opportunities for PV professionals from across the world.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Short-term solar forecasting for utility solar sites: core business or distraction?

Forecasting | Solar farm operators are coming under growing pressure to help maintain network stability by providing accurate generation forecasts. As Nick Engerer writes, innovations in short-term forecasting are providing operators with new options for making this task less of a distraction from their core business

Credit: ARENA

As the rate of growth in installed solar capacity accelerates globally, along with it has come a new suite of challenges to integrate the incredible volumes of new capacity into our energy markets and networks. With just shy of 100GW of new solar added in 2017, following on from 75GW in 2016, many energy markets around the world have experienced a breakdown in the long-established processes and methods for forecasting supply and demand, and planning and operating electrical networks. Load forecasting models have begun to stop working. Increasing volatility is being seen in ancillary services markets. Energy market trading strategies are shifting. The long-term business models dependent on wholesale electricity prices are being challenged in new ways. Such are the growing pains of our global transition to depending on the weather conditions to supply our energy needs. However, there is one segment of the solar energy industry that is beginning to bear the responsibility of these consequences in an unexpected way, as often, the response of the local energy market operator or system operator is to pass the responsibility for delivering accurate forecasts to the market or network onto the owners/operators of the solar farm. This is a trend that is just getting started, and likely to expand significantly over the coming decade.

Short-term forecasting is becoming an increasing burden for operators of utility solar farms, such as Australia's Broken Hill

For a solar farm operator, this can be a significant distraction from core business. I've rarely met a solar farm owner, operator, asset manager or O&M provider who wasn't actively managing several projects, in various stages of their life cycle. Prospecting, planning and modelling, completing connection agreements, reaching financial close, commissioning and then the day-to-day operations are not an easy set of tasks to manage. Plus these tasks all tend to arrive at different times across a growing pipeline of projects, then interspersed by unexpected problems. When these teams are required by their local market or system operator to start delivering a forecast for their solar facility, yet another responsibility is added to an already full agenda.

What's more, inaccurate forecasting can often be tied to financial penalties, imposed by the market or system operator, as well as lost revenue and adverse impacts upon the bottom line of the project as a whole. For example, in Australia, solar farm operators are required to pay fees for ancillary services to offset forecasting errors. In India, state distribution companies are now due to enforce penalties for inaccurate forecasts, while in Europe and the United States, forecasting services have been required for a number of years already, and grid operators there are increasingly using constraint or curtailment in lieu of direct financial penalty. The exact forecasting requirements and consequences for solar farm operators vary significantly by region, but one aspect of this transition is clear: as penetrations increase, accurate forecasting becomes more important, particularly at shorter timescales (minutes to hours ahead). This is apparent in the increasing importance of the 15-minute-ahead forecast in India, the 5-minute-ahead forecast in Australia and 5-minute market operating in California, each of which has seen very fast growth in utility scale solar farm sites.

Short-term solar forecasting is fundamentally different from hours-ahead or day-ahead forecasting

At these forecasting horizons (minutes to hours ahead), another challenge appears, this time for the solar forecasting technologies themselves. Over the past decade, day-ahead forecasting for unit commitment and hourly forecasting for load balancing across a given day have been the status quo. And for these purposes, modelling approaches based on numerical weather models and machine learning techniques have been suitable. Weather models, with rather coarse resolutions of tens of kilometers, produce forecast outputs in three-hourly increments (with some models now producing hourly outputs), and generate estimates of moisture content by layer of the atmosphere. These can be tweaked to represent cloud forecasts, and make general estimates of the future solar radiation resource. Machine learning techniques are often applied against actual measured generation from solar facilities or solar radiation measurement sites, to generate regressions to 'fit' them to the weather model data.

However, these approaches are far from suitable for making a short-term prediction of solar farm power output on the timescale of minutes ahead, for one fundamental reason: none of them know where the clouds actually are at any given time. Contrary to popular belief, weather models do not actually model cloud conditions directly, they instead rely on parameterisations and other tricks to handle them at a broad scale. Their purpose is to capture rainfall development and to calculate overall incoming and outgoing radiation balance so as to make a prediction of temperature and relative humidity. They aim to make predictions of the weather that are suitable for a wide variety of purposes, and are not made to track or forecast actual cloud cover features. Furthermore, they update only every 3-6 hours, and rely on outdated cloud data sources or proxies to do so. Even with the best machine learning methods available, if the forecasting approach doesn't actually use knowledge of local cloud cover conditions, it will fail to make accurate short-term forecasts.

Satellite based solar forecasts: better, but not always

This is where satellite based imagery and forecasting can offer significant improvements. Weather satellites are placed in geostationary orbits where they record images of the Earth, which includes the surface and cloud cover. These images update every 10-15 minutes, and are available resolutions as fine as 1km^2, which is exactly the kind of data input short-term solar forecasting methods should be utilising.

Yet, not all satellite-based forecasting services are the same. Just because one can pull in this imagery data does not actually mean they are able to identify clouds or track their motion with precision, let alone model the amount of solar radiation arriving at the Earth's surface or the eventual power output from a solar facility.

Take, for example, making an estimate of the energy generation at a solar farm facility for the current time (no forecasting involved). To do this, there are several important modelling steps in between. Satellite images must be decomposed into cloud versus no-cloud regions. Cloud opacity (its opaqueness to light transmission) must be estimated. The location of the cloud shadow needs to be projected spatially. Appropriate application of solar radiation modelling tools is then required, as well as PV power plant modelling to create the energy generation estimate. This is not an easy set of tasks, which each rely on domain expert knowledge to implement. This type of expertise is hard to come by.

Assuming these steps can be competently managed, using satellite imagery to produce a forecast is an entirely different application. Clouds are always changing; whether moving their position, forming, decaying or changing shape, cloud cover is a rapidly evolving phenomenon, whose underlying microphysics are not yet completely understood. They are affected by terrain and the types of land surface beneath them, and move through the atmosphere according to the wind velocities at their given level of the atmosphere. This last point is particularly important, as wind shear, the change of wind direction and intensity with height, means that clouds at a lower level of the atmosphere are often moving in a different direction to clouds at higher levels. Unfortunately, nearly every satellite-based forecast methodology in practice oversimplifies these problems, extrapolating a motion vector from previous cloud movement and projecting the cloud positions forward all as one mass, in the same direction, to make a forecast.

Incorporating solar forecasts into utility-scale operations

So let's loop back to our overall storyline here. We have incredible growth in solar installations globally, primarily driven by our hard-working solar farm owners and operators. In response to the large volumes of solar being added to energy markets and networks, they are increasingly being tasked with delivering short-term predictions of the energy generation from their facility to their local market or network. This is outside core business, and is arguably a distraction from their mission. The short-term solar forecasting they are tasked with acquiring depends on expertise and techniques that are difficult to acquire, with many forecasting providers using outdated approaches, and possibly altogether lacking the expertise required to engage with a complex meteorological problem. Where does this leave asset managers, O&M providers, solar farm owners and operators, but in a difficult position, with exposure to financial penalties and a responsibility to choose a forecast provider in a time-poor environment? Is that a recipe for building the solar powered future, at an ever increasing pace? Not in my opinion.

Making solar forecasting easy

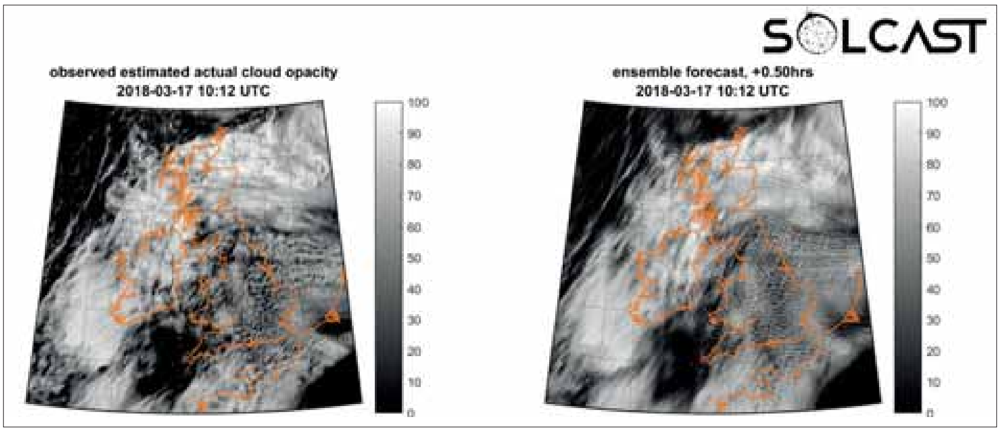
This is challenge is precisely why I co-founded Solcast along with our CEO James Luffman. As lifelong meteorologists, we have both been long fascinated by cloud cover and the processes that drive it. With all that we have learned about meteorology over the years of studying, practising it, teaching it and managing companies that retail products based on forecasting services, we have come to see cloud cover forecasting as a place where we can dedicate our talents, skills and interest to further the accomplishments of the solar energy industry. As a result it has become our team's goal to enable solar farm owners and operators to accomplish their core mission: planning, building and operating their facilities, by making solar forecasting services easy to access and assess. By applying our domain knowledge to these goals, we have taken on the tasks of managing the incredible volumes of data produced by weather satellites and sorting through the complexity of deploying high quality solar radiation and PV plant modelling, so that our solar farm owners and operators can get back to hard work of building the solar powered future.

Reflecting on that journey to date, our team has found many of the barriers to generating satellite based solar forecasts and making them easy to access quite remarkable. Along the way, these have forced us to be quite creative, and to turn to new solutions such as cloud-based computing infrastructure, APIs and machine learning.

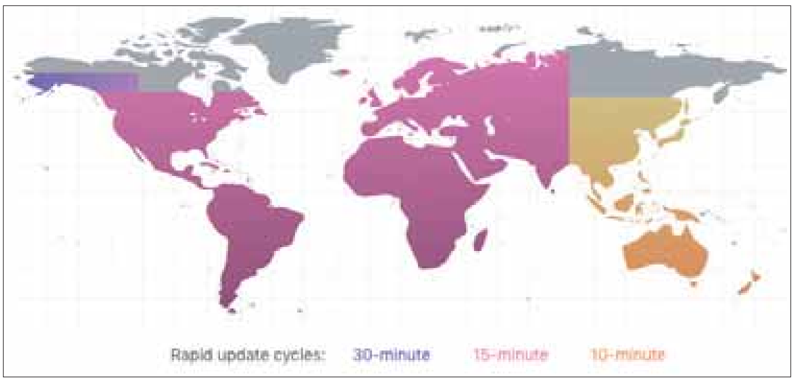
Challenge: Generating satellite-based solar forecasts globally

There are several geostationary weather satellites in orbit around the planet, and altogether Solcast currently pulls in data from five of these. Several of these are next-generation weather satellites that provide new imagery of the Earth's surface and its cloud cover every 10-15 minutes, at 1-2km^2 spatial resolution – including the GOES-17 satellite, which is likely to have begun operations over western North and South America and the Pacific by the time of the publication of this article. Altogether, this stacks up to 30-40GB of satellite imagery data each day that need to be downloaded, processed, quality controlled and then delivered to the forecasting algorithms. Some quick mathematics will tell you that adds up to more than 12TB of storage just for the satellite images, each year! After this data pipeline is managed, algorithms must then be applied to track the actual locations, determine the characteristics of cloud cover in real-time, and estimate how thick they are with respect to sunlight. Each of these processing steps are dealing with geospatial data in the order of hundreds of megabytes from the satellites alone, with several additional gigabytes of data added once information from numerical weather models is also incorporated.

All of that, and we still haven't even crunched a single forecast! In fact, it is the forecast computation and delivery that really pushes the computational limits, as each satellite is sending Solcast new data every 10 to 15 minutes. At each scan interval, we have to re-forecast for every location on the planet, our prediction of cloud cover and solar radiation over the next four hours. At each forecast step, that involves applying machine learning, to review the previous round of forecasts, in order to determine how to adjust the next lot of forecasts according to the local weather conditions (are clouds fast changing? Slow moving? etc.). Looking at these numbers, a total of 600 million forecasts are generated every hour, adding up to more than 9 billion forecasts each day. When our team was first planning on deploying forecasting services to a global audience, these numbers shocked us. In fact, they were about double that estimate when we first worked it out on paper. But along the way, we found several ways to be smarter about managing our total volume of data, but more importantly, we also discovered the answer to the problems of deploying a global cloud forecasting service – by, ironically, moving them to the cloud!



Rapid update forecasts over the UK

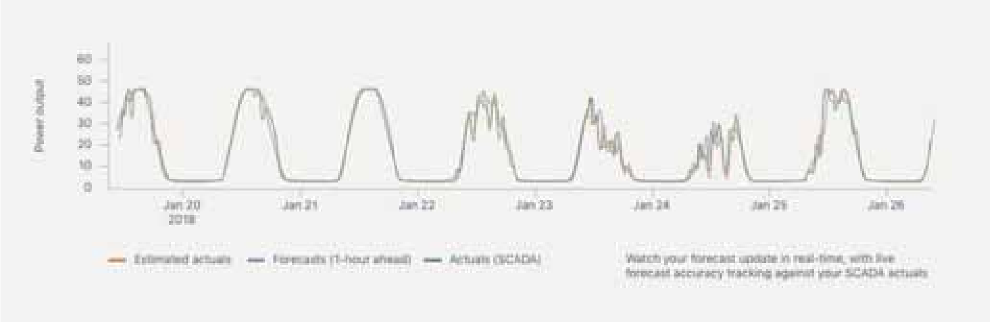


Global coverage map

In response to the fantastic volumes of forecasting data required to deploy a global solar forecasting service, Solcast made an early stage decision to operate from the Amazon Web Services (AWS) platform. There, we were able to take advantage of new technologies like Redis databases and the large storage volumes of S3 and long-term storage solutions like Glacier to reach the levels of performance required for operational services, whilst not totally upending our operational budget. The flexibility of spinning up new instances for compute and memory power according to our current needs was also a powerful option. What's more, this decision then allowed us to pivot into another AWS-based solution, this time confronting another challenge: making those solar forecasts easy to access.

Challenge: delivering solar forecasting data

By switching over to AWS, were able to take advantage of a whole host of solutions that



make deploying an API framework much easier. This includes tools like load-balancers which can accommodate a sudden influx of new API requests, and Elastic Compute Cloud (EC2) instances to power the API itself. We elected to move ahead with a REST API running on Microsoft's .NET Core technology, which was made very easy by using the ServiceStack framework. Servicestack made it straightforward for Solcast to deliver solar forecasts via HTML, JSON, XML, csv and jsv formats. We highly recommend this approach for other software engineers in the solar energy industry looking to deliver data via API.

One of the best things about an API-based service is that, unlike FTP or other similar approaches, it allows a two-way flow of data. And that two-way flow of data, via API, allowed us to tackle yet another challenge in delivering utility scale solar farm forecasts….

Challenge: every solar farm is different

It's one thing to deliver a forecast of solar radiation; it is a completely different task to deliver a forecast of the power output from a utility-scale solar farm. Yet this isn't traditionally how this problem is approached. Standard practice in the industry is to use a forecast of Global Horizontal Irradiance (GHI) and other related solar radiation or weather parameters, as inputs to a PV power plant model. And while we're happy to provide solar radiation forecasts, Solcast has hardly been satisfied with this solution. It's just not easy enough.

And that is because utility-scale solar installations are often quite complicated! Even with perfect execution against a construction plan, once commissioned, solar facilities encounter a host of real-world challenges that can impact performance in many ways. Modules and other hardware are split amongst many different arrays, each potentially impacted by topography, and having widely varying orientations. They are often differentially shaded, are always accumulating soiling and dust, and also experience different rates of degradation. Where does this leave solar farm owners and operators, but with another round of headaches? However, as alluded to earlier, APIs can provide us a clever solution to this problem.

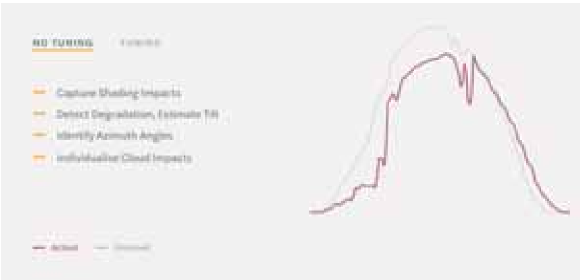
Utility-scale solar farm forecasts can be tracked against SCADA data

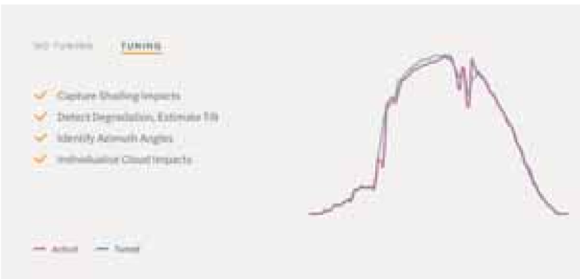
APIs are a two-way street. Users can use a GET request to retrieve their forecasting data, which is where the traditional solar forecast customer relationship usually ends (e.g. grab solar radiation data from an FTP), but with an API, users can also POST request, meaning they send data to the API. We've used this opportunity to allow our customers to send recent SCADA data measurements back to Solcast, which then allows us to confront the issues of uniqueness in each solar plant, with a little machine learning magic.

To take advantage of the ability users have to POST data to the API, we've deployed PV Tuning technologies which apply machine learning to measured power output data in order to learn how the utility-scale solar farm responds to a given set of radiation conditions. By matching up the performance of the solar farm site with solar irradiance and weather data, a 'tuned' forecast that represents that specific facility is produced. Altogether it allows the forecast to:

Tuning technologies learn how utility solar farms respond under certain radiation conditions

- Capture the impacts of shading on your system, including vegetation, topography and surrounding infrastructure
- Detect overall impact of the varying orientations of the arrays in a PV site (azimuth and tilt angles)
- Sense the degradation of your utility scale site, assigning it a loss factor
- Individualise the way your solar farm respond to a given level of cloud cover
- Use these learned parameters to provide you with an improved solar forecast specific to that asset
- Accommodate both fixed and single-axis tracking sites

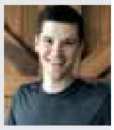




Closing thoughts

Upon review, solar forecasting at scale isn't easy. Simply put, it is a "big data" problem. But new solutions such a cloud computing resources and APIs are enabling a new suite of solutions for solar forecasting, which is good news for our hard-working solar farm owners and operators. These folks are deploying impressive amounts of solar all around the world, building the solar future on our behalf. But as time goes on, that task becomes increasingly challenging, as they are tasked with delivering short-term power forecasts to their local market operator. Since this is decidedly outside of core business, as it is not aligned with their mission, they deserve solutions which remove the pain of having to source and implement them. But with many forecasting providers using outdated approaches to generate, deliver and assess their forecasts, we are confident there's room for improvement. Hopefully we've done our part to make your life a little easier.

Author



Dr. Nick Engerer is the CTO of Solcast. He is an expert in the field of solar radiation modelling and forecasting, and has co-founded Solcast out of a desire to enable others to build the solar-powered future. Nick displays an unusual level of passion for developing applied research projects and collaborating with industry to make BIG ideas a reality. Follow him on Twitter @nickengerer or connect on LinkedIn. For further information on Solcast's technologies and details on a free trial of its project forecasting service, visit http://solcast.com.au

Presented to you by: Energy Storage NEWS

STORAGE & SMART POWER

Energy Storage NEWS

Introduction

Hello again for the last time this year, from 'Storage & Smart Power', brought to you each quarter by the team at Solar Media's Energy-Storage.news. As you may remember, ESN originally launched as PV Tech Storage in late 2014.

We've seen energy storage grow as a standalone technology in the meantime, but solar-plus-storage is beginning to make economic and environmental sense in many parts of the world too, in a variety of business segments. There's so much else to look out for this year, such as the ongoing commercialisation of new technologies including thermal and mechanical energy storage to new ways of increasing the value of behind-the-meter aggregated systems, but the solar-plus-storage space, from large-scale to rooftop, will be the focus of many markets as we look ahead into 2019.

Don't forget, the news items we've selected for this section are just a quick taster of what's on the site and a primer for some of the biggest story of the past quarter. Visit the website and subscribe to the Energy-Storage.news newsletter for free to keep yourself updated. That said, you can tell just from the handful of stories we were able to include in this edition that it's been another busy quarter for the energy storage industry.

We also say a sad farewell to David Pratt, UK deputy editor at Solar Media who has contributed to Energy-Storage.news and other titles for almost three years. He has moved on to pastures new and we wish him all the best. Our thoughts also are with the family of UK energy storage and off-grid solar maverick, ecologist and entrepreneur, James Dean of Circuitree, who sadly passed away this year at a young age. James and others like him that have worked tirelessly to make clean energy a viable and working reality cannot be celebrated enough.

The role of energy storage in battling climate change and bringing affordable power to all has been much discussed this year. As you can see from our interview with Janice Lin of the California Energy Storage Alliance (CESA), there is still much to do. From making policy makers and regulators aware of the role they can play, to making the wider business community aware of the opportunity to do more than just good public relations, 2019 will be another year of action for the energy storage industry.

Many thanks once again to our contributors, commentators and interviewees, including, but not limited to Pason Power, California Energy Storage Alliance, Strategen Consulting and Energy Storage North America, Ice Energy, Sonnen, Panasonic and Stem Inc.

"We can be heroes, just for one day."
David Bowie, 'Heroes', 1977.

Andy Colthorpe
Solar Media

US Congress urged to include storage in ITC

Congress has been urged to support energy storage through the ITC

The US government has been urged to recognise the "critical role" energy storage can play in making the grid cleaner and able to accept more renewable energy, by increasing the eligibility of batteries and other technologies to receive the Investment Tax Credit (ITC).

The ITC is applicable to purchases of solar energy equipment in the US and effectively represents a 30% rebate for investors if fully realised. In recent years the policy scheme has been adjusted to include energy storage but for a long time, storage systems could only receive the Federal subsidy if installed at the same time as solar equipment.

A joint letter was sent in late November by six groups including the national Energy Storage Association (ESA) and Solar Energy Industries' Association (SEIA), urging Congress to support a bill proposed in 2016 by Senator Martin Heinrich of New Mexico, S.1868.

SolarEdge acquires Kokam

Smart energy and inverter company SolarEdge will acquire the South Korean battery manufacturer Kokam.

SolarEdge has initially taken a 75% share for US$88 million with the intention of purchasing the remaining shares in the future.

Kokam produces lithium-ion batteries for a variety of applications including aerospace, electric vehicles and energy storage systems. It claims to have more than 700MWh of deployments and has a product range that includes high power nickel manganese cobalt (NMC) lithium batteries.

SolarEdge VP of marketing and strategy Lior Handelsman said the acquisition enables a level of vertical integration that could make the PV company a 'one-stop-shop' for customers, while SolarEdge could diversify into areas outside solar energy.

Modi officially kicks off India's National Storage Mission

At the beginning of October, India's prime minister Narendra Modi made an official commitment towards the launch of the country's first National Energy Storage Mission at a ministerial event also attended by the UN Secretary General, Antonio Guterres.

In the last 150 to 200 years, Modi said, mankind has depended on fossil fuels. He said that as a transition to renewable sources of energy continues, he hoped the International Solar Alliance would be "at the top of the list" of organisations working to further the "welfare of mankind".

South Africa makes huge distributed energy storage commitment

South Africa's state-owned utility Eskom unveiled its Distributed Battery Storage Programme in October, committing to solar-plus-storage and energy storage projects totalling 1,400MWh.

The wide-ranging plan will see storage deployed across all nine provinces of South Africa, in two phases of development and construction. In the first, 800MWh of battery energy storage will be deployed along distribution sites while in the second, 640MWh of battery energy storage will be deployed in combination with 60MW of distributed solar PV.

12MWh flow battery commissioned in China

Vanadium redox flow battery maker VRB Energy has begun commissioning a 3MW / 12MWh energy storage system project in Hubei, China, which is expected to help serve as a demonstrator for much larger projects to come.

The project, Hubei Zaoyang Storage Integration Demonstration, is being used to demonstrate the use of storage systems in combination with solar PV. It is being installed in Zaoyang, Hubei Province and is planned to eventually reach 10MW/40MWh.

It could then lead to the development and deployment of a 100MW/500MWh vanadium energy storage system that would form "the cornerstone of a new smart energy grid" for the region.

South Australia's home and grid ESS support schemes

Subsidies will be available to residents of South Australia who want to purchase home battery systems, with up to 40,000 households eligible to receive funding towards the cost of home battery storage systems, which are in most cases – although not always – paired with solar PV installations.

The state government will provide up to AU$100 million (US$71.22 million) in funding for the Home Battery Scheme, while the national Clean Energy Finance Council (CEFC) will match the amount.

The South Australian Government has also introduced a AU$50 million (US$36 million) Grid Scale Storage Fund (GSSF) to help accelerate the deployment of new large energy storage projects, including pumped hydro, hydrogen, gas storage, solar thermal, bioenergy and battery storage.

UK's Capacity Market suspended

The UK's Capacity Market has been initially suspended in mid-November after the European Court of Justice annulled the European Commission's decision not to object to the scheme. Britain's Department for Business, Energy and Industrial Strategy said it intended to work closely with the European Commission to reinstate the scheme as soon as possible.

The ruling essentially prevents the government from holding future auctions and making payments under existing agreements.

Clean energy technology provider Tempus Energy challenged the decision to grant the UK's Capacity Market with state aid approval, claiming that its very design unfairly discriminated against clean energy projects, paving the way for the market to be "dominated" by coal, gas and diesel generators.

One market participant told Energy-Storage.news that despite the difficulty of facing the sudden suspension of payments, better market design as a consequence of the ruling could mean "long-term gain, short-term pain."

The smarts inside the storage

Credit: NEC

Storage control | Energy storage projects often fail to deliver value because of economic miscalculations. These computational issues, however, can now be mitigated by applying software, analytics and machine learning, write Enrico Ladendorf and Bryce Evans

Over the past few years, strides in material science, applied chemistry, manufacturing and logistics have caused energy storage system costs to drop significantly. However, as the industry matures, and "early adopters" give way to the "early majority", the economic fine-tuning required to make storage projects as successful in the field as they seem on paper determines the fate of storage projects before they even leave the planning stage.

Energy storage has held the promise of solutions for companies that generate, transmit and distribute energy; this is especially true for anyone in the business of solar. Even end-users have come to see storage as a solution to issues such as balancing generation and consumption, reducing line losses, reviving grid assets after a blackout, avoiding expensive infrastructure upgrades, reducing curtailment of renewables and so on. Certainly, batteries can address these challenges, but most are inherently financial in nature and demand collaboration between the facilities, engineering and finance disciplines.

In California, for example, new solar projects are made possible through the addition of storage. However, if a developer recommends a storage system that's too large or too small, the asset owner may consider the project a "failure" and that developer will not get the referral for the next project.

A grossly oversized storage system will do the job but never pay off or meet the internal rate of return (IRR) requirement. An undersized storage system will not do the job and suffer a similar economic fate. Software and analytics brought to bear early in the process provide 'inoculation' to storage miscalculation disease.

Expensive and time-consuming financial analysis (real fine-tuning) has relegated energy storage to the kind of mega-projects that could require a high level of analytical sophistication. In reality, this mostly manifests in cubicles full of analysts and shared drives filled with spreadsheets. The growth of the storage industry slows down when storage developers don't have access to intelligent and easy-to-use tools with which to compare the possible value of a system against the costs of execution. Software and analytics are now driving a first-order change in this model, with machine learning and artificial intelligence quickly producing drastic second-order change.

Before construction begins, the business case for an energy storage project has to be as well designed as the system itself

The cost of analysis

Storage developers that are still in business do not just start pouring foundations and dispatching cranes on a whim. Every project opportunity is compared to a collection of possible project sizes and scenarios. This portfolio of project options is analysed to determine which ones will generate the most value, either by producing revenue or reducing cost. This process quickly becomes very complicated if you have to rely on spreadsheets or rudimentary online tools.

A quality analysis must comprehend load requirements, storage power output and storage capacity, system cost, the contribution of existing renewable resources, and the capability to scale. In effect, the more data a model can ingest and analyse, the higher the reliability of the analysis. Viable projects are compiled into a final report, which is presented to project stakeholders in a comprehensive format that helps decision-makers translate high-fidelity analysis with enough clarity to drive good management decisions.

This analytical process requires a large contingent of professionals tasked with data gathering, financial modelling, product research, and knowledge of available government incentives and their requirements. This exercise is labour-intensive, time-consuming and costly. Worse still, this human-led process is inherently vulnerable to error, which requires even more effort to correct – if discovered at all.

This analysis complexity and risk is what drives up the cost of prospective energy storage projects. It is no wonder that many projects never even make it to the concept stage, much less to construction and operation. Those that do are usually either from customers who are unconcerned with the real ROI of their systems, or big firms with the means to solicit large-scale opportunities and commensurate balance sheets to absorb the costs of identifying, vetting and proposing storage projects.

Machine learning: The great equaliser

Software and data analytics have radically transformed the dynamics of everything from video games to healthcare. The storage industry is now entering the fray. Within a few minutes, sophisticated algorithms can crunch a year's worth of 15-minute energy consumption data, a region's historical spot prices for wholesale power, the number of critical peak events promulgated by a grid operator during the previous summer, and the price-per-kilowatt of demand charges for a commercial electrical tariff into a tidy visual representation.

This still relatively simple example is not beyond the cognitive capacity of humans, it is just beyond the capability of humans to do quickly and accurately the first time. Advanced software and analytics are revolutionary because the commercial tools that do this work are available at prices even the sole proprietor of a business, storage or solar company can afford.

Individuals can now assess a portfolio of projects quickly and accurately and handle the entire process from project lead identification to analysis, and through to the proposal stage. As 'the little guys' leverage these tools to deliver projects at a lower price and faster, the market will become more dynamic.

The confluence of cheaper, more capable components and the democratisation of analytical prowess is the source of more capable systems, available for the same price, with less risk and more economic value. This potent cocktail is now propelling more energy storage projects beyond the proposal stage. But that is not where the story ends.

The value of computation in execution

Modern energy storage systems are capable of storing and discharging significant amounts of energy with high precision in fractions of seconds. However, the value of the asset can only be realised once these capabilities are engaged at the right time and the proper rate. Backup is a banner use case, but there is little computational complexity in waiting until an interruption in grid service is detected, isolating the local circuit from the grid, and discharging at the appropriate frequency until either the capacity of the system is exhausted or grid service returns. Backup is not trivial, but it is relatively simple.

Demand charge reduction, on the other hand, requires reliably predicting several data sets: when the next peak in electrical demand may occur, what other peaks could be expected during the day, how much solar production can be expected, and so on. Individually, these are complex computational models, but taken together and executed in real-time these models become as complex as they are valuable. To wit, additional complexity comes through the context of federal and state level incentives, such as the Investment Tax Credit (ITC) or Self Generation Incentive Programme (SGIP), offered across the United States and in California respectively. Solar-plus-storage projects claiming the ITC or SGIP incentives will forfeit the financial benefits of these programmes if the storage system is not charged exclusively by the associated, qualified renewable generation infrastructure.

Incurring demand charges will quickly and profoundly undermine (or even eliminate) an asset's value proposition. Under electrical tariffs with a ratchet structure for demand charges, such a mistake can eliminate the expected savings of a demand charge reduction system for six months or more. As such, a storage system is dependent on solar generation, for example, to replenish during the charge cycle or intelligently and quickly adjust its peak

Credit: Pason Power

The next phase in the evolution of energy storage will be about unlocking its value through advanced analytics

Credit: Pason Power

Actual demand for the site (orange) and what Pason Power forecast the demand would be (dashed pink). Pason Power AI accurately estimates the demand and allows the control system to prepare for peaks

shaving strategy. Storage management systems must ingest and comprehend real-time data sources such as weather forecasts, irradiance sensor readings, and on-site submeter outputs to achieve the necessary prediction accuracy required to deliver demand charge savings. Only by pushing this sophistication and insight to the storage devices themselves can modern machine learning methods reliably provide demand charge reduction.

The importance of constants

Understanding whether a storage system is appropriately sized and capable of performing a given set of functions is critical in the planning process. Moreover, ensuring that a storage system has access to the fabric of data required to respond in real-time is crucial to the value-added operation of the system.

In all but the fewest cases, however, do the same people work on the former and the latter. Rarer still is the application of the same computational model in planning and operation. This discontinuity is one of if not the most significant contributors to stalling the storage market today.

To unleash the next level of value in the storage market, the assumptions used during the planning phase must be the same as the assumptions used in the finished system. Put another way, the realities of the working life of a system must serve as assumptions during the planning phase. It sounds obvious. Perhaps it sounds flippant. However, this bit of common sense is the exception, not the rule, in the storage industry today.

Time to stop talking about value-stacking

As an industry, we've had our fill of looking at and presenting value-stacking slides. Layering multiple applications is orders of magnitude more complex than what we've discussed above, and few initiatives ever make it past PowerPoint. Real world value-stacking demands that the cumulative advances in software and analytics perform at their limits, but only a handful of companies specialise in software and analytics to the extent required to know the limits, much less push them. Value-stacking, therefore, must go beyond executing on a given use case for a solar-plus-storage project and to co-optimise maximal operation with other often competing means of exploiting the asset.

An energy storage system may be intended to generate value through a combination of demand charge reduction, PV load-shifting, a demand response programme, and wholesale power market participation as a component of a virtual power plant (VPP). The software controlling the system must employ advanced analytics to anticipate possible savings or revenue across these four strategies continually, and determine in real-time which use case should be pursued with the available capacity.

For example, awareness of the utility tariff structure and historical performance of the system can be used to determine that there will not be an opportunity to peak shave the facility's electrical demand on a given day. Instead, the system may opt to store the solar generation from the PV array and discharge it later in the day where the spread between the respective prices for power, accounting for system losses, would lead to an increase in the value of the solar energy produced.

The software controlling an energy storage system must continually leverage a variety of data sources as well as communicate with demand response servers, or distributed energy resource management systems (DERMS), to determine the likelihood of being able to participate in applications that may be more lucrative for the asset owner than merely shifting the PV production to a more valuable time-of-use period. If the system is too optimistic or aggressive about pursuing these opportunities, it may miss the chance to generate value by executing an alternative application. Storage software, therefore, must take into account a multitude of possible value streams, comprehend the likelihood of capturing them, enumerate their relative values and account for the consequences of pursuing any of them given the impact on equipment lifespan. This software now exists and will relieve executives and managers of their PowerPoint duties.

Extracting value

What got us here won't get us there. The first generation of storage was built on chemistry, charge controllers and amp-hours. The next generation of storage is being built on massive heterogeneous datasets, machine learning and sensor networks. These new domains of expertise will not replace the old ones; instead, they will augment them and serve to unleash vast amounts of new value. In years past, we knew there was more value in storage. We could describe this value on paper (or in presentations). Today we have the technology to extract this value, and that makes this an exciting time for the entire energy storage value chain. ■

Authors

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Is California dreaming? Energy storage's role in reaching 100% renewables

Policy & markets | This year's Solar Power International trade show dedicated what seemed like almost as much space to energy storage as solar. As Andy Colthorpe reports, this is likely a strong indication of the way the world is adopting renewable energy, particularly California, where storage looks set to play a key role in helping the Golden State realise its green ambitions

Credit: Flickr/awnisALAN

It's likely a strong indication of the way the world is adopting renewable energy rapidly that in September, one of the best-established trade shows for solar in the US featured what seemed like almost as much space dedicated to national and international energy storage companies and technologies, as it did for solar.

Solar Power International, which was held this year in Anaheim, California, is co-located with Energy Storage International, but you could almost say that the show as a whole is almost like a solar-plus-storage show in many ways. Sure, the module manufacturers you read about on PV Tech were there, and there's still clearly markets for 'standalone solar' all over the US. But it has become so inevitable that storage – mainly in the form of batteries – will play a huge role coupled with renewables that several conference speakers and sources I spoke to said that it could even be just a handful of years before we no longer talk of solar without storage at all in the US, perhaps excepting a few specific applications or business cases.

"Storage has always been on the horizon for the solar industry but today with time-of-use shifts, the movement of the more valuable electricity to later in the day, makes storage able to provide a uniquely attractive value proposition to the solar industry, to the solar customer, now," Alan Russo of Stem Inc says.

One of the leaders in providing smart storage systems to commercial and industrial (C&I) operations that want to lower their peak energy costs, Stem has made its first-ever foray into adding solar to its offerings in a rare example of storage industry folk coming to solar rather than the other way around. Russo said Stem believes the combined offering can provide value in several directions too.

"The solar only marketplace is becoming more competitive, the value of solar is dropping as rates are shifting to later in the day," Russo says.

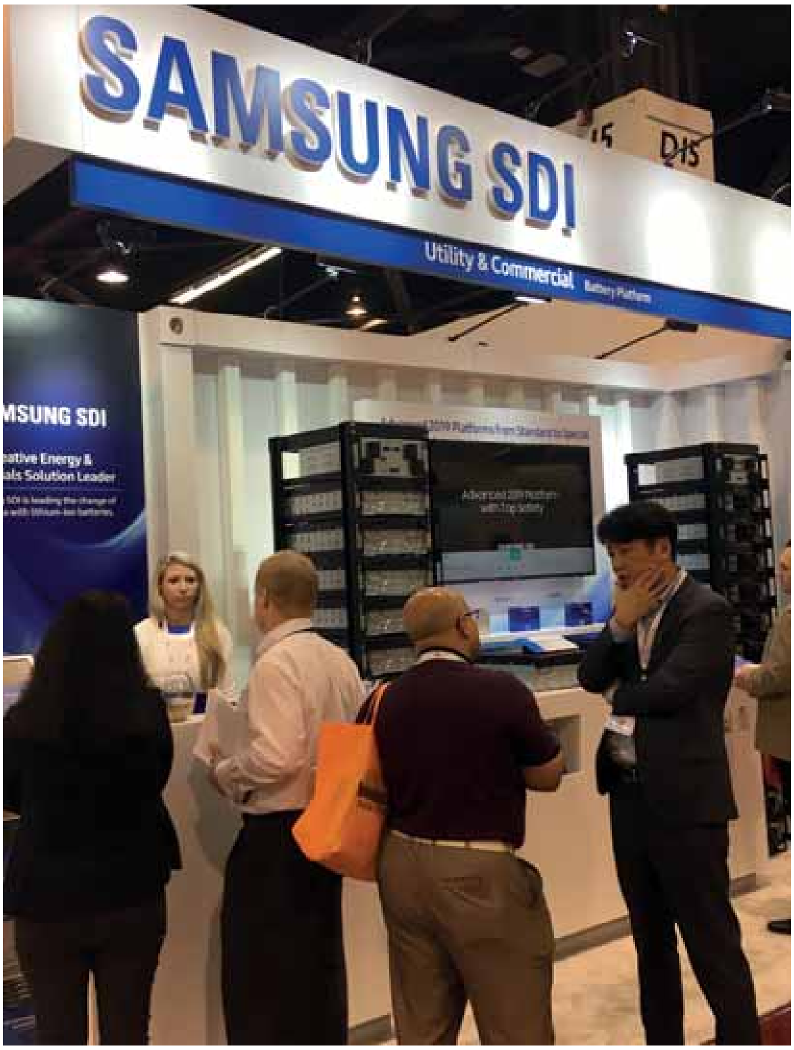
"When you add storage you increase the gross margin for the engineering, procurement and construction (EPC) partner, you increase customer returns and then you provide utilities with the value they're seeking by shifting those rates. Rate shifts are designed to change consumer behaviour, [but] we allow customers to operate how they want to, and everyone benefits from the improved economics."

Peaking Duck

The venue for the show changes every year. Previously it was held in Vegas, which seemed like an interesting choice for an industry priding itself on sustainability but then again Nevada as a state is increasingly favourable to renewables – and storage. Next year it'll be Salt Lake City, Utah, but this year it was California, which of course was the cradle of much of the early solar industry and is now host to Silicon Valley's tech bros and wizards, many of whom are now turning their attention to smart energy.

And only weeks ago, California as a state also set aggressive renewable energy targets, committing to a complete transition to 100% of retail electricity to be carbon-free by 2045. That's in addition to regulatory and policy measures such as the SGIP (Self-generation Incentive Programme), which offers support for solar-plus-storage purchases, AB2514, through which utilities are mandated to procure over 1.3GW of behind-the-meter storage by the early 2020s and the addition of energy storage into utilities' long-term Integrated Resource Planning (IRP).

Mukesh Sethi, general manager for solar



Credit: Andy Colthorpe

SPI in Anaheim this year was a solar-plus-storage event in many ways

and storage at Panasonic Eco Solutions America, said he was excited by SB100, but even more excited by the race to reach the interim target of 50% by 2030, which would be a big leap from the current level between 5% and 10%.

"It's a long way to go in a short period of time and if California can do it, that'll lead the way for the rest of the country. Initiatives like this are very important, they're what keeps us going, if we're to be completely independent of fossil fuels," Sethi said.

While batteries will be vital for meeting SB100's goals, there's also other sectors to think about, namely transport – which will be pretty well covered given the growing popularity of electric vehicles – and heat. We met with representatives of Ice Energy, which makes a sort of thermal cooling battery for air conditioning units, essentially converting electrical energy from PV and other sources and storing it for release as cooled air using fairly simple components and materials like copper.

California's famous 'duck curve' of solar production versus demand is what has kept grid operators awake at night for many years and foretells what might be in store for many other parts of the world. Solar generation goes up in the morning and then comes down in the afternoon and evening, just as demand starts to really kick in. That's it in a nutshell.

If the peak load in California is around 50GW, air conditioning could be as much as 30% of that, argued Ice Energy's VP for marketing and sales Greg Miller, with air conditioning technology having barely moved forward in decades from an efficiency standpoint. One largely unreported detail of Elon Musk's recent controversial appearance on Joe Rogan's podcast was that the Tesla man referred to exactly this, teasing the possibility Tesla would move into AC units (well, he can't announce it on Twitter any more). Far from being fearful, Ice Energy said they would welcome the competition, because it would raise awareness and help set industry benchmarks. While there are others such as Calmac putting thermal storage into large-scale industrial settings, Ice Energy remains the only provider in the US of thermal energy storage for residential air conditioning.

Houses are the new power plants

Frankly, it's a little flippant to say houses will replace power plants and it most likely isn't true. Greg Smith says that the idea of defecting entirely from the grid is not a good one, while there will of course still be a need for commercial and large-scale – hopefully renewable – facilities.

The legislation also sets in motion a goal for all new homes in California to be net zero energy from 2020, a goal matched by similar policy at national level in Japan. Many people I spoke to said that the homebuilding industry will be a big driver of solar and storage and firms are already proactively engaging with architects, construction and housing companies and possible financiers.

Furthermore, net metering policies appear to be on their way out, increased application of time-of-use rates, which put dollar values on electrons relative to supply and demand and therefore to peaks, are on their way in. While we don't yet know exactly what their values will be, lots of residential energy storage companies at Energy Storage International were excited to be bringing something resembling a business case as well as the offer of energy independence and ecology.

Generating, then storing power and using it when grid power becomes expensive will make more financial sense than injecting the power into the grid for diminishing returns. Then there's the opportunity to use the batteries to do something else entirely, such as grid services. To use the shorthand term, aggregating virtual power plants (VPP) from connected home storage systems can be done in many ways. Pooling together the capabilities of many systems offers several ways forward, both economically and from the viewpoint of energy reliability.

"[In] California you have the infamous duck curve, and it's a real issue," Greg Smith, technical training manager for installers at Sonnen, said, pointing to one of the company's new home automation units, which includes smart thermostat control.

"This can intelligently take care of that. The crest [of the duck curve], the peak is that 'end of level boss' for us, to use a gaming term. The solution is the VPP, but we've already done it in Germany, it's old hat for us."

Hawaii is another big leader in US

renewables ambitions, and Ensync Energy's Dan Nordloh said a project his company is executing on the islands demonstrates how a community or closed network can maximise the benefit of having their own rooftop and canopy solar generation. After 30 or so projects creating intelligent energy networks for commercial and industrial customers, Ensync is putting solar-plus-storage into around 300 affordable housing units for a planned development, all running through a common DC link.

"It's a true peer-to-peer (P2P) exchange, so we've created that transactional marketplace. Each of these units can buy, sell, trade amongst themselves and they're acting as an aggregated independent power provider, using grid as secondary or a backup source for electricity."

However, as with Sonnen's 2900-home project with Mandalay Homes in Arizona, not only the homebuilders but the utility will have to be involved, with most states of the US operating highly regulated markets for electricity.

"The utility was heavily involved [in the Mandalay project]. The architects and homebuilders all engaged to pull this off – but a lot of it was about the utility coming to us and saying: this is the platform they wanted to use."

Actually, a Sonnen representative later reached out and explained that Greg Smith had misspoken a little - while it is true that the utility partnership was key to the project's development, as Sonnen executives based in the company's home territory of Germany had told Energy-Storage.news at the time the Arizona plan got underway, it was more the case that the solution was developed by Sonnen and Mandalay, according to tariff and rate structures put out by APS.

Credit: Andy Colthorpe

Credit: Andy Colthorpe

"While APS, the local utility, was not involved at the outset of the project, sonnen and Mandalay Homes were able to take advantage of its rate tariff program when planning the development. However, we are now collaborating directly with APS on the future of the Mandalay Homes sonnenCommunity," the representative said via email.

Joining the dots back to SB100, Greg Smith said he thought California could succeed, but "utilities are going to have to be key to that".

"Those guys will have to catch up, it'll be a bit of a challenge but they want to do it. They understand this will be important."

And it won't just be California that transforms itself, targets or no targets. On a national level, the Federal Energy Regulatory Commission (FERC), has ordered the restructuring of wholesale markets to allow energy storage resources to participate. Believe it or not, this means even Ice Energy's Ice Bear units could be earning money for providing capacity or energy services to the grid.

"FERC Order 841 will drive change in all the FERC jurisdictional ISOs (independent system operator) and RTOs (regional transmission organisation)," Janice Lin, head of the California Energy Storage Alliance and national and international energy storage expert consultant, said.

"[The order will] really force, from the top down, a focus on developing the appropriate tariffs and market structures to allow even very small storage to participate."

So, whether California is a leader to follow, or whether states will find their own way, energy storage and solar-plus-storage is going to be a big part of reaching aggressive decarbonisation targets and frankly modernising systems and networks long due for modernisation. On a national level the picture looks varied and ever-more exciting, NEC Energy Solutions CEO Steve Fludder said.

"The US really is one of the leading markets for the storage business in the world. Here in the western part of the US with such aggressive renewable portfolio standard targets, California is on a path to perhaps 100% renewables in less than 30 years.

"There's a lot of activity in Arizona too. So the western part of the US continues to blaze a trail towards much longer duration, bulk energy storage and shifting, from daytime to early evening peak.

"[But] We're [also] beginning to see the same developments in the eastern part of the US, in Massachusetts, in New York State, which has some pretty aggressive aspirations in this area.

Another interesting thing is that in addition to solar and onshore wind there's a tremendous amount of offshore wind activity in the north-east US, which was virtually unheard of a few years ago. We're on this inexorable march towards very high percentages of renewables in the system and we are an enabler of that transformation." ■

Accelerating to 100%

Policy | Andy Colthorpe speaks to Janice Lin of the California Energy Storage Alliance on what sort of role energy storage will play in reaching the '100% carbon-free retail electricity' goal of the state's SB100 legislation

Along with leading the formation of the Global Energy Storage Alliance in 2014 and remaining its chair until earlier this year, Janice Lin, head of Strategen Consulting, is executive director of the California Energy Storage Alliance (CESA). There's probably nobody better to ask about how SB100 can be viewed in the wider context of what's happening in California's energy storage industry.

We heard from commentators at SPI this year that before long it might be more common to see new solar with storage than without. Lin agrees that energy storage is only going to become more closely partnered with clean energy generation.

"Solar and storage will be like peanut butter and chocolate, they're way better together! I've had developers tell me, at least going forward in the West, they don't see a lot of solar procurement without storage and they're proactively including storage in their business now," Lin says.

And it isn't just the likes of California's big investor-owned utilities (IOUs), which are mandated to procure energy storage or to consider it in their resource planning, getting involved. Municipal utility Los Angeles Department of Water and Light uses a 20MW battery at the 250MW Beacon Solar Plant and Beacon Energy Storage System in the Mojave Desert. It provides AC frequency control, voltage support and assists in the utility's compliance of balancing requirements, helping keep T&D lines stable, while allowing more power to be usable from the PV.

That said, the "beautiful thing" about energy storage is that it can be deployed with solar onsite, but it doesn't have to be, Lin continues.

"Storage can do so many things for the grid and it need not necessarily be directly coupled with PV. There's discussion in California to deploy solar but to have it integrated with distributed, customer-sited storage, as the means by which you improve the capacity factor and shift peaks. This is something that can only be done by a community choice aggregator in California. So there's been creativity on the deployment model – and the lines between utility-scale and behind-the-meter (BTM) are really blurring."

SB100 is ambitious, but a logical next step

We have often heard that increasing the value of BTM storage could be a question of allowing aggregated residential or C&I storage systems to work together as networks, trading energy or performing virtual power plant (VPP) roles. Lin says there's already precedence for BTM systems providing services to utilities in this way.

"Where they (utilities) used to procure local capacity in very large contracts with generators, they're doing it in an aggregated fashion from smaller aggregated assets behind-the-meter."

So how is the state supporting this shift? Does it even need supporting or will market forces take care of everything? Janice Lin is quick to point out that SB100 has not just appeared from thin air, and the 100% renewables policy sits alongside other policy and regulatory initiatives that have already changed the game.

Credit: Andy Colthorpe

A zero-emissions electric bike. Janice Lin says now more than ever, decarbonisation and energy network modernisation is a multi-sectoral goal

"California historically has been a leader for how to use distributed resources generally for grid support and those aggregated BTM local capacity procurements that happened some years ago here, I think that was the first time anywhere in the world that was done. Now we have multiple programmes to encourage BTM storage."

These include the SGIP (Self Generation Incentive Programme), which gives Californians a discount on energy equipment that achieves greenhouse gas (GHG) savings. The state also has programmes for demand response, another market opportunity for energy storage asset owners.

The challenge, and not only in California, is to raise the market value of BTM storage by allowing greater recognition of the services and benefits it can provide. Previously, we heard from Janice Lin and others on the expected big impact of FERC Order 841, a Federal Energy Regulatory Commission (FERC) ruling which instructs regional or state T&D networks to create frameworks for energy storage to participate in wholesale electricity markets. That ruling is still in the process of being hammered out and so Lin offers a more general comment on how the value of storage can be better recognised.

"One of the challenges for BTM storage is getting the signals – the market signals – right. For the most part, BTM storage is deployed today to help the host customer manage their electric bill. Typically it's to avoid a demand charge, conduct some energy arbitrage and

of course the price signal that guides that behaviour is going to be the electricity tariff. But as we know, electricity tariffs are an artificial construct, they're regulated and they weren't designed to optimise shifting on the part of a consumer for the benefit of the grid overall."

"So we're still learning about how BTM storage functions, we're still learning how that impacts GHG emissions. Also, how do you share the asset? If you're using it for the host but also want to use it to provide, say, local capacity, how do you actually implement this multi-use functionality and make it count towards your overall electric power sector planning? In that regard I think we're really still learning. There's been a lot of progress but I think from here on out, it'll just get more exciting and when we overlay the power of smart computing, data analysis [and] smart algorithms, we're really just entering a very exciting time where distributed energy resources can be a key tool for grid planning going forward."

Tech wars? Not so much

California obviously has Silicon Valley and its technologists, and whether or not it is only hype that means California is better known as a tech centre than, say, Bangalore, the state has numerous software, hardware, system and equipment makers that have brought commercialised technologies into the energy storage industry. Lin says that she believes – and we get the impression she's explained this once or twice before – the technology is there, but the regulatory and policy spaces have yet to catch up.

"What's needed is innovation on the regulatory side and the market design side so that the value that newer, yet commercially available technologies can deliver be recognised and be compensated for the value they can provide today to the grid. We need regulatory innovation to keep pace, with commercially available technology innovation."

From first-hand experience, Lin says she knows it is hard but not impossible. Policy makers and regulators Lin has herself worked with were absolutely willing to make changes once they could be helped in understanding the value of those changes. "Regulators will innovate when they understand the value that is at hand," she says.

Time and again the California 'duck curve' is cited as the ongoing puzzle of balancing solar production versus overall demand. Lin says that is changing, as distributed renewables increasingly generate during the day and with the help of storage, can be dispatched later and later into the evenings as peaks tail off. The graph over the course of a week or a month will start to look less duck-like and begin to resemble a "saw-toothed monster", Lin jokes.

"If you look at the spread of a week and look at the net load it kind of looks like a saw-toothed monster! I call them 'icicles of opportunity' because it gets that wonderful renewable energy in the middle of the day and use it to address demand later in the evening. We need a roadmap for how to integrate storage and use storage in a smart way and in a cost-effective way, taking advantage of its multi-use capabilities, smart recharging all of our electric vehicles (EVs) so there are multiple solutions to managing and integrating our abundant low-cost renewables. That's what we've got to figure out going forward."

Multi-sectoral goals

No one – at least not anyone sane – believes any single clean, renewable or distributed energy technology can slow global warming or give people low cost, reliable energy forever. Lin agrees with the wisdom of the increased trend in Europe to talk about sector coupling i.e. solving energy problems by looking holistically at the electricity, heat and transportation sectors. One great example is how batteries will increasingly be used to buffer electric vehicle chargers as solar provides the charge, while vehicle-to-grid (V2G) technology could make EV batteries themselves into grid assets.

Energy Storage North America, the trade show Lin, Strategen and CESA helps to runs each year in California, focused this year on transportation as well as the power sector when it took place at the beginning of November in Pasadena.

"There's a growing recognition that this goal [SB100] is a multi-sectoral goal. It's not just the power sector. We have to think clearly about the transportation sector, we have to think creatively about how we retire gas resources and eventually someday maybe only use a handful of them for emergency backup or using them entirely on renewable fuel, whether biogas or green hydrogen. These are all pathways that we need to figure out in the coming years."

And it is a transition, Lin argues. There will still likely be some role for gas in the near if not long-term future, but even there, gas-plus-storage achieves emissions reductions over standalone gas. It may be controversial to hear, but Californians cannot just expect to wake up tomorrow (or even in 2045 by which time the target must be achieved) to a 100% renewable energy world.

"You can't get to the goals of SB100, just by snapping your fingers and you're there. You have to have a rational plan for going from A to B and a plan for having optimised the use of the assets that we already have. Whether that's an existing gas plant, T&D, natural gas infrastructure, existing solar and wind, geothermal, you name it. So storage has a really important role in finding a rational, reliable and cost-effective pathway forward."

Getting there is only part of the journey

Nonetheless, it is obvious the pride Lin takes in the energy storage industry in her home state and it appears SB100 will bring a lot of what she has worked for over the past 20 years into reality.

"I think SB100 is the policy impetus to really amp up storage here in California. How do you achieve an emissions-free power sector without energy storage? It's just not possible. I would also argue that some of the other policy work on storage that has already been undertaken has given our legislators courage that this is even achievable.

"We're going to definitely get there. There are multiple pathways forward, of different storage solutions that can assist everything from short, duration, longer durations, and really long bulk duration storage with green hydrogen, pumped hydro, compressed air and so on.

"It's not a question of technology. It's truly a question of how do we get there in a way that has the best outcomes for ratepayers and ensure grid reliability and resiliency and equity for all Californians. That's the challenge before us." ■

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Chile: Land of opportunity for renewable energy

Latin America | The Chilean wind and solar market can now be considered a pioneer in the grid parity trend that is currently developing in southern Europe, writes Martin Libra

Chile has been historically characterised as a country heavily dependent on imported fuels. This sparked the interest in quickly developing renewable energy technologies, particularly, from 2013, in solar PV, when the marginal costs of 1MWh of electricity in Chile pierced US$240.

The need to change the trajectory of ever higher energy prices has led the Chilean government to outline and implement a strategy to attract international capital and revolutionise energy generation in the country.

The most important renewable technologies in the Chilean market are hydro, solar PV and wind. In 2018, after five years of unprecedented boom across the renewable energy technologies, especially solar and wind, the country has managed to increase the share of generation from renewable energy sources from 5% to 18%. Utility-scale solar PV has decreased from US$350/MWh in 2009 to approximately US$90/MWh in 2013 and US$50/MWh in 2017, representing overall decrease by 85%. In September 2018 the cumulative installed capacity of solar photovoltaic generation reached 2.38GW from only 12MW in 2013. The most numerous group of projects has been the PMGD category – that is, plants of up to 9MW. The aggregate capacity of the 10 largest solar PV plants in Chile is 1,173MW, with the largest plant being of 196MW (El Romero of Acciona). Chile has publicly announced its targets: 60% by 2035 and 70% by 2050. With the current pace of deployment of renewable energy technologies, these targets will likely be achieved ahead of schedule.

With regard to the wind market, approximately 1.3GW of installed capacity have been added since 2013. Wind, as a more mature technology, has not experienced the same decrease in levelised cost of electricity as solar PV did and its deployment has been relatively slower. For comparison, during the same period, from 2009 to 2013, wind has decreased from approximately US$170/MWh to US$60/MWh, representing overall decrease by 64%. Similarly to the solar PV market, the combined capacity of the 10 largest wind plants in Chile exceeds 1GW and it is thus very concentrated.

As said, Chile has not introduced feed-in tariffs. Therefore, there are three basic options of commercialisation: i) publicly owned, utility-backed PPA; ii) stabilised price for small medium solar projects and iii) fully merchant/spot market.

A sought-after class of PPA contracts has been those obtained through public tenders organised by CNE and the Chilean government. In these tenders, producers compete to obtain 20-year PPA contracts with off-takers – Chilean distribution companies. Given the four largest distribution companies in Chile (Enel, CGE Distribución, Chilquinta, Saesa) concentrate 97% of the market, their counterparty credit risk is reduced to systemic risk. In the future, new opportunities in the PPA tenders are expected with the market being driven by fundamentals in electricity prices.

With the advancements the Chilean market has undergone since 2013, the market will now enter in a consolidation phase as experienced in other more mature markets. The consolidation is mostly expected in the 3-9MWp PV plants category, where the highest number of players is. Nevertheless, some large wind portfolios are coming to the market, and they will dominate in terms of equity ticket.

As the market has matured and many players can already show one or more successfully connected plants, some of the transactions are taking place in earlier stages – that is, during the project development or before construction. Private equity like investors and industrial players are acquiring ready-to-build projects to be transferred to long-term investors once in operation. An important class of investors in Chile are family offices, with good access to capital looking to diversify their portfolios with renewable energy assets.

Credit: Acciona

Country stability and macroeconomic fundamentals make Chile a market with strong prospects

Despite the expected consolidation phase, considering the long-term government targets, rapid development is expected in both solar and wind markets. Both small-scale and large-scale solar are expected to continue the strong growth experienced in the latest years. The solar PV market in particular will be dominated by new developments and new constructions for the next three to five years.

An important feature of the Chilean renewable market development is the absence of support mechanisms, tax benefits or feed-in tariffs. When financed by investors or banks, strong emphasis is put on modelling and spot prices forecasts (as well as the Stabilised Price regimen mentioned above). Chile can be considered a pioneer market in the grid parity trend that is currently developing in southern Europe.

Chile is experiencing the same market prospect in terms of ability to bring projects to financial close under a merchant scenario which we have been experiencing in Australia and southern Europe. Country stability, macroeconomic fundamentals, and the global race to energy transition make us at Prothea convinced that Chile is a market with strong prospects. ■

Martin Libra is head of LATAM for Prothea, which provides advisory and asset management services in the renewable energy sector assisting primarily institutional investors.

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