PV TECH POWER

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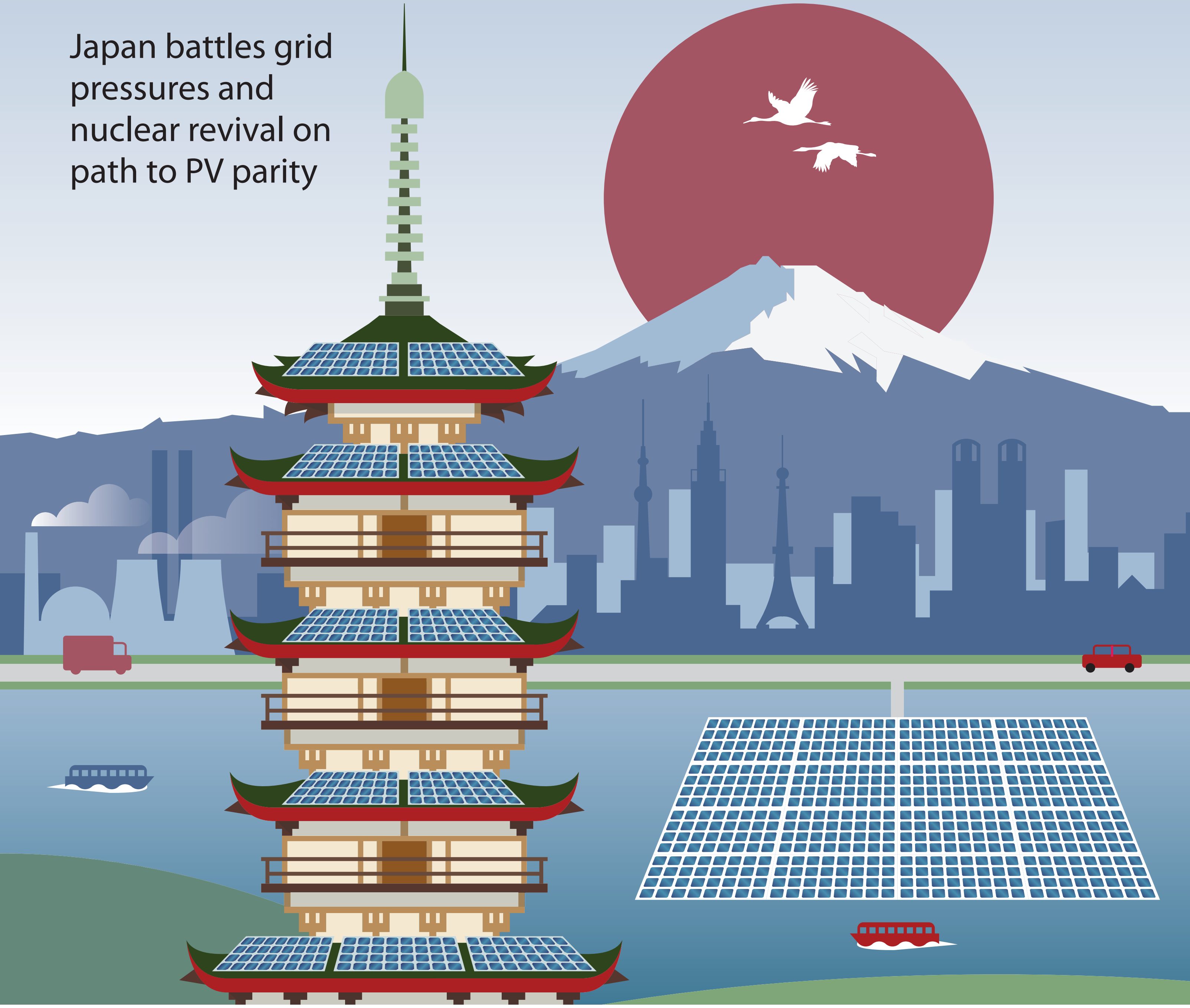
ONWARDS AND UPWARDS

Japan battles grid pressures and nuclear revival on path to PV parity



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Belectric breaks new ground with large-scale solar and storage

PLANT PERFORMANCE

Sandia National Laboratories on the latest thinking in PV monitoring

DESIGN AND BUILD

How the state of the art in PV logistics is cutting supply chain costs

PROJECT FINANCE

Why plant quality assurance is the next piece in the bankability jigsaw

PV TECH POWER

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Introduction

As PV Expo rolls into Tokyo for its eighth outing this month, it coincides with what has been a pivotal time for solar in Japan. Behind the headlines of explosive growth over the past couple of years, some darker currents have been swirling that have threatened if not to bring the wheels off, then certainly to prompt questions over the longevity of Japan's solar success story.

The two pivotal issues Japan has faced in the past year or so concern delays in getting feed-in tariff-qualified projects built and, alongside that, claims by some of the country's grid operators that there is no spare capacity to connect the flood of projects that has been approved.

Our in-depth special report on the state of Japan's solar industry (p.30) reveals some of the effects these two issues have had. The FiT explosion has led to concerns over possible project speculation, with some developers sitting on certified projects to wait for equipment prices to drop. Meanwhile, the actions of five of Japan's 10 grid operators in suspending solar project connection applications have had a tangible impact on investor confidence, as revealed in an as-yet unpublished survey by Japan's PV trade body seen by *PV Tech Power*.

Adding fuel to this fire is the prospect of Japan's nuclear power plants reopening. Since the Fukushima disaster of 2011, all of Japan's nuclear power stations have been shuttered. But with the price of power steadily increasing, two or three of those are now expected to come back online from this year.

As the nuclear question is far from being fully answered, the full impact of a restart programme on solar is as yet unknown and as such will continue to cast a long shadow. But on the other issues facing solar in Japan, there appears to be some agreement that the government's moves to address them should head off the problems that had threatened to blow up, at least for now.

Elsewhere in this issue of PV Tech Power, we explore what is emerging as a key next stage in the quest to make solar a competitive power source – plant bankability.

Last year, US firm First Solar revealed its Macho Springs project in New Mexico had become the first to receive a new kite mark offered by testing house, VDE, aimed at certifying an entire plant's quality. Although such certification is common practice for individual components such as modules, it's still relatively rare at a plant level. On p.35 **VDE** and **Fraunhofer ISE** give a detailed briefing on how to measure plant quality, while on p.* First Solar explains how it was applied to Macho Springs and how it hopes the industry will follow its lead.

Along with an in-depth look at new monitoring strategies by America's **Sandia Laboratory** on p.62, an investigation into how companies are cutting costs through improved PV component logistics processes (p.49) and a briefing from **TÜV Rheinland** on the growing risk profile of power plants in Japan, we hope you will find this issue of *PV Tech Power* helpful and informative in making the right decisions to maximise the potential of your power plant projects.

Ben Willis
Head of content, Solar Media

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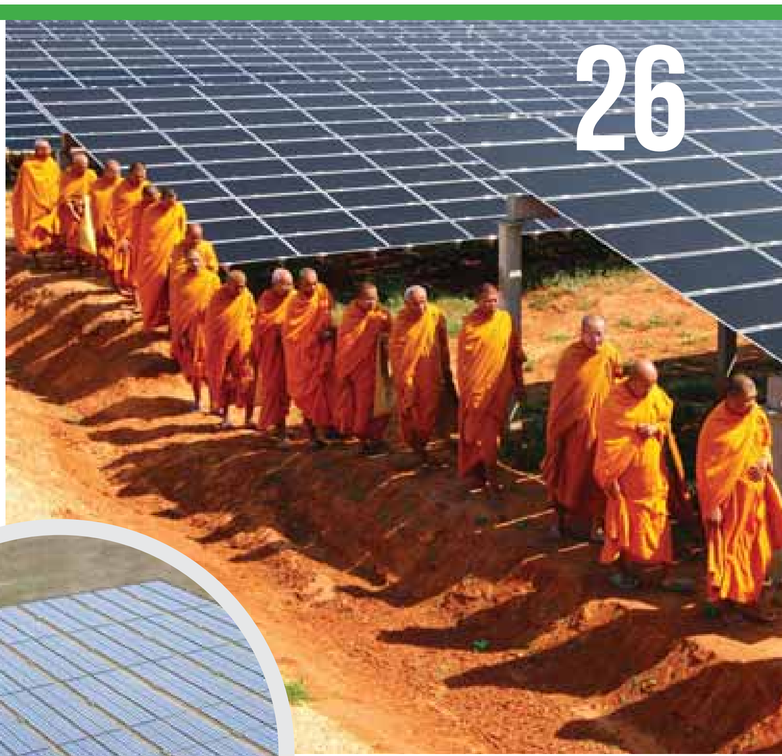


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EUROPE

Climate talks
Ramp up the volume

A leading figure in European PV technology research has urged the global solar industry to pull together to make itself heard at the COP 21 climate change talks in Paris later this year. Professor Wim Sinke, head of the solar programme at the Energy Research Centre of the Netherlands (ECN), says the sector needs to speak "with one voice" about what PV has to offer negotiators looking to break the deadlock on a legally binding climate agreement. Although Sinke was sceptical the industry could have much influence on talks, he said it was important to inform the discussions.

Senior industry figures are looking to amplify solar's voice ahead of the crucial UN climate change talks in Paris. *Credit: Wikimedia/Arturo de Frias Marques*

France
Re-ignition of the market

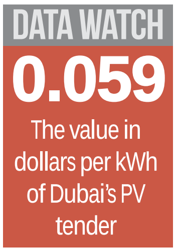
France's government appears keen to reignite activity in the country's PV market, launching a 400MW tender for projects of over 250kW capacity. The tender has 50MW ring-fenced for projects in parking facilities below 4.5MW in size, along with specific allocations for rooftop and ground-mounted projects. The tender's launch followed the award of 40.7MWp worth of FiTs to 217 'medium' PV projects, ranging from 100kWp to 250kWp. The average sale price for those and other medium-sized projects awarded in a previous round was €162.2 (US$203.46) per MWh.

Large-scale solar
Europe's largest project planned in Bordeaux

Staying with France, developer Neoen is planning a 300MW solar park near Bordeaux in the south west, which would make it the largest PV plant in Europe. Neoen intends to connect the park to the grid by October with power sold at €105/MWh (US$131/MWh) for 20 years. Other developers have had contrasting fortunes in France, with Enel Green Power confirming its exit from the country's renewable energy sector, while Baywa R.E and Solairdirect recently closed €228 million (US$264 million) in financing for PV projects there.

Germany
Ground-mount solar tender criticised

After official figures confirmed that Germany installed less than 1.9GW of solar in 2014, the country will also launch tenders to limit ground mount PV to 1.2GW between now and 2017. Industry bodies including the European Photovoltaic Industry Association (EPIA) and Germany's BSW Solar criticised the process, saying that expansion of solar farms will be slowed down even though capital costs and PV electricity prices are falling. Also wounded by the German market slowdown has been inverter maker SMA, which will shed 1,000 jobs in a restructuring.



Tariff watch
No end for Italy's woes

The Italian government has introduced new charges for all owners of PV systems larger than 3kW capacity, under both the feed-in tariff (FiT) and net metering schemes. They are said to be for covering costs incurred by running the support programmes. The new charges will be applied alongside controversial retroactive cuts to feed-in tariffs paid to solar projects over 200kW, which could see revenues from plants drop by 10%. Some have predicted this year will see PV power plants going cheap on the Italian market in a "fire sale".

Auction
UK's new support scheme

Sealed bidding for support for large-scale solar in the UK began in late January. Under the Contracts for Difference (CfDs) scheme, PV is forced to compete with onshore wind. Support for solar over 5MW under the renewable obligation certificates (ROCs) scheme closes in March, leaving CfDs as the only subsidy option. UK-based yield-co Foresight Solar Fund says it is already seeing the development of an active secondary market for projects over 5MW and expects "large pipelines" of sub-5MW projects develop.

UK
Solarcentury's busy year

UK developer Solarcentury has sold a 71MW pipeline of projects to PV investor Magnetar Solar. Magnetar has also selected Solarcentury to construct a further 40MW of capacity. Solarcentury intends to complete and connect all 111MW in time to receive support under the Renewable Obligation scheme before it is replaced by the controversial CfDs in April. Chinese tier one module manufacturers JA Solar and Yingli Green were busy supplying the developer in 2014, with Yingli securing a deal shipping 72MW to Solarcentury in November and JA supplying 100MW throughout the year.

AMERICAS

ITC
Obama floats prospect of ITC extension in budget proposal

President Obama included an indefinite extension to the investment tax credit (ITC) when he published his budget proposal in early February. The ITC, set to drop from 30% to 10% at the end of 2016, will now be subject to several months of debate and lobbying while the final budget is negotiated. Republicans control both the House and the Senate but solar carries a degree of bi-partisan support. Proponents will be hoping solar's job creation success will trump the negative perception of the ITC as a wasteful subsidy. "The solar ITC has been a tremendous boon to both the US economy and our environment. The proposal would extend this proven, successful policy for years to come," said Rhone Resch, CEO of the Solar Energy Industries Association.

Chile pipeline
Merchant potential drive Chile projects forward

Chile's solar progress continues with a series of project announcements, including one with the potential to be the world's largest merchant PV plant. Greenwood Energy said its 80MW Project Inti in Antofagasta could be online in early 2016. Swiss firm Etrion Corp said its latest 25.9MW – also in Antofagasta – could join its 70MW Salvador project in selling power directly to the market as well. An application for a 205MW project near the capital Santiago was submitted in January as the country's pipeline continued its steady expansion.

Trade war

US sets final trade tariffs on China and Taiwan

The US issued its final anti-dumping (AD) and anti-subsidies (AS) of up to 165% and as high as 50% for some of the top producers. Trina was given an AD tariff of 26.71% and AS rate of 49.79%. Yingli faces a 52.13% AD rate and the China wide anti-subsidy of 38.72%. The AD rate for companies not assigned an individual level of tariff will be 165.04%.

Taiwanese producers have been given an AD rate of 19.5% with the exceptions of Motech and Gintech who were assigned 11.45% and 27.55% respectively.

An opportunity to overturn the ruling was predictably ignored when the US International Trade Commission ruled that injury to US manufacturing had occurred and the tariffs could stand.

'Toil', as depicted at the US Department of Commerce building *Credit: Flickr/Tim Evanson*

M&A

SunEdison becomes world's largest renewables developer

SunEdison has become the world's largest renewable energy developer following the US$2.4 billion acquisition of First Wind. The deal, first mooted in November, will add 500MW of operational wind assets and 8GW of development stage projects. SunEdison's installation guidance for 2015 is now 2.1-2.3GW, up 29% from 1.6-1.8GW. The deployment forecast for 2016 is now 3GW. SunEdison president and CEO Ahmad Chatilla said the deal would allow the company to "drive significant growth in global renewable energy markets".

Project

First Solar completes half-gigawatt project in California

Thin-film manufacturer and project developer First Solar completed the 550MW Desert Sunlight project in December, according to documents filed with the California Independent System Operator (CAISO). Desert Sunlight is located in Riverside County and is co-owned by NextEra Energy Resources, GE Energy Financial Services and Sumitomo Corporation of America. Power from the plant will be sold under two separate power purchase agreements – 300MW to Pacific Gas & Electric over 25 years and 250MW to Southern California Edison (SCE) over 20 years.

Finance boom

US residential installers raise more than US$1 billion in January

Residential installers in the US raised more than US$1 billion in finance in January 2015. SolarCity secured a US$350 million agreement with investment bank JP Morgan and a US$200 million deal with Credit Suisse. The money is to fund expansion plans this year. Meanwhile, SunRun closed a US$195 million deal with Investec. Morgan Stanley invested US$250 million into the MySolar programme, which is co-owned by Main Street Power and MS Solar Investments.

Trade war

Canada advances solar trade complaint against China

The Canadian International Trade Tribunal (CITT) has found evidence of dumping and subsidies in Chinese crystalline and thin-film solar panels and components imported into the country. The body issued the results of its preliminary inquiry, which was triggered by a complaint in December 2014 by four Ontario-based manufacturers, namely Eclipsall Energy Corporation, Heliene, Silfab Ontario and Solgate. CIGS, CdTe and a-Si technologies are all mentioned by name. The complaint also covers solar-powered appliances. CITT only had to determine if the evidence presented amounted to a "reasonable indication" that the dumping and subsidies caused injury or even threatened to cause injury to domestic firms.

MIDDLE EAST & AFRICA

Egypt

Egypt's 2.3GW solar tender twice oversubscribed

Egypt has announced the results of its 2.3GW solar tender, which was twice oversubscribed. Feed-in tariffs for the 2GW of large-scale capacity ranged from US$0.136/kWh to US$0.1434/kWh for 25 years. The procurement round also included 300MW for project under 500kW. In total 40 consortia were approved for solar projects. European utilities and independent power producers were well represented with EDF, GDF Suez and Enel Green Power all on the list. Daewoo, Toyota and Total are also members of approved groups. Saudi Arabia's ACWA Power, which set a world record low bid for solar production in a tender in Dubai, was also approved.

Markets

Forecast cut as Saudi delays solar targets

Market research firm, IHS has significantly lowered its PV demand forecast for Saudi Arabia in response to the country pushing back its renewable energy plans by eight years in the wake of plummeting oil prices. IHS said that it had halved the five-year outlook for PV installations in Saudi Arabia from 1.6GW to just 800MW. Worse is that IHS

Price watch

Dubai doubles up on world's 'lowest cost' solar

The winning proposal for a 100MW tender in Dubai that submitted what is considered a record low bid, will be converted to a 200MW project. Saudi Arabian power engineering firm, ACWA Power, and Spanish engineering firm TSK were selected for their bid of US$0.059/kWh. When ACWA was confirmed as the winning lead developer, it was also confirmed that a proposal to double the size of the project to 200MW had been agreed. The project has proposed to use fixed First Solar modules.

Dubai doubled the size of the project to 200MW after the winning bid produced a price per kWh under US$0.06. *Credit: Flickr/Kemal Kestelli* expects the country to deploy the bulk of new PV capacity in the period from 2020 to 2040, with only 1GW expected to be deployed through to 2020.

Kenya

UK's Solarcentury aggress Kenyan joint venture

UK-based PV developer Solarcentury has partnered with Kenyan firm East African Solar to form a new joint venture. Solarcentury in East Africa will work across the region and have already previously collaborated in a 1MW plant at the Williamson Tea farm in western Kenya. "Government support for renewables in this region is growing – it's encouraging that in Kenya, for example, the government's Kenya Vision 2030 recognises the opportunity for renewable energy to support economic growth and the need for the country to switch to more sustainable energy sources," said Dan Davies, a Solarcentury co-founder who will head the new company.

South Africa

South Africa's REIPPPP stalls as country's largest project goes online

There was mixed news for South Africa at the tail end of 2014. The 96MW Jasper project, the largest in the country to date, was completed in November. It was developed by SolarReserve and part-funded by Google. The power will be sold to the South African utility Eskom. In December, there was less positive news as the successful Renewable Energy Independent Power Producer Procurement Programme (REIPPPP) announced its fourth round would be delayed. Winning bidders had expected to be notified in November but were results had still not been released at the time of press.

Jordan

Scatec Solar continues in-roads in Middle East and Africa

Norway's Scatec Solar has secured US$100 million in finance for 43MW of projects in Jordan. The company secured debt financing from the European Bank for Reconstruction and Development (EBRD) and the French development agency Société de Promotion et de Participation pour la Coopération Economique (Proparco). The portfolio is split between three projects.

ASIA-PACIFIC

Net metering

Pakistan approves net metering laws

While not as dramatic as the Modi-driven renewable energy push by neighbouring India, Pakistan approved new net metering laws at the beginning of 2015 as part of a raft of new policies that could boost the development of solar in the country. The government also eliminated an import tax on solar equipment. The government has also developed a financial mechanism to allow homeowners to borrow up to US$50,000 against their mortgage at a low interest rate to fund a solar installation.

Downstream

India's busy developers

Along with hopefully conferring widespread societal benefits, India's renewables push will keep developers busy. SunEdison has confirmed an agreement with the state government of Karnataka to build 5GW of subsidy-free wind and solar in a five-year deal, including 1-1.5GW by the end of December 2016. SunEdison will provide hardware, project development and finance know-how to the plants. India's own Welspun

WINNERS & LOSERS

Top level solar push in India

India is expected to install double its 2014 solar installation figures this year, with consultancy firm Mercom predicting that the removal of existing barriers will boost deployment to around 1.85GW this year. While the short term has seen something of a stumble due to these barriers, which have included anti-dumping and domestic content requirement disputes, the National Solar Mission's 3GW of 2015 tenders and 2019 target of 15GW through 'ultra mega' solar projects (500MW+) and the Modi government's commitment to solar are likely to drive activity upwards.

India's PV push looks unstoppable as the government continues to increase its ambitions for country's solar-powered future. *Credit: Welspun Renewables*

Falling giant

Ironically, while India could be celebrating 1.85GW of PV installations by the end of 2015 as an optimistic signpost to the future, Germany installed a similar amount in 2014, as its solar industry continues to shrink. Official figures show that only 1.89GW of PV was added in 2014. Well-publicised tensions have led to the government capping PV deployment at 2.5GW a year from 2015 onwards. Having said that, Germany's cumulative PV capacity has surpassed 38GW and the industry is seeing a growing focus on self-consumption, often using customer-sited energy storage.

Germany is on a long journey to set aside nuclear power but the government is now reluctant to back solar to the extent seen previously. *Credit: Wikimedia/Arnold Paul*

China

China out of 2015 starting blocks

Unsurprisingly, China is racing ahead to get 2015 started, with another year's worth of ambitious deployment targets (see Market Watch, p.23). The investment community has paid attention, with Kong Sun Holdings announcing a three-year investment in 800MW of distributed projects. GCL New Energy Holdings has already guided plans to build 2GW of PV power plant projects in China in 2015, increasing by 500MW per annum to reach planned installations of 3GW in 2017. Yingli Green, with a 1.4GW pipeline last year, has already started work on a 20MW project in Xinjiang Province while Trina Solar announced the connection of a 90MW solar farm in January.

Investors in China have been backing the distributed generation sector, which could be crucial in helping the country achieve its 2015 ambitions. *Credit: Clenergy*

Energy has struck recent deals including the building of 600MW of solar in Gujarat and a 100.1MW solar farm in Andra Pradesh.

National reform

Thai reforms include solar ambitions

Yingli Green and Chinese telecoms giant Huawei will make a push for the Thai PV market, partnering on both utility scale and distributed solar projects. The pair will work with Thailand's KBank and Spanish integrator, Solventia Solar. Thailand has targets to install 3GW of PV by 2021 and meet 20% of energy demand from renewables by 2022. The rooftop market is seen as holding particular potential.

Australia

Anti-renewables policy backfires

Australian Prime Minister Tony Abbott seems intent on tearing down renewables support, but may not find it a vote-winner. A World Wildlife Fund (WWF) poll found 89% of Australians surveyed objected to cuts to the Renewable Energy Target (RET).

Pipeline

Japan's bottleneck provides sustenance

Japan's bottle-necked large-scale solar industry is likely to be sustained for the immediate future by the existing 50GW-plus of already applied-for projects. This will mean the purchase of existing pipelines by big players, with project development still seen as the most financially rewarding market segment. Softbank and Toshiba announced the construction of 80MW of projects between them in December, while US yield-co, Pattern Energy, has bought a stake in Japan's Green Power Investment Corp that could give it access to a 1GW pipeline of projects.

ON PAGE 30

Andy Colthorpe reports on Japan's solar progress with grid connection issues and the recent resurgence of nuclear power looming large.

WORLD VIEW

Analysts agree 2015 will be a +50GW year

IHS, Bloomberg New Energy Finance, Mercom Capital and Deutsche Bank have all issued forecasts above 50GW for this year.

	2015
IHS	53-57GW
Mercom Capital	54.5GW
BNEF	58.3GW
Deutsche Bank	54GW

EnergyTrend calls 2014 demand at 44GW

Taiwanese PV analyst EnergyTrend estimated 2014 PV demand at 44GW with Japan and the US making up for a lower than expected figure in China. The company expects 2015 to top the 50GW mark at 51.4W with Japan, China and the US taking a 57% share.

Latin America undergoes massive solar growth in 2014

The Latin American solar market ushered in 625MW of projects and grew at an annual rate of 370% in 2014, according to a report from GTM Research.

PV installations in China could top 15GW in 2015 - CICC investment bank

Investment bank, China International Capital Corporation (CICC), is forecasting PV installations in China exceeding 15GW in 2015. That is inline with analyst firm IHS and the government's own, initial, 15GW target for this year.

India set for 1.8GW of solar deployment in 2015 predicts Mercom

Mercom Capital has estimated that India will more than double its 2014 deployment in 2015. The firm estimates that around 800MW was installed last year taking cumulative capacity past the 3GW mark. 2015 could see a further 1.8GW added to that tally.

Solar leading falling renewable energy costs, says IRENA

The cost of solar power is falling faster than any other technology, the International Renewable Energy Agency (IRENA) has found. Power from utility-scale PV plants has fallen 50% since 2010 while the cost of installation fell 65% between 2010 and 2014. The cost of residential solar installs has fallen 70% since 2008, according to IRENA.

Solar took half of all renewables investment in 2014

Solar energy took almost half of all renewable energy investment in 2014, according to figures from BNEF. Investment in all renewables grew 16% in 2014 to US$310 billion. Investment in the solar industry as a whole was US$149.6 billion, a 25% increase on 2013. Asset finance for project development made up US$170.7 billion of this year's total.

Solar took half of all renewables investment in 2014

Japan is thought to have installed over 8GW of new PV generation capacity during 2014, according to analysis and research firm RTS PV. The company was quick to stress however that this figure was not yet confirmed but the expectation was that it would top 8GW.

Product reviews

Storage | Enphase develops next-gen energy storage system with bidirectional microinverter

Product Outline: Enphase Energy showcased its new 'Energy Management System' at Solar Power International 2014 ahead of a major product launch in the third quarter of 2015. The system offers a next-generation, smart-grid-ready bidirectional microinverter, plug-and-play storage, advanced control capabilities and load management.

Problem: Solar installers and distributors are faced with a rapidly changing energy landscape, which is dominated by static, isolated systems that do not integrate, communicate, scale or adapt quickly to changes in power generation. What is required is a seamless integration of solar PV generation, storage, cloud-connected communications and load management that would enable installers and distributors to better manage the design, installation and management of PV arrays and expected demand for higher levels of energy storage capability.

Solution: The Enphase system integrates the critical technologies needed to solve solar energy

challenges at scale: smart grid intelligence, communications, big data analytics and storage. The new system is claimed to have three main advantages: it provides a better return on investment for system owners, expands the range of profitable business models for installers and provides broader insight and control for utilities. The smart-grid ready system shares information, and in some cases control functions, with the utilities over the cloud. By making it easier for utilities to integrate and sustain solar energy, Enphase's systems help maximise their profits and their infrastructure.

Applications: PV and battery storage systems for residential and commercial rooftop markets.

Platform: The Enphase Energy Management System comprises four main components. First, the fully bidirectional, software-defined 'S-Series' microinverter supports reactive power control and other advanced grid functionalities and will be the company's fifth-generation microinverter. Secondly, the 'Enphase AC Battery' is an advanced energy storage solution with a modular, plug-and-play storage device fully integrated into the system. Thirdly, Enphase's new Envoy-S expands from energy monitoring into full revenue-grade metering of solar production, metering of home consumption and storage management. Fourthly, Enphase's Enlighten software platform enables customers to monitor system performance from any PC tablet or smartphone.

Availability: On a rolling basis beginning in the US in the third quarter of 2015.

Fault detection | Shoals adds UL1699B listing to SNAPshot wireless arc fault solution

Product Outline: Shoals Technologies Group has added UL1699B listing to the SNAPshot Wireless Arc Fault solution. The SNAPshot Wireless Arc Fault Solution protects solar assets and property by detecting arcing at the string-level and disconnecting the inverter or charge components.

Problem: With the progressive adoption of US National Electric Code (NEC) 2011, it is increasingly important to have a trusted solution to potential arc faulting that complies with the requirements.

Solution: The SNAPshot Wireless Arc Fault Solution enables owners and operations & maintenance (O&M) crews to be remotely alerted to fault conditions in their fields. The SNAPshot Wireless Arc Fault solution uses advanced signal processing technology to identify the electrical noise signature created by arc faults in the array wiring. It now is an integrated option in the Shoals Wireless Smart Combiner and can also be installed as a stand-alone device, integrating to most popular SCADA systems. Shoals is currently taking orders for the solution and expects availability in Q1 2015.

Applications: Residential and commercial rooftop remote arc fault detection.

Platform: The UL listed Wireless Arc Fault solution is the latest addition to the SNAPshot Solar Management Ecosystem. SNAPshot, developed under a strategic partnership between Shoals and Synapse Wireless, lets owners benefit through improved financial and energy production visibility, shortened time-to-revenue, and the cost advantages of wireless communication. EPCs benefit by completing installations more quickly and both EPCs and O&M providers can streamline operations via advanced troubleshooting and intelligent analytics.

Availability: First quarter 2015 onwards.

Module | Canadian Solar launches glass/glass 'Diamond' 1500V module for lower BOS

Product Outline: Canadian Solar has launched a new glass/glass 1500V multicrystalline PV module. The 'Diamond' module is designed for harsh environments as well as providing lower degradation over a 30-year lifespan, while enabling the use of longer strings to reduce the overall balance of systems (BOS) cost.

Problem: PV power plants in harsh environments require modules specifically designed to withstand the effects of conditions such as high temperatures and humidity, and sandstorms.

Solution: The Diamond module uses thin, glass/glass substrates without the need for an aluminum frame and therefore does not require grounding, thereby eliminating the cause of potential induced degradation (PID). In addition, the Diamond module has the ability to withstand harsh environmental conditions, including high humidity, high temperature, sandstorms and ultraviolet (UV) conditions. The module's increased resistance to salt corrosion makes it a robust solution for coastal installation. Rated for 1500V systems, the Diamond module significantly reduces BOS costs by increasing modules in a string and decreasing the number of combiners, cables and other system parts.

Applications: Designed for high-voltage systems of up to 1500 VDC, saving on BOS costs and harsh environments.

Platform: The glass/glass multicrystalline 60-cell encapsulation blocks moisture permeability, enhancing long-term system performance reliability. The first-year annual power degradation is 2.5% and 0.5% each year afterwards. With that, module output at the 25th year is maintained at 85% versus the current 80%, according to Canadian Solar.

Availability: Officially to be launched in early 2015 after IEC, UL and CEC certification.

Tracker | Exosun offers single-axis tracker with intelligent backtracking process

Product Outline: Exosun's 'Exotrack' HZ horizontal single-axis tracker offers an intelligent patented backtracking process, called 'SMARTracking', to provide higher yielding tracker systems and lower system LCOE.

Problem: Solar trackers are motorised structures that orient PV panels towards the sun throughout the day, to significantly increase PV plant output in comparison to fixed-tilt structures. All PV tracker control programs include a standard backtracking system to minimise shading on PV modules during periods of low solar height (early morning and late afternoon). It usually relies on the theoretical positioning of the trackers on the plant, possibly followed by arduous on-site fine tuning.

Solution: The SMARTracking system is based on a three-dimensional positioning analysis of each solar tracker on site, thereby achieving the best alignment for the trackers and enabling the control of each tracker to be individualised. Consequently, SMARTracking allows a PV plant to generate up to 5% more energy yield annually compared to other traditional single-axis trackers, Exosun claims. For example, a 7MW project in South West France, generated 440MWh of electricity more per year than would be expected.

Applications: PV power plants.

Platform: The Exotrack HZ is claimed to have 30 to 50% fewer piles than traditional trackers. The low number of piles required per metre-squared of solar modules, associated with its high installation tolerances, has a direct impact on CapEx since it decreases material needs and installation time. Typically five or six trackers are required per MWp. Up to 1200m2 of (12,916 ft2) of tracked area is used with a ground coverage ratio of up to 50%.

Availability: Already available.

Microinverter | Enphase combines C250 microinverter with design software, O&M and financial services for commercial rooftops

Product Outline: Enphase Energy is launching a new solar energy solution for the commercial market. The new offering combines Enphase's microinverter technology with a comprehensive set of services and partnerships to assist the owner and installer of a commercial solar project from concept through implementation and eventually to maintenance.

Problem: Despite recent growth, commercial PV remains the most underdeveloped sector in the US, trailing utility-scale and residential sectors. PV installers are seeking innovative solutions that will speed up the installation process and increase design flexibility while increasing the value and dependability of the energy delivered to the end customer.

Solution: Enphase's solution is said to be capable of taking a commercial-scale system from concept to long-term operations and maintenance. The commercial-grade system includes the C250 microinverter, the cloud-based Enlighten monitoring system, the Envoy Communications Gateway and a rapid-response Enphase Energy Services (EES) team. Enphase has partnered with Folsom Labs to incorporate the C250 Microinverter system into HelioScope, Folsom Labs' advanced system design tool. This integrated solution is said to enable PV installations to be rapidly designed and modelled. A growing network of financial service providers are partnering with Enphase to fast-track the financing of commercial solar projects and help customers unlock and enhance the long-term value of their systems.

Applications: Commercial rooftop systems.

Platform: The C250 microinverter system is aimed at medium and large commercial projects. It supports three-phase 480V AC installations for 60- and 72-cell PV modules, which is claimed to deliver improved performance for larger commercial projects and a levelised cost of energy lower than that of competing inverters. The system is said to require less wiring and balance-of-system components, reducing labour and installation costs.

Availability: Made available in the first quarter of 2015 in the US.

Plant design software | PVComplete's commercial PV system design software cuts engineering time in half

Product Outline: PV software specialist, PVComplete, has launched a commercial solar system design platform that is intended to streamline commercial solar project design.

Problem: Although module costs have fallen dramatically, soft costs now account for nearly half of solar project costs. Design, engineering and permitting are expensive parts of the soft-cost equation. Commercial and utility design is complicated and time consuming; design methods have not changed considerably from a decade ago.

Solution: The software tool completely automates electrical design and module layout utilising a cloud-based PV module database while observing roof zones and obstructions with sophisticated shadow models. The software

enables multiple design iterations resulting in project optimisation. PVComplete is seamlessly integrated with AutoCAD and available as an application or a bundled 'solar CAD' solution. PVComplete tools are said to cut engineering time in half through the automation of the most time-consuming tasks. Automated layouts and engineering calculations reduce potential costly errors.

Applications: Commercial rooftop PV system design.

Platform: PVComplete 2.0 includes mechanical design features such as automatic module layout, a cloud-based PV module database, roof zoning and shadow modelling. Electrical design features include automatic string assignment, a commercial inverter database, combiner box placement, string size calculator, wire size and length calculator, and voltage drop calculator. The company offers full training and backup services.

Availability: PVComplete 2.0 will be fully released for US and European markets in February 2015.

Monitoring | Schneider Electric launches remote monitoring and asset management platform, 'Conext Insight'

Product Outline: Schneider Electric Solar Business has launched the 'Conext Insight', a remote monitoring and asset management platform for distributed PV plants. The web portal gives PV installers detailed insight into the performance of PV plants from one central platform. The next version of Conext Insight will cover remote monitoring of decentralised PV plants using Schneider Electric's Conext string inverters in April 2015.

Problem: Increased PV adoption has resulted in the need for better 24/7 data and monitoring control of PV systems. Web-based systems provide monitoring, fault detection and maintenance capabilities that also reduce false call-outs.

Solution: Conext Insight provides smart insight to installers by facilitating remote diagnostics of PV plant issues, which can minimise their truck rolls in response to service calls. Installers can leverage Conext Insight to remain connected with their customers and offer value-added services. At the same time, Conext Insight also provides PV plant owners with powerful insight. The web portal gives them access to their plant's performance data to ensure the desired investment return is realised.

Applications: Remote monitoring and asset management platform for distributed PV plants.

Platform: Conext Insight comes with an intuitive dashboard, historical performance charts and events log, enabling a comprehensive understanding of the performance and health of PV plants, remotely. It includes facilities to notify customers of upcoming maintenance requirements, make suggestions for system improvements, and make confident decisions.

Availability: January 2015 onwards.

Interconnection | Clean Power Research targets US interconnection soft cost reduction

Product Outline: Clean Power Research's new software, 'PowerClerk', funded by a US DOE SunShot Incubator award, takes solar interconnection online to streamline application processes, shorten time to interconnection and reduce soft costs.

Problem: According to the Solar Electric Power Association research report, "Distributed Solar Interconnection Challenges and Best Practices", utilities that use an online interconnection platform are able to process applications twice as quickly as the approximately 85% of utilities that only accept emailed, mailed or in-person applications.

Solution: PowerClerk is a scalable business process management platform that will enable utilities of all types to quickly and cost-effectively take their interconnection processes online with no internal development. It is designed to help reduce soft costs for both utilities and installers through streamlined processes, better communication and shorter time to interconnection. With PowerClerk Interconnect, utility programme administrators are able to take control of interconnection processes, while workflows and forms can be defined and quickly updated to meet changes in programme requirements without requiring IT involvement. The software provides error-free auto-document generation, electronic signatures and electronic document storage and streamlines formerly paper-intensive processes, reducing the time it takes to process applications. Application status visibility and built-in automatic email features keep customers informed through each stage of the interconnection process, reducing the number of customer calls.

Applications: Online PV system interconnection programmes.

Platform: Interconnected solar fleet data is stored in secure databases, making it accessible for reporting and integration with customer engagement, planning and operational tools such as 'WattPlan' and 'SolarAnywhere' 'FleetView'. Using the PowerClerk application programming interface (API), installers can automate application submittal directly from their quoting, customer relationship management (CRM) or sales automation software.

Availability: Already available.

Inverter | Ginlong's 'Solis-Mini' claimed to be lightest PV string inverter

Product Outline: Ginlong Technologies' latest 'Solis-Mini' PV string inverter is claimed to be the lightest single-phase transformerless PV string inverter on the global market, with a weight of less than 13lbs (5.6 kg).

Problem: Space constraints and difficult access points can restrict the optimal location and therefore raise the cost of residential PV installations. Providing a lightweight, easily portable PV inverter can simplify installations and provide optimal system performance without increasing costs.

Solution: Solis-Mini boasts the same features as Solis 2G single-phase PV inverter, including over 97% maximum efficiency, dual CPU design, lowest input voltage from 50V, precision MPPT algorithm, NEMA 4X enclosure, web and smart-phone apps data monitoring. However, its light weight can provide installation flexibility and reduce the need for strengthening framework or non-optimal location.

Applications: Residential rooftop PV installations.

Platform: Solis-Mini comes with 700W, 1000W, 1500W, 2000W models and unique 127V AC low-voltage solution. The inverter is compact and light for easy installation, and includes numerous protection functions. Solis Mini features an ultra-low voltage start up, precise MPPT algorithm and controlled PWM inverter technology, and numerous monitoring options via RS485, WIFI and GPRS interface.

Availability: Already available

Tracker | NEXTracker offer's self-powered tracking technology to lower BOS

Product Outline: NEXTracker has unveiled its 'NEXTracker SPT,' self-powered tracking technology that eliminates power wiring to the tracker motors, reducing material and installation costs. The company claims the latest advancement simplifies the design, installation and commissioning process for solar PV tracking systems.

Problem: Traditionally, using single-axis trackers carried additional balance of system (BOS) costs due to the need to build an extensive power distribution system for trackers to function and provide costly backup systems.

Solution: NEXTracker SPT has self-tracking capabilities that are made possible by a design that enables independent tracker rows to be driven with minimal motor power. A single small, dedicated solar panel with battery backup easily powers an 80-module row. Tracker operation

is faster and more precise with individual row control; this improves energy yield and enhances safety with rapid stowing in rapidly changing weather conditions. Self-tracking technology also eliminates the grid as the power source for the tracker, which means there is no 'parasitic' energy loss in the system. Each NEXTracker row has more than seven days of back-up battery power in case of loss of solar input. Advanced remote monitoring of motor and battery health/charge status is claimed to offer the highest level of reliability.

Applications: Large-scale PV power plants using single-axis trackers.

Platform: Certified to stringent UL2703 requirements, NEXTracker eliminates separate grounding materials and associated installation costs. Its independently driven rows with wide tracking range enable maximum site flexibility, energy production and power capacity, while simultaneously reducing operating costs.

Availability: Already available.

Inverter | SMA Solar offers 'Sunny Boy' TL-US series inverters for large residential projects

Product Outline: SMA Solar Technology has introduced an expanded range of 'Sunny Boy' TL-US inverters with 'Secure Power Supply.' The higher power ratings of the new Sunny Boy 7000TL-US and 7700TL-US are designed to meet the needs of large residential PV projects and are able to provide daytime power in the event of a grid outage.

Problem: Large residential PV projects border the need for commercial rooftop balance of system (BOS) components and configuration, increasing installation costs and limiting the ability to optimise the system for best performance and lowest LCOE.

Solution: The Sunny Boy 7700TL-US is specifi-

cally configured for homes with 200-amp service panels, allowing solar installers to maximise system size and energy production without expensive service panel upgrades. Each model of the Sunny Boy TL-US series is equipped with the Secure Power Supply feature, which makes it possible for the inverter to provide up to 1,500W of daytime standby power when the grid is down for charging laptops, cell phones and more, without the need of additional, costly batteries. The inverter's shade-tolerant 'OptiTrac' Global Peak MPP tracking algorithm and two MPP trackers provide increased energy production for complex arrays with partial shading or multiple roof orientations.

Applications: Large residential PV systems.

Platform: Additional features of the Sunny Boy TL-US series include a transformerless design for high efficiency and reduced weight, and integrated DC AFCI functionality meeting NEC arc-fault protection requirements and certified to the UL 1699B standard. Monitoring and control features include a large graphic display and the optional plug-and-play Webconnect data module. With high CEC efficiencies, a wide input voltage and extended operating temperature ranges from -40 to 140 F, the Sunny Boy TL-US series is claimed to offer enhanced power production under a variety of conditions.

Availability: Already available.

Module | Sunpreme offers first 500W bifacial glass/glass PV module

Product Outline: Start-up Sunpreme has launched what it claims to be the world's first bifacial double-glass module with a measured STC output of 503W. It is designed to maximise energy production in ground-mount as well as tracker configurations, and with a 15% bifacial power boost, the effective panel wattage can be enhanced to 575W with an effective module efficiency of 22.2%, according to the company. Upon full market release, the product warranty will be backed by insurers Munich Re.

Problem: PV project developers look for the lowest levelised cost of electricity (LCOE) on projects. Providing large panel sizes with high-performance cells, resulting in high module power output, can reduce the overall balance of system (BOS) cost of a project.

Solution: The underlying technology platform is Sunpreme's proprietary 'SmartSilicon' Hybrid Cell Technology (HCT) developed five years ago, which provides an effective module efficiency of 22.2%. A second performance bonus comes from a record low thermal coefficient of module efficiency of 0.28%/C. The product is claimed to achieve an unsurpassed BOS cost reduction for distributed power generation applications.

Applications: Commercial and utility-scale PV power plants.

Platform: The module consists of 156.75mm AFS cells sealed between two panels of tempered glass. Being frameless it comes in at 34kg in weight, which is close to the weight two installers can do in repetitive lifts, and requires no grounding.

Availability: The company has yet to provided details of release dates.

Solar breaking oil's Middle East stranglehold

Credit: Masdar.

Solar deployment is growing in the Middle East despite the collapse in oil prices.

Middle East | While oil falls and Saudi stalls, detractors are questioning the future of solar in the Middle East and North Africa. But rising electricity prices coupled with rising demand mean solar power remains an important investment from Muscat to Marrakech, writes John Parnell

For a while, solar energy in the Middle East has been all potential and no conviction. All eyes were on Saudi Arabia with top manufacturers and developers jostling for position on trade missions and hoping to find themselves at the front of the queue when deployment began.

Saudi Arabia's lack of progress continues to baffle onlookers with the country recently pushing its 2032 ambitions for 54GW of solar back to 2040. The recent drop in oil price has added fuel to the fire of sceptics who have little faith that the region would ever match its lofty renewbale energy ambitions.

Quietly however, away from Saudi Arabia, Egypt has put 2.3GW to tender, Dubai has accelerated its own 1GW process and Jordan's long-awaited procurement round has seen power purchase agreements signed. Morocco and Tunisia are also pressing ahead with PV and concentrated solar power plans.

The impact of the price of falling oil on renewable energy rollout has neglected to consider that electricity prices in the region have largely been increasing as governments chip away at the subsidies on offer, a process reduced oil receipts will surely only accelerate. In January, Kuwait announced six-fold increases in the per-kilowatt hour tariff for households that consume more than 10,600kWh a year. Smaller users are rewarded with more modest increases and the smallest users (under 6000kWh) with no increase in tariff at all. The current rate is two fils, about two-thirds of one US cent.

These prices are one reason why Sami Khoreibi, CEO of Abu Dhabi-based EPC firm Enviromena, is bullish about solar's future in the region, despite falling oil prices.

"We're a lot more competitive with today's cost of solar than the delivered cost of electricity from oil power plants and diesel, which is what we are displacing a lot of the time," he says adding that the market, not government targets and schemes, are driving solar's rollout.

"We're starting to see that in places like Egypt and Jordan, and even parts of the UAE where you have the high delivered costs of electricity. Solar projects are being driven and led by private sector players outside of the framework of government programmes. We're simply displacing higher cost energy. The underlying economics of any source of any energy are what is going to drive growth in an industry and, for solar, they are quite compelling."

Khoreibi also points out that while volatility in fossil fuel prices may appear to be working against solar for now, it can swing the other way just as easily.

"It's very hard to predict what direction oil prices or gas prices are going to go," he says. "Solar power systems have a 25-year life and you are capturing that price of electricity for 25 years all at once. So if we're looking at the case for solar I think it is strengthened when we see massive swings in [traditional] energy cost. We're still more competitive than oil-fired power plants but to a lesser extent. I think the predictability of our feedstock – the sun comes up and the sun goes down – is something that should supply a degree of comfort not just to regional governments but to all power producers globally."

These factors have seen a number of procurement rounds gain traction in the Middle East. They may be less headline grabbing, but they're also more tangible. Thierry Lepercq, CEO of developer Solairedirect, says they represent a second phase in the development of solar in the region.

"I think there have been two periods for solar in the Middle East," says Lepercq. "The first was a few years back when you had the big political announcements. Masdar on the one side, big announcements with a PR aim, and in Saudi Arabia there was KA CARE and talk of 54GW by 2032 and so on."

Since then the KA CARE plans have stalled and state oil company Saudi Aramco and Saudi Electricity Company (SEC) have looked to use their project expertise to launch projects separately.

According to a Citigroup report in 2012, Saudi Arabia risks becoming a net oil importer unless it can address its electricity supplies. Using solar in Saudi is not just about freeing up oil for export however; Lepercq says the country also has a reliance on imported diesel to contend with.

"There's insufficient power supply in many areas of Saudi Arabia so there is a lot of power generation from diesel. Strange as it is, the country imports diesel at a rate of US$1 billion a month, largely from India," says Lepercq.

Pressures like this could exert similar pressures on Saudi Arabia to adopt solar, as are currently being applied on Jordan. Oil prices may be low for now, but the cost of electricity in the face of rising demand is a more predictable and immediate concern.

United Arab Emirates

Dubai has stolen a march on its big brother emirate, Abu Dhabi, with the announcement that the winner of a 100MW PV tender round will actually double the project to a 200MW install. On top of that the winning bid of US$0.059/kWh is the lowest ever for a solar power plant.

A further tender round for another 200MW has been announced for 2016 as part of its 1GW Mohammed bin Rashid al Maktoum Solar Park, named after the Emirate's ruler. The rock bottom prices are reminiscent of the early bids in India that proved too low when the time came to close financing.

Enviromena's Khoreibi thinks the winning parties, ACWA Power and Spanish firm, TSK, will be confident that they can fulfil their promises.

"Both companies are highly sophisticated entities that I'm sure had a very studied approach to their pricing. They have won and delivered solar systems in the past. There is real potential considering the access to capital to build up solar power plants well below US$0.10/kWh," says Khoreibi, adding that the development should be considered positive by everyone working in the industry in that region.

"We're going to get to the point where we are not just competitive with oil-fired power plants but we'll be competitive with gas-fired power plants regionally as well. The average production cost in Abu Dhabi is US$0.08-0.12/kWh for the true cost of gas and when we start falling within that band we open up a more significant marketplace. From our point of view we think this is exciting."

Abu Dhabi's Masdar vehicle has installed a 10MW PV plant, a 100MW parabolic trough CSP plant and 2.3MW of rooftop solar on government buildings. It has invested in renewable energy projects overseas including the 630MW London Array offshore wind farm in the North Sea. With a steadier pipeline of projects available at home in the future, there is no reason why Masdar and other regional investors can't reap the benefits.

Even one of the smaller emirates, conservative Sharjah to the northeast of Dubai, has announced a 20MW solar tender.

Turkey

Turkey is one of the fastest growing economies in the world. At an energy markets event in Ankara in January, President Erdogan said the country's energy demand had doubled in the space of 12 years and was forecast to double again in the next 12 years.

The UAE has taken an early lead in deploying solar with projects such as the 100MW Shams CSP plan.

Credit: Masdar.

Credit: IBC Solar.

For a country with no meaningful oil or gas resources, that is an immense challenge and the opportunity for renewables is obvious. Erdogan's government estimates that the cost of building new generation capacity will be US$120 billion.

"Turkey is in a very interesting situation because it has no domestic production of oil or gas so it has a very big energy deficit. It has great radiation in the south west of the country – we try to avoid the east for a number of reasons including political," says Solairdirect's Lepercq, adding that the country already has a well-functioning power market.

"The only thing is that they are yet to be fully aware of how competitive solar can be. They have done tenders for wind and they have on average US$87/MWh for a wind project, more or less at the level of wholesale prices. With solar they expect it to be more expensive so they have issued tenders for 600MW at US$133/MWh, which is far too high. We're in the situation where in the tenders they are asking for a payment to sign for the tenders at a high price." In practice, the regulator is asking for bidders to offer compensation to offset the high price that has been set.

Results were expected at the end of January 2015 as this publication was going to print. The first round of the tender in 2013 attracted almost 9000MW of interest. This would suggest the country's goal of installing 3GW of PV by 2023 is achievable. Lepercq can add to that body of evidence with his own personal experience.

"We had a meeting with a presidential aide in Istanbul recently and I think that they are opening their eyes to the incredible potential of solar in Turkey. I would not be surprised if once this 600MW tender is passed, a massive amount of India-style procurement followed. That would suit perfectly the needs of Turkey as a power user," he says.

Policy makers are beginning to understand the enormous potential of solar in Turkey.

Egypt

With a period of extreme political instability seemingly behind it, the Egyptian government is in a better position to be making long-term plans and it appears that solar is actually fairly high on the to-do list. Lepercq claims Egypt's finance and investment ministers have placed it solar right at the top.

Investment minister Ashraf Salman has identified power cuts as the major roadblock to economic progress.

Michelle T Davies, head of law firm Eversheds' clean energy and sustainability group, praises the long-term approach the government is taking: "Egypt has identified the sectors in which it can achieve growth – [such as] financial services, retail – but in order to achieve growth it needs to have the infrastructure in place so transport and energy are key areas of focus for it..

"From what I can see about Egypt they are going about this in a really considered way across their whole growth programme and if you look at what they are doing with energy, including coal and nuclear and renewables, it is so well thought out. They have looked at what else happens around the world and as long they get the PPA right, they are creating a system that to the private sector and for private investment, is almost ideal."

Jordan

Jordan's progress may have stuttered in late 2014 but its hard work to piece together a PPA capable of attracting top solar developers was a significant milestone for the region.

The country is one of the energy "have-nots" in the region; prices are high, supply not entirely steady. Solar makes perfect sense and the first 200MW tender is set to deliver projects with Trina, Scatec and Phoenix solar among the winners. The next 400MW round of renewable energy procurement – four projects of 100MW each, open to wind and solar – has been postponed but not cancelled.

See next page for Raymond Carlsen of Scatec Solar's account of PV in Jordan. ▶

The best of the rest

Iran

The country is starting from a very low base, but in October 2014 it did confirm plans to double its renewable energy capacity by March 2015. It is eyeing 5GW of renewables generation capacity in the next five years.

Oman

GlassPoint Solar last year secured a US$53million in financing for an enhanced oil recovery (EOR) project. EOR uses steam to increase the return from the well. Remote oilfield operations usually use gas to generate steam. GlassPoint encloses a parabolic CSP system – inside a glass house to reduce the impact of dust – to generate the steam required.

GlassPoint has dealt with the Middle East's dust problem by enclosing its system entirely.
Credit: GlassPoint.

Morocco

Egypt is not the only North African nation that has made progress with solar energy development. Morocco is aiming for 2GW of solar by 2020 and has so far been focused on CSP developments with part-funding from the World Bank.

Tunisia

Clean energy investor Low Carbon and developer Nur Energie are working on a 2GW solar energy export plan from CSP plants. The idea is to send the power to the European grid. It is possible that the CSP project could receive subsidy support from the UK's contracts for difference scheme, which is open to overseas-based projects that export power to Britain.

Algeria

The country's FiT scheme, launched in April 2014, offers a fixed rate for five years followed by 15 years at a new rate determined by plant performance. Two bands of 1-5MW and over 5MW have helped get around 350MW of solar projects into development. Rates vary from US$0.09-0.21/kWh. The scheme seems well on its way to hitting its 800MW target by 2020. In January, the government doubled its 2030 renewable energy target to 25GW in a further boost to the market's health.

Sealing the deal in Jordan

Having blazed a trail in building PV power plants in Africa, Norway's Scatec Solar recently secured financing for its first 43MW of projects in Jordan. Its chief executive, Raymond Carlsen, tells Ben Willis how the company is making the projects work financially

PV Tech Power: What was the story behind the deal in Jordan?

Raymond Carlsen: For us it was important at least initially to have a portfolio approach. So we wanted to have the same banks involved on all three projects – that will reduce costs and ease administration and so forth. So we approached EBRD [the European Bank for Reconstruction and Development] and PROPARCO [the investment arm of France AFD development agency], and they said we like you guys, we're ready. So we connected with them quite early and developed partially some of the projects together with them to make sure that when we moved forward we would satisfy then all the conditions that the banks would want to be satisfied on if they are going to provide most of the debt.

PV Tech Power: In terms of pricing, how much were you at the mercy of NEPCO, Jordan's national power company, or was it relatively straight forward to agree a price?

You probably know these projects were a bit delayed, and I think there were some different opinions in the government on what the right price would be. But on the other hand, we have a programme now, we need to be predictable, if we're not predictable people are going to lose faith in us. So there were a lot of discussions, and what came out I think was a tariff that was pretty close to what it was expected to be in the first place – US$0.16.

PV Tech Power: We've seen solar projects win bids on very low pricing – India, Brazil last year and now Dubai. What danger is there of projects becoming unfeasible because of the very low prices being bid?

RC: You saw the same thing in the US – a bunch of projects were awarded, and no one could deliver. I think it's always troublesome for a company like ours when you're meeting people who have no clue about what it takes to finance [a solar project]. So I think it's sad for the countries who do not understand it. We know what the costs are – nobody is going to throw money after projects at a loss or for free; that doesn't make sense. So if you go in at 5, 10% IRR and you have the normal interest rates, we know what it's going to be. Some people may have a different perception of what the risks are. So I don't think a lot of these low bid projects are going to be built.

PV Tech Power: Development banks have played a key role in financing your projects to date, both in Africa and now Jordan. Will that change as solar becomes more accepted and understood and commercial banks start to come in?

RC: Yes I think so, but I think what you will see before that is that once these projects have been proven with development banks, the IRR expectations to the investors will be coming down. And then slightly in parallel with that you will see more commercial banks coming in.

If you haven't done this before as a bank, you're thinking what is this, I don't know what a panel is, I don't know what consultants these guys are working with, don't know who's going to execute, don't know what the local issues are. Remember we had 91% unskilled workers when we started in South Africa. So there is risk and uncertainty everywhere. But then you see, ok, these guys delivered ok, no problems and you see the first payments coming in from the utility – that's good sign. And slowly the risk is taken out. And of course you don't have any fuel risk: the sun is there, mean deviation every year plus or minus 4%, but that's it. And the fuel is free.

PV Tech Power: The speed with which South Africa has taken off suggests that once projects start happening, that process happens quickly.

RC: Yes, but one element on top of this is the predictability of the programme, if you have a programme. The government of South Africa has a predictable programme – there have been deviations here or there, but they have in their evaluation criteria been open and they've stuck to that. And of course for international investors, that's a boon.

PV Tech Power: How much has that been the case in Jordan?

RC: Overall it's a well run programme. There are a few things that are a little bit different, and those are very local, linked to land issues, who has the rights; some of that took a bit longer, because they had some cumbersome processes, but it seems to work – the documents are coming out of the end of the tunnel, but perhaps not exactly in a process you can follow on a day-to-day basis. But it happens.

PV Tech Power: Are you looking at other countries in the Middle East?

RC: Yes, we are part of the bidding in Egypt now. And we have a strategic relationship with a very important conglomerate in Saudi, but when is that going to happen!

PV Tech Power: Your IPO last year went off fairly well. What difference has that made to your ability to finance your international expansion drive?

RC: What we presented to the market was that we were going to grow from an installed capacity on October 1 2014 of 220MW to 750MW by end of 2016. And then we designed the capital requirements to do that. We got the money in and we are on the road to meeting those targets. That's a pretty steep increase. ■

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Brazil's solar waiting game nearly over

Solar auctions | Months after becoming an unexpected star of the 2014 football World Cup, solar struck gold once again in Brazil when it attracted huge interest in a national energy auction. But low bidding prices and the complexities of a local content requirement have tempered some of the excitement about Brazil's emergence as a solar heavyweight. Lucy Woods weighs up its prospects

Credit: Luan SR, Wikimedia Commons.

After taking a starring role atop a number of the 2014 Football World Cup stadia, solar is poised for further success in Brazil.

Brazil's government has finally turned its focus to solar. "Finally, after all these years of waiting - everyone thought Brazil would come a long time ago and now [the government] has given a pretty clear signal: we are going for PV," says Christian Hallén, business director of developer Solatio Energia.

The announcement of solar-only auctions, the re-election of pro-solar President Dilma Rousseff last October and Brazil's latest national energy expansion plan to 2023 including 3.5GW of solar all signal that Brazil's leaders have finally cottoned on to solar energy's mass potential in the country.

"Politicians just waited and waited till the prices were even lower, to buy even cheaper electricity; they let others, like Europe, subsidise PV in the starting phase," says Hallén. "Brazil decided to stay outside in the beginning, and only started to come in when the prices were low; now they have come down the level is low enough that Brazil has said, 'let's bring PV in'," says Hallén.

The world's fifth largest country straddles the equator, which runs through its northern reaches, providing swathes of land with high natural solar irradiance. Yet the country's inhabitants suffer exorbitant electricity prices, and a booming middle class is pushing up energy demand; the huge country is pleading for solar energy.

With more than 75% of Brazil's energy capacity relying on hydro-power, a sudden and severe drought that began last summer caused energy prices to rocket. Expensive thermal power replaced power from parched hydro plants. Predictions from the Brazilian Photovoltaic Solar Energy Association (ABSOLAR) for 2015 show the drought and a lack of cheap alternative energy sources, will cause electricity prices to rise by another 20-25% on top of last year's 20% rise.

But there is now an economically viable solution. In 2014 ministers announced BNDES, Brazil's national development bank, would help fund solar energy projects. The rules set a number of different local content requirements that must be met for different components of a solar module and system. These will gradually be ramped up to 2020, after which a blanket 60% local requirement will be in place for modules.

BNDES said in a statement last August that the aim of the funding was to "seize the opportunity".

With funding in place, on the 31 October 2014, the national reserve (renewable energy-only) auction attracted investments of BRL7.1 billion, for the construction of 31 solar projects and 31 wind projects. The national auction saw very low project prices bid, averaging out at less than US$87/MWh.

With fossil fuel plants selling power at up to BRL800 (US$325) per megawatt hour, the recent national energy auctions set a ceiling price of BRL260/MWh (US$96) for solar energy, offering Brazil the chance of replacing some fossil fuel generation with renewables at an incredibly low price: 31 out of 400 PV project bids totalling 889.7MW were granted approval at providing electricity at the fixed price of US$86.78/MWh for 20 years, beginning on 1 October 2017.

Although this also means delays in development will result in high penalties, the auctions were overall a "positive surprise", says Rodrigo Lopes Sauaia, executive director of ABSOLAR. The results of the auctions show that "if price levels are adequate the government is interested in introducing more PV into the country; these are very positive signs", Sauaia says.

The BNDES funding provided the financial rocket fuel required to spark international interest and bargain prices. Without BNDES "the prices would be much higher, you would have to go to commercial banks and get interest rates around 12% or more", says Sauaia. There could still be PV in Brazil, but the prices would be much higher, "and the government would not find it interesting at this price, so instead of giving subsidies, BNDES can give financing", adds Sauaia.

Low bidding

The flipside of this is that there are now concerns circulating in the industry that the very low prices bid in the government solar auctions will mean solar projects fail to reach completion, will not come online in time and face penalties, or operate at an unsustainable loss. But others believe that the low profits implied by the level of the bids could be a sacrifice worth making just to get on the first rung of what is a potentially huge emerging market.

"There are no developers that will not have the financial resources, or technical capacity to bring the projects to operation," says Marcos Meireles, the CEO of Rio Energy, a major winner of solar energy tenders last year, in conjunction with Fotowatio. Meireles points out that the winners are not small risk takers, but the likes of global renewable corporates such as SunEdison and Enel Green Power. Big players appear to be the only participants, with consequently little risk of any solar projects being undermined with capital shortages.

The low prices demonstrate Brazil's solar industry is attracting market leaders, agrees Sauaia. "Companies wanted to position themselves as a leading participant in a very strategic emerging market and therefore they were open to reduce some of their financial returns," he explains.

Successful parties in Brazil's 2014 auction

Investor	Installed capacity (MW)
ACS/Solatio	270.00
Enelgreenpower	210.00
Fotowatio (FRV)	149.91
Renova/Sunedison	99.75
Canadian Solar/Solatio	90.00
JMP	30.00
Inharé	30.00
Grupo FCR	10.00
Total	**889.66**

What's more, Hallén believes many concerned commentators of Brazil's solar industry missed the inflation factor: every year the strike prices awarded for solar energy will increase with inflation; by the time the winning solar bids are fully constructed in three years, ready for the 2017 deadline, the contracted price for energy will already have been increased three times with the inflation rate – which is currently about 6% in Brazil.

Hallén predicts by the time projects come online, the price will already have increased by almost 20%, meaning the average selling price will have increased from BRL215/MWh to BRL256/MWh. Inflation will increase every year for the 20-year power purchase agreements signed for solar energy generation too. This "fits perfectly with financial calculations and high radiation," says Hallén. Solatio Energia itself was one of the biggest winners in Brazil's 2014 solar only auction, winning tenders for 360MW by partnering up with ACS Cobra and Canadian Solar, bidding around BRL216 /MWh (US$80).

Domestic manufacturing

The catch to getting such convenient cash injections from BNDES and seemingly super-cheap deals on solar development is of course the local content rule, something that has caused no end of problems in other countries. But the domestic content restrictions on the BNDES funding have been planned out to be slow and progressive, hoping to avoid the mistakes of India and Canada's restrictions in stifling international interest, while tentatively growing Brazil's very own home-grown PV manufacturing industry.

As a result, Sauaia believes Brazil can repeat with solar what it achieved with wind and develop a local manufacturing base. "Brazil very successfully implemented a wind sector locally, including bringing in manufacturing, even though the international market was overloaded with wind equipment. I believe the government can use this knowledge and experience with the wind sector to promote a PV value chain," he explains.

At first, only module assembly lines are needed to meet the BNDES funding requirements. "It makes sense, as it is difficult for a country to fully develop manufacturing in a short amount of time. You need more time to establish a downstream value chain so that you can go up in the value chain in time; it is the natural process in time," says Sauaia.

Meireles also says that cell producing in Brazil right now would be "too aggressive", but Brazil can certainly do the assembling. Solar projects that have won government tenders are required to come online by 2017, and a few years is needed for manufacturers to set up base camps. "2015 will be a very important year for these decisions," says Sauaia. "You need the factories to be able to run by the end of 2015 or there will be a lack of modules for the [winning] projects."

From 2015, BNDES funding requires locally produced aluminium, then from 2018- 2019 additional components will need to be made locally such as junction boxes, then from 2020 onwards, solar cells will be produced in Brazil, along with inverters, structures and cables.

If developers cannot get locally produced modules they will not get the funding, but Hallén is confident this will not be the case. "I am sure everyone will get locally produced modules; in three years you can set this up, and there are now plans with module manufacturers," he says. "If everything continues as it has started now, then there will be enough [locally produced] modules."

As an example of this, at the end of

Credit: Gehrlicher Solar.

last year it emerged that a consortium of German research institutes was carrying out a feasibility study for the establishment of a fully integrated, Brazilian PV manufacturing facility on behalf of the Brazilian-Paraguayan power company, ITAIPU and industry association, FIEP. The study is to test the waters for a 10,000MT polysilicon plant and integrated wafer, cell and module production with a capacity of 680MW.

Latin America has also become a key emerging market focus for module manufacturer, Yingli Green, which has recently announced that it plans to partner up in Brazil to operate a PV module assembly plant too. Several other tier-one module manufacturers "are evaluating bringing their assembly lines to Brazil", says Sauaia. Sauaia and Meireles cite Canadian Solar, Jinko Solar and First Solar as being among the big-name manufacturers looking at ways to bring manufacturing to Brazil. "But these are not established decisions, they are still evaluating the possibilities," adds Sauaia.

Hallén says demand is all that is required to spur domestic manufacturing in Brazil. "As long as the volume is big enough and there is an attractive market to enter for manufacturers, then it should all work."

Credit: Solatio Energia.

The site for one of Solatio Energia's proposed PV projects in the state of Sao Paulo.

However while the continuity of Rousseff's presidency, decided in national elections in 2014 also "provided some certainty for developers and first buyers trying to get PV off the ground" in Brazil, says Adam James, Latin America expert at market research firm, GTM, not 24 hours into Rousseff's second term leading the world's seventh largest economy, Brazil's currency and market tanked after government bonds were downgraded on the back of her re-election.

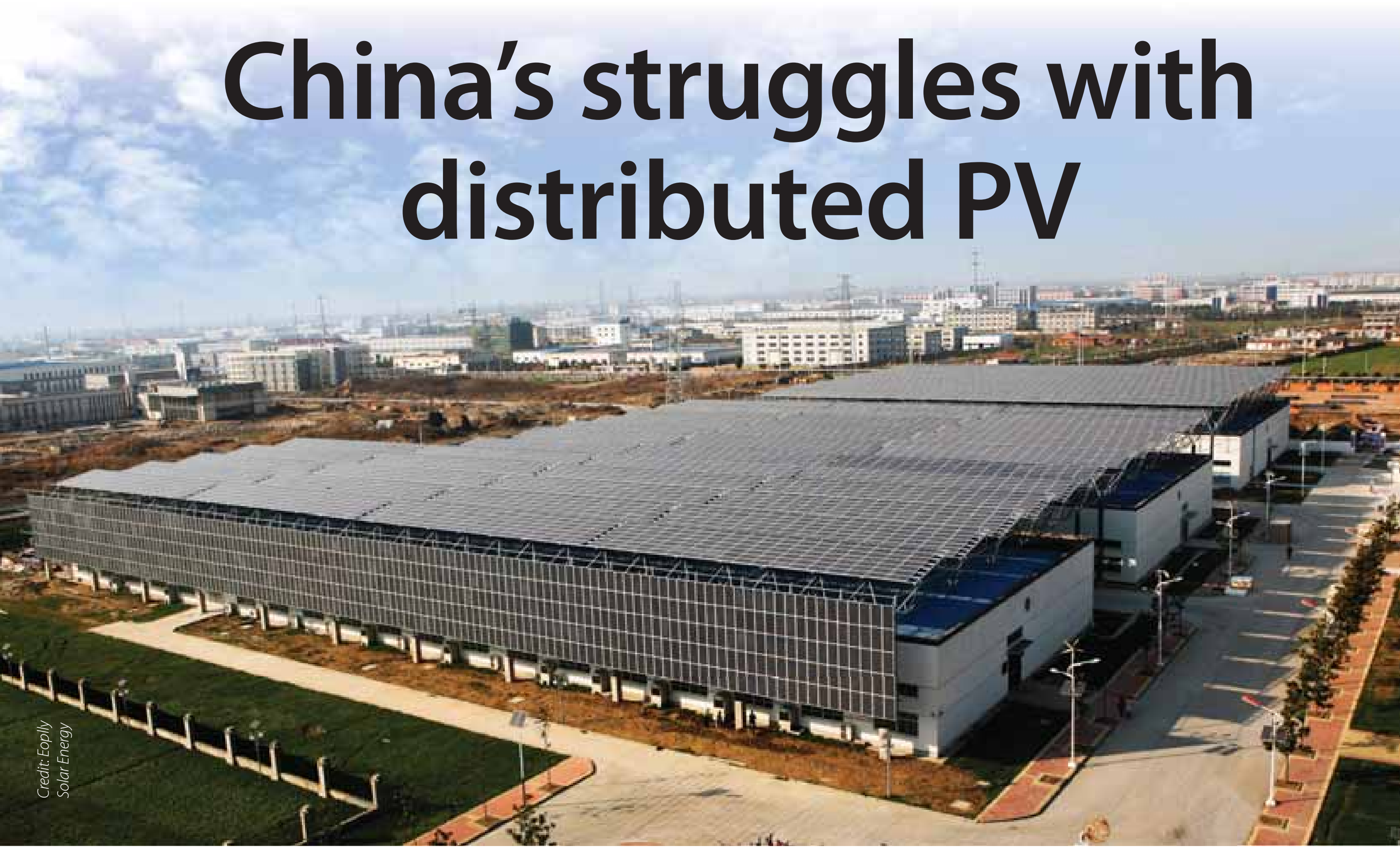
Before Brazil can inject life into its small domestic solar manufacturing, it has to address its falling currency. The value of the Brazilian real against the dollar means an additional challenge for solar projects looking to attract foreign equipment. "You have to watch out for conversion; a currency rate is one thing that is very difficult for investors to predict: how the dollar will behave, it could make a lot of difference between a huge loss and huge gain," says Meireles.

With the elections over, if Brazil can keep currency, solar development financing and domestic manufacturing in harmony, ABSOLAR is planning to advocate for a 1GW solar market in 2015, with Brazil playing a stronger role in manufacturing. For this to happen ABSOLAR is specifically advocating 1GW to be contracted through more auctions.

Meireles reckons the success of the solar auctions last year is just the beginning. "To have solar well developed in Brazil, start with the auctions and then go to the distributed energy – imagine how many jobs you would have," he says.

Hallen says for 2015, "if it is a big enough market, I am convinced there will be more than 1GW a year going forward. Not just speaking about the auction but the residential market too." ■

China's struggles with distributed PV



Credit: Eoplly Solar Energy

Distributed solar | Throughout 2014, there were widespread reports of China's struggles to hit ambitious PV targets, particularly with distributed projects. Beijing-based solar expert, Frank Haugwitz, reveals the difficulties Chinese developers experienced

In January 2013 the National Energy Administration (NEA) of China officially announced an annual target of a minimum of 10GW of solar PV power generation capacity to be installed between 2013 and 2015. The same year, China installed an impressive 13GW – not only more than any other country in a single year ever before, but also exceeding by 3GW the official target.

Reasons why China exceeded its minimum target by 30% are fourfold. First, projects put up for tender during Q4/2012 were not facing any feed-in tariff (FiT) reduction as Q4/2013 projects did, thus these projects were executed in 2013. Secondly, in November 2012 central governmental institutions approved the last batch of so-called Golden Sun projects amounting to 2,834MW. Accordingly, the deadline of these projects was 30 June 2013, but eventually was extended twice until the end of 2013.

Thirdly, in August 2013 the National Development and Reform Commission (NDRC) and the NEA announced the approval of 1,823MW of so-called 'solar PV distributed generation demonstration projects' out of which 793MW of projects were scheduled to be realised by 31 December 2013. Fourthly, in August/September 2013 new 10% lower FiTs effective from January 2014 onwards were announced, triggering a year-end rally and leading to an impressive 6-7GW of executed installations in Q4/2013 alone. By the end of 2013 China's total installed PV power generation capacity amounted to approximately 19.4GW, according to NEA figures.

During the first weeks of January last year various Chinese central governmental entities were quoted as having announced different solar PV deployment targets for 2014 ranging from 8 to 14GW. Eventually, the NEA finally announced a 14.05GW target, divided into 8GW (distributed generation) and 6.05GW (utility-scale, ground-mounted) to be installed in the course of 2014. The government's direction to promote distributed generation versus utility-scale projects is obvious; given its approximately 60% share of 14.05GW, as well a moderate growth of approximately 8% year-on-year, this was clearly considered to be more sustainable.

Distributed solar fell short of deployment targets in China in 2014.

Importantly, for the first time, the NEA released a breakdown of the 14.05GW national annual target into individual provincial targets, which were further divided into both types of project categories (distributed and utility-scale). The purpose of the annual target breakdown was to underline the central government intention to guide the overall market development, as well as to avoid more PV power plants being subject to grid curtailment in western provinces such as Gansu, Qinghai and Xinjiang in particular.

To take Gansu Province as an example, in 2013 it was the most favoured destination across China with 3,842MW additionally installed PV power generation capacity. The same year the solar curtailment rate in Gansu was on average 13.78% according to generation companies, compared to just 5.49% claimed by the Gansu grid company. Against this background, it did not come as a surprise to see Gansu's 2014 target being set at just 500MW (utility) and 50MW (distributed), which basically is a reduction of approximately 85% year on year. Latest figures suggest that in 2014 approximately 700MW were installed.

The National Energy Administration's announcement to aim for 8GW of distributed solar PV in 2014 was met with some scepticism by the Chinese solar PV industry, due to the fact that in 2013 out of the 13GW installed in total merely 800MW of projects were considered 'distributed', thus the NEA aimed for a tenfold increase in a single year. In an attempt to ensure realisation of this 8GW target, in early February 2014 the NEA released a list of 81 so-called 'new energy demonstration cities' and eight so-called 'industrial demonstration zones' spread across 28 and eight provinces respectively. Accordingly, by the end of 2015 these cities and zones are required to realise their respective mandatory targets in terms of, for example, an X amount of megawatts of PV installations and/or an X% share of installed renewable energy power generation capacities.

Slow going for distributed projects

Chinese project developers supported the government's drive towards distributed generation. However, given the prevailing administrative, financial, technical, and operational complexity of distributed solar PV compared with large-scale ground mounted projects it did not come as a surprise that in the first nine months of 2014 distributed solar installations fell very short of its expectations. According to NEA figures, between Q1 and Q3 just 2.45GW of utility-scale and 1.34GW of distributed solar PV projects were realised.

There were a number of reasons explaining why distributed solar PV installations experienced a rather slow development: the average lifetime of buildings not matching a business model based on 20 years of FiT payments; identification of roof ownership; the quality of roofs in too many cases not being good enough for rooftop systems; the favoured self-consumption model by NEA assuming that 80% of the self-generated power would be consumed on-site with the remaining 20% sold at a lower tariff to the grid, when reality showed that the self-consumption ratio was well below 80% thus causing a negative impact on projects' financial viability; contractual risks in case of ownership transfer of the buildings; and the perceived risks among local financial institutions making it challenging to mobilise the required funding for such projects.

Given the myriad constraints hampering a fast and smooth execution of distributed projects across China, industry and governmental representatives between March and August last year frequently met, in order to discuss how a fine-tuning of corresponding policies could ensure a removal of the main barriers. As a result of this consultation process NEA published its distributed solar PV policy update on 2 September.

> "Given the complexity of distributed PV, it did not come as a surprise that in the first nine months of the 2014 distributed solar installations fell very short of expectations"

The 'new' policy was considered fairly comprehensive and sufficiently detailed allowing distributed projects to be developed at a much faster pace than before. Relevant responsibilities were identified and allocated accordingly. The emphasis on 'quality' and the planned establishment of a nationwide monitoring and reporting system certainly adds pressure to developers and for example EPC service providers to ensure that installed systems deliver a high performance on a long-term basis.

Meanwhile, NEA's encouragement that all administrative levels shall implement further financial support policies will undoubtedly increase the financial viability and stimulate demand. As of today, at least two-thirds of all provinces in China are offering additional financial incentives, for example in the form of an additional tariff per kWh, capital subsidies for the procurement of the hardware, or both. Generally such additional incentives are designed to promote distributed solar PV. In addtion, several local governments pursued a local content requirement policy, i.e. additional local financial support was provided as long as fairly significant share of goods were locally procured. In an official notification released by NEA in October such practice shall be abolished as it was felt to be holding projects back.

The new policy will certainly require time to bear fruit and it remains to be seen how much China was able to install in Q4 last year. An indication for sustained demand is that in October the NEA granted the Southern Xinjiang Autonomous Region permission to install an additional 1GW, taking that region in total to 1.85GW. Apparently the provincial targets set earlier last year were not set in stone.

In addition there is a 'new' definition of distributed projects; since September projects up to 20MW including ground-mounted applications in specific areas like fishponds, agriculture, mountain slopes, tidal zones, etc. feeding into the mid-voltage (35kV) grid have been included in the category of distributed systems, which thus allows projects prior to the policy announcement classified as utility-scale now to 'migrate' into the distributed category. Such a migration of projects has the potential to 'add' an estimated 1.5 to 2GW of projects to the NEA's desired share of distributed projects and could result in overall distributed solar projects amounting to approximately 4GW.

On December 25, China's NEA held its annual national energy conference in Beijing and its now former head, Mr Wu Xinxiong, announced that by the end of 2014 China's total installed and grid-connected solar PV power generation capacity amounted to 30GW. This statement implies that last year's installations were at least 10.5GW taking into account that by the end of 2013 NEA announced a total installed capacity of 19.4GW.

Given that the announcement was made before the end of the year the author of this article believes there "is room for more", i.e. in light of AECEA's project demand monitoring that a 12GW appears to be feasible. This would mean the share of utility-scale projects increased from the 6GW initially set in 2014 to up to 8GW. ■

Author

Frank Haugwitz is an expert on PV and renewable energy in China. Based in Beijing since 2002, he founded and directs Asia Europe Clean Energy (Solar) Advisory (AECEA), a consultancy working to help European and Asian companies understand Chinese renewable energy regulation and policy. Since 2013 he has been the elected vice chairman of the Renewable Energy Working Group of the European Chamber of Commerce in China.

Diesel faces the squeeze in Southeast Asia

Diesel offsetting | At a conference in Thailand at the end of 2014, delegates heard of the region's attempts to break free of costly diesel power. Lucy Woods reports on the progress solar energy is making in displacing the diesel generators

Credit: Sonnedix.

The sub-continental region of Southeast Asia is one of the last places on the map to be electrified – but the region could also be one of the first to displace the majority of its fossil fuel generation with solar. At the end of 2014, Solar Energy Southeast Asia, hosted in Bangkok, Thailand, by *PV Tech Power's* publisher, Solar Media, heard multiple speakers hailing solar's growing competitiveness with the current dominant fuel source: diesel.

Crude oil-based diesel generators fuel the vast majority of Southeast Asia, where sprawling island geographies make centralised grids something of a rarity. In a region prone to typhoons and the worst effects of climate change, the case for solar in Southeast Asia is particularly symbolic, and all these factors are making the region a fertile testing ground for solar energy innovation, including storage, hybrid and mini-grid technologies.

Using "hybrid mini-grid" technology is the only way for Southeast Asia to go, said Andy Schroeter, CEO of off-grid specialist, Sunlabob. Mini-grids, decentralised new technologies are proving the cheapest and quickest way to provide power to the 134 million people, or 22% of the population of Southeast Asia, who do not have access to electricity, Schroeter said.

Southeast Asia's reliance on costly diesel generation is providing impetus for the deployment of solar in the region.

There are very low electrification rates in Cambodia, Myannmar, Indonesia and the Philippines, along with high grid rates, said Schroeter, adding the best commercial possibilities for solar is away from highly hydro-based countries such as Laos and Thailand.

According to Sunlabob the most commercially viable solar opportunities for solar hybrid projects in Southeast Asia are in areas where there are high loads relying mainly on diesel fuel. From private mini grid operators using generators, on- and off-grid factories, fish processing centres, agricultural processing buildings, telecommunications towers, to hotels and hospitals: there are many possibilities for solar to replace and offset diesel generators.

Solar is easier and cheaper to maintain, cleaner and safer and saves money over time, said Schroeter – but education is required on the longevity and reliability of solar energy., he added.

Solar-diesel parity

"Solar is at parity" with diesel in the Philippines, said Tetchie Capellan, founder of the Philippine Solar Power Alliance (PSPA) and managing director of local installer, Solarus Partners. Capellan is certain that solar-hybrid development is the solution for bringing clean energy to the 7,100 islands in the Philippines. Due to the Philippines' archipelago geography, formed of thousands of islands, there is no centralised grid but diesel generators instead, which Capellan said are "perfect for transitioning to solar off-grid hybrid solutions, due to the rich solar resource".

According to PSPA, in the Philippines, solar costs US$0.21 per kWh, while diesel costs US$0.28 – and provides zero investment opportunities to get generation costs back.

"There is no return on diesel", whereas solar has a return on investment (RoI) in "four to five years", agreed Wuthipong Suponthana, founding member of the Thai Solar Club and managing director of hybrid system specialist, Leonics.

"Solar today is competitive with diesel," added Deepak Verma, managing director of nv vogt – which is developing a PV project in the Philippines to offset diesel generation. However, Verma explained that solar cannot yet completely replace diesel; because solar energy cannot meet evening peak energy use, it could only offset diesel use.

Nevertheless Verma said that with 40% of peak energy generated by diesel today, just in the Philippines, displacement of solely peak energy use creates an 800MW opportunity for solar energy. Capellan said that most islands that have electricity in the Philippines only have electricity for a few hours; solar-diesel hybrids could provide electricity 24 hours a day

Solar's inroads in Southeast Asia

Singapore

Singapore is developing plans to aggregate its solar energy generation, to defeat solar's perennial problem with intermittency due to cloud cover. Power would still be variable, but more stable, and would require vast amounts of weather data, which the government is currently attempting to gather. So far the data indicates Singapore is too large to be covered in cloud simultaneously, therefore continuous solar energy should be possible with adequate, smart distribution and storage systems. The government is also in the process of creating an online PV potential map for all of Singapore using GPS mapping. Members of the public will be able to go online and find out the PV potential of their rooftops.

Thailand

Thailand is the leading solar deployment in Southeast Asia, with 1.087GW total installed capacity in 2014, an increase from 785MW in 2013 and 220MW in 2012. Solar is also cheaper than liquid natural gas (LNG) on a levelised cost of energy (LCOE) basis in many cases in Thailand, depending on the reduction of fuel costs and caps to the cost of new national infrastructure fund programmes. Currently under discussion by the Thai government are regulations on government power purchasing from solar PV generation, the creation of an agricultural cooperation programme and the negotiations of a new solar PV ground-mount committee, with possible changes to the feed-in tariff (FiT) on the table.

Philippines

Made up of over 7,000 islands, the Philippines has vast potential for mini-grids and distributed solar, and small solar panels with batteries have been used in rural parts of the Philippines for more than a decade. But now the country looks to be on the cusp of becoming a serious solar market. The Philippines recently introduced a feed-in-tariff for 50MW of solar, at US$0.22 per kWh; the cap was increased last year to a further 150MW total. It is predicted the Philippines will reach a 1GW market in the next few years at least, hot on the heels of the region's leading solar deployment champion, Thailand.

Indonesia

At the Brisbane G20 summit last November, Indonesia's newly elected president, Joko Widodo, announced a 35GW power plan for the island nation, including 20% renewables – of which 20% will be solar. Streamlined solar licensing and PPA application procedures have been promised by the new government, as well as the introduction of special economic zones to attract investors and private business, and the creation of a solar fund. Local authorities will provide local land, and national government will provide 25-year standard power purchase agreements to independent power producers. In May last year, the two Australian firms SGI International and Mitabu Australia, merged to form SGI-Mitabu and develop a 50MW solar power plant in South Sumatra, Indonesia.

Diesel subsidies

One of the major barriers to developing solar, despite its many merits, is governments subsidising diesel fuel heavily. This is particularly the case in Vietnam, where solar project developers should be flocking to the large land and natural solar resources, but government diesel prices are barring the way, said Paul Puthenpurekal, president and CEO of renewable energy developer, Solutions Using Renewable Energy (SURE).

At current tariff prices in Vietnam, solar development "is not possible" said Puthenpurekal; diesel-generated power is now US$0.06 per kWh in Vietnam – "too low" for solar to compete. Puthenpurekal said revenues of between US$0.10 and US$0.12 per kWh were needed to make solar projects profitable, as currently the price of electricity in Vietnam is far beyond US$0.10-0.12, "but the government is suppressing the prices based on subsidies [for diesel]", he said. Puthenpurekal said without subsidies, diesel fuel costs close to US$0.30 per kWh – three times the break-even cost of solar energy.

In Indonesia, solar is being provided with political green lights as a newly elected president begins changes to national energy policy to help replace at least 20% of current diesel power use. "The focus is to replace existing diesel power stations on provinces relying heavily on diesel," said M Rusydi, director of solar developer, the Solar Guys International (SGI) Mitabu Australia.

Although some governments are understandably slow to transition while resources are prioritised for rebuilding natural disaster-stricken cities, solar is finding opportunities, breaking technology barriers and innovating its way into this tricky emerging market. ■

Solar Media will host Solar Energy Southeast Asia again in Bangkok later this year, on the 24 & 25 November. Further details are available from http://seasia.solarenergyevents.com/

Emerging solar markets in 2015

In 2014, a number of countries around the world began to develop into serious solar end markets. Ben Willis asks IHS analyst Josefin Berg to give her tips on the emerging markets to watch over the coming year

PV Tech Power: Which were some of the emerging-market star performers in 2014?

Josefin Berg: There were some very positive developments last year. We saw South Africa really moving ahead quickly, ahead of time; projects that were scheduled to come online in 2015 were commissioned already in 2014. Now however that's going to impact growth in 2015, since South Africa is depending on what's been awarded in previous tenders, so we might see a slight drop in South Africa. And there was even a bit more of a cautious attitude towards renewables at the end of 2014 in South Africa because of problems with the grid, which led to the postponement of round four bidder announcements [under its renewables programme]. So it started cautious then grew quickly, and now there are some new barriers. But overall the growth of South Africa has been very positive.

Another market we saw take off is Chile. It's another of these countries that people have been looking at and talking about for several years, and wondering when it's going to take off. And after SunEdison installed its first project in 2013, we've seen more and more projects taking off there. It's taken a long time for projects to get PPAs [power purchase agreements] in Chile; we've seen some projects are betting on the spot market to get their projects built and and they might be looking to get a PPA later on. There's a lot of IFC funding and other multilaterals in Chile; we've also seen some private banks opening up for projects in Chile. Chile will definitely be for 2015 a very strong market. We think it could install up to 800MW, so by the end of 2015 it could have 1GW. But this is the beginning of the year – projects could go faster or slower.

If we're looking at the new markets, we saw some very positive indications from Jordan, which finally closed financing for some of the projects that have been in the pipeline for a while. We think Jordan could install up to 200MW this year.

And Egypt in December awarded feed-in tariff contracts to 2GW of projects. There will be a lot of hurdles for these projects to be deployed, but it definitely raises our outlook for Egypt and we're looking into that now to see how we should assess it – whether it could go like what we've seen in South Africa, or if there will be a lot of hurdles. They've awarded the projects, but they still have to go through the whole processing of PPAs, and it could be like Jordan where it's been a very cumbersome process to get projects ready to build.

Then of course Brazil's solar auction has been very positive news for emerging markets. Brazil has been one of these markets that we feel has to take off at some point. The policy hasn't been there; we've seen the pipeline build up, but in Brazil wind has been the strong renewable technology. So coming out with a solar-specific auction, that's very positive for Brazil.

PV Tech Power: Where else do you expect to see break-throughs in 2015?

JB: Our recent 2015 predictions paper highlighted the Philippines. We've forecasted over 200MW for the Philippines this year, but in a high-case scenario it could go up to 500MW. We're still assessing how much is going to be installed until the feed-in tariff (FiT) cut expected in March, and then exactly what the FiT is going to be after that. But there are projects being built outside the FiT in the Philippines, so that's definitely a market to look at.

And also in Honduras we saw projects signing PPAs last year with the regulator. They had a plan to install 300MW in Honduras, but they've oversubscribed in terms of the PPAs they've signed. And we've seen already projects starting construction; SunEdison has just received finance for a project, Scatec Solar is also starting a big project there.

PV Tech Power: What are the main factors propelling these markets forward?

JB: The first and most important thing in most markets is policy. Policy has developed; policy-makers are allowing private project development to go ahead. And they're encouraging solar technology – that's what's making the difference in these markets. There's a lot of talk about non-subsidised solar and that solar can stand on its own two feet now. But whatever the power technology you're talking about, it needs to be anchored in policy and regulation, and ideally have some kind of support.

> "Policy-makers are allowing private project development to go ahead. There's a lot of talk about non-subsidised solar, but whatever the power technology you're talking about, it needs to be anchored in policy and regulation"

PV Tech Power: What about the laggards? A number of places get talked up but haven't delivered yet – Saudi Arabia, Turkey and Mexico to name a few. What's holding them back?

JB: Saudi Arabia raised great expectations across the solar industry when it first announced renewable power targets in 2012. The plan to open up tenders in one of the world's wealthiest nations attracted a hoard of developers and manufacturers to Saudi Arabia to develop new business. As regulators have not progressed on the planned tenders, and PV installations have stagnated at less than

Chile was one of the emerging market success stories of 2014 and looks set to carry that good form into 2015.

20MW, the PV industry is growing restless. The latest announcement to postpone the target year to 2040 deflates further expectations of near- to mid-term growth.

The past months' extraordinary decline in global oil prices is likely to reframe the Saudi position toward new power generation sources. At current global oil prices, the incentive to save oil for export weakens for near-term deployment. In the long-term, the argument to reduce oil consumption remains valid, for which IHS expects Saudi to deploy the bulk of new PV capacity in the period from 2020 to 2040.

As for the other markets where we see uncertainty, Brazil has made a huge leap forward by holding solar auctions. Now the second step for these projects to move forward is to organise financing and then have a realistic plan for installation. There are still a lot of question marks in Brazil regarding local content and the whole financing situation.

In Turkey it's also about policy. They awarded the first part of licences last year, and they're set to award the remaining capacity this year – auctions are coming up at the end of January. What we've seen from the first round of projects last year is that it's been a slow process from awarding the projects to getting contracts and details implemented; the bureaucracy is holding things back.

Mexico is one of the markets that's more complicated. Financing is a big problem because a lot of the projects there are depending on spot prices and they're competing with wind projects. Solar is still struggling to find its place in the Mexican market.

PV Tech Power: Does sub-Saharan Africa, outside of South Africa, offer much potential this year?

JB: There are a lot of announcements in Africa of very big projects ranging from 100MW up to 1GW of projects, and then a couple of memoranda of understanding, but nothing much beyond that. There have been projects that have been cancelled – Zimbabwe had a big pipeline, but the projects were cancelled or postponed indefinitely. That's very likely to happen in other markets too. There will be some countries where projects are installed, but it will be on an individual basis and not at a programme level or as a general trend. Any power project you want to pursue in the region is going to be quite a challenge.

PV Tech Power: Are we likely to see any surprises this year in terms of new markets opening up?

JB: Well have to see what's happening in the rest of Latin America. Until now it's been quite concentrated in a few countries. Overall in the rest of Latin America, there are a lot of other power generation sources in the region [for solar to compete against]. But it would be interesting to see which of those countries open up – maybe just even a small programme or tender.

Also Southeast Asia is one of those regions people expected a lot from but aside from Thailand hasn't delivered that much over the past years. Now we're seeing the Philippines taking off and we'll have to see what the other countries in the region are willing or able to move on and accelerate the success of their solar programmes. ■

Japan battles solar gridlock on path to parity

Credit: Kyocera.

Policy and regulation | Grid constraints, feed-in tariff fears and the spectre of a nuclear resurgence have all threatened to derail solar's astonishing rise to prominence in Japan, but the country still looks on course to be 2014's second largest PV market. Andy Colthorpe reports on the state of Japanese solar as it begins its five-year countdown to grid parity

Japan's solar feed-in tariff has catapulted the nation to being second largest solar end market after China for the past two years. With over 10GW installed in just under two and a half years, the support solar has enjoyed, both from the public and in policy incentives, has been unrivalled, so much so that all solar of over a megawatt generation capacity has gained the typically Japanese-sounding nickname "megasolar" in the country's popular parlance.

However, the picture has become ever more complex as the market has matured, with a number of recent issues unsettling the industry. Concerns have mounted over a variety of issues: the possible impact of widespread solar deployment on the country's grid network; a review of the feed-in tariff programme, which has set stringent new rules for developers, a lack of suitable land for large-scale projects, and the pressure on electricity bill-payers to foot the cost of renewable energy programmes. Add to the mix the prospect of a limited restart of Japan's shuttered nuclear power stations, and the result is that there now seems to be a growing consensus that the days of the 'megasolar' rush are already fading for Japan.

Nevertheless, as the solar feed-in tariff programme enters the last five years of its intended lifespan, there is a determination among industry players and advocacy groups to weather the current challenges and nurture the evolution of Japan's PV market into a sustainable facet of the economy – and of Japanese energy security.

Grid concerns

The most widely documented aspect of Japan's recent solar troubles is the decision last year by five of its 10 regional utility companies – which are also responsible for grid infrastructure in their respective areas – to suspend the approval of grid connection applications for utility-scale solar projects. Beginning first in September 2014 with Kyushu Electric company, which is responsible for electricity supplies on Kyushu, the most southern of the four main Japanese islands, utilities in the regions of Tohoku, Shikoku, Hokkaido and Okinawa all followed suit.

Japan has a seen a proliferation of 'megasolar' plants being planned and build since its feed-in tariff was launched.

It is thought that grid disturbances become more commonplace when PV penetration exceeds 10% and while none of Japan's utilities had reached that point by last September, Kyushu Electric was closer to that point than the others. Keiji Kimura, senior researcher with advocacy group Japan Renewable Energy Foundation (JREF), says the decision by Kyushu Electric was perhaps fair, but questions why the four others also stopped accepting applications when their capacity was nothing like as acute a situation as Kyushu's.

"Five utilities put solar applications on hold. Of these, the only one you could definitely say had concrete issues with capacity addition was Kyushu Electric. It's the most southern of the main electric utilities, where solar capacity has greatly increased. If PV-generated power was to continue to be added to the grid at the rate at which projects were being accredited, it would soon have become more than it could handle, I think that's true. It hasn't actually come to pass yet, but in the case of Kyushu Electric you could say it would genuinely become a problem before long," Kimura says.

"At the other four electric companies in question, their situation may not have been so acute but they must have seen Kyushu step forward and also seen it as an opportunity to confront the issue. It's fair to say that the issue of grid connection merited and needed further study. However, the way utility companies announced that they would suspend approvals and followed through on that threat the very next day was pretty bad."

RTS PV, the Tokyo-headquartered PV market research and analysis firm, was invited to act as an independent observer of the deliberations of a working group set up in October by Japan's Ministry of Economy, Trade and Industry (METI) to examine the grid issue. RTS PV's Hiroshi Matsukawa believes the group, which concluded its deliberations in December, appeared to arrive at reasonable conclusions given the available data. Yet when asked if the working group was effective, Matsukawa points out that the working group made all of its calculations using data provided by the electric companies in the first place.

"That's a difficult question to answer," Matsukawa says. "I'm sure the deliberations of the working group are correct, but when it comes to that complex and detailed data, only the electric companies have it. So in truth, it's very hard to know whether the conclusions on grid capacity are entirely correct."

Keiji Hidaka, deputy director of the Agency for New and Renewable Energy at METI, bats away Matsukawa's concerns. According to Hidaka, his department was satisfied that data submitted was accurate, following extensive discussions with the utilities.

However, JREF's Kimura has further criticisms of the process, including one linked to the question of the nuclear restart.

"All of Japan's reactors are currently shuttered, yet the data used for the study of available grid connection was conducted with nuclear power capacity from all of Japan's reactors factored in, as if they were all restarted as part of the load on the grid," he says. "Quite aside from concerns over the nuclear restart itself (see box), the predicted amount of available capacity for renewable energy is greatly reduced as a result of this methodology being used."

METI's Hidaka confirms to *PV Tech Power* that "two or three" of Japan's nuclear reactors are expected to come back online this year, but in conversation did not account for the entire fleet of reactors being included in the calculations of the working group.

The working group made its calculations nonetheless and, as Matsukawa reports, the five utilities were found to have received around 17.3GW of applications more than could be accommodated – according to the electric company data – meaning some disappointments are unavoidable. But despite the situation being portrayed in mainstream media as severe, this still leaves over 50GW of approved utility-scale solar projects in development.

The rush to build 'megasolar' power plants in Japan has led to claims of a grid bottleneck.

Credit: Solar Frontier.

Negative impacts

So what impact have these grid connection issues had on Japan's solar industry? While it is too early to say, JREF has conducted a survey of solar companies, with over 130 respondents, which it intends to publish during the first quarter of this year.

Kimura says that around 60% of the companies that responded nationwide said they were directly negatively affected by both the grid connection issue and its attempted resolution. Respondents attributed three separate negative effects to the grid problem, Kimura says. The first was that some companies have had to cancel certain projects and plans, as customers that they were working with have given up on the idea that utilities will buy their PV-generated electricity.

The second is that would-be developers are starting to fear that utilities could turn their backs on solar and will no longer buy from solar power producers. There is a belief that even well-developed projects will not have the chance to connect to the grid, Kimura says. The third and final reason, possibly the most damaging of all, is that developers, their partners and customers are finding it increasingly difficult to plan ahead in such uncertain circumstances.

"Many companies in solar are used to making three- or five-year business plans, yet there is a feeling that electric companies could again announce that they cannot accept more solar or pay for existing output capacity," Kimura says.

"There's also a belief that the other five utilities not involved in the original grid connection issue could suddenly do something similar at some point in the future. So it's hard for companies in the solar industry to know how much business they will be able to do over a number of years."

FiT review

It is of course a fact of life that adding large amounts of variable generation from solar (and wind) can present challenges for

Credit: Solar Frontier.

transmission and distribution networks. There is also recognition that an attempted pipeline of more than 70GW of projects, over double Germany's entire installed PV capacity to date, would not be a path to fostering sustainable development and deployment.

As well as setting up the working group on grid connection, the government also recently undertook a review of the FiT rules as a response to the bottleneck of project approvals that many feared would lead to a possible boom-and-bust or 'bubble' scenario.

On this point JREF's Kimura, RTS PV's Matsukawa and government representative Hidaka all agree a review was needed. In Japan, projects are put to the Ministry of Economy, Trade and Industry (METI) for equipment accreditation to qualify for the FiT and get a grid connection. If the equipment registered to be used on a project was from a government-sanctioned list of suppliers, equipment accreditation was not refused, explaining why so many projects had been accepted; Matsukawa says that 24GW of projects were given equipment accreditation for the FiT in March 2014 alone. Fears had persisted of developers or investors scrambling to secure high FiT rates for their projects and waiting for equipment and other costs to fall before actually applying for grid connection. Other forms of speculation, such as the trading of projects, are also coming in the line of fire of the rule revisions.

Distributed PV arrays on rooftops are expected to become more common as the pipeline of utility-scale projects runs dry.

Kimura, while critical of some of the details, says the review could help take some of the rising cost of the FiT away from the public purse.

"We don't know yet what the effect [of the review] will be, but as a whole we think it will probably take things in the right direction. The purchase price is now decided at the time of grid connection rather than at the equipment accreditation stage, so that only companies that really want to do business will have the benefit of the high FiT rate," Kimura says. "Committed and serious companies should still be able to get grid connection in future so overall this is probably a good thing."

However, RTS PV's Matuskawa describes some of the new rules as "very strict". To ease possible strain on the network, utilities will now have the right to make decisions hourly on whether to purchase the output from solar plants for the equivalent of 30 days a year, rather than informing PV plant operators with a day's notice as before. It is also compulsory for new PV plants to be fitted with remote output controls on inverters.

One rule that will present a challenge for foreign firms looking to do business in Japan is that once equipment accreditation has been granted, a project's developers can no longer change components from those registered, without seeking METI approval – even if the project itself has changed hands since. With the exception of PV module manufacturers from abroad, mainly from China, for foreign companies the interest in Japan remains primarily the more lucrative project development side of the business. The new rule presents a challenge for companies such as Conergy, which recently completed its first Japan project as an engineering, procurement and construction (EPC) firm.

"Many project rights were traded and if people like us or other investors would buy these projects, the first thing you'd do is change to components you would normally use, in order to guarantee quality and make it bankable," the company's head of Asia operations, Alexander Lenz, says.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"After January, it's not possible any more to change your components, or if you want to do that you have to go down to the current or actual FiT."

But Lenz says he agrees with the Japanese government and others that the rule changes were largely positive in that they will make it more difficult for speculators to enter the market and buy projects as investments. Another positive highlighted by Lenz and others is that none of the measures are to be retroactively applied to existing plants.

Government answers critics

METI's Hidaka says the government understands that the FiT review's results present some challenges for the solar industry. However, he says it would be a question of serious companies weathering the storm and realising that the priority should be the Japanese public.

"It is true that there are some companies for whom making business plans will become more difficult, yes. Having said that, prices for solar in Japan are very high compared to places like much of Europe and this leads to a situation where some are able to make a lot of money from it. We want participants to think about why are they are involved in the solar energy business here in Japan and do their best to keep lowering the cost of renewable energy," Hidaka says.

While the rules are tough, Hidaka says, committed companies would still manage to do good business – a point with which Hiroshi Matsukawa of RTS PV seems broadly to agree.

"It's a very strict set of rules, and even for many serious industry participants, it's considered a nuisance. However this bubble situation is really growing excessive and not eradicating it would lead to problems even for those sincere and committed industry players," he says.

Targeting a sustainable future

In the context of the bigger picture, Japan is reaching the last five years of its FiT, due to expire in 2020. As with every other country to have used support schemes to foster the growth of solar, the race to grid parity is becoming more and more of a priority. However, as the Japanese government will launch its first set of concrete targets for the national energy mix since 2010 this year, solar will be guaranteed at least some support from the top level.

Therefore the view from the ground in Japan is that the next two, three and perhaps five years will see several gigawatts of solar installed annually, much of it large scale and the vast majority taken from the existing pipeline of some 70GW-plus of approved projects. A spokesman from Japanese vertically integrated thin-film manufacturer and developer, Solar Frontier, tells *PV Tech Power* his firm expects to see "6GW to 8GW of installations per year over the coming three to four years".

Beyond that, many in the industry largely see a move toward more distributed models of generation, which would necessitate a shift to more rooftop PV plants and for long-awaited, long-promised reform of the electricity market to finally begin in earnest.

While Japan's utilities have regional monopolies over their service areas, controlling generation as well as transmission and electricity sales, as well as stifling competition, there is also little interconnection between each region's grid. While the parameters of a unified or partially unified grid network will be discussed this year, it is hoped that liberalisation of retail electricity sales will happen in 2016 ahead of the unbundling of electricity transmission and distribution at some unspecified point in the future.

Many have expressed doubts that this will happen on schedule, citing a lack of evidence that talks have made any real progress, but according to JREF director Mika Ohbayashi, if successfully followed through, EMR could change the picture once again for Japan. ■

Land matters

Another issue currently being addressed, both at a policy level and by private companies in Japan, is the lack of available land for solar.

While it will not prove to be a miracle cure, the government has begun offering extra subsidies for PV projects developed on landfill sites. It was reported in August last year that around 7.4GW of extra solar capacity could be added across 3,600 such sites.

Developers themselves are also actively looking for new ways to site their projects. The use of land reclaimed from the sea for commercial and residential purposes is an existing tradition in the Japanese construction industry. The international airport at Kansai in the south west is one such example and a 70MW PV project in Kagoshima, Kyushu, is another.

Not unique to Japan, but expected to proliferate quickly, are the floating PV plants on reservoirs and other bodies of water, with Kyocera planning to develop over 60MW of PV on such sites. Other sites where space has been freed up include a number of PV plants being built on defunct golf courses, of which Japan has many.

Credit: Kyocera.

Floating PV plants, such as this one built by Kyocera, are seen as a solution to land shortages in Japan.

The nuclear question

According to Keiji Kimura's colleague Mika Ohbayashi, director of JREF, support for solar among the Japanese public remains at a high level while popular sentiment against nuclear energy remains strong.

Arguably, no country in the world could be expected to be more wary of nuclear power than Japan. However, as one Japanese source who works in the renewable energy industry and did not wish to be named said, the need for energy security was a pressing enough concern that many Japanese were accepting reluctantly that nuclear return is inevitable, the only caveat being that the falling or fluctuating price of oil could yet have an unknown impact on energy economics in Japan.

For many Japanese, accepting that economics and Japan's lack of natural resources is driving the country back towards a pact with the nuclear restart – or 'sai kadou' - will be a bitter pill to swallow.

Credit: Hoshu, Wikimedia Commons.

The possible restart of some of Japan's nuclear fleet is a source of controversy.

All about PV power plants: Challenges for technical bankability

Quality assurance | More than ever, the global PV market provides attractive new investment opportunities, but the elements driving such rapid expansion also increase the risk of solar financial assets failing to meet long-term fiscal and performance goals. Boris Farnung, Björn Müller and Klaus Kiefer of Fraunhofer ISE, and Peter Bostock and John Sedgwick of VDE Americas explore major quality-assurance measures and the challenges today for achieving bankability of utility-scale PV plants

The PV market is growing rapidly and globally. Ongoing R&D coupled with economies of scale drives cost reduction and efficiency. Competitive price levels of PV power plants have led to solar energy being less dependent on government support to provide attractive levels of investor returns. In order to achieve bankability and differentiation, a first-rate level of certification and quality assurance at the system level is essential.

Importantly, it is necessary to go beyond the existing standards and implement new and customised quality-assurance products that address quality on a system-wide level. Such an approach leads to lower technical risk and increased trust and confidence for a PV system as a secure investment. Real-world experience highlights the importance of system design, proper planning, engineering, component selection and construction work for the success of a PV system. Thus, comprehensive quality assurance for PV power plants needs to cover all phases of the completion process, from planning to system operation and maintenance [1].

Quality assurance for PV plants

In general, technical risks arise from the components, construction and operation of PV power plants. Over the past few years, the modules have been the key component for bankability. However, because the investment share for modules is now decreasing, the inverters and other balance of system (BOS) components, as well as the system as a whole, are gaining more focus. The inverter, as the interface between generator and grid, is an essential component with regard to reliability and technical bankability. Today, the quality of large-scale PV plants is also differentiated by their design and construction.

On the other hand, components such as modules are produced under enormous cost pressure, at different locations worldwide, with frequently changing bill of materials (BOM), but indicated as the same module type. These trends are additionally challenging the quality assurance for the manufacturers as well as for the customer. Furthermore, recently observed failure mechanisms – such as potential-induced degradation, micro-cracks, snail trails and discolorations – may lead to a declining investor trust in the reliability of PV power plants.

Performance ratio (PR) and levelised cost of energy (LCOE) are the key figures for evaluating the quality of large-scale PV power plants. Recently developed approaches allow an independent assessment of both component and design quality in order to maintain the best values of PR and LCOE over the system's lifetime.

Evaluating performance

Today's utility-scale PV installations are multi-MW plants ranging from 10MWp to 500MWp. The quality assurance must therefore cover millions of modules, installed on several miles of metal rails, connected with bunches of cables to hundreds of inverters over an area of thousands of acres. This makes it clear why the quality of large-scale PV plants is also differentiated by design and manufacturing. State-of-the-art system engineering requires standardised plant units with sophisticated designs for efficient and flawless construction, since 100% testing is not possible, neither at the component level nor at the system level.

> "In order to achieve bankability and differentiation, a first-rate level of certification and quality assurance at the system level is essential"

One key figure in assessing a PV plant as a whole is the PR – an internationally introduced measure for the level of utilisation of an entire PV system [2]. The PR is defined in IEC 61724 and can be derived directly from global plane-of-array (GPOA) irradiance and AC energy produced. Thus, it indicates the efficiency of system operation by taking into account losses on the PV system's rated output due to temperature, incomplete use of the irradiation (soiling, spectral or reflection losses), and component efficiencies or failures.

Another key figure is the LCOE – the ratio of the sum of all the costs of energy production (from construction to operation and maintenance) and the total energy produced:

$$\text{LCOE} = \frac{\text{Cost of produced electric energy}}{\text{Produced electric energy}} \quad (1)$$

From a detailed analysis of this equation, several quality-sensitive parameters (circled in Equation 2) can be distinguished:

$$\mathrm{LCOE} = \frac{I_0 + C_0 \sum_{t=1}^{n} \frac{(1+i)^t}{(1+r)^t}}{R_P \cdot \eta_{STC} \cdot E_Y \sum_{t=1}^{n} \frac{(1+d)^t}{(1+r)^t}} \tag{2}$$

where (quality-sensitive parameters are highlighted in bold):

- I_0 = initial investment for the power plant
- $\mathbf{C_0}$ = annual operation and maintenance (O&M) cost
- n = service life
- i = annual inflation rate
- r = annual discount rate
- $\mathbf{R_P}$ = initial PR of the power plant
- $\boldsymbol{\eta_{STC}}$ = initial module efficiency in standard test conditions (STC)
- $\mathbf{E_Y}$ = energy irradiated on the module plane (i.e. POA)
- $\mathbf{d}$ = annual degradation rate

To ensure the levelised costs of energy, and thus the return on investment (ROI), the quality-sensitive parameters have to be predicted as accurately as possible (e.g. E_Y) or guaranteed to be stable (e.g. η_{STC} or R_P). For the quality of PV plants, the appropriate quality measure can be derived from the LCOE. An example for quality-assurance testing in different project phases is shown in Fig. 1.

In the following section, major quality-assurance measures will be introduced, and related challenges for assessing utility-scale PV plants will be addressed.

▲**Figure 1. Quality assurance for different phases of a project.**

The basis – accurate yield assessment

A primary practical challenge is that of a PV system realising its assumed yield prediction. Experience shows that this does not necessarily hold true if no acceptance tests are performed [3]. At first glance it may not appear that any deviations from the design will have an influence on the expected energy yield, but they could well be significant (e.g. a decrease in installed power may result from reducing inter-row distances and hence increasing shading losses). A yield prediction without any checks that the system has been built as expected is more or less worthless.

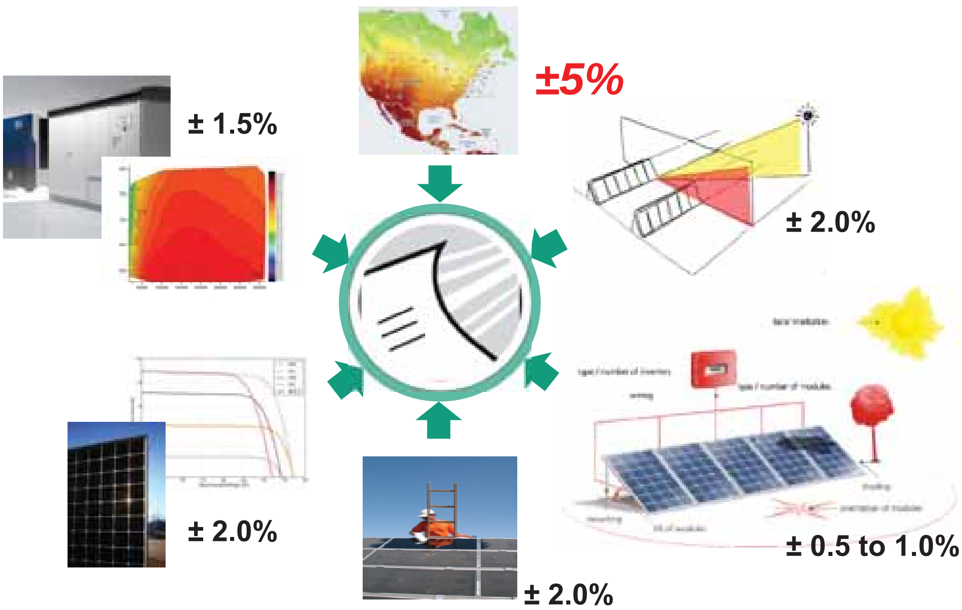
The main types of input data and their uncertainties are shown in Fig. 2. It is obvious that the weather data has the highest contribution to the uncertainty budget for yield prediction. State-of-the-art yield predictions generally use satellite-derived irradiance time series as a basis for system modelling. The quality of these time series has considerably improved over the last 10 years: this applies to the overall mean bias deviation as well as to the irradiance distribution compared with ground measurements. The mean of the bias deviations computed over multiple locations varies around zero, while deviations of about 3% can be expected for single locations. For a detailed analysis, the reader is referred to Ineichen [4].

A recent topic regarding the quality of yield predictions, which possibly has not gained due attention up to now, is the existence of long-term trends in solar irradiance, which could influence expected energy yields. These multi-decadal trends, known as *global dimming and brightening* [5–7], are observed in most parts of the world (to varying extents). In general, after a dimming phase from the 1950s to the 1980s, a brightening phase began in the mid 1980s.

Muller et al. [8] analysed the influences of these trends on solar resource assessments for Germany: resulting uncertainties of approximately 4–5% were estimated for irradiance in south-facing planes with 30-degree tilt angles. For recent solar resource assessments, an increase of up to 5% is expected when only the last 10 years of irradiance data are used for the estimation. An elaboration of these findings for other parts of the world is still lacking.

PV system modelling itself seems to introduce relatively low overall uncertainties (at any rate for time periods of

▼**Figure 2. Input parameters for yield predictions and typical uncertainties.**



a year or more) [2,9]. Other modelling steps that may introduce higher uncertainties under particular conditions are shading and soiling losses. In addition, the calculation of the effective irradiance received by the module (angle of incidence effects, spectrum) is so far not fully understood. However, at least for silicon modules, it seems that the overall effect can be estimated by using relatively simple models, and the deviations are within measurement uncertainties [9].

Big challenges concerning the input parameters exist for PV modules with regard to the behaviour of PV modules in conditions different from STC. It has been shown that datasheet information about the low-light behaviour of PV modules is usually not adequate for reliably assessing yield [10]: therefore the parameters used for yield prediction should be determined independently by the application of the power-rating standard IEC 61853-1, or by the measurements of temperature coefficients at 1000W/m² irradiance and low-light behaviour at 25°C. Usually, the characteristics are measured for several modules. Fig. 3 shows an example of an evaluation of the measured low-light behaviour for two different manufacturers. In the case of manufacturer 1, the nominal values are in excellent agreement with the mean value (average of five modules) measured in the laboratory. For manufacturer 2, there are strong deviations between the nominal and measured values; such deviations can lead to significant overestimation of the yield [3,10].

The same evaluation was done for the temperature coefficients, as shown in Fig. 4. In particular the temperature coefficients given for the open-circuit voltage (V_{oc}) demonstrated large deviations from the expected range (90% quantile). The 90% quantile, shown as the green area in Figs. 3 and 4, represents more than 100 measurements performed at Fraunhofer ISE in the last two years. These evaluations allow an initial validation of datasheet and manufacturer data before being used as input data for yield predictions. Besides a validation of the input data by laboratory measurements, confidence in a yield prediction can be increased by on-site testing and performance evaluation as described later, in the system testing section.

Laboratory testing

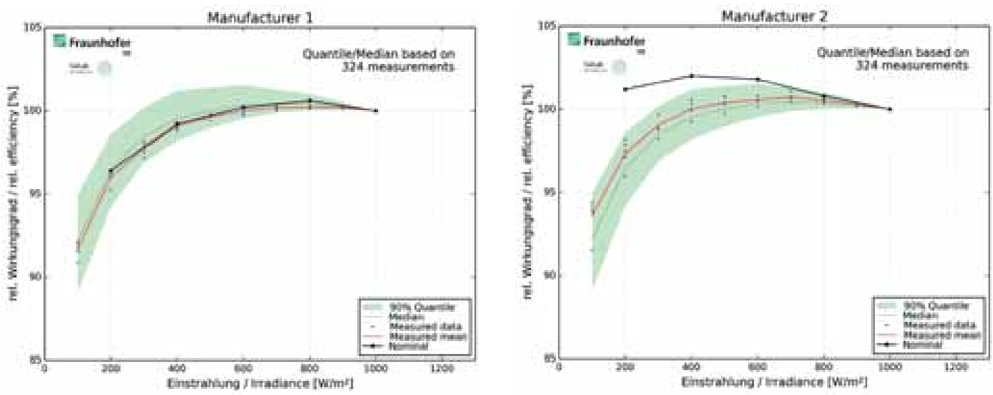
Laboratory testing is valuable at different stages of the project, starting at the planning and design phase, as shown in the previous section. But the planning and design phase is also when the cornerstone is laid for confidence in the product. A quality benchmarking process, with predefined quality criteria, will help to:

- prevent systematic underperformance;
- provide independent parameters for yield assessments;
- detect sensitivity of modules to known failure mechanisms (e.g. snail trails, yellowing, potential-induced degradation, etc.);
- compare the products with state-of-the-art results.

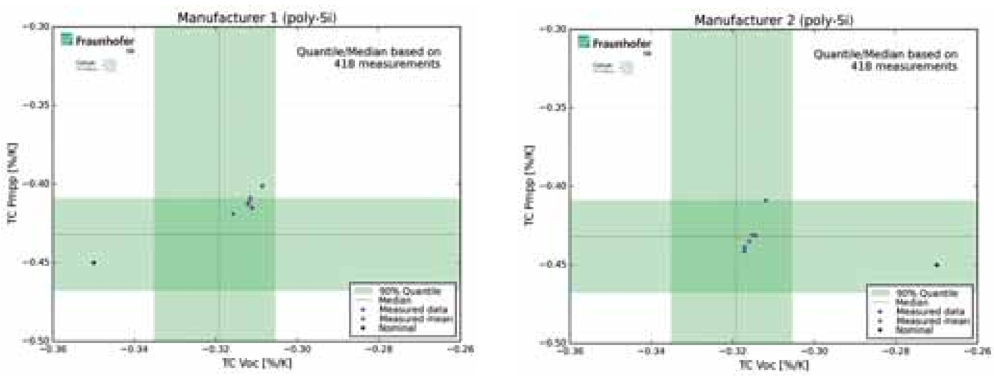
The final testing procedure, especially in the case of reliability testing, should be derived from the customer's quality criteria, the experiences gained in the field, and the environmental conditions (installation site, system layout, etc.). The goal of the laboratory testing is not to repeat the testing specified in the standards, without any possibility to extrapolate the data to an estimated lifetime: the goal must be to prevent known failure mechanisms occurring in the field (e.g. snail trails, yellowing, PID, etc.) and to gain confidence in the fact that this module type is not sensitive to these degradation mechanisms.

During implementation, an independent performance check of the modules is recommended to prevent a systematic underperformance of the purchased module lot. In this process, the values indicated in the manufacturer's flash list (list of electrical characteristics) should be evaluated on the basis of a selected sample set. It is particularly important to select modules from different time (serial number) and power ranges, as shown in Fig. 5.

The bank or investor often stipulates a specific number of modules for testing. To simplify matters, modules are randomly selected; in most cases this means that, if 50 modules are required, two boxes are sent for laboratory testing without specifically selecting the modules. In this case, most of the modules are from the same serial number range and thus represent the same time frame of production. An example shown in Fig. 6 clearly shows the small range. In actual fact, there is no practical value in measuring 25 modules from a single box with the aim of preventing a systematic under-

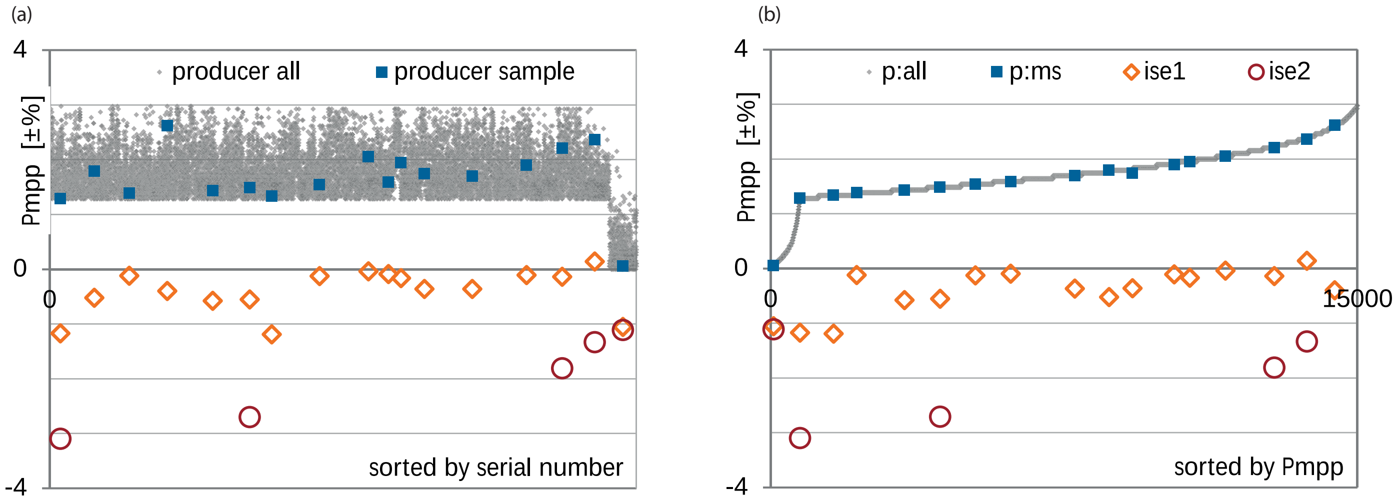


▼Figure 3 (top). Measured irradiance dependency (average of five modules) compared with nominal and typical values for two manufacturers (typical = range covered by 90% of all modules measured at Fraunhofer ISE during the last year).



▼Figure 4 (bottom). Measured temperature dependency compared with nominal and typical values for two manufacturers (typical = range covered by 90% of all modules measured at Fraunhofer ISE during the last year).

Figure 5. Flash list (15,000 modules) evaluation based on a small sample: (a) sorted by serial number; (b) sorted by Pmpp. (p:all = power value of all modules in this flash list; p:ms = selected modules for measurement; ise1 = power value of the selected module 'out of the box'; ise2 = power value of the selected module after light-induced degradation (LID) with 20kWh/m² sun exposure.)



“There is no practical value in measuring 25 modules from a single box with the aim of preventing a systematic underperformance of the total quantity of purchased modules”

performance of the total quantity of purchased modules.

To remove the risk of systematic underperformance of the modules, the sampling needs to be done carefully, and the evaluation of the results requires a high accuracy. At Fraunhofer ISE, measurements are carried out with an industry-leading uncertainty of 1.6% [11] for crystalline modules, or with a slightly greater uncertainty in the case of thin-film modules.

For the evaluation it is also essential to take into account initial effects with an impact on performance in the field. Crystalline modules lose up to 3% of their power in the first hours of operation [12]; this degradation is usually finished within 10 to 20kWh/m² of light exposure and the module will have stabilised. In accordance with the standard DIN EN 50380:2003-09 [13], the modules must comply with the rated power at STC specified on the nameplate and datasheet after preconditioning with a sun exposure of 20kWh/m² or more.

For thin-film PV modules, determining the power representative of field operation demands technology-specific know-how [12,14]. Depending on the technology, the effects of initial degradation or dark storage change the power. Preconditioning procedures therefore have to be applied prior to the *I–V* curve measurement, in order to bring the module to a state that is representative of field operation (CIGS, CdTe).

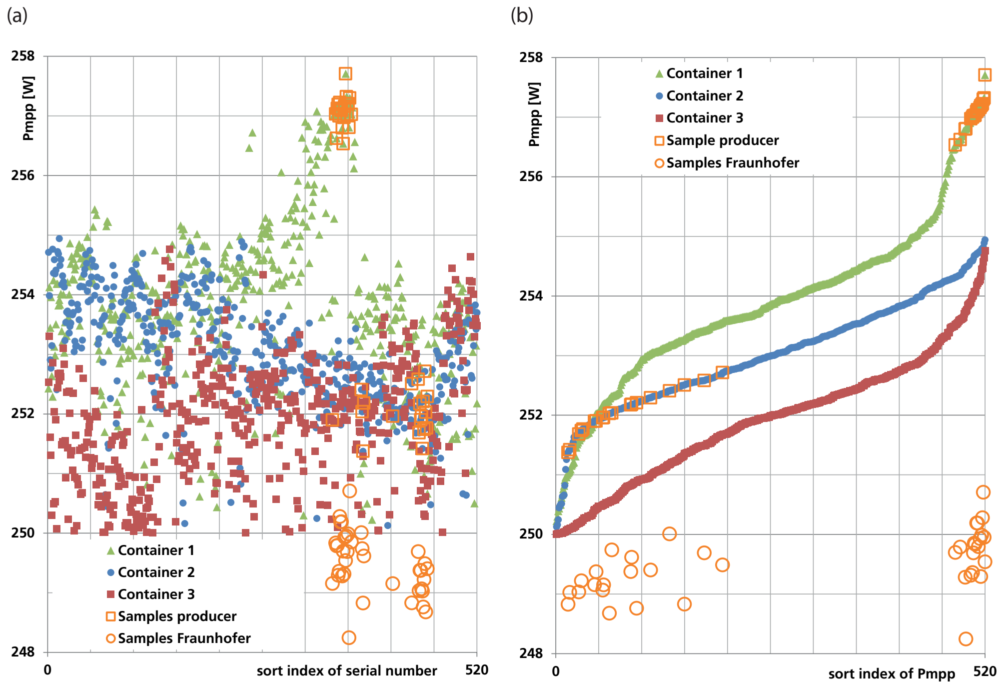
System testing

Most of the acceptance testing, initial performance and safety evaluation or plant certification takes place in the commissioning phase of a project. As mentioned before, the PR is a key figure in assessing a PV plant as a whole – it indicates how well a PV system is performing.

Besides a visual inspection and safety and component testing, the actual PR of the system should be validated. By comparing actual (measured) and expected (simulated) PRs, one can obtain valuable information about whether the system is performing as expected. Important input data for the PR calculation are the actual irradiance and the system output, which means that both values have to be measured accurately during operation. However, it has been observed that, in many cases, unreliable and inaccurate measurement equipment is used.

In this approach, therefore, available monitoring data is validated by comparison with calibrated and high-quality measurement equipment that has been installed for a defined time frame; if

▼Figure 6. Randomly selected modules – two boxes selected from three containers (520 modules each): (a) sorted by serial number; (b) sorted by Pmpp.



necessary, the measurements from the calibrated instruments are used to correct the monitoring data. Higher accuracy can be achieved if the actual power loss due to soiling is measured. The tests are conducted on selected strings with and without soiling, and cleaning procedures are reviewed to provide an estimate of the impact of soiling for a specific site.

After validation and correction, existing monitoring can be used to determine the actual performance ratio. For comparison with the expected performance ratio, the measured weather data (irradiance, temperature) are used to simulate the PR using an established procedure and the system model and parameters from the original yield prediction (Figs. 7 and 8).

This procedure has been developed over the last few years and corresponds to the current state of science and technology. Out of all the specific plant parameters (e.g. inverter efficiency, cable losses, etc.), the ones resulting from the power-rating measurements performed on modules selected in the plant are included in the model.

In recent years this procedure for performance verification has been successfully applied to utility-scale PV plants worldwide. It has been shown that performance can be accurately evaluated within just a few weeks, and, as a plant's monitoring system is validated, a third-party evaluation of existing and future yield data is possible.

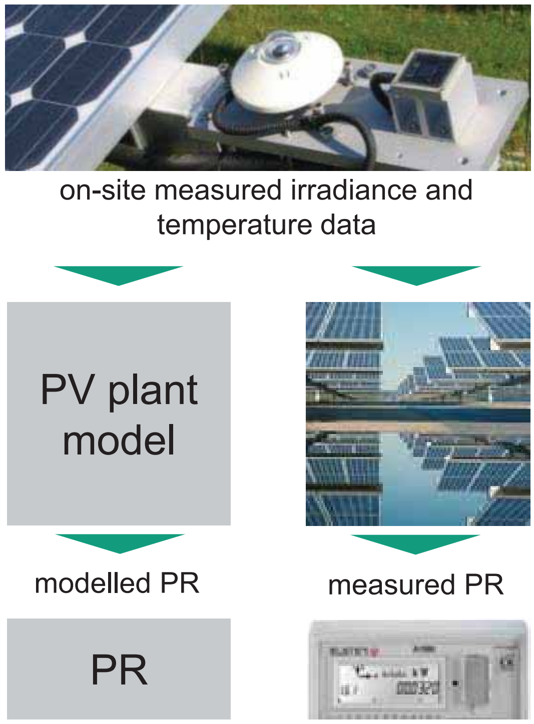
Another important aspect is that performance evaluation should cover all components of the PV system and their behaviour. The inverter in particular, as the interface between generator and grid, is an essential component with regard to reliability and technical bankability. On the basis of efficiency, availability and long-term repair or replacement cost, the inverter can decide between success and failure for an investment. Even if an inverter itself has passed tests in accordance with all current standards, the conditions at a specific location may cause noticeable yield losses. For instance, the operation of hundreds of inverters in parallel and the interaction with other inverters or a noisy grid can cause problems in the field. Thus, for the technical bankability of a system, looking not just at single components is of utmost importance.

> "Quality is the key factor in achieving technical bankability"

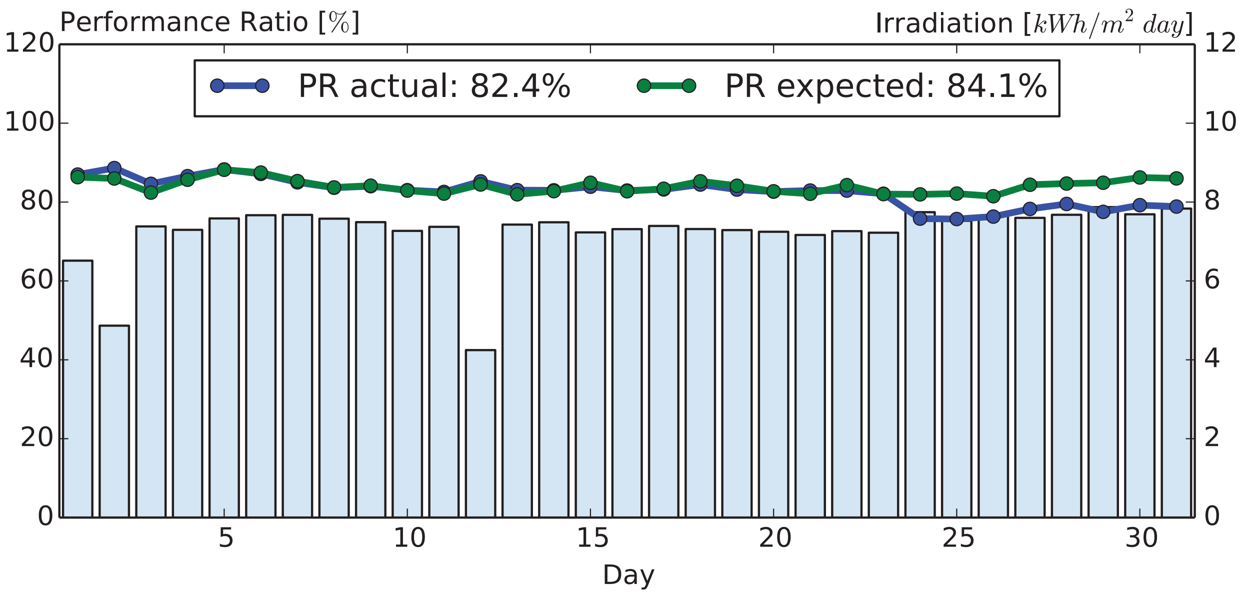
Experience of PV plants in operation

Appropriate monitoring and control of plant operation is mandatory for commercial- and utility-scale PV installations. Failures during operation must be detected using reliable methods in order to avoid major yield losses. Accurate monitoring, however, also shows whether the plant performance is stable, which will guarantee the ROI; moreover, the monitoring provides the basic data for logging the track records of the system layout, workmanship and components used. Therefore, independent third-party performance reports are required for the bankability of projects.

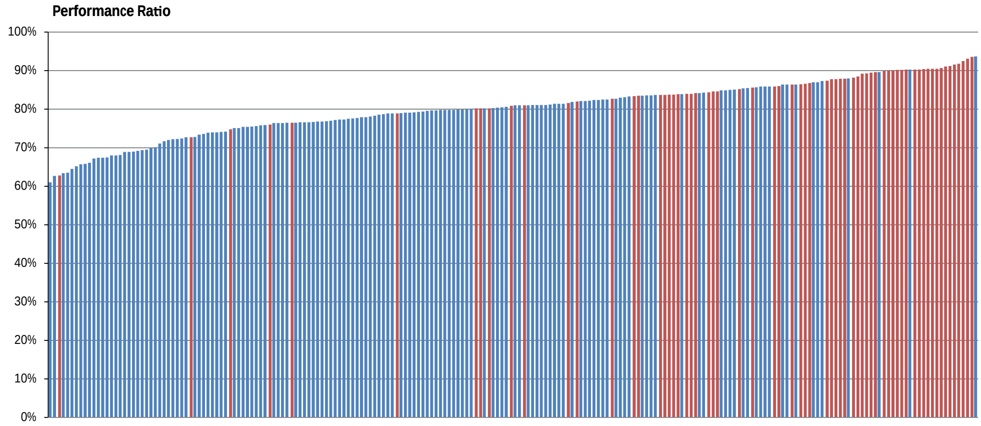
Benchmarking of the 300+ PV plants



▲ **Figure 7. Process for performance verification. On-site measured and validated irradiance and temperature data are used for: 1) the calculation of the expected (modelled) yield by using a plant model, and 2) the calculation of the actual (measured) plant PR based on the data from the energy meter.**



▲ **Figure 8. Comparison of actual and nominal PR values for July 2013 for a utility-scale PV system in southern Spain. On 24 July, a failure in the system caused a drop in PR of almost 10%.**



▲**Figure 9. PR measurements for 300 PV plants carried out by Fraunhofer ISE. Red bars represent plants with basic initial quality assurance and continuous O&M contracts.**

monitored by Fraunhofer ISE demonstrated annual PRs between 60 and ~90% for the year 2014 (Fig. 9). For most new PV plants with basic initial quality assurance and continuous O&M contracts, PRs greater than 80% were reported. In central Europe, initial PRs above 85% can be expected for today's high-quality PV plants.

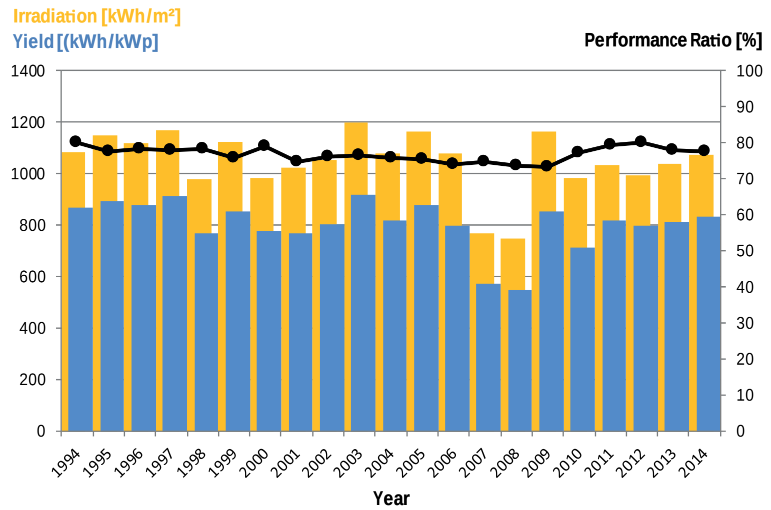
PRs of 75 to 80% were also found for plants that had been in operation for 15 to 20 years. The evolution of the performance of a 4.88kWp plant in operation since 1993 in the northern part of Germany is shown in Fig. 10. This system had an average PR of 77% for the last 20 years and very small variations from year to year of just ±2.7%. There are many other examples showing that solar energy today is a reliable source of energy if appropriate quality-assurance measures are adopted.

Conclusions

Quality is the key factor in achieving technical bankability; this implies state-of-the art system design and standardisation. Appropriate quality-assurance measures, such as plant certification, reduce the technical risk of component or system failure, as well as validating performance with a higher degree of certainty. Thus, quality provides a clearer picture of the financial returns of a system. For component suppliers and system integrators, quality can help to achieve differentiation in the competitive market, where the various stakeholders involved now have different criteria for evaluating investment in projects.

Finally, technical bankability is an indicator of the attractiveness of a project from the perspective of the financing institution. Whereas assessments of bankability in the past were often derived from the particular components selected, today the quality of the plant as a whole is becoming more and more important. ■

▼**Figure 10.**
PRs of a 4.88kWp system, which has been in operation for 20 years, installed in the northern part of Germany.



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The stamp of quality

Bankability | Last year First Solar revealed that its 50MW Macho Springs project in New Mexico had become the first to receive a 'Quality Tested' certification from VDE and Fraunhofer ISE, as described on the previous pages. Ben Willis asks Azmat Siddiqi, First Solar's senior vice president of quality and reliability, and John Sedgwick, president of VDE Americas Quality, what the accolade means

VDE's John Sedgwick, top, and First Solar's Azmat Siddiqi.

PV Tech Power: First Solar is already a respected player in the PV power plant business. Why was this certification step felt to be necessary?
Azmat Siddiqi: As we pursue excellence and quality in all our operations and all our endeavours, it's very important to raise the bar in the industry. So this was not just for First Solar, but to raise the bar in the industry.
John Sedgwick: We're clearly seeing the industry trend now towards what are more normalised financing mechanisms, and when that happens you need standardised certifications for plants. And we're leaning, almost pulling the industry along to something that's quite standard in other industries. In other industries when you have a US$100 million asset, you have a certification on that asset saying everything's fine; in the solar industry we're not children, but we're maybe young teenagers.

PV Tech Power: Is this certification a reflection of the changing nature of the investors now being attracted to solar and what they're demanding?
JS: Absolutely. What we're seeing is that there's been a change in the way these assets are financed, where they're no longer based on tax equity or feed-in tariffs. They're going to be financial assets with traditional returns, and so banks are going to want to see certification to reduce risk; insurance companies will want to see these for reduced risk. It's just a maturing process in the industry is happening now.

PV Tech Power: What does the actual certification process look at?
JS: It's a very comprehensive analysis of the plant. It checks everything, from documentation of the smallest component, all the way up to the high-end system. And so it really certifies that that plant is a world-class, world-standard, highest-quality solar PV financial asset. So it's a very comprehensive analysis.
AS: There are over 300 different areas of focus, attention and certification in the process; it's a very comprehensive programme. Throughout our value chain, we try to put these new practices of technology readiness in place. So right up to commissioning, we've got these internal practices; now is the best time to have them certified.

PV Tech Power: How long does it take to do one of these tests?
JS: It's usually about three to four months, depending on what stage the plant is at. You can start it as the plant begins construction, or you can do it in the middle, or you can do it when it's completed.

PV Tech Power: Do you anticipate that your competitors in the industry will follow your lead?
AS: I would certainly hope so. Raising that bar is where the real win for the industry is; when the industry's acceptance of this certification becomes the norm, then we can all compete on our individual differentiators.
JS: Anything you do in the solar industry you do to drive costs down. And where we need to focus is on soft costs and financing, and the perceived risk that financial lenders and insurance companies assign to solar assets. And when you get just a small movement, a little movement in that reduction, it has a very large impact on reducing the cost of the asset and thereby increasing the market that's available to it.

PV Tech Power: Will First Solar's intention be to do this for all projects in the future now?
AS: The intention will be there. It depends a lot on individual customers and their intents, but our intention is to make this a standard practice so we stand technically and financially behind all our projects and ensure we have met all the requirements.

PV Tech Power: Investors are increasingly driving the quality assurance process on the demand side of the market through third-party quality assurance processes for components – can you see that happening at a PV system level?
JS: Yes, we are hearing from various financial institutions that at a systems level these kind of certifications more and more will be required as part of a financing package. It's not there yet, but it's going to become obvious that you need to have some level of risk reduction assurance that's more organised.

PV Tech Power: Is this part of the industry's growing up process?
AS: Yes, it's about risk identification, classification and mitigation. Mitigation is the key. ■

Credit: First Solar

First Solar's Macho Springs project is the first PV plant to receive VDE and Fraunhofer ISE's QT certification.

The land of rising risk?

Due diligence | A significant part of the risk management process associated with large-scale solar PV installations is 'technical due diligence', which seeks to define and minimise all technical risks associated with the project. Fred Martin and Nick Morley of TÜV Rheinland explore due diligence challenges for PV power plants in Japan

Rapidly declining production costs and various government incentives have created an attractive investment environment for large-scale solar PV in several countries, leading to massive increases in PV power plant installations around the world – particularly in Japan. Several gigawatts of utility-scale solar have been installed in Japan in just a few years following the introduction of a feed-in tariff (FiT) in 2012. Capital for these projects is often acquired through project financing, and therefore the participation of financial institutions and investors has been essential to the rapid development of large-scale PV installations in recent years. Given the large sums involved, banks and other investors require assurance that they will see a return on their investments through the long-term cash flow generated by the power plant; in order to do this they will typically contract the services of independent specialists to advise them on project-specific risks.

Risk factors

Risk factors at the project level can be roughly categorised into financial, legal and technical risks, each managed in a different way. The financial structure of the project is designed to ensure sufficient cash flow in order to manage the project's ongoing debt obligations under a variety of scenarios. Legal risks are usually managed with the aid of specialised legal firms who ensure all applicable regulatory requirements have been adhered to. Legal advisors also assist in managing the contractual structure to ensure that the project owners are protected – through an array of warranties, guarantees and insurance – from risks arising from the work of various contracting parties.

Technical risks can be found throughout the legal and financial structures and arise at all stages in the project life cycle: from design and performance modelling, through construction and operation, to decommissioning. The opportunities to control these risks, however, are concentrated in the initial phases of the project development. To that end it is common practice for lenders to contract a technical advisor whose job it is to review all technical aspects of the design, specifications, contracts, commissioning tests, and technical inputs for the financial models, with the aim of detecting, quantifying and mitigating potential risks.

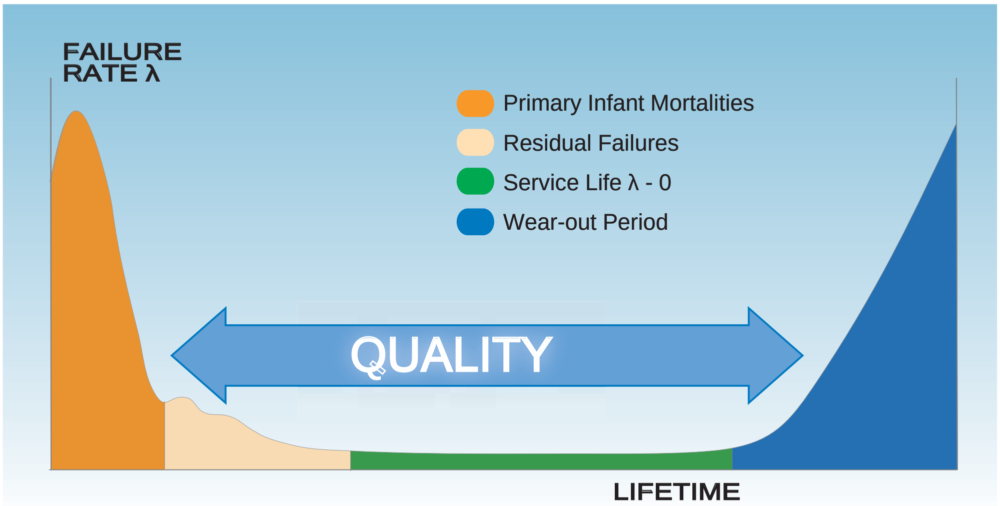


Figure 1. The bathtub curve: quality reduces failures and risks, increasing usable lifetime.

Quality and minimising risk

The 'bathtub curve', which shows the failure rate of components and systems over their lifetimes, is helpful for explaining the effect that quality has on risk (Fig. 1): it includes four lifetime segments in which failures occur. Taking the example of a power plant, early failures, called *primary infant mortalities*, could be caused by component-manufacturing errors or by damage that occurs during installation. *Residual failures* are those that occur indirectly through stress or as a follow-on from infant mortalities; an example is incorrect dimensioning of string inverter ratios or components, which present faulty operation at a later stage.

"To minimise failures and the associated risks to the project, it is essential to achieve high quality with the help of technical due diligence"

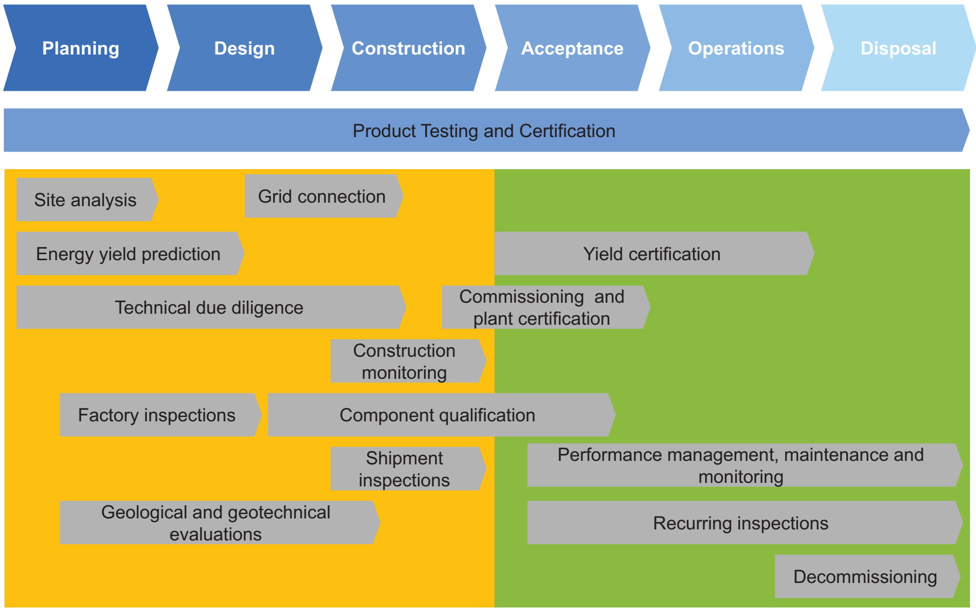
During its *service life*, a well-designed power plant will usually operate without major incidents apart from some planned maintenance, such as inverter replacement, which normally occurs after around 10 years. Finally, materials age and fail during the *wear-out period*. In a PV power plant it is essential to either plan ahead for maintenance at or before the wear-out period, or ensure that the component lifetimes are longer than the intended lifetime of the plant.

Quality can be described as the area lying between the two failure rate peaks – an increase in quality translates to a decrease in the failure rate at the beginning of the component lifetime and an increase in the lifetime at the end. In order to minimise failures and the associated risks to the project, it is essential to achieve high quality with the help of technical due diligence.

Project technical due diligence

While some large banks may possess the necessary technical knowledge to perform their own technical analysis in-house, often they do not, and in any case it is necessary for the group of lenders to receive opinions from third parties who do not have a conflicting interest in the project. For large projects it is important that the due diligence providers are not only technically competent, but also established businesses with proven track records that are likely to continue operating in the region throughout the lifetime of the project. This is particularly important if the project is to be sold later on as an investment product, since the technical advisor may need to stand behind their work or provide additional consultations and services to satisfy future investors.

Fig. 2 shows the project phases in the lifetime of a PV power plant, along with the associated services that can accompany each phase. The inspectors perform initial assessments during the site analysis, covering the site topography and other local factors – such as soiling, slope, vegetation, and construction logistics – that may affect the suitability of the site for the PV project. If a site visit is performed, photographs and shading profiles are also taken in order to evaluate the quality of the solar resource at the site. This information can then be used as input data for the energy yield prediction (EYP). The EYP involves gathering a range of technical inputs that also include the PV module performance characteristics and weather data specific to the site, and using them with commercial software to predict the amount of energy that will be generated by the power plant. To complement a more extensive site analysis and EYP, initial technical due diligence also includes a complete review of the engineering, procurement and construction (EPC), and operations and maintenance (O&M) contracts. These contracts cover the electrical design, contractors and suppliers, warranties, guarantees, and acceptance criteria for the completion of the plant.



▲**Figure 2. Project phases in the lifetime of a PV power plant value chain, and the associated services.**

During the construction and acceptance phases, a due diligence service provider may be utilised to:

- inspect shipments of components, such as the PV modules, to ensure that they are packaged and handled in accordance with the manufacturer's instructions;
- supervise construction and verify project milestones;
- ensure that the commissioning tests are performed in compliance with procedure at provisional and final acceptance, as often defined in the EPC contract (time frames between provisional and final acceptance vary from a few months to three years).

▼**Table 1. Important PV areas and their main respective standards. Some of the JIS equivalents may be adopted in the near future.**

Area	Japanese Industrial Standard (JIS) and International Electrotechnical Commission (IEC)
Module	IEC 61215:2005, IEC 61730-1,-2:2004, IEC 61646:2008 JIS C 8990:2009, JIS C 8991:2011, JIS C 8992-1:2010, JIS C 8992-2:2010, JIS Q 8901:2012
Inverter	IEC 62109-2:2011, IEC 62116:2014 JEAC 9701:2012 (Japan Electric Association Code) Grid connection guidelines No IEC equivalent certification scheme for commercial inverter available in Japan (>20kw)
Cable (string)	JCS 4517:2013 (Japanese Cable Makers' Association Standard) Halogen-free cable for PV applications
Mounting system	JIS C 8955:2011 for rack design and JIS A 1221:2002 for geotechnical testing
System	IEC 60364-7-712:2002 Requirements for special installation or locations solar PV power supply systems JIS C 0364-7-712:2008 Electrical installations of buildings – Part 7-712: Requirements for special installations or locations – Solar photovoltaic (PV) power supply systems
Testing, commissioning and documentation	IEC 62446 ed1.0:2009 Grid-connected photovoltaic systems – Minimum requirements for system documentation, commissioning tests and inspection No equivalent available in Japan – Electric business act (laws) where applicable
Design	IEC 62548:2013 Photovoltaic (PV) arrays – Design requirements No equivalent available in Japan

Further into the project lifetime during the operational phase, technical advisors are occasionally required to verify the power plant performance level through a yield or performance ratio (PR) certification in order to resolve disputes, or to verify to a new investor or buyer that the plant is operating correctly.

Challenges for due diligence in Japan

There are specific challenges related to the Japanese market that are important to consider in terms of the technical due diligence process. The first of these is the issue of standards and experience. Japan has long been one of the largest solar markets in the world; however, before the introduction of the FiT in 2012, this was almost entirely due to residential and small commercial rooftop installations. With several gigawatts of utility-scale PV projects now being added to the grid, this trend has begun to change dramatically. Because of this rapid development, a comprehensive set of local standards does not yet exist for PV power plants, and the use of international equivalents has been sporadic because of language barriers and differences in established practices. The high project returns made possible by the FiT also attracted many new and inexperienced players to the market, further exacerbating the issue of inconsistent design and construction. For example, there have been multiple instances where module-mounting structures were not adequately designed to support heavy, non-uniform snow loads, and as a result of heavy snowfalls in 2014, several systems across Japan suffered severe damage [1].

Additionally, since many projects in Japan are being developed in mountainous areas the subsoil content is often inhomogeneous, and therefore multiple geotechnical tests are usually required to ensure that the ground is suitable for the mounting structure design. Geotechnical investigations performed during the planning stages have occasionally been inadequate, with developers later discovering that the intended structure design could not be driven into the ground because of large basaltic layers and rocks under the surface, leading to late-stage design changes at much higher costs during the construction phase.

Table 1 lists some relevant standards for PV power plant design, testing, commissioning and documentation. These standards not only support developers by increasing efficiency, reducing risks and driving down overall costs of their design processes, but also help banks, investors and relevant stakeholders by allowing them to easily verify whether a project meets a minimum set of technical requirements. Without an agreed standard, the quality, the results of the contract negotiations and the degree of risk in each project become almost entirely subject to the opinions of the technical advisors and the EPC manager and to the experience level of the banks and investors. These factors can be different from project to project, and, unsurprisingly, projects in Japan have been seen to vary widely in quality over the last few years.

With regard to PV modules, IEC 61215, 61646 and 61730 are essential qualification test standards designed to identify infant mortalities and are a basic requirement for modules to be considered for a large-scale project. In the Japanese market, JET PVm module certification and JIS Q8901 quality system audits have also become commonplace. Neither is obligatory; however, they help manufacturers to demonstrate a long-term commitment to their Japanese customers and are well regarded by local investors and developers.

> "Another major challenge for PV power plants in Japan is accurate modelling of the expected yield and performance"

Although various certifications may aid manufacturers to sell their products in a competitive market, from a risk standpoint they are of secondary importance, since none of the current testing programmes can guarantee a module's lifetime and degradation rate. Banks and ratings agencies instead look for a successful track record and real data from previous projects where the modules have been used, in order to judge their reliability. This can be particularly challenging for newer manufacturers whose products may not yet have been deployed for long periods of time. In these circumstances, a technical due diligence advisor will look for extended accelerated stress test programmes that the modules have completed. While these programmes do not guarantee the module lifetime, they nevertheless provide indications of long-term quality and data about the module's behaviour during its service life and wear-out period. One way or another, it is important to establish that the modules are likely to perform well in the field, since the degradation rates assumed in the project financial models are typically less than those guaranteed by the manufacturer. This risk should be managed by verifying the plant's performance at regular intervals, and in some cases by also taking samples from the module shipments and testing them at an accredited laboratory using a calibrated solar simulator.

It is important to keep in mind that while much emphasis is often placed on PV module reliability and 'bankability', from a risk perspective the module is just one part of a much larger project system requiring comprehensive risk management.

Performance prediction models

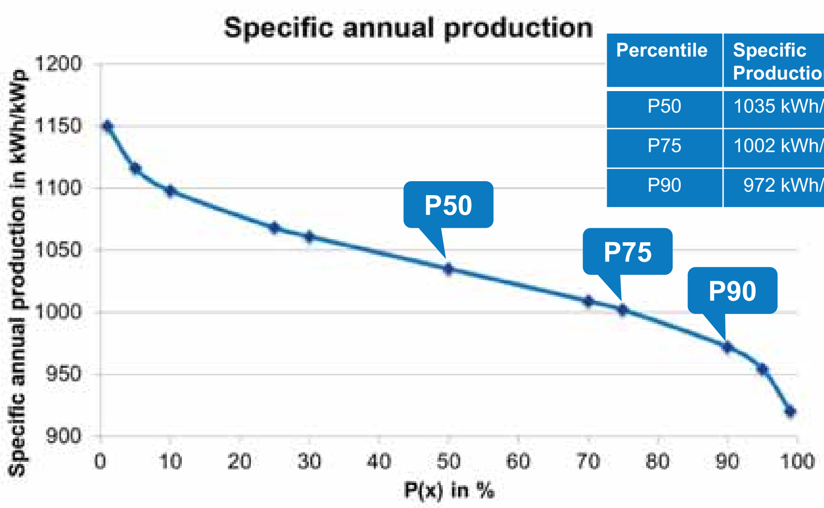
Another major challenge for PV power plants in Japan is accurate modelling of the expected yield and performance (Fig. 3). This is done by selecting an appropriate irradiation database and horizon shading profile, and then combining them with a model of the power plant using commercial software that calculates monthly yields and performance ratios (PRs). The PR is the ratio of the actual output compared with the maximum theoretical output, and is one of the most important values associated with determining the efficiency of a PV power plant [2]. It is essential in the technical due diligence process, since while the EPC manager cannot guarantee the amount of incident sunshine over the year (and, in turn, the plant yield in kWh), they can, and should, guarantee a minimum plant efficiency level based on a realistic performance model, in order to minimise the performance risk borne by the lenders and investors.

The first challenge here has been a reluctance of some EPC providers to guarantee their work through the PR. For a company inexperienced in solar construction, such a guarantee may be viewed as too risky, since they do not have data from similar projects that they can use to confidently guarantee the plant's performance. In addition to this there are also particular challenges in ensuring the accuracy of the energy yield model in Japan, where microclimatic conditions caused by the mountainous island geography increase annual variations in irradiation. Compared with zones that have previously been popular for utility-scale PV power plants, such as Spain and the USA, Japan also has relatively large differences in average annual irradiation over smaller areas, leading to increased uncertainty. This uncertainty carries over into the financial model, as cash flow is directly affected by the amount of available solar irradiation.

Several different irradiation databases map estimates for expected irradiation over both Japan and the world using ground-based measurements, satellite data, or a combination of both. While ground-based measurements are generally considered to be more reliable, the further the site is from the measurement station, the greater the uncertainty will be. When selecting the database for a site, there may be several nearby ground-based stations showing different levels of irradiation, and it is not always clear which one is most appropriate. Significant differences in altitude and topography can also have an effect on reliability because of microclimates, reducing the accuracy of both satellite and ground-based measurements.

A variety of different irradiation databases exist for use in Japan. Japan's New Energy and Industrial Technology Development Organization (NEDO) operates an extensive network of ground-based measurement stations in cooperation with the Japan Meteorological Association (JMA), called MONSOLA. The NASA SSE satellite radiation data is also frequently referred to, and comprises a grid of resolution 1° × 1° (approximately 111km × 111km) built from average irradiation data collected between 1983 and 2005. Meteonorm is a commercial software tool that uses up to six nearby ground-based stations (NEDO stations are used for Japan) and interpolates between them with reference to the coordinates of the installation site.

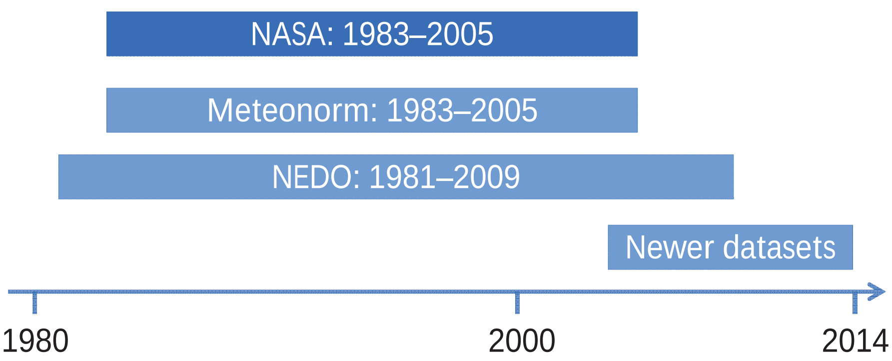
Several other satellite-based sources exist, including SolarGIS and OREL, which have more recent datasets, often covering a shorter period of time (Fig. 4). These newer datasets generally show higher



Percentile	Specific Production
P50	1035 kWh/kWp
P75	1002 kWh/kWp
P90	972 kWh/kWp

▲**Figure 3. Energy yield prediction models are statistically validated and presented in probability values with given uncertainty (50th, 75th and 90th percentiles).**

▼**Figure 4. Main datasets and their durations. The period and type of data are essential for any statistical validation, and should be taken into account when comparing data values and results.**



irradiation values as a result of increasing amounts of solar irradiation experienced in recent years. It is also generally understood that the satellite method tends to overestimate radiant exposure in wet, cloudy conditions, and to underestimate it in dry conditions [3]. It is essential to take these effects into consideration for the humid sub-tropical climate that exists in Kyushu, Shikoku and most of Honshu, and for the humid continental climate in Hokkaido.

Unlike in the USA and Europe, where PV power plants are usually constructed in desert regions or open fields, because of a lack of available land in Japan, PV power plants are often placed in more mountainous areas, such as old golf courses (Fig. 5) or terraced fields, making the selection of an appropriate irradiation database particularly challenging. In their risk methodology for utility-scale solar PV projects, Standard & Poor's state that "it is important to have conservative resource data, given that we rely on predictions of cash flow in our credit analysis" [4]. But being conservative can be challenging when developers are faced with large differences between reputable sources, as there is significant temptation to adopt the database that delivers the highest results to the financial model.

A brief comparison of a variety of satellite irradiation databases with several nearby NEDO ground-stations that was recently performed for a site north-east of Tokyo showed a maximum difference in expected irradiation of 14.5%. In another analysis, ground-station irradiation measurements from different regions in the last two years were compared with the 20-year average: a maximum increase of 8% was found. Despite a trend of higher values in recent years, it was also observed that several areas received less irradiation. Long-term mean values from a traceable source are therefore more relevant for prediction discussions, since they are less affected by natural yearly fluctuations.

In some cases, due diligence providers will seek to account for these uncertainties by averaging data from multiple sources, asserting that the calculated mean will be a conservative value. However, not all of these sources are independent, since they often use the same meteorological data sources, and the mean can easily be manipulated by selecting which database values are included in the calculation. Both satellite and ground-based measurements have their own advantages, and the database selection in each performance model should rather be based on a thorough investigation of the conditions specific to the site, with the aim always being to deliver a performance model that is realistic.

Despite the challenges of building a consensus around the underlying assumptions for factors affecting the project yield, improvements are gradually being seen over time in average modelled PV power plant efficiencies compared with actual values, which is a promising indication of

Credit: TÜV Rheinland

◀ Figure 5. Aerial perspective showing typical inhomogeneous topography, taken via drone during construction monitoring of a golf course being prepared for a PV power plant. Many PV projects are being developed in Japan at decommissioned golf courses, which were developed during the 1980s but later proved to be unprofitable. They have found a second life through PV plant development.

“An array of solutions exists for controlling risk factors in PV power plants, and it is most important – and economical – to address problems at the early stages of development”

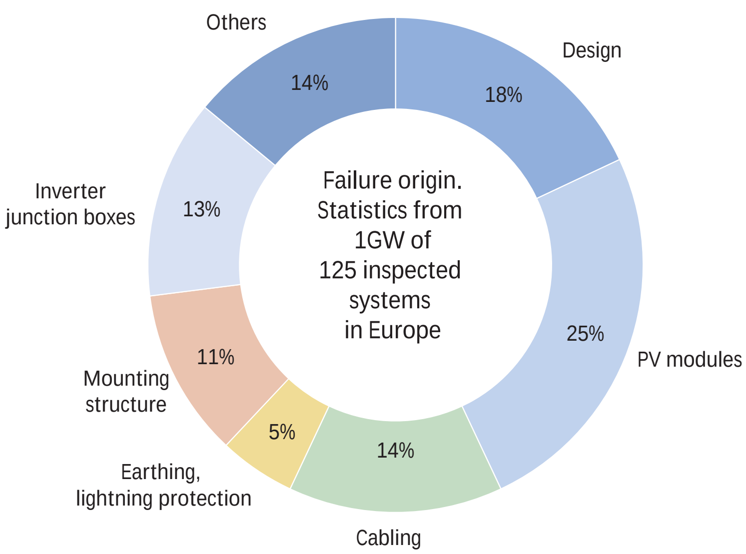
increasing overall quality, in line with other markets worldwide [5].

Japan – land of the rising risk?

Although the Japanese market remains one of the strongest in the world, there are several factors that may hamper growth in the near future and represent long-term risks to project returns. For example, the extremely large number of projects vying for connection to the grid that have materialised as a result of the uncapped FiT has placed stress on the capacity of smaller utilities to absorb further sources; as a result, Kyushu Electric, Hokkaido Electric Power Company (HEPCO) and Tohoku EPCO have all recently taken various measures to suspend new applications [6]. While it is currently unknown if other Japanese electric utilities are considering similar action, it is clear that intense competition for connection approvals in Japan is a rising source of risk. It is also expected that the FiT rates will be revised again around the new Japanese fiscal year in 2015.

Despite the progress made so far, failure to quickly agree on a set of design and documentation standards for the industry will continue to keep costs high in this area and increase the likelihood of errors. As the majority of large-scale projects in Japan are still in their early stages, it can also be expected that infant mortalities, residual failures, and associated performance issues resulting from poor design and inappropriate installation practices will begin to appear in some of the affected projects over the next two to seven years, as witnessed in other markets (refer to Fig. 6). High-quality O&M will be able to manage some, but not all, of these, and the impact on investors will depend on the quality of the industrial contracts that have been put in place to protect them.

Figure 6. Research done by TÜV Rheinland in collaboration with Mannheimer Insurance showed that around 50% of failures are traced back to installation mistakes [7].

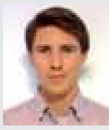


Conclusion

The take-away here is that an array of solutions exists for controlling risk factors in PV power plants, and that it is most important – and economical – to address problems at the early stages of development. Careful selection of a professional project due diligence service that is integrated into the project planning at the beginning will help to ensure a smoother design phase, reduce risk and significantly increase the likelihood of healthy project returns. ■

Authors

Fred Martin has spent the last seven years in Japan, leading PV power plant services at TÜV Rheinland. His team has provided PV-related due diligence services for over 150 systems totalling 1.4GW across Japan, for both domestic and international customers.



Nick Morley specialises in technical due diligence advice for contract structures of PV power plants and PV reliability testing services at TÜV Rheinland. The group has serviced 8GW worldwide and has 35 years' experience in PV.

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Signed, sealed, delivered

Logistics | As PV expands its global footprint, logistics – transporting goods from factory to project site – is becoming a complicated challenge for manufacturers. Sara Ver Bruggen reports on efforts by the industry to reduce costs arising from equipment damaged in transit

Credit: Hellman Worldwide Logistics.

According to German test institute TÜV Rheinland between 5 and 10% of PV modules sustain a degree of damage during transportation, from when they leave the factory gate to arrival at their final destination. During transportation, loading and unloading, and handling, modules are exposed to shocks and vibrations that can potentially have a damaging effect on fragile solar cells, reducing the module's power output. Considering the global PV module market was worth just over US$30.5 billion in 2013, according to GTM Research, this percentage represents a significant figure.

Not only that, logistics, if poorly addressed, can incur costs in other ways too, through lengthy delays of shipments at major ports and complex customs procedures, for example. The industry association Solar United (previously the International Photovoltaic Equipment Association) estimates the PV industry annually loses between US$400-500 million due to inefficient logistics processes along the entire supply chain.

Adapting to new market challenges

Logistics is more than just having warehouse facilities at strategic locations to serve local markets in different continents. Some manufacturers and suppliers in the PV industry are recruiting specialist staff in response to the challenge. During 2014 German inverter supplier SMA has reorganised its global logistics strategy, which had previously operated along product lines. Now this part of the business is organised globally with local logistics teams established at the company's factory locations around the world and in local sales and services offices.

This is in response to what SMA's head of global logistics, Axel Brewe, describes as the fragmentation of the PV industry, where new markets are opening up across the continents. The Germany-headquartered inverter maker has also been investing in its staff, hiring people with backgrounds and skills in freight forwarding. SMA also works with large as well as local logistics service providers across air, sea and road freight.

The safe transportation of PV equipment to site is becoming a key part of the cost equation in plant economics.

"We are prepared for the market today but this will probably change in future so we will have to keep an eye on this development," says Brewe.

SMA started as a mainly domestic supplier but as the PV industry has grown and become more globalised, export markets make up over 70% of the company's trade, with 17% of sales in Europe, outside of Germany, and just over 55% in the rest of the world. The company procures freight and also warehouse capacity and puts out tenders for the major logistics providers to quote for. "Price is an important factor but so is quality and service," says Brewe.

Logistics hubs are set up at SMA's production sites, which include the US and South Africa. In North America, the company has three logistics centres, including one at its factory in Denver. From the US SMA serves Latin America, supported by local sales and services offices on the ground in places such as Chile. The company's coverage is comprehensive so that the logistics team already has in place agreed lead times for existing routes and lanes.

"However, if a new route or lane is opened due to a new project or client then the logistics team is involved in the deal with a client before it closes. It is crucial to establish lead times and other details, such as custom clearance procedures and logistics costs," says Brewe.

More routes, more issues

According to Holger Meyer, renewable energy manager at Hellman Worldwide Logistics, procuring the sea or air freight is more complex than it used to be. The company's PV industry customers include REC and Talesun, among others.

"The freight industry operates like the stock market. Prices change, depending on routes and how busy they are," Meyer says. When capacity is tight prices are driven upwards. Expensive times are the months leading up to Christmas and Easter, as goods destined for global retail giants dominate container ships on busy routes.

Fab to farm

GPS tracking and sensor technologies combined with smart software is enabling PV suppliers and clients to keep tabs on their shipment and make alternative plans should anything happen to goods in transportation.

Hellmann Logistics, which has been working with the PV industry for a number of years, is able to provide full transparency for shipments with a tool called Smart Visibility, initially launched as a tracking and monitoring system for perishable goods and cold chain logistics. Every five minutes, the small device, attached to cargo, transmits the location of the shipment and the exposure of goods to various factors and forces.

The tool was developed using conventional freight tracking hardware combined with real-time data transmission. The device, powered by a solar cell, tracks the geo-position of the shipment, which lets the logistics manager know the current location of products.

Temperature, pressure, light exposure, shocks and motion of goods, even the opening of container doors, are all measurable incidences that can be transmitted in real-time.

Such information ensures PV shipments cannot get lost and provides manufacturers with information they need to take measures such as organising a compensation delivery, or alarming security agencies if it looks likely that theft has occurred.

Many of the global logistics firms have their own tracking systems that enable customers in the PV industry to keep a close eye on their cargo. An advantage of the Smart Visibility technology is its open platform design that means it can be used by any customer independent of the logistics service providers used.

Using GPS hardware and specialist software Hellmann Worldwide Logistics is able to track the whereabouts of PV module shipments worldwide for clients.

Credit: Hellmann Worldwide Logistics

With fragmentation of the market, PV manufacturers are more likely to be sending cargo on several different containers as opposed to one bound for one or two destination ports in Europe. "How do you control your stock on three to five carriers? If your volume is down on each one, so is your influence. Then prices go up," says Meyer. Global logistics and freight forwarding service companies, like Hellman, have relationships with large shipping firms and knowledge of global routes and networks.

Even savings achieved by securing cheaper freight costs can disappear or even start to eat into earnings when shipments that have been offloaded at port exceed moorage times – a grace period, usually several days for shipments unloaded at ports. Meyer refers to a case in Europe where containers of PV modules destined for a project in eastern Europe were held up because the correct documentation for customs could not be found. Once moorage times are exceeded a daily fee is charged, which can range from US$150 to US$500 a day. Extrapolate this across tens and even hundreds of containers, in different ports, across a year, and the costs can begin to mount.

"It's not simply moving boxes and containers from one destination to another. We have helped customers bring down costs by optimising packaging, reducing amount of container space taken up. We can manage cashflows, for example by deferring or delaying what would otherwise be upfront VAT costs on entry into destination markets. The company deals with customs too," says Meyer. With Solar United, Hellmann has been discussing logistics issues at PV industry conferences and Meyer hopes to continue educating the industry during 2015.

Such services will be increasingly in demand as new PV markets become established and suppliers are expected to provide goods on 'delivered duty paid' terms, which is where the seller has to bear all of the risks and costs associated with delivering the goods to the destination market, including duties, taxes and other considerations to be cleared for importation. Delivered duty paid is part of a service provided by logistics providers.

According to management consultancy Accenture, as manufacturers and industry sectors enter new markets, especially in emerging economies, they expect much more than traditional transportation and warehousing services from their logistics and freight forwarding service providers, such as customs and insurance brokerage, as well as trade and transportation management.

Logistics, which can cover a myriad of different services, but essentially is about ensuring the timely, safe delivery of valuable goods from one point to another, underpins any globalised industry. Done well, logistics can help manufacturers maintain or even improve their margins and provide their customers with value-added services.

Protecting goods

In mid-2014 Hanwha SolarOne was one of the first PV module makers to be awarded a transport packaging certificate that complies with a new standard, IEC 62759-1 ('Transportation testing of photovoltaic modules').

The module supplier developed the packaging in-house in cooperation with a packaging producer, over several years of iterations. Subjected to the test with partners TÜV Rheinland and logistics

Credit: Hanwha SolarOne.

services provider DB Schenker, the packaging passed the qualification at first attempt.

In reality the number of defective modules during transport is difficult to determine as things like micro-cracks are not visible. "However, by making sure that packaging is designed and qualified for the purpose of transport PV manufacturers can eliminate discussions with customers about potential defects," says Winfried Wahl, senior director, products and marketing at Hanwha SolarOne. "Customers can save money and time on incoming inspection costs and the PV manufacturer delivers a value added service. Additionally, transport insurance costs can be reduced if the risk of damage is lowered through adequate packaging and the IEC certification."

Hanwha SolarOne was one of the first PV module makers to be certified with the IEC 62759-1 standard, 'Transportation testing of photovoltaic modules'.

Good packaging that adequately protects modules during transport and handling can protect them from damage, but to ensure traceability DB Schenker uses sensors to detect when any breaches such as modules being knocked around occur during transport and notify the manufacturer or other companies concerned about any abnormal loads that occur during sea or road transport.

Logistics and PV industry services

For companies in the PV industry robust, efficient logistics strategies are critical to the provision of post-sales service ensuring, for instance, that if a product needs a component replacement when it arrives at a site that this can be delivered to the project within a day or two. "This requires forward planning such as how much buffer stock to keep in strategic locations," says Brewe.

As more solar farms come out of their warranty periods and the services sub-segments of the PV industry grow in areas like operations and maintenance (O&M), logistics will arguably become more critical to ensure that spare parts and repair replacements can be delivered to sites rapidly and cost-effectively. This is the challenging aspect of the job, which Brewe says is also interesting and what makes working in logistics a good career within the PV industry.

In an increasingly competitive global marketplace having a PV module that ticks all the performance versus quality versus cost boxes is one thing. But, customer satisfaction is also influenced by factors dependent on how well, or badly, logistics is done. While some incidences and delays happen even despite the best laid plans, late deliveries, damaged goods and avoidable setbacks can all chip away at a brand, especially if they end up causing project delays or extended downtime, all of which will impact on its profitability. ■

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Pack test for PV modules

With intense cost pressures bearing down on the industry, it can be tempting to claw back savings on module packaging, using corner stacks between horizontal modules on a pallet all wrapped up in film. However, manufacturers can save on transport insurance costs as well as give customers at the other end peace of mind if they invest in adequate packaging for modules.

The certification process developed by TÜV Rheinland for its new transport packaging certificate (compliant with IEC 62759-1) for PV modules has several steps.

First, the sample is exposed to a vibration test, including simulations of shocks from road transport or acceleration procedures during cornering or braking. Serious impacts that could be caused by a shipping unit being knocked over by a fork lift are also simulated.

Next, the solar modules go through a check for possible damage, which includes a visual inspection, EL imaging and STC measurements, as well as dry and wet insulation testing.

In order to identify possible long-term effects, advanced ageing and load tests involving processes such as wind-load simulation and the application of thermo-mechanical loads are carried out in TÜV Rheinland laboratories.

Throughout the process, possible power degradation is analysed and evaluated. In addition, quality management aspects concerning the package and the traceability of the materials are included within the certification.

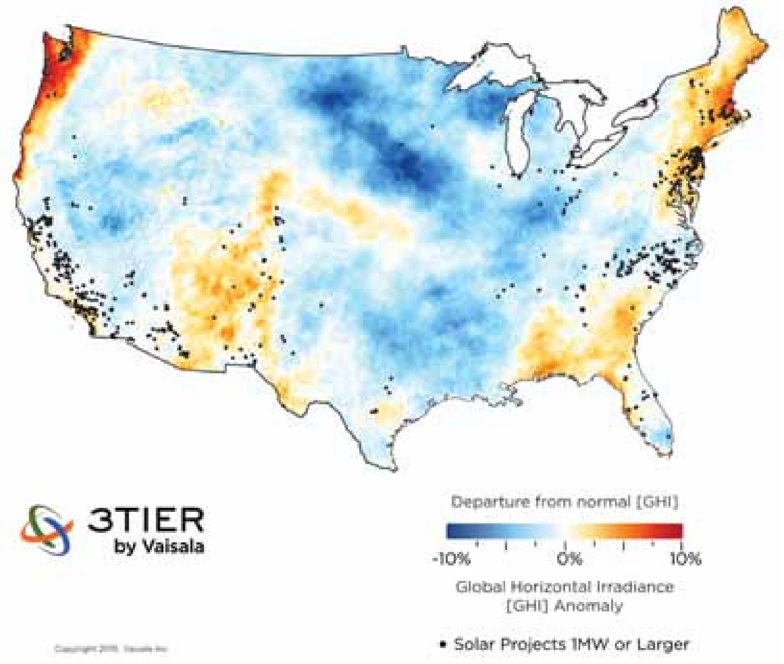
TÜV Rheinland's work to develop the PV module packaging certification is part of a wider initiative, called PVChain, in partnership with logistics provider DB Schenker, to establish a quality assurance programme for modules in transport to improve transparency and safety during global transportation. The system, launched in February 2014, following a year of development, aims to prevent as well as discover transport damage by monitoring transport, such as freight trucks, and validate the performance of PV modules, for example at their port of entry or at the project construction site, compared with results from the inspection before the modules leave the manufacturer's fab.

Within DB Schenker's facilities at Antwerp, which is a major port of entry into Europe, TÜV Rheinland has set up a testing hub. Here, once unloaded from shipping containers, shipping units containing modules, often several individually packaged units packaged up together or palletised, are unpacked and are flashed – tested – in a small laboratory environment and the data is logged.

More recently TÜV Rheinland has been presenting the PVChain initiative to investors from the finance industry and global insurers, as adopting the system can help manufacturers to reduce their insurance costs if the system is recognised by insurance firms.

A model approach

Yield assessment | Evidence is emerging that data used in PV yield modelling, an essential element in optimising a plant's design and profitability, is leading to erroneous results. Ben Willis reports on the solar industry's data challenge and how it is responding



Source: Vaisala.

Solar performance in US over the summer months of 2014 varied relative to 18-year averages.

Late last summer researchers at the Fraunhofer Institute for Solar Energy revealed that a fleet of German PV power plants it had been monitoring were producing around 5% more power than had been predicted in their initial yield assessments. Using recent satellite data, the team linked the plants' relative over-performance to a phenomenon known as 'global dimming and brightening', whereby atmospheric changes over time cause average solar radiation conditions to fluctuate.

As the Fraunhofer team's findings revealed, the underestimation of the plants' likely performance was down to the initial data on which these estimates had been based. Previous assessments had assumed future radiation levels would not differ greatly from average values over the past 30 years; however analysis by the Fraunhofer team of recent satellite data from DWD, Germany's national meteorological service, revealed disparities between the two sets of figures.

"Relying on average radiation values from the past 30 years causes a systematic underestimation of actual PV system yields in Germany by around 5%," said the Fraunhofer ISE project leader, Björn Müller, at the time. "We expect that other regions experiencing the brightening effect are seeing similar underestimations."

The Fraunhofer study highlights what Müller and others believe is emerging as a crucial issue for the solar industry to get to grips with as it matures: the need for better data to improve the accuracy of PV power plant yield assessments. Speaking to *PV Tech Power*, Müller says the main conclusion from last year's study was the need for the industry to use up-to-date data for its modelling. "If you have long-term changes in irradiance, then you should use recent data, because that should be the best estimate for the future," he says.

And this is more than just a point of academic interest; it's a fact that could have big implications for the profitability or otherwise of PV power plants. PV yield – or energy – assessments form the basis of decisions by the financial community on whether or not to back a proposed project. Conservative forecasting can lead to lost investment dollars, while overly optimistic assessments will inevitably lead to questions for the solar industry when plants fail to deliver expected outputs.

Over-performance expected

Gwen Bender, an energy assessment product manager for forecasting firm, Vaisala, believes the solar industry is likely to see further instances of divergence between the predictions and actual performance of PV power plants. "There's going to be a ton of over-performance in the solar industry, quite honestly, because I think people have been too conservative," Bender says.

The basis for Bender's assertion is the fact that, as she explains, the general practice in the industry has been to rely on 'typical meteorological year' (TMY) data for assessments. This essentially distils a number of years' irradiance data into one 'typical' year, often combining that with ground measurements taken from pyranometers. These figures are then used to arrive at so-called P50 and P90 figures, which describe a probable level of generation that will be exceeded respectively 50% or 90% of the time.

When presented with a project proposal, an investor will consider both figures, with the spread between them giving an idea of the variability of the forecast resource at the site and therefore the risk attached to the project. The closer the P90 to the P50, the less the variability at the site and therefore the less risky a project; the greater the spread, the greater the variability at the site.

The problem with using TMY data for this exercise, says Bender, is that because it is based on only one year of data, it is unable to give a particularly nuanced picture of the likely climatic variability over a project's lifetime. That means a developer must "guess" at the distribution between the P50 and P90, leading them to err on the side of caution.

"Depending on how you assume the distribution [between the P50 and P90], there is a likelihood that you could over- or under-predict what that full range of variability might be," Bender explains. "And those have different consequences – like if you over-predict, if you say the distribution between your P50 and P90 is tighter than it turns out to be, you may end up underperforming.

"The other thing is that you under-predict – you say I think this spread is really wide, and you give yourself a P90 that's fairly low.

In terms of industry perception that's probably ok, because then the plants are performing better than expected. But then in terms of you as a developer, you just dropped a ton of money with the bank, because you picked a number that was too conservative."

Bender says the PV industry's caution is partly a reaction to a spate of large over-predictions that hit the wind energy industry in around 2008 and led to plants underperforming relative to expectation. "A lot of people would have been using the same consultants to do their solar," she says. "So because of a reaction among the major consultants to be conservative, so as not to have the same under-performance problem, I suspect we're going to see an over-performance in solar, which, again, is good for industry perceptions, but means that a lot of investment dollars were left on the table."

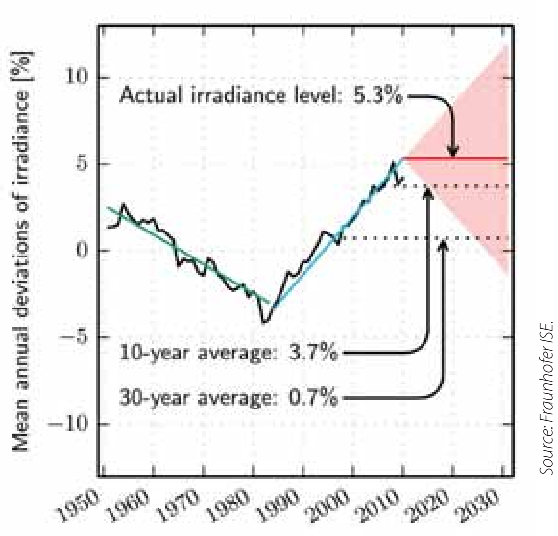
And that could be a lot of dollars. "It's extremely variable – depending on the tax situation, depending on how you finance your project and so on, a particular plant could be seeing that they left US$500,000 to US$1 million on the table every year, if you were overly conservative and you were over-performing," Bender says.

Better data

In an era when solar is increasingly moving into unsubsidised territory, where every kilowatt-hour generated by a plant will count, the trend of conservative estimates highlighted by Bender could cost developers dearly. "As we shift to a system where you are not paid for what's in the ground, but for what you produce, which is the world we're looking at in 2016 [when the US investment tax credit is due to run out], then all of a sudden you care a lot more about the variability of what you're going to produce," she says.

The message for developers and financiers is that the quality of the data that sits behind yield forecasting must improve at an industry-wide level. Bender's company, Vaisala, offers an assessment service that can produce a model based on 18 years of data, and she says she gets the sense that the industry is starting to realise the need to move towards more accurate modelling. "It's partly because there is enough installed now that my guess is people are not seeing the results they expected one way or another," she says, citing one unnamed client who came to her company because their plant was over-performing and "they needed a better number" to negotiate refinancing.

Fraunhofer ISE's Müller agrees that the industry needs to adop better modelling



Graph showing the annual deviations in solar radiation from the average value in Germany.

practices. "We had a lot of discussions last year about this, and it's starting, but it's not something that's already happening widely," he says. "TMYs are good, because they are quite cheap and they are available, but you need to use satellite time series, 10-year time series, so you can simulate a whole 10-year period and get from this the expected annual energy yield, but up to now satellite-derived irradiance time series have been quite expensive."

Others are more positive about the industry's awareness of the data issue. César Hidalgo, head of solar at the Barcelona office of renewables advisory DNV GL, agrees that some TMY data that has hitherto been available in the market, particularly for emerging markets in regions such as Latin America and South Africa, has not been particularly representative of the past 15 or 20 years. But that situation is now changing, Hidalgo believes: "People are more concerned about the quality of the data sets for solar resource assessments. Most lenders and developers are now well educated regarding the need for good solar resource data."

One important development says Hidalgo has been that the national meteorological offices in many countries, particularly emerging solar markets, have been concerned about the need to get good quality solar data. They have been installing masts at ground stations with pyranometers. Alongside this, Hidalgo believes that the quality of satellite data has generally improved. "There are a number of providers in the market that can provide very good quality data that a few years ago was very difficult to find," he says.

Hidalgo's colleague Ray Hudson, DNV GL's global solar service leader, agrees that the industry is becoming more sophisticated in its gathering and use of data. "Now that both the cost of the system components has come down and the margins have come down on what can be expected for the financial returns, this makes having a very accurate energy assessment much more important," he says.

But Hudson believes there is still room for improvement in some aspects of the energy assessment process, particularly around how data on component performance and actual field performance are incorporated. "There are areas to make the fundamental simulation tools for the conversion process in the modules better; there are opportunities to improve models to incorporate more of the parameters of the individual components," Hudson says. "As more solar is installed, incorporating lessons learned and actual performance, and feeding that back into the modeling, will be key. That's especially the case in areas like availability modelling and O&M."

Hudson says data on individual components such as modules and inverters has improved vastly, a fact that, combined with improved satellite data, is improving the precision of yield assessments. "Those combined have helped with accuracy," he says. "The state of the art is to actually do testing of components, especially modules, and in some cases doing project-specific model files for the energy estimate. Some of them have gone to that level of detail. And actually that's one of the services DNV GL provides through our test lab to support the increased accuracy of the assessments."

The advances described by Hudson as well as the adoption by the industry of more sophisticated resource and performance data will all undoubtedly be key steps for solar to take as it matures as a mainstream power source. The long-term performance of PV plants is still a relative unknown, but enough evidence is now beginning to emerge of plant over- and under-performance to suggest that smarter use of resource and actual performance should now become a priority for the industry.

Bender believes the industry is beginning to wake up to this. One piece of evidence she cites for this is the fact that when she gave a talk at last October's Solar Power International show in Las Vegas, although it was one she'd given many times before, this time she felt it finally began to hit home.

"I've been giving the same talk for five years, but it was the first year I feel like people heard it," Bender says. "So I think the industry is hearing the message, because they're seeing in the future they're going have to make the numbers work on production, not just building [power plants]. A project could be viable four out of five years, but you have to pay the bank five out of five years." ■

Project briefing

JASPER SOLAR POWER PROJECT, SOUTH AFRICA

Project name: Jasper solar power project
Location: Near Kimberly, Northern Cape Province, South Africa
Capacity: 96MWp
Annual Generation: 180,000MWh

The South African PV market has certainly been kind to US utility-scale PV solar project developer SolarReserve — both in terms of opportunity and returns.

In particular, the country's arid Northern Cape region, where summer temperatures usually top 40 degrees Celsius, provides a haven for potential PV installations. "There's just very, very good solar insolation in that region. When you look at it on the world standard, it's up there as a region that is bathed in solar resource and that is throughout the year. It's there to be harvested," says Alistair Jessop, SolarReserve's senior vice president of development, South Africa.

SolarReserve's first opportunity to enter such a promising market came about around five years ago, when the South African Department of Energy (DOE) held meetings with various PV market players in an attempt to spearhead an initiative that would later morph into the Renewable Energy Independent Power Producer Procurement Programme (REIPPPP).

"We were attracted to the South African market back in 2010," Jessop notes. "There was a conference held in conjunction with the DOE and [utility] Eskom and a lot of the related parties, where it was clear that there was going to be a process under which a renewable programme was going to be constructed. At that point, we then took the decision to move forward with the development of projects in South Africa."

Under the REIPPPP, three rounds of bidding for sites have led to 64 PV projects totalling almost 1.5GW being awarded contracts in South Africa — all of which will supply energy to Eskom. News of the successful bidders in the fourth round is expected soon from the South African government.

SolarReserve immediately saw the results of participating in the REIPPPP, as the company was awarded two projects during the first round of bidding, eventually developing the Lesedi and Letsatsi projects — totalling a combined 150MW of capacity. Both sites came online in May 2014 and marked SolarReserve's first big step into the South African PV sector.

Planning

In the next round of bidding for the REIPPPP, SolarReserve was once again awarded a project, giving the company an outlet to develop the largest solar installation on the African continent — the 96MWp Jasper solar power project.

It was a long road in terms of planning and development for Jasper, which was completed in November 2014 and has started to generate energy for Eskom through a 20-year power purchase agreement.

After the project was awarded, SolarReserve went about fostering a financial plan for the installation. With the assistance of South African investment firm Kensani Group, SolarReserve was able to roll out a strong roster of shareholders and investors, including Public Investment Corporation, Intikon Energy, Kensani Capital Investments, the PEACE Humansrus Community Trust and Rand Merchant Bank.

SolarReserve also attracted the interest of one particularly high-profile investor in the project – the internet giant Google, which was making its first renewable-energy investment in South Africa.

Jessop remarks: "I think Google took a good amount of time looking at the market and decided that our project was a project that was worthwhile investing in. I mean, clearly, we're delighted to have Google in the Jasper project … It was to great to get them in on this and it's great to have them alongside us today."

The Northern Cape, already home to the Lesedi project, proved to be the ideal spot to develop Jasper, thanks to the arid terrain and a heavy amount of solar energy received in the area.

"To be suitable, the terrain had to be applicable for solar application," Jessop

At 96MWp, Jasper is currently Africa's largest operational PV power plant by capacity.

Credit: All images SolarReserve

says. "We did environmental sweeps, we looked at any grid connection issues, we looked at any local issues. So you take all of that into consideration before we really start developing the site from the ground up. It's a great location – it's got the right conditions to construct these large infrastructure projects."

After determining that the site was primed for development, construction began on Jasper.

During the plant's installation, over 1,000,000 man-hours were generated, including over 800 on-site jobs at one point. Looking to capitalise on the climate around the site, SolarReserve utilised 325,000 Yingli Green Energy 'YL295P-35b' multicrystalline modules, which were installed onto the project.

The project — which was completed two months ahead of schedule — is set to produce 180,000MWh of renewable energy per year for South African residents, enough to power at least 80,000 homes. As part of the REIPPP, the plant will allocate a percentage of its revenue towards the Enterprise Development and Socio-Economic Development for the purpose of benefiting local communities.

In order to ensure the project's optimal operation and profitability — as well as appease their shareholders — SolarReserve says it made it a point to select the top materials and components on the market. "There was an effort in panel selection and also the mounting designs in order to make sure that we got the optimum performance," Jessop says.

The construction of Jasper used over one million man hours.

Jessop adds: "With round one happening, the local banks were tremendously supportive of the programme. Clearly, it was beneficial for them to support the programme, but at the same time, they didn't want to take risk on technology improvement, so they wanted it to have proven technology in the projects and that meant fixed-tilt PV systems, What we're seeing in rounds three and round four [of the REIPPP] obviously, people are now looking at single-axis trackers. … It was a step in the times."

Despite being tasked with developing the largest PV installation in Africa, Jessop says that SolarReserve dealt with relatively few challenges during the execution of the project.

"South Africa benefits from a world-class infrastructure in terms of road, rail and ports. The Jasper project came on ahead of schedule and started producing energy which was being put on the grid about two months early," he says. "There's a substantial distance between port and site in terms of hundreds of kilometres, but we didn't have any issues with any transportation. It was well run. … We had a fantastic, trouble-free experience."

Looking ahead, SolarReserve still has much more planned for the young South African PV sector. During the third round of the REIPPPP, the company was once again awarded a project — the 100MW Redstone solar power plant — which is set to be developed alongside Lesedi and Jasper in the Northern Cape.

Jessop notes: "We've enjoyed success here and we're building a pipeline with a view to taking a very long-term high position in both developing and earning projects within the South African market." ■

Solar opportunities in East Africa will be under the spotlight at Solar Energy East Africa. The event, organised by PV Tech Power's publisher, Solar Media, will be held on 10-11 March in Nairobi, Kenya. Further details are available at eastafrica.solarenergyevents.com

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Distributed versus central architectures in solar arrays

New inverter technologies offer installers the choice of central or distributed systems for PV arrays. Deciding which system is the most optimal to use isn't always based on the size of a solar system, writes Alvaro Zanon

Inverter technology has come a long way since the first solar installations, which typically featured a single central inverter. Today, designers are increasingly choosing a distributed approach – utilising multiple string inverters throughout a solar array. But now that a variety of choices exist, the challenge is to decide which is the most optimal architecture for a given PV array: distributed or central.

Larger utility-scale projects have tended to opt for large, central inverters due to the cost and utility interactive controls from a plant management perspective. Residential and small commercial projects have favoured the decentralised approach using micro-inverters, where the ability to install an inverter within the module is ideal for carports and multiple azimuth and angled applications. A relatively new approach to distributed architectures using string inverters has become increasingly popular in recent years, especially in the commercial and small utility-scale range. A number of factors influence this decision, and it's not as clear-cut as past tendencies may make it seem. Although the size of the PV system is important to inverter architecture decisions, it's not the only factor. In certain cases, a central inverter could be the better choice in smaller commercial systems, while smaller, distributed string inverters could be optimal for larger PV plants up to utility scale.

Given the potential of string inverters to be used in large commercial and utility-scale projects, such as in multiple cases throughout Europe, the goal of this article is to help decision makers choose between central inverters (central architecture) and string inverters (distributed architecture). The primary considerations for most developers are total cost and energy production. However, when total costs are comparable, deciding factors may include space constraints, system uptime, code compliance and other issues discussed at the end of this article.

Cost comparison study

To compare costs in an impartial fashion, Advanced Energy commissioned Blue Oak Energy to evaluate both system architectures in three PV systems ranging in size from a small commercial installation to a utility-scale installation. The results of this analysis are detailed below, and confirm what most designers may suspect: the distributed architecture with string inverters has a clear cost advantage in smaller arrays, while the central inverter begins to enjoy a slight cost advantage in the low 1 to 2MW range.

For the discussion here, the evaluation of inverter features is based on different models in Advanced Energy's distributed string and central inverter product lines, but readers also can easily use the considerations for comparing inverters from other vendors.

The choice between distributed and central PV system architectures is meaningful only for arrays where it becomes possible to utilise more than one inverter. In other words, when a PV system has only a single inverter, it uses by definition a "central" architecture. Conversely, the distributed architecture could use several string inverters, one for each sub-array of the PV array.

To make for a valid architectural comparison, this analysis conducted by Blue Oak Energy established a minimum array size of 100kW AC and a minimum string inverter size of 20kW AC for the distributed architecture.

To evaluate the effect of scale on distributed and central architectures, three different application scenarios were used in the comparison: a small commercial installation, a large commercial installation, and a utility-scale installation. To make the comparison representative of 'real-world' conditions, the study picked Newark, New Jersey as a location offering a realistic temperature profile. Sixty percent of the modules were south-facing at a 20° fixed tilt. The remaining 40% of the modules were west-facing at a 5° fixed tilt. These conditions, as well as the inverter and balance of system (BoS) configurations used, are summarised in Table 1.

The cost comparison was performed by creating electrical and mechanical designs for all of the systems, and then comparing the equipment, material, and labour costs associated with each design. The results of the analysis are summarised graphically in

Table 1. Summary of conditions and inverter/BoS configurations used in this comparison performed by Blue Oak Energy

	Centralized Architecture	Distributed Architecture
Location	Newark, NJ	
Site Latitude	40°±	
Max Dry Bulb (°C)	34°	
Min Dry Bulb (°C)	-15°	
Array Configuration	60% of modules: South-facing (180°) and 20° tilt	
	40% of modules: West-facing (270°) and 5° tilt	
Inverter Overload	130% approx	
Interconnection Voltage	480Y/277 V	

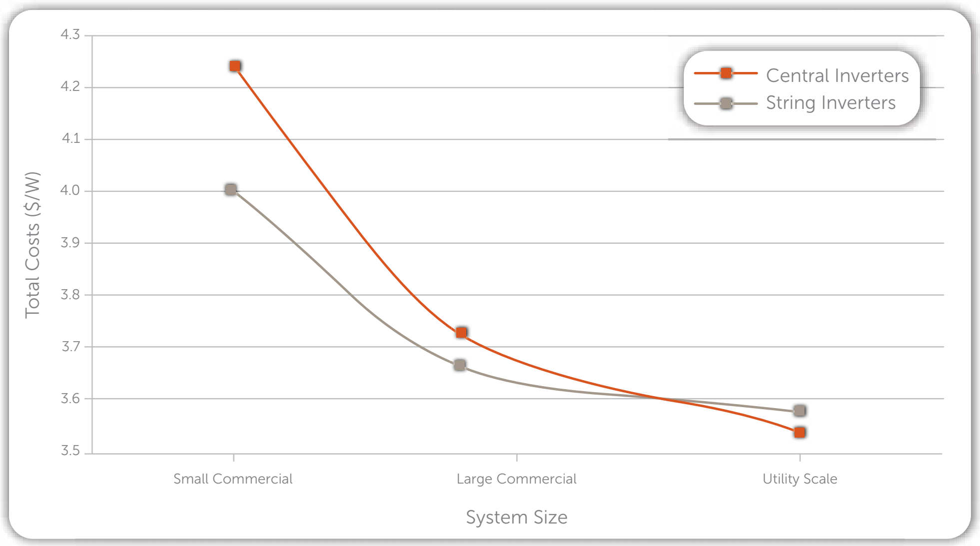

Figure 1. Total costs using distributed string and central inverters in systems ranging in size from small commercial to utility scale

Figure 1. As might be expected, the smaller string inverters enjoyed a clear advantage in total cost in the smaller arrays, with the distributed architecture being up to 5% less expensive than the central architecture. By interpolating the findings, the cost advantage appears to change in the low 1 MW to 2 MW range to the central inverter.

To evaluate real-world energy production, the effect of voltage and current mismatch was included with the introduction of inter-row shading on the south-facing array, and partial shading from trees on the west-facing array. A constant module-mismatch factor and a soiling factor that varied over the course of a year were also included in the simulations to make the energy production comparison as realistic as possible.

Again as might be expected, the distributed architecture, with its smaller strings or sub-arrays of modules, enjoyed a slight advantage in energy production based primarily on having the maximum power point tracking (MPPT) occur at what would be the combiner box level in the central architecture. While wiring losses were similar in both architectures, they came from different sources, with the AC losses of the distributed architecture being comparable to the DC losses of the central architecture. The distributed string inverter efficiency losses were slightly lower, however, compared to those of the central inverter, at ~2 and ~4%, respectively. The multiple array planes also gave the decentralised architecture a slight production advantage. The combination of these factors yielded in average a 1.5% higher performance ratio for the string inverters in all three scenarios.

It is worth noting that, in general, PV systems with multiple solar angles and/or partial shading benefit from the use of string inverters in a distributed architecture. This remains the case independently of the

Figure 2 Four-rooftop and 12-carport 855kW DC PV system utilising a distributed architecture design; installed at the VF Outdoor Coalition Campus, Alameda, CA. Source: Hawkeye Photography.

system's total capacity, which can easily exceed 1MW AC in campus settings. This means that string inverters might have a financial advantage in larger systems based on energy generation despite costing more than central inverters. Systems with arrays in multiple locations might also have space or weight constraints that favour the use of string inverters, which are much more compact and lighter than central inverters.

Other considerations in an optimal system design

In PV systems where the total costs and energy production are comparable between distributed and central architectures, creating an optimal design requires a more detailed evaluation of the specific capabilities or features of the inverter(s), as well as the site, any constraints and the overall monetary goals of the project. These considerations are assessed in this section, and because they are all necessarily product-specific, the discussion is based on Advanced Energy's TL-series string inverters and TX-series central inverters.

Although these considerations are mostly qualitative, some can have a significant effect on the quantitative economic analysis, and these are identified in Table 2 in the context of levelised cost of energy. As shown in Figure 4, the major differences are to be found in the BoS and the warranty period, which have an effect on the capital and operational expenditures, respectively. It is important to note that because the Blue Oak Energy study considered only the initial costs, the effect of the warranty and repair costs on ongoing operations and maintenance (O&M) expenditures could become an important consideration in the choice of architecture.

As indicated in Table 2, some peripheral considerations can have a profound impact on PV system economics. Such considerations may include the availability and cost of an O&M agreement, or the desire to minimise energy loss due to inverter failures. Or a plant designed to maximise the capacity factor with a high DC:AC ratio would require an inverter capable of supporting these higher ratios, as shown in Table 3. There are also scenarios where costs can become secondary to an inverter's ability to meet critical system design requirements. For example, Advanced Energy's central inverters operate at 60Hz, so only the TL series string inverters are suitable for a 50Hz system. Or in a system that requires very wide voltage trip settings, Advanced Energy supports this feature only in the TX series inverters currently. These and other 'feature factors' are identified in Table 3 as general design considerations. Other specific factors to consider:

Uptime: The decentralised design reduces lost output in the event of inverter failure. Typically, string inverters are replaced with new ones, or repaired offline. In most cases, it's recommended that spares are kept on site to reduce downtime. While the repair time of a central inverter may take several days, the uptime can be increased with a service plan. The decision between a distributed generation and centralised generation approach can sometimes be driven by the skill of the labour available and by the mean time to repair (MTTR). Thus, the decision between distributed and centralised generation will be impacted by the experience and capabilities of the inverter manufacturer or service provider.

Reliability: To best assess the reliability impact of the system as a whole, it's impor-

Figure 3. 500kW ground-mount PV system utilising a central architecture design; installed at the City of Greeley Water Pollution Control Facility.
Source: City of Greeley.

tant to carry out a reliability study to evaluate the respective failure rate of central and string inverters, and the number of inverters that will be used in the project.

O&M: The decentralised approach can reduce maintenance, given that string inverters do not require the preventive maintenance that is typical for central, such as inspection of the cooling system and thermographic imaging.

Investment performance: In order to capture all of the financial advantages and disadvantages of both the decentralised and the central approaches, the system designer may calculate several financial metrics, including return on investment, LCOE, internal rate of return or net present value.

Space constraints: System designers need to ask a range of questions to determine if a decentralised or central approach best fits a project's space limits. For example, they need to consider whether there is only room for a wall mount, or if there is room for a pad. Also, is there a requirement to mount it on a roof, or is there room on the ground? For carport applications, is there room on the ground, or can it be mounted on a post?

Code compliance and interconnect requirements: System designers need to consider the varying codes and utility requirements for each project location and select an inverter that meets those requirements.

Market conditions and future trends

The conditions and requirements discussed here indicate that growing demand for string inverters is likely, with increased utility-interactive control requirements for them. In the past, lack of familiarity was a significant roadblock to the utilisation of string inverters. Growing interest will likely

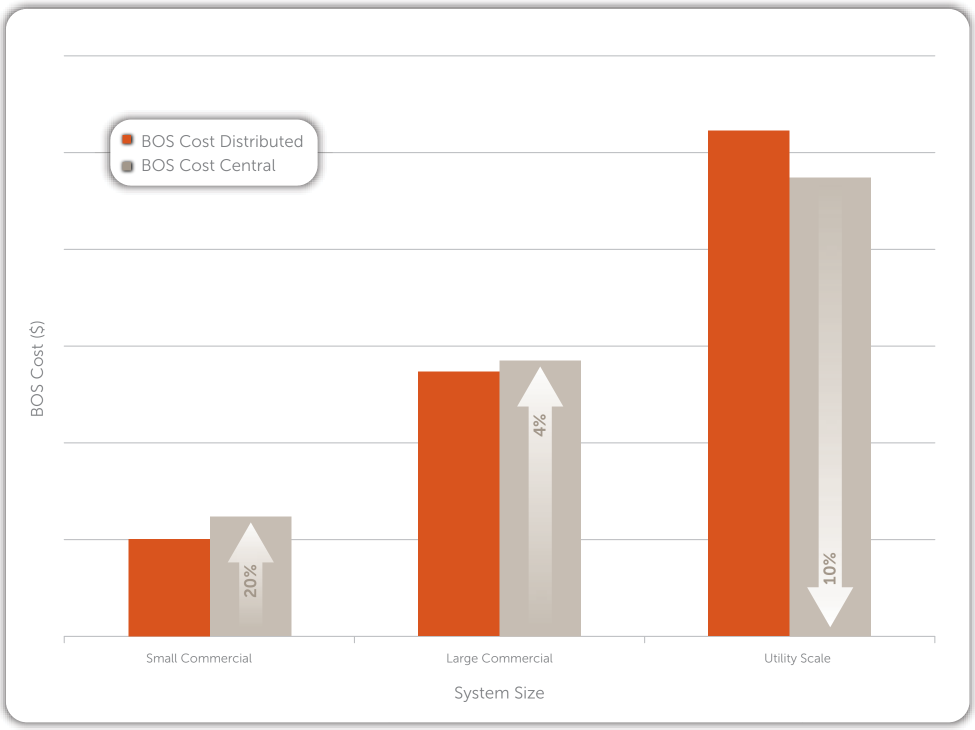

Figure 4. Balance of system cost analysis

LCOE Considerations	TL	TX	NX
Efficiency	✔	✔	✔
Balance of System Benefit			
No DC Combiner	✔		
Integrated Sub-Combiner		✔	
Integrated Breaker		✔	
Combiner-Level PV Tie for Long Home-Runs			✔
Integrated Revenue Meter		✔	
Reliability	✔	✔	✔
On-Site Service	✔	✔	✔
Remove and Replace	✔		
Standard Warranty (Years)	5	10	5
Extended Warranty (up to 20 Years)	✔	✔	✔

Table 2 . These inverter considerations all have at least some effect on the total cost of a PV system, especially on the BoS, as well as on the operational and maintenance costs.

Design Considerations	TL	TX	NX
High DC/AC Ratio	✔	✔	✔
Advanced UIC			
LVRT	✔ (IEC only)		✔
Expanded Trips		✔	
Voltage Control		✔	✔
600 VDC	✔	✔	✔
1000 VDC	✔		✔
Wide MPPT	✔	✔	✔
Multiple Angles or Shading	✔	✔	
Medium Voltage Interconnect	✔	✔	
Architecture	Floating	Grounded	Bipolar
50 Hz	✔ (IEC only)		
60 Hz	✔	✔	✔
Ontario FIT Compliance	✔ (UL only)	✔	✔
208 VAC		✔	
400 VAC	✔ (IEC only)		
480 VAC	✔ (UL only)	✔	✔
600 VAC		✔	

motivate developers/installers to implement them in solar arrays at an increasing rate, despite the fact that past successes with central inverters likely will continue to drive the use of central architectures as well.

The availability and successful use of string inverters increases their perception as a highly viable and competitive option for large commercial and small utility-scale projects, which have traditionally used central inverters. For example, string inverters were proposed for a recent 20MW-AC ground-mount project.

Distributed architectures also expand the possibilities for solar installations in remote areas of Latin America and Africa, and in small island locations. These locations aren't traditionally served with central inverters for three main reasons:

- Difficulty and cost for servicing central inverters in these locations
- Lack of local labor with experience installing central inverters
- Large cost of transportation of central inverters

Which is the better architecture in a PV system? As shown here, it depends on a number of factors. The size of the project might make a compelling economic case for either a distributed or a central architecture. For systems below 1MW-AC, a distributed architecture with string inverters normally incurs a lower capital expenditure; above that size, central inverters are usually (but not always) more cost-effective. But in many if not most situations, other factors will need to be considered to achieve an optimal system design.

So while project size does matter, it should not dominate the design. For a variety of reasons (or maybe only a single one) a central inverter designed for large-scale applications could be the better choice in relatively small commercial systems, while smaller, distributed string inverters could be optimal in some utility-scale plants. As described here, it depends on a number of factors, which must be evaluated on a case-by-case basis. ■

Table 3 (bottom). These inverter considerations can become determinative factors in the design of some PV systems, and may have an indirect effect on total costs or energy production.

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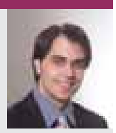

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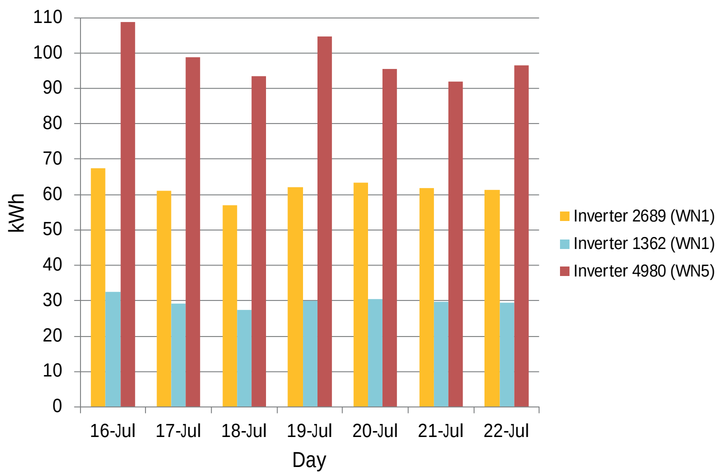
Novel strategies for PV system monitoring

System monitoring | Maximising production from a PV system is critical, since nearly all of the investment is made prior to system activation. Monitoring of PV systems allows operators to identify any performance or safety problems early so that they can be repaired quickly, thus minimising energy losses. Joshua Stein of Sandia National Laboratories and Mike Green of M.G. Lightning Electrical Engineering discuss some new monitoring strategies that are necessary for expeditiously identifying and locating system faults

The state of the art in PV system monitoring is relatively simplistic, relying either on comparisons of outputs between various parts of the system (e.g. inverters), or on an evaluation of a performance metric which normalises output to available irradiance and other environmental conditions. However, neither of these methods is very effective in discovering the source of identified problems or in identifying component-level failures, especially if they occur at the module or string level and thus have only a small, proportional effect on system output at the inverter or plant energy meter: hence the need for new system-monitoring methods.

"PV systems tend to suffer from a lack of monitoring, since, in principle, no danger is involved, no serious safety issues exist, and monitoring is easily overlooked"

(a)



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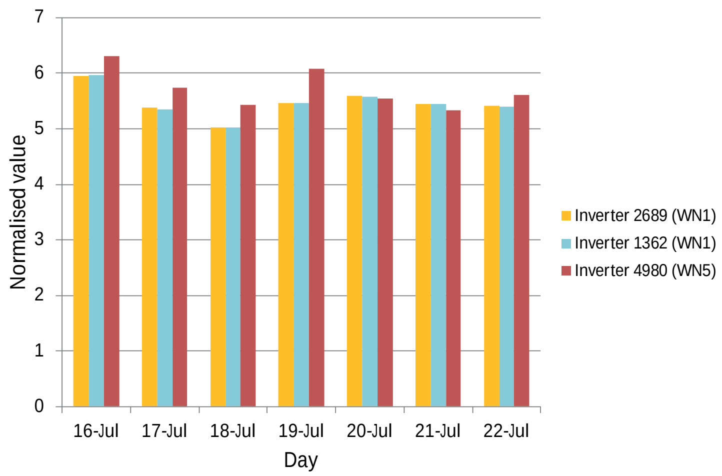


Figure 1. (a) Energy output comparison; (b) normalised energy comparison.

PV solar energy technology is usually static in nature. Aside from fans used to cool inverters, and when tracking systems are used, there are no moving parts, and these systems run cool and quiet compared with conventional energy-producing systems. It is not surprising, then, that PV systems tend to suffer from a lack of monitoring, since, in principle, no danger is involved, no serious safety issues exist, and monitoring is easily overlooked. However, PV systems have high parts counts and are characterised by numerous identical pieces (e.g. modules). Even low failure rates for individual components are more likely to occur when there are many components, and the failure of one component can put more stress on other components and thus lead to cascading failures.

Current monitoring practice

Because of the overall lack of a monitoring imperative in the PV industry, the state of the art for monitoring is relatively simplistic, compared with the overall capex when related to that of other industries. There are two basic types of monitoring employed today:

1. Comparative monitoring

2. Performance metric monitoring

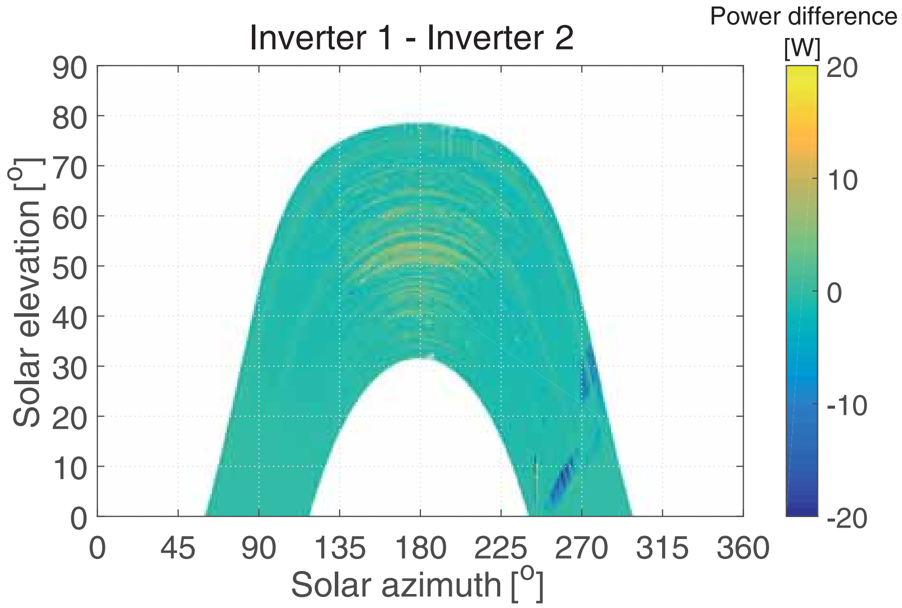
A good overview of current best practices employed in PV system monitoring is discussed in a recent report from the International Energy Agency's (IEA) Photovoltaic Power Systems Programme (PVPS) Task 13 [1].

Comparative monitoring

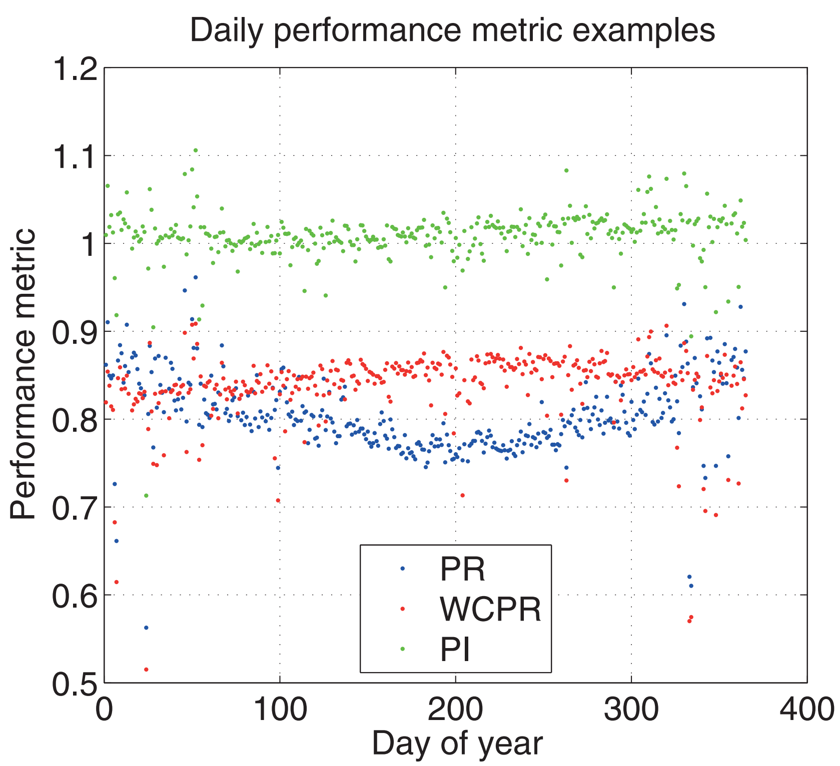
Comparative monitoring is used in smaller systems in which no meteorological sensors are installed. In this method, the power output from various inverters is compared. The preferred method is to normalise the energy with respect to the installed power of the array: this makes the comparison easier when the inverters are of different sizes or the number of modules attached to each inverter differs. Fig. 1 presents the advantage of a normalised energy comparison as opposed to a direct comparison of energy produced by inverters of different sizes. The inverter shown in red appears to experience a problem on the fifth day, as evidenced by a relative reduction in its output when compared with two other nearby inverters. This is readily apparent in the normalised graph (Fig. 1 (b)), but difficult to detect in the raw energy data graph (Fig. 1(a)). This method only works when there is more than one inverter or monitoring point to compare.

For a single inverter (e.g. residential system), this method is not very useful, unless other systems from the same neighbourhood can be used for comparison. However, since different small systems usually differ in array tilt and orientation, even these comparisons are difficult to perform in practice. In the case where a local monitoring company has access to a number of systems in the same neighbourhood, it is possible to perform comparative monitoring, even with the differences in system orientation, if the comparisons are carried out at particular times of the day and sun positions. This method is used by a number of PV-monitoring and operations-and-maintenance (O&M) companies.

When differences between inverters are observed, plotting these differences as a function of other variables can be informative. For example, Fig. 2 shows the difference in power between two inverters (in this case, microinverters) plotted as a function of sun position. The negative differences that appear in the late afternoon are due to shading of one of the systems by a nearby large power distribution pole. Simply comparing these differences daily, as in Fig. 1, might mislead the operator into thinking that there were equipment problems.



▼Figure 2 (top). Comparative monitoring between two microinverters plotted as a function of sun position illustrates shading effects.



▼Figure 3 (bottom). Comparison of three different performance metrics applied to the same system data.

Performance metric monitoring

Monitoring using a performance metric simply involves comparing the measured performance with a prediction of what the performance should have been, as determined from a model. Performance metrics vary in sophistication and in their required inputs; the more inputs needed, the more barriers there are to implementation, because of the lack of installed sensors.

The performance ratio (PR), currently the most popular metric, is also the least accurate measure of performance. Defined in IEC 61724, the PR is essentially a quantity that normalises the energy output of a PV system with respect to measured insolation and DC system capacity at standard test conditions (STC). This metric requires the measurement of plane-of-array (POA) irradiance in addition to AC power output. The standard version of the PR does not include corrections for changes

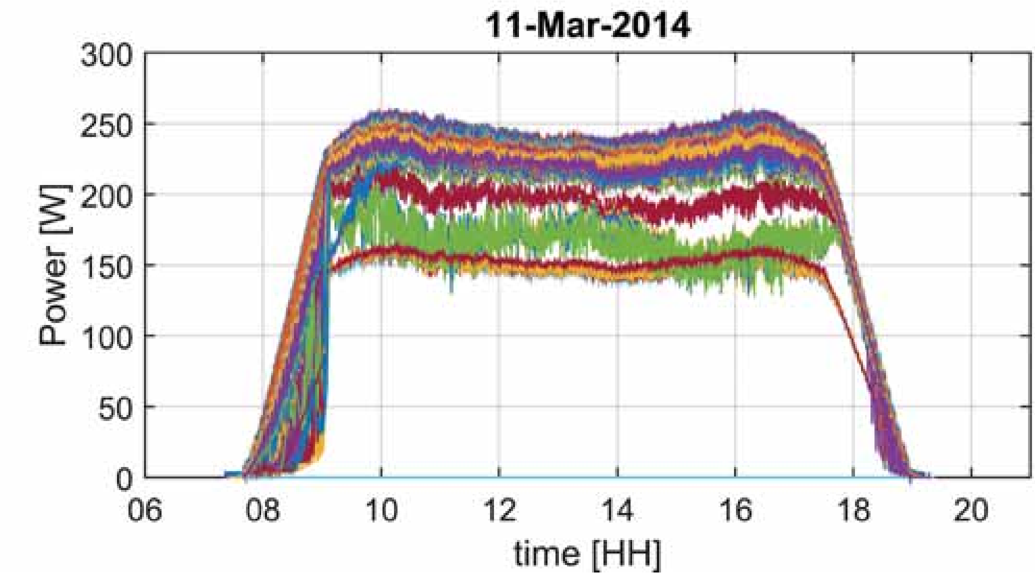


Figure 4. One day of module-scale monitoring data from over 400 PV modules in a 500kW PV array at a PV plant near Santa Fe, New Mexico.

in temperature, spectrum or angle of incidence of the sunlight, which all affect the performance of a PV system: PR values will therefore vary when any of these inputs change (e.g. as a function of weather, season or time of day). Since the purpose of employing a performance metric for monitoring is to use variations in the metric as an indicator of performance problems, the use of the standard PR is not a very sensitive indicator of health, because of its natural variations.

A newer version of the PR, called the *weather-corrected performance ratio* (WCPR) [2], has been proposed and shown to better stabilise annual calculations, but has not yet gained much of a following in the industry. One possible reason for the slow adoption of the WCPR is that it requires the measurement of more quantities, such as back-of-module temperature or air temperature and wind speed, in addition to POA irradiance.

Perhaps the best performance metric, which is referred to as the *performance index* (PI), is the ratio of measured performance and predicted performance using the best performance model available. This metric is typically used for large installations where sufficient meteorological inputs are measured to run a full PV performance model. Such models predict performance by accounting for the effects of irradiance, temperature, spectrum, angle of incidence, soiling, etc. There are many commercial examples of such models (e.g. PVsyst and PVSol). There are also free modelling applications available (e.g. PVWatts, SAM and PV_LIB Toolbox, among others).

Fig. 3 compares the three performance metrics, calculated daily over one year using PV system-monitoring data from a small, fixed tilt (1.1kW) c-Si array deployed in Albuquerque, New Mexico, USA. Noteworthy features include the seasonal dip in PR values (blue) during the summer due to high temperatures, the lack of such dip in the WCPR values (red), and significantly less scatter in the PI values (green) due to the ability of the performance model to account for more-realistic performance processes (spectral effects, angle of incidence, nonlinear low-light efficiency, etc.). The remaining scatter represents either variables that are not controlled (e.g. soiling) or measurement or modelling uncertainties.

New novel approaches to monitoring PV systems

As described above, the current state of the art in PV system monitoring is generally limited to comparisons between systems and the use of performance metrics, neither of which includes information about the nature of any discovered problem or its location. New monitoring approaches are needed that can quickly identify, classify and locate faults, ideally before they result in any system losses. The following sections will introduce a number of different approaches, ranging from laboratory and commercial research projects to early commercial deployments. What must be considered when evaluating any monitoring solution is that the monitoring method cannot cost more than the value of the energy that is recovered. This means that the best solutions for small residential systems will quite likely be different from those for large commercial- and utility-scale systems.

Community-scale monitoring

One of the barriers to employing performance metrics is the need for local irradiance measurements at the POA. One solution that is being employed by M.G. Lightning is to use communal irradiance and weather stations as the input to performance metrics for systems in the same vicinity (e.g. city or town). One challenge of this approach is that it may not work during certain types of weather: for example, under partly cloudy skies, cloud shadows will affect some systems and not others, even over relatively small distances. Fortunately, many regions experience at least some period of time each week when clear conditions prevail, even if only for part of the day. Another source of irradiance data is satellite irradiance vendors. While the errors in these data sources can be large for short time periods, over longer periods beyond a few days, the errors decrease significantly and this data can provide valuable inputs to calculations of performance metrics.

> "New monitoring approaches are needed that can quickly identify, classify and locate faults, ideally before they result in any system losses"

Another issue that is easily solved relates to systems having different orientations. In this application, simple models are available to translate horizontal irradiance to different tilt angles for use in calculating a performance metric. However, these models are most accurate during clear sky conditions.

Module-scale monitoring

Several companies have developed module-scale monitoring solutions. Perhaps the best-known examples of these are microinverters, almost all of which include the ability to monitor the output from each module individually. This feature is one of the main selling points used to market this technology, and can be quite valuable for small residential installations that suffer from partial shading from trees and building features. However, the higher costs and lower inverter efficiencies of microinverters make their use less desirable in large systems.

Other companies offer module-scale monitoring devices that attach to the module in series with the standard connectors and communicate wirelessly to a base station. These devices can be either attached to every module in the field or connected to only one or two modules per series string. In the string configuration they measure the current and voltage in the string, and this information may be sufficient for detecting a single-module failure.

Sandia National Laboratories (Sandia) recently participated in a project to evaluate module-scale monitoring at a 1MW single-axis tracking PV plant near Santa Fe, New Mexico. In half of the plant (500kW), module-scale monitoring was installed on one module per string, for nearly 400 modules in the array. Fig. 4 shows an example of a clear day of data. A few modules (9) were 'dead' and reported no power output, several (~20) performed at approximately two-thirds power, a few had noisy signals, and the majority (~350) operated within around ±20W of one another. The modules running at two-thirds power most likely had a substring of cells that was disconnected, possibly arising from a failed bypass diode.

The fidelity of this level of monitoring is impressive and provides very detailed information about this plant. If the costs associated with such a solution are sufficiently low, this technique provides valuable information to a system owner.

Health of the DC circuit

In addition to monitoring the power output from various parts of the PV array, it is also possible to collect other types of data that can be used to assess the health of the PV system more directly. For example, the series resistance (R_s) of a PV system (i.e. cell, module or array) represents the sum of the resistances contributed by all of the series-connected cell layers, contacts, and wiring between both ends of the system's circuit. Because the series resistance value is affected by changes in resistance in any of these component and subcomponent parts, the monitoring of series resistance over time provides valuable information about the system's electrical health and material properties. Increases in series resistance have been linked to corrosion inside modules and connectors, UV degradation of silicon, and other processes that contribute to overall degradation of PV system performance. Typical methods used to measure R_s involve measuring current–voltage (*I–V*) curves of modules on a flash tester or of strings in the field, and fitting equivalent circuit models (e.g. single-diode model) to the data; R_s is one of the model parameters that results. A problem with this approach is that it is largely manual, requiring labour and specialised equipment. In addition, R_s varies as a function of irradiance and its determination is therefore usually referenced to STC conditions.

Sandia and Draker Energy have collaborated on a demonstration of a new methodology to monitor R_s without the need for *I–V* curves [3]. Instead, measurements commonly available from an inverter (maximum power DC current and voltage) and the open-circuit voltage, which the authors believe should be relatively easy to obtain, are used to estimate values of R_s. This approach was tested on a string of 12 PV modules in the field, and fixed resistors were added in series to mimic increases in R_s. Fig. 5 shows the results of the predicted R_s values as a function of irradiance for various amounts of added resistance. The fact that each dataset is distinct means that changes in R_s are readily detectable.

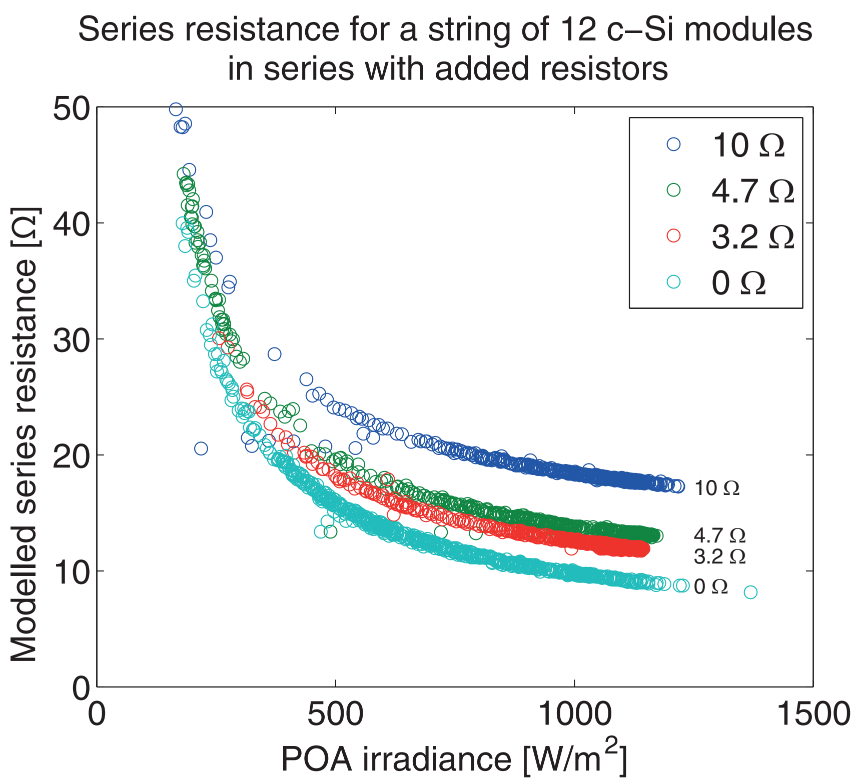


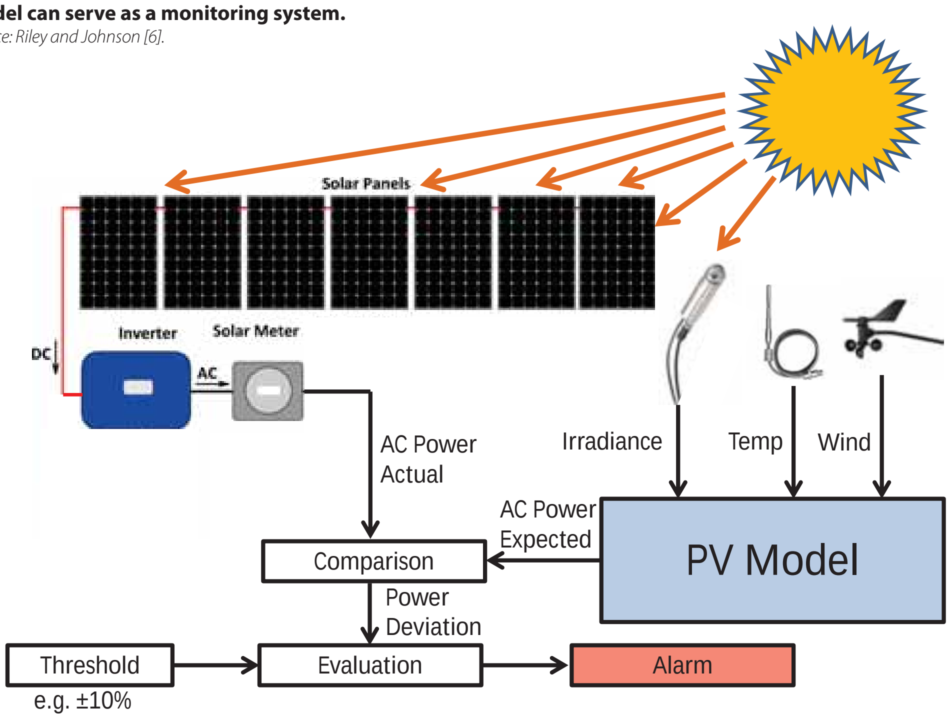
Figure 5. Validation results demonstrating a new method for monitoring series resistance without the need to collect and analyse *I–V* curves.

Sandia is also working with several companies to develop new monitoring hardware that would be able to automatically bypass either a single module or a single string, sweep its *I–V* curve and then reconnect it to the system without disrupting the inverter from delivering power to the grid from the rest of the array. Single-module units from Stratasense [4] are currently in the process of being tested, and work with Pordis, LLC [5] is under way to develop a multi-string automated *I–V* tracer, designed for larger commercial PV systems. The capability to automatically measure *I–V* curves from the PV system creates numerous opportunities for more-detailed monitoring in the future.

Health of the whole system

A promising approach to monitoring the whole system has been demonstrated on a small scale using neural network algorithms and is soon to be offered commercially to all sizes of PV system using machine-learning algorithms (Fig. 6). After the system has been commis-

Figure 6. Conceptual diagram of how a learning algorithm PV model can serve as a monitoring system.
Source: Riley and Johnson [6].



sioned, a learning algorithm is trained to estimate AC power production from available meteorological data (irradiance, temperature, wind speed, time of day, etc.). Research has shown that this methodology can be as accurate as the best PV performance models; the advantage of the learning algorithm is that it does not require design specifications for the system components, which can be hard to collect [6,7]. Current research is focused on whether learning algorithms are able to distinguish signatures from specific types of fault (open circuit, short circuit, bypass diode failure, excessive soiling, etc.). If these efforts are successful, it is conceivable that monitoring systems of the future will send out an alarm indicating the type of fault that is suspected.

Prognostic monitoring

Prognostic monitoring is intended to detect and interpret signals which can indicate that a problem or fault is likely to happen in the near future. Machine-learning algorithms are designed to learn the normal behaviour of monitored inverter parameters in conjunction with onsite weather conditions taken from a weather server. When a parameter strays from what is expected, an alarm is issued. Work led by M.G. Lightning in association with the IEA PVPS Task 13 has begun to catalogue these precursors to faults. The goal is to develop a predictive system that will alert system operators of an impending problem. This system with a prognostic capability would monitor system performance and be able to predict imminent faults before they occur, just as an engine check light helps avoid catastrophic failures in a motor car.

Next-generation monitoring systems

The future is ripe for innovative PV monitoring. The authors believe that monitoring systems of the future will be able to collect data from inexpensive sensors and use it in conjunction with data collected from other systems in the region, including weather and irradiance stations and/or satellite data, to determine the health status of a PV system. In addition, if *I–V* curves can be automatically collected at a low cost without disrupting PV generation, such information would be invaluable for detecting module degradation, locating system faults, and providing diagnostic information for O&M activities, including commissioning. In other words, be on the lookout for new monitoring products and services in the near future. ■

"Monitoring systems of the future will be able to collect data from inexpensive sensors and use it in conjunction with data collected from other systems to determine the health status of a PV system"

Acknowledgement

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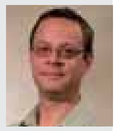
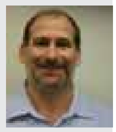
Authors

Joshua Stein is a distinguished member of the technical staff at Sandia National Laboratories, and works in the area of PV and grid integration. He currently develops and validates models of solar irradiance, PV system performance, reliability, and PV interactions with the grid. Joshua leads the PV Performance Modeling Collaborative at Sandia and is a member of the IEA PVPS Task 13 Working Group on PV performance and reliability.



Mike Green owns and manages the electrical engineering firm M.G. Lightning Ltd, which specialises in the design, consulting and maintenance management of PV systems in the Middle East, Africa and Eastern Europe. The firm has recently initiated iPVsolar, marketing a fault-recognition software as a service (SaaS) using machine-learning software based on predicting next-day hourly yield. Mike has been involved with IEA PVPS Task 13 for over four years, working on PV system reliability.



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Cleaning is the key!

Energy yield | As early as 2010, Phoenix Solar along with Saudi Aramco installed the first of three PV test facilities in Dhahran, Saudi Arabia, putting four different module technologies (monocrystalline, amorphous-microcrystalline, CdTe and CIS) to the test in extreme climatic conditions. Klaus Friedl of Phoenix Solar LLC shares some hints and lessons learned from the tests

Before the initial results from the tests carried out at the Phoenix Solar PV test field were evaluated, little had been known about actual module behaviour when confronted with the extreme climatic and technical challenges of the Near and Middle East deserts. The main objective of the tests was to investigate a number of parameters which were deemed critical for the purpose of building the first megawatt-scale PV power plant in Saudi Arabia. Saudi Aramco, a highly demanding customer of Phoenix Solar, was keen on determining the best possible technical solutions for this prestigious project.

The first phase of the research project, which began in July 2010, lasted approximately six months. The results did indeed serve as a reliable platform in the course of engineering and building a 3.5MWp ground-mounted PV power plant, which has been operational since 2013, on the premises of the King Abdullah Petroleum Studies and Research Center (KAPSARC) in Riyadh.

The aim of this pioneering project was to expand Phoenix Solar's knowledge base regarding the performance of different PV modules subjected to the climatic conditions of Saudi Arabia. Since the temperature of a PV module has quite a big influence on the efficiency of the modules as well as of the inverters, the overall PV system efficiency might be significantly affected by the climatic conditions.

The climate

One set of basic data which had to be gathered beforehand related to the actual climate. The following climatic factors, assumed to exert an influence on the potential energy harvest, were investigated in three different locations:

- **Irradiation:** clearly of paramount importance and key to the common assumption that the Gulf countries are likely to enjoy extremely high solar energy yields.
- **Ambient temperature:** heat is well known for causing stress in all electrical and electronic devices.
- **Wind:** this has an impact on the effect of ambient temperature on module temperature.
- **Pollution:** sand and other pollutant particles may obscure the modules and hence reduce their efficiency.
- **Humidity:** the widespread ground fogs as well as the climate of the Saudi Arabian coastal areas have been found to have some link with output performance.

Table 1 roughly outlines the findings for the three locations for comparison purposes; the subsequent detailed discussion will focus on the Dhahran test field location.

Dhahran test field

The test field for which the results will be presented in this article took three months to construct on the premises of Phoenix Solar's customer Saudi Aramco in Dhahran, with the actual test programme beginning in September 2010. The installation consisted of three to four modules of each technology, namely monocrystalline, amorphous-microcrystalline, CdTe and CIS. The test system was equipped with a pyranometer for irradiation measurements (full spectrum), an ambient temperature sensor, an anemometer for wind speed measurements, and a humidity sensor.

In order to observe the performance of individual modules, each one was connected to its own DC/DC converter (Solar Magic by National Semiconductor); this took over the MPP (maximum power point) tracking for each individual module and converted the output voltage to a level that allowed the module to be connected to the inverter. The inverter, a product of SMA Technology AG (SB4000TL-20), had two independent inputs with MPP trackers. It converted the total DC energy from all DC/DC converters to AC, which is necessary for the connection of the installation directly to the AC grid.

In addition, the individual modules were each connected to an Omega Pt1000 module temperature sensor, a DC voltage measurement sensor on the PV module output, and a DC current measurement sensor on the PV module output (shunt). These sensors were connected to a Campbell Scientific CR3000 data acquisition system, and all data were stored by the data logger.

The temperature

A very important factor is the module temperature. All specification sheets for PV modules provide a temperature coefficient; however, no public data exist for the real behaviour of modules in hot climatic conditions, such as those found in Saudi Arabia, where maximum temperatures exceed 58°C. Table 2 shows the characteristics of the types of module that were put to the test at the Phoenix Solar test field.

The different temperature coefficients, acquired from the published product specifications, indicated already that the

Table 1. Basic climatic data of the three test fields.

	Dhahran (on the Gulf coast, a Saudi Aramco location)	Jeddah (on the Red Sea coast)	Riyadh (location of KAPSARC)
Temperature (°C)	-1 / +50	+11 / +49	-2 / +48
Humidity	54.7%, frequent ground fogs	62.8%, frequent ground fogs	26.0%, rare ground fogs
Air quality	Salty	Salty	Dry

high-temperature behaviours would differ to some extent. Actual findings, however, exceeded the expected range of differences in performance. Table 3 gives an overview of the climatic and module performance data over the first five months of data collection.

Technology	Module efficiency	Pmpp (temperature coefficient in %/°K)
Monocrystalline	14.5%	–0.48
Amorphous-microcrystalline	9.5%	–0.24
CdTe	11.1%	–0.25
CIS	9.8%	–0.45

▲Table 2. Module data extracted from manufacturers' datasheets, as of September 2010.

Discussion of findings

September

The best energy yield related to the rated power was achieved by the microcrystalline modules, followed by the monocrystalline modules; CdTe and CIS modules achieved approximately the same level of energy yield.

The first cleaning of the test field took place at the end of September, which means that, from 7 July until 30 September, the system had not been cleaned since its installation.

October

It was significant that the amorphous microcrystalline curve was above that for monocrystalline, CdTe and CIS modules. The temperatures in October were already lower than in September.
Amorphous-microcrystalline: 1st in performance ratio; huge break-in (reduction in energy yield) at low light; best temperature behaviour.
Monocrystalline: 2nd in performance ratio; best low-light behaviour; biggest break-in at noon (worst temperature behaviour).
CdTe: 3rd in performance ratio; good low-light behaviour; break-in at noon.
CIS: 4th in performance ratio; huge break-in at low light; break-in at noon.

November

It was again significant that the amorphous microcrystalline curve was above that for monocrystalline, CdTe and CIS modules. There were colder temperatures in November compared with October.
Amorphous-microcrystalline: 1st in performance ratio; huge break-in at low light; best temperature behaviour.
Monocrystalline: 2nd in performance ratio; best low-light behaviour; biggest break-in at noon (worst temperature behaviour).
CdTe: 3rd in performance ratio; good low-light behaviour; break-in at noon.
CIS: 4th in performance ratio; huge break-in at low light; break-in in the afternoon.

December

Likewise in December it was significant that the amorphous microcrystalline curve was above that for monocrystalline, CdTe and CIS modules. The temperatures in December were lower than in November.
Monocrystalline: 1st in performance ratio; best low-light behaviour; biggest break-in at noon (worst temperature behaviour).
Amorphous-microcrystalline: 2nd in performance ratio; huge break-in at low light; best temperature behaviour.
CdTe: 3rd in performance ratio; good low-light behaviour; break-in at noon.
CIS: 4th in performance ratio; huge break-in at low light; break-in in the afternoon.

January

It was found that the CIS panel performed much better in the cooler January climate than in the previous months.
Monocrystalline: 1st in performance ratio; best low-light behaviour; biggest break-in at noon (worst temperature behaviour).
CIS: 2nd in performance ratio; huge break-in at low light; break-in in the afternoon.
Amorphous-microcrystalline: 3rd in performance ratio; huge break-in at low light; best temperature behaviour.
CdTe: 4th in performance ratio; good low-light behaviour; break-in at noon.

When the basic technologies at stake were compared it became clear that under the specific climatic conditions of the region, crystalline technology took the lead over the thin-film technologies, while there were only minor performance differences within each of the four technology groups. The crystalline modules turned out to be less heat sensitive and performed decisively better than their thin-film counterparts, particularly in the summer months. This is most strikingly evident from the graph in Fig. 1, which highlights the performance advantage of a monocrystalline over a CdTe module on 22 July 2010.

> "The crystalline modules turned out to be less heat sensitive and performed decisively better than their thin-film counterparts, particularly in the summer months"

In direct comparison the performance of the modules was assessed as follows:

- *Monocrystalline:* Above expectations (despite the high temperature coefficient, but good low-light behaviour).
- *Amorphous-microcrystalline:* Good, as expected (because of the good

▼Table 3. Results from September 2010 to January 2011 (only for modules which were cleaned every month).

Module comparison (average and cumulative yields)*	Sep 2010	Oct 2010	Nov 2010	Dec 2010	Jan 2011
Ambient temperature [°C]	34.8	30.6	23.5	18.6	16.6
Module temperature [°C]	39.2	35.3	26.6	21.7	19.9
Wind speed [mph]	5.0	4.7	4.5	5.0	5.3
Humidity [%]	46.8	49.2	49.0	53.4	69.4
Panels and pyranometer	**Cumulative yields [W/m²]**				
Irradiation	183.06	174.23	138.63	125.74	128.10
Monocrystalline (2nd place)	119.60	148.90	132.11	118.50	133.86
Amorphous-microcrystalline (1st place)	123.75	156.25	131.96	115.96	127.66
CdTe	106.86	137.56	118.10	106.38	114.69
CIS	81.90	130.82	121.14	96.34	124.14

* 'Average' refers only to the irradiation, and 'cumulated' refers to the module yields. All data are summed for each technology for the period of one month.

temperature coefficient).

- *CdTe:* Below expectations (despite the good temperature coefficient and constantly good low-light behaviour).
- *CIS:* Below expectations (because of the high temperature coefficient and weak low-light behaviour). CIS was able to improve somewhat in the lower-temperature winter months, but this was not enough to make up for the shortcomings throughout the rest of the year.

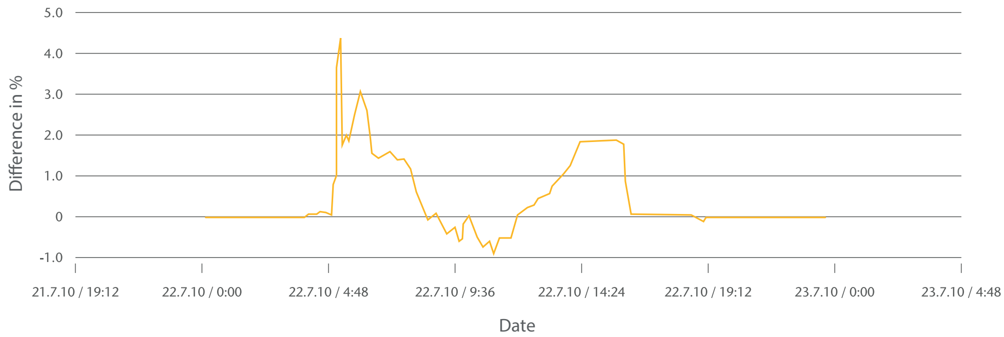
From an overall perspective, therefore, it was concluded that in terms of temperature dependency, the best average performance is to be expected from amorphous-microcrystalline modules, which performed best under high-temperature conditions. It had to be accepted, however, that those particular modules had significant drawbacks as regards low-light behaviour, but these did not outweigh the performance advantages at times of high irradiation.

The pollution

Besides the effects of temperature, it was considered important to find out how strong the impact of dust pollution on the energy yield would be and how much the yield could be improved by cleaning; moreover, at what intervals and how should the cleaning be carried out? To this end, the following aspects were monitored:

- Characteristics and intensity of the pollution.
- Cleaning methods, with special attention being paid to water consumption.
- Specific module behaviour.
- Respective power losses.

Performance was measured before and after cleaning. The impact of pollution was then determined from the differences in output between the cleaned modules on the day after cleaning and the ones left dirty. In order to correct differences between panels of the same brand, a correction factor was calculated and used after the first cleaning of all modules in the field.



▲ **Figure 1. Difference in percentage yield between monocrystalline (yellow line) and CdTe (zero line) modules.**

After one month of constant pollution, the reduction in energy yield was already considerable – around 15% (Table 4).

> "After one month of constant pollution, the reduction in energy yield was already considerable"

Technology	Yield losses after consecutive months of constant pollution [%]		
	1 month	2 months	3 months
Monocrystalline	15.42	28.98	36.03
Amorphous-microcrystalline	15.14	30.90	31.97
CdTe	16.49	17.39[1]	28.12
CIS	14.18	29.75	26.31[2]

[1] The low value for CdTe could not be precisely traced, and may be due to a failing of the cleaning team.
[2] Wind may be responsible for this abnormal deviation.

◀ **Table 4. Results for October, November and December 2010 for modules exposed to pollution, without any cleaning at all.**

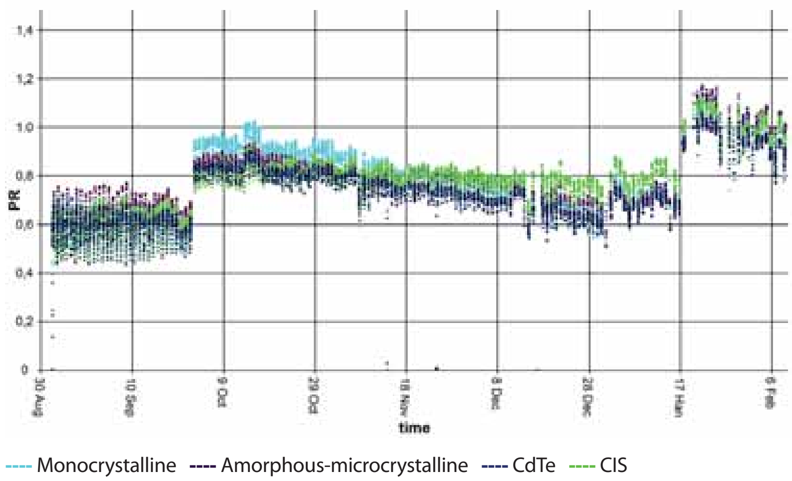
◀ **Figure 2. Test field in Dhahran, Saudi Arabia (photo taken on 1 November 2010 after partial cleaning).**

◀ **Figure 3. Zoom-in on the polluted modules of the test field.**

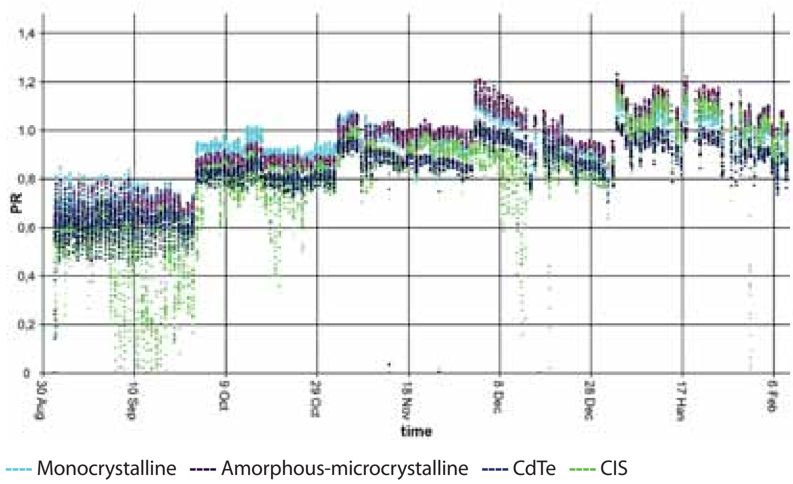
Over the next four weeks, the effect of the aggravating soiling increased at the same rate as in the first month, leading to a cumulative reduction in yield of around 30% after two months. However, performance differences between the technologies occurred which could not be explained in the course of the evaluation. The impact on yield losses after three months of pollution was still around 30%. The values were spread out much more among the modules than in the previous two months. As the losses did not increase at the same rate as before, it seemed as if the pollution had already reached a certain kind of peak or final stage at some point after two months of pollution.

There was no denying the fact that pollution began to have a significant negative impact after only a fairly short period of time. Another line of investigation, therefore, was to determine the best intervals and techniques of cleaning. In Spain and other European countries, Phoenix Solar has already experimented with various cleaning methods, devices and technologies – experience which could be built upon in the Saudi Arabian environment, but which also had to be adapted to suit the specific conditions of the region.

The actual level of pollution and its subsequent effects all exceeded expectations. It was even discovered that irradiation



◄ Figure 4. Module performance ratios for the period September 2010 to February 2011, with two cleaning sessions over a three-month period.



◄ Figure 5. Module performance ratios for the period September 2010 to February 2011, with frequent cleaning (monthly).

is often lower than anticipated as a result of the high amount of sand and dust in the air. This also seems to be a likely explanation for the high day-to-day volatility of the irradiation, even under clear skies and in bright sunshine.

Figs. 2 and 3 give an excellent idea of the heavy soiling on the module surface formed after only four weeks by the coagulation of sand, dust and salt because of the surprisingly high humidity in the coastal area. The test field had turned grey after just one month; for contrast, the blue modules had been cleaned immediately before the picture was taken. The character of the coating can be clearly observed on the zoom-in image in Fig. 3.

The actual extent to which cleaning affects module performance independently of the different technologies can be seen in the graphs of Figs. 4 and 5. One has to keep in mind that the temperature was decreasing steadily over the five months of observation and that there was some rain in December and January. In addition, groups were formed by picking modules of each technology; these groups were then cleaned in different cleaning intervals.

Fig. 4 shows how much the performance of the modules was reduced over time between the two cleaning sessions carried out on this group of modules over the three-month period. Note the jumps in performance ratio right after the cleaning sessions.

More frequent cleaning not only improved the performance because of a smaller reduction in energy yield but also resulted in a sustained higher average yield, as shown in Fig. 5. Again, from the graph it is evident that after each cleaning session, the module performance improved significantly, which reinforced the increase in energy yield resulting from the lower temperatures in winter.

Summary and conclusion

As a rule of thumb one may assume that the agglutination of sand, dust and salt takes effect after around one week. The option to wipe the modules dry with soft brushes either by hand or using appropriate machinery will not be possible after approximately ten days: the coating becomes too sticky and the risk of damaging the modules increases rapidly. After two weeks, wet cleaning is the only reasonable option.

Experience gained from the test fields as well as from operating the KAPSARC power plant in Riyadh leads to a recommendation of a wet cleaning every three to four months, complemented by regular intervals of dry cleaning; the actual frequency of the latter will undoubtedly depend on the exact location and the size of the PV power plant. Moreover, it has to be noted that, for various reasons, the cleaning task is far from easy in these areas with extreme climates. For example, it always needs to be borne in mind that water is a highly critical resource in desert regions and cannot be used as lavishly as may be necessary to get the best results. Obviously, regular dry wiping with soft brushes might be an option.

In terms of cost effectiveness, one factor to take into account is the low cost of labour in the region, keeping in mind, however, that a local workforce would have to be advised to work carefully in order to avoid scratches and other damages. The use of cleaning machines will be cost effective in plants of more than 50MWp, but different plant construction types will require different machinery for the purpose. In order to save water and cost, Phoenix Solar recommends a system that is efficient but not too sophisticated: small amounts of air-pressurized water are conveyed over the field through a system of pipes and spray valves, rinsing the modules as required.

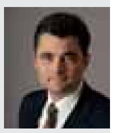
To summarise:

- High temperatures as well as high intra-day temperature spreads affect module efficiency.
- Wind mitigates the influence of heat.
- Wind, however, carries sand and dust, which obscure the modules.
- Rain helps to clean the modules to some extent.
- Humidity, e.g. in a coastal environment, on the other hand, will promote the agglutination of sand, dust and salt on the module surface and form an opaque coating.

Cleaning, therefore, is the key to maintaining high energy yields under desert and desert/coast conditions, and clearly requires thorough attention and care. ■

Author

Klaus Friedl has a degree in mechanical engineering and is the managing director of Phoenix Solar LLC in Muscat, Oman. He has been with Phoenix since 2009, and realized the first megawatt-scale PV power plant in Saudi Arabia (5.2MWp) in 2012 as the senior vice president of project development in EMEA at Phoenix Solar AG.



The evolution of O&M

Operations and maintenance | The effective operation and maintenance of large PV power plants is critical to ensuring these facilities perform optimally. Sara Ver-Bruggen looks at the latest O&M technologies and strategies emerging as plant owners seek to maximise their investment returns

Credit: SunPower.

New strategies and technologies, such as SunPower's module-cleaning robots, are helping drive down the cost of O&M.

A multitude of factors and variables impact a PV power plant's levelised cost of energy (LCOE), a metric that accounts for all the costs associated with the build and the operation of any power plant. Planning, design, engineering and construction phases have all seen improvements and refinements over the years as the industry gathers more experience from building more megawatts of capacity. More recently, the falling cost of components – modules mainly – as well as efficiency improvements have contributed to dramatic reductions in the cost of PV-generated electricity.

But, the industry is turning its attention to what needs to be done to ensure plants are kept in the best condition over their operational lifetime so that PV LCOE is competitive with other forms of conventional and renewable energy generation. Getting the most from assets, through regular inspections, cleaning modules, cutting back vegetation or replacing components in inverters, before faults develop, are addressed by the operations and services (O&M) side of the industry.

PV power plants today must operate as reliably as existing, incumbent generation technologies in use for many decades. Jörg Heinemann, executive vice president, global power plants, customer operations and EPC at SunPower, says: "Clients and investors expect PV power plants to behave like conventional power plants." Good O&M strategies and investments are critical to this.

Black & Veatch renewable energy consultant Emily Leslie has reviewed 75-100 utility-scale PV projects in the US in the course of producing independent engineer reports, prerequisites for raising the financing needed to build these large plants. The reviews are carried out once the construction phase is completed and are focused heavily on O&M.

According to Leslie "base" O&M service packages for large and utility-scale PV plants typically include: preventive maintenance for modules, DC wiring, combiner boxes, disconnects, inverters and MV transformers, protective equipment, the maintenance building, mounting structure, civil works and grounds, storage of parts inventory, warranty management, monitoring and reporting, array washing (if any), onsite electricity, telecoms and water.

Leslie says: "About US$20/kWp is a typical figure for base O&M services but when you add in other variables such as insurance or land leases this can increase to US$40/kWp or more. If a utility or investor happens to own the land on which the plant will be built then this can reduce O&M costs. So, these figures are general but can vary widely."

Reactive versus preventive maintenance

Maintenance can be split into two categories – reactive, or corrective, maintenance and preventive, or planned, maintenance. In the wind industry, for example, preventive maintenance forms a large part of O&M packages. If a gearbox breaks down, the resulting downtime from repairing or replacing such a large crucial component can be very costly.

Solichamba Consulting's Cedric Brehaut, who has authored GTM Research study 'Megawatt-Scale PV O&M and Asset Management: Services, Markets and Competitors 2014-2018', says: "In the PV industry preventive maintenance is important, though not as much as in the wind industry because PV plants have fewer mechanical components. But certainly inverters and also trackers – which are the only moving parts in a solar plant – require preventive maintenance.

"Tracker-specific preventative maintenance includes inspection and lubrication of moving parts (such as motors, gearboxes and jackscrews), while corrective maintenance consists of replacing components upon failure (such as drive motors, controller units, bearings, etc.)," says Brehaut. "The amount of preventative and corrective maintenance is highly dependent on the specific tracker make and model, and on the quality of installation."

Inspections are also part of most preventive maintenance plans, and use of technologies like infrared (IR) imaging to detect hotspots in inverters, combiners, and modules, are common practice. "System monitoring and performance analysis are key, and many large plants also require advanced control functions to support the grid," Brehaut adds.

Inverters, which convert DC to AC electricity, are a critical part of any PV plant and faults or breakdowns can directly impact the plant's productivity. Large central inverter cabinets for multi-megawatt farms contain lots of components that need regular checks.

Terry Oswald, vice president, systems performance and operations at Sunpower says: "Inverters, as they are electrical, require lots of IR scanning and torqueing while mounting/tracking systems require regular lubricating, calibrating and torqueing."

According to Florian Danner, managing

director of Conergy Services and globally responsible for the Germany-based firm's service business, central inverters require more preventive maintenance because of their complexity, whereas string inverters tend to demand reactive maintenance; when one goes it is simply replaced. "It's difficult to say which is the more cost-effective approach in terms of O&M as there tends to be cyclical swings between each inverter technology type every two to three years driven by technological improvements. At the moment the trend is going back to central inverters," Danner says.

Module cleaning

Module cleaning and managing site vegetation can represent a significant portion of maintenance costs but is highly variable between locations, depending on climate. "In the south and south-west of the US, where the climate and conditions tend to be hotter, drier and dustier, then more panel cleaning is needed. In the eastern and north-eastern regions there is more rainfall that tends to keep panels clean," says Black & Veatch's Leslie.

Specific maintenance practices can vary around the world. Much of Sunpower's portfolio in the US can be found in states such as California. Regular cleaning of panels forms a core part of the company's maintenance service activities, so much so that this led to the company's acquisition in 2013 of Greenbotics, which builds robots designed to clean solar panels. The technology is also important as Sunpower targets new markets outside the US, in places such as Latin America, Africa and the Middle East where dry dusty conditions often prevail.

The robotic system uses 90% less water, is three times faster than conventional cleaning and also operates at night for minimal interruption. The system is being installed as part of the Solar Star projects, which are two co-located solar installations in Kern and Los Angeles Counties in California that will have a capacity of 579MW when completed at the end of 2015. The company uses other advanced technology such as drones to identify what portion of the plant needs cleaning and reveal what part of plants need more regular cleaning or vegetation management. This means that SunPower can meet the high performance guarantees that it has in place with its investors and clients.

"The maintenance instrumentation we use feeds into a centralised structure – we do a lot of remote monitoring and despatch technicians to the site where they are needed. Everything is centralised and scalable for every location," says SunPower's Heinemann.

"However it's important that we not only flag problems and fix them in the field but that we use these to inform development upstream of our technologies. We're on our sixth generation tracking system which has been developed to resolve issues with earlier versions and we also incorporate learning and knowledge gathered from our other operational plants into the ones we are currently building."

Conergy has a portfolio of over 500MW under O&M management, largely in Europe, but increasing globally.

The full scope of O&M activities including maintenance on central inverters is offered by the company in separated service packages. "We will provide module cleaning if it is something that clients specifically require."

For its EPC business, Conergy will only use equipment from tier-one OEMs and suppliers, and carries out regular warranty assessments. "Supplier warranties are key. For central inverters it is a precondition that preventive maintenance is carried out on them. We assess thoroughly per country and service whether to perform the work with our own personnel or contract maintenance work out," Danner says.

Using high-quality products with good warranties from tier-one suppliers means clients can be offered higher performance guarantees for the total park. Danner expects to see this trend continue. "Additionally to high-quality products, O&M plays a key role in sustaining the PV plants' high performance throughout the investment period and beyond, as well as reducing the time of break even."

In the US market PV EPC firms tend also to be the O&M provider for new plants for the first few years matching the initial warranty period, and vertically integrated firms such as First Solar, SunEdison and Sunpower often sign long-term O&M contracts. Other O&M providers include independent power producers, inverter manufacturers and third-party firms also known as independent O&M providers. Some EPCs also offer O&M services for plants they did not build.

"When the initial warranty periods fizzle out and O&M contracts are up for renewal, the asset owner may decide to switch to a different provider. But these aftermarket O&M agreements do not come with the same warranties because an O&M provider is usually reluctant to take on risks related to hardware reliability or plant construction quality," says Brehaut. In the US a hybrid model has emerged in the last two years. "Some EPCs are partnering with independent providers to perform the O&M work right from the plant's start of operation. This model requires a tight collaboration during the design and construction phase," Brehaut explains.

Last year saw mergers and acquisitions of O&M businesses in the PV industry, such as First Solar's acquisition of Skytron Energy. Brehaut expects the trend to continue. The fast-growing markets are the US as well as Asia-Pacific, in countries such as Japan and in future China, where the installed base of large-scale PV has grown rapidly. "China has not really emerged yet as an O&M market – utilities tend to do the O&M themselves or contract out to the EPC, so for now the US is a key O&M market to watch. Even though the PV market is happening on a global basis it is really a collection of local markets, and this creates strong challenges for providers that attempt to expand their O&M business globally."

How to replicate a successful O&M business and strategy in one market in new ones is going to be important in future. "This is what will continue to drive the M&A trend," Brehaut concludes. "In Europe there is little construction of new utility-scale PV plants, except in France and the UK, so you have many providers fighting over a finite O&M market."

What is certain, though, is that the value of O&M will only grow in the coming years. The solar PV industry has managed to achieve dramatic cost reductions in recent years. In south-western US states such as California, for instance, PV power purchase agreements (PPA) prices are almost as competitive as those of wind. But as the industry takes its next steps as a growing mainstream source of energy, investors have high expectations for these power plants to operate effectively and maximise returns over their 25-year lifetimes. Good O&M approaches, as much as high quality components, plant design and other factors, are going to be critical.

Investing in O&M staff, resources and technologies will enable developers and EPC firms to grow the services side of their businesses in the coming years as this portion of the global PV market grows when more large-scale plants come out of warranty. ■

Author

Sara Ver-Bruggen is a freelance journalist

Utility-scale PV installations and their challenges in grid-code compliance testing

PV inverter testing | The market outlook for utility-scale PV installations is very positive. These PV plants have the capability of supporting grid operation, and the ability to do this is being increasingly required in grid codes. Testing the capabilities of very large PV inverters, however, is demanding for laboratories. Gunter Arnold, Diana Craciun, Wolfram Heckmann and Nils Schäfer from Fraunhofer IWES discuss current developments and resulting challenges and address the gaps and diversity in testing guidelines and standardisation

At the beginning of 2013 the European PV industry tried out two scenarios in its outlook on the market development of ground-mounted, utility-scale PV plants: 1) business as usual, with a little more than 10GW installed globally; and 2) policy driven, with about 18GW [1]. But for 2013, even the policy-driven scenario estimate worked out to be too conservative: by the end of 2013, the globally installed utility-scale PV added up to more than 21GW. In particular, the installations in 2013 by the USA with 2.8GW, China with 1.6GW, India with 0.7GW and the UK with 0.4GW drove this development [2].

The installed capacity of utility-scale PV plants is envisaged to double within the next five years according to the business-as-usual scenario of the EPIA [1], and a strong increase in utility-scale PV installations worldwide (Fig. 1) is predicted in market outlooks. There is a global market for very large PV inverters, but there are associated local grid-code requirements. Testing laboratories are thus doubly challenged – by inverters with increasing rated power and by diverse testing guidelines. Grid-code requirements and the resulting challenges for testing laboratories are examined in this article.

Grid-code developments and testing guidelines

With more and more PV installed at all levels of the electricity grid, the requirements for generators have to cover various aspects of system stability, operation and security. These entail the support of remote-controlled network operation activities, such as feed-in management or power curtailment, as well of dynamic behaviour in the case of network faults. Accordingly, the scope of the testing has to be broadened.

Grid-code comparison

Advanced inverter functionalities required by grid codes are related to frequency and voltage support. But the focus in this paper is on functionalities supporting the secure grid operation at the point of connection to the grid, especially static voltage support/reactive power provision and dynamic voltage support/fault-ride-through (FRT) capabilities. With distributed generation (DG) providing active power depending on the actual frequency, and reactive power depending on the local voltage, the loss-of-mains (LOM)/anti-islanding detection is gaining importance. LOM testing is therefore considered here as well.

> "The installed capacity of utility-scale PV plants is envisaged to double within the next five years according to the business-as-usual scenario of the EPIA"

For static voltage support, the DG installations have to provide inductive or capacitive reactive power. There are three approaches:

- **Reactive power (*Q*) control:** fixed or scheduled *Q* value or remote controllable, over a certain threshold, independent of the active power (*P*) production.
- **Power factor (cos*φ*) control:** fixed cos*φ* or dependent on the actual *P* production.
- **Voltage (*U*) control:** *Q* or cos*φ* dependent on the actual voltage at the connection point.

Specific requirements for Germany, Italy and South Africa are summarised in Table 1.

Dynamic voltage support is requested

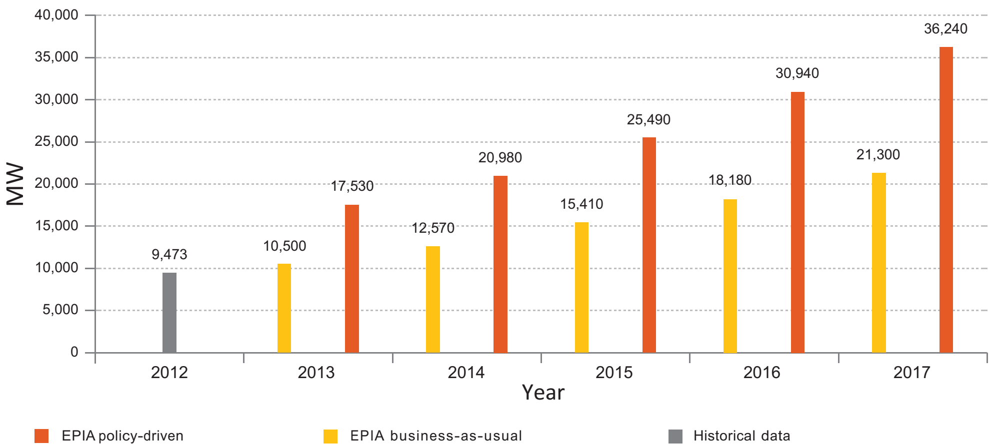


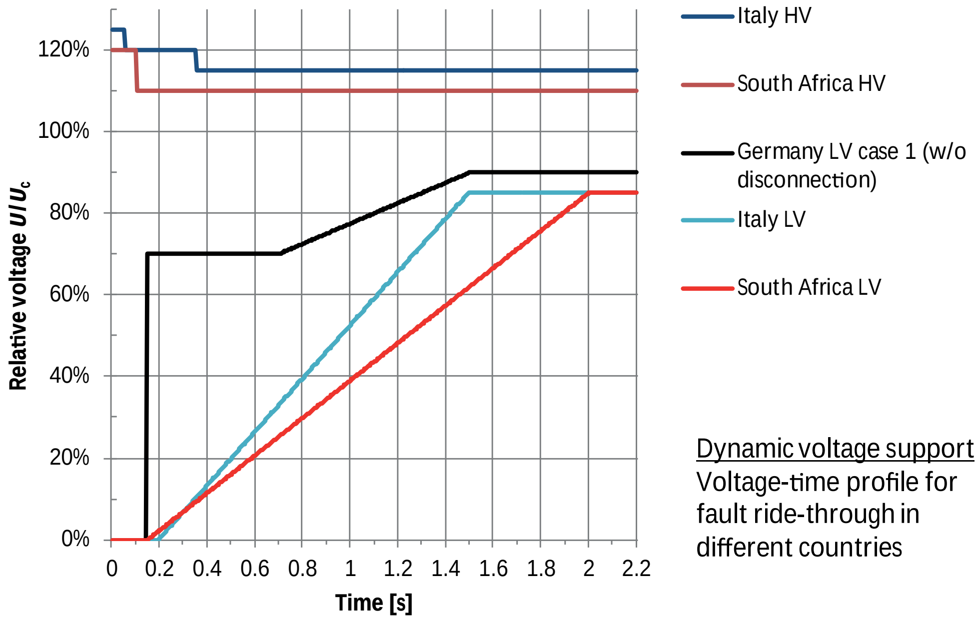
Figure 1. Global utility-scale PV development scenarios up to 2017. *Source: EPIA [1]*

where the share of DG becomes big enough to cause stability problems or to amplify the consequences of a fault in the network when it is operated solely within the usual voltage band of ±10–15% of the agreed service voltage U_c. There are two modes of FRT requirements. The low-voltage (LV) ride-through mode is related, for example, to distant network faults or to faults in neighbouring lines; DG should stay connected for voltages above the LV boundaries, shown in Fig. 2. The high-voltage (HV) mode can occur, for example, following switching operations – see the two upper boundaries in the same figure.

Besides being requested to stay connected, the distributed energy resource (DER) can be additionally asked to actively support the voltage by a feed-in of reactive current. This is described, for example, in the German grid code and shown in Fig. 3; DER should be able to provide reactive current within the area between the two boundaries.

In the context of DG, a main concern for network operators has always been ‘unintentional islanding’ – i.e. the balancing of loads and generation regarding active and reactive power in a separated, no longer remote-controllable grid area. One of the issues is safety, for maintenance teams and in terms of the functionality of network protection schemes; another is linked with the question of re-synchronisation. For these reasons reliable LOM detection is mandatory.

It is important to note that grid codes also look at the possibility of intentional islanding related to the security of supply or black-start procedures. In ENTSO-E [7] the capability to take part in isolated network operation is defined for type C generators. The detection of the change from an interconnected system to an island operation should not rely solely on the network operator’s switchgear position signals, but should also be implemented at the generator level.



▲**Figure 2. FRT: high voltage (HV) and low voltage (LV) vs. time profile used in Germany [3], Italy [4] and South Africa [5].**

Comparison of specifications for LOM and FRT requirements

Specifications given in different grid codes, standards or testing guidelines may vary. Some types of capability may be demanded only in a particular grid code, or different grid codes may specify the same type of capability differently. This section presents a more detailed description of some of these capabilities, while also looking at existing differences in the specifications.

LOM detection

The application of LOM detection for DG plants is often considered by utilities because of its high importance for the safety of personnel. Grid codes therefore typically require a type of LOM detection to be implemented in the DG–grid interface, but the type and degree to which it is applied are usually not further specified. In EN 62116:2011 [8] a test procedure of islanding prevention measures for utility-interconnected PV inverters is described using an adjustable RLC load connected in parallel to the AC source/the public grid at the AC side of the inverter. To prepare the testing, the RLC load is configured to form a resonant circuit with the PV inverter (Fig. 4). With the inverter operating and the RLC load balanced to the generated power, the utility-disconnect switch is opened and the run-on time is measured. The test has to be repeated by adjusting the RLC load according to different classes of load imbalances, which are given as a percentage value of the output power of the PV inverter (first class: 0%, 5% and 10%; second class: 1%, 2%, … 5%).

“The application of LOM detection for DG plants is often considered by utilities because of its high importance for the safety of personnel”

▼**Table 1. Reactive power provision according to the grid codes in Germany [3], Italy [4] and South Africa [5].**

Reactive power provision	Germany	Italy	South Africa (category B)
Operating range	From cosφ = 0.95 under-excited to cosφ = 0.95 over-excited	Up to full semicircle, depending on P_{rated}	From cosφ = 0.975 under-excited to cosφ = 0.975 over-excited
Operating requirements	Fixed set point or scheduled set points or remote controllable	Fixed set point or scheduled set points or remote controllable	Remote controllable or droop controlled
Set point types	cosφ, cosφ(P), Q, Q(U)	cosφ, cosφ(P), Q, Q(U)	Q, Q(U), cosφ(U)
Response time span	< 10s for cosφ(P), between 10 and 60s for Q(U), < 60s for remote control	< 10s (for remote control too)	< 30s for remote control

Usually the run-on time has to be less than 2s.

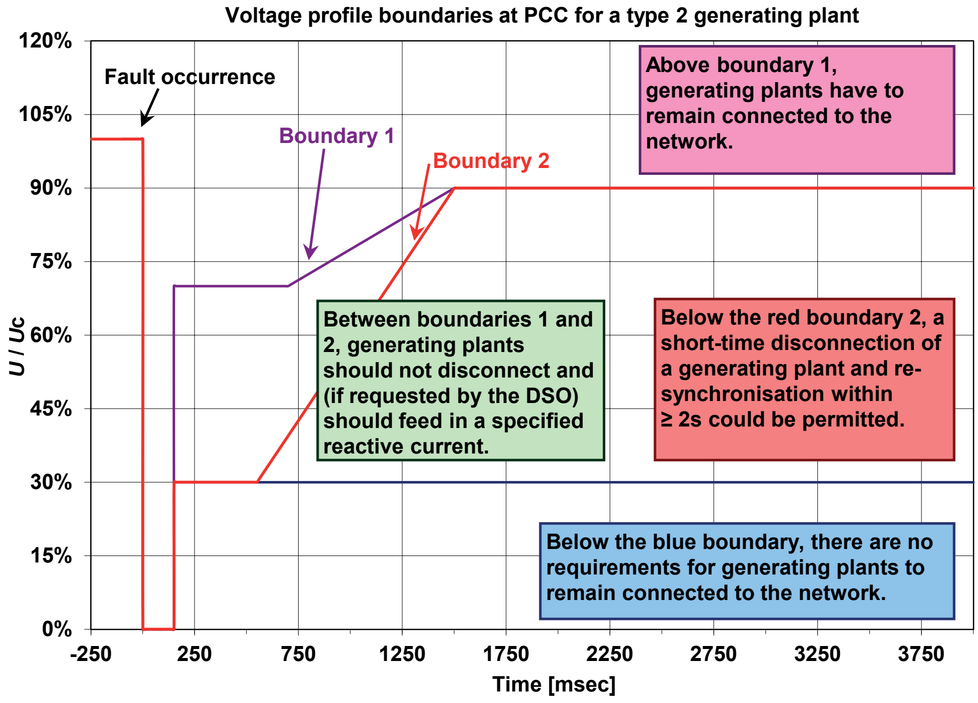
LOM detection testing is one example in which testing procedures for small-scale PV inverters are extended to utility scale. Testing of LOM detection involves adjusting the RLC load according to different classes of load imbalances, which are given as a percentage value of the output power. For central inverters with a rated power range of several hundred kilowatts, the given specification for the load imbalance as a percentage value of the output power may lead to very large steps between testing points.

Dynamic voltage support/FRT

Different requirements exist for the capability of LV-FRT. All the requirements comprise specifications on the type of fault which is applied to the equipment under test (EUT). For instance, both FGW TR3 [6] (Germany) and CEI 0-16 [4] (Italy) specify symmetrical and unsymmetrical (two-phase) faults at voltage drops of 5%, 25%, 50% and 75% U/U_c. For the voltage dip of 5% U/U_c, the fault durations differ (FGW TR3: 150ms; CEI 0-16: 200ms).

Further requirements imposed on the behaviour of the EUT differ from standard to standard and can be described by introducing three time segments: the times before, during and after the fault. The condition of the EUT before the fault is described in the same way in both documents (10–30% P_{rated} for partial-load tests, and at least 90% P_{rated} for full-load tests), whereas FGW TR3 Rev. 23 requires that tests be carried out in test stands with 100% P_{rated} for full-load tests.

For the time during the fault, according to FGW TR3 the EUT has to prove its ability to actively support the grid voltage by feed-in of reactive current following a predefined value, called the 'k' factor. According to CEI 0-16, the only



Type 2 generating plant = non-directly coupled synchronous generator, e.g inverter coupled
PCC = point of common coupling (between generating installation and public grid)
DSO = distribution system operator

▲Figure 3. FRT requirements in Germany, with reactive current provision [6].

Figure 4. Configurable RLC loads (3 × 200kW/kvar each) at Fraunhofer IWES SysTec.

Credit: Fraunhofer IWES, Beushausen

Credit: Fraunhofer IWES, Prall

Figure 5. Fraunhofer IWES SysTec test centre: the testing shed, a test track for inductive charging, and an adjacent commercial PV installation (22MW).

requirement is to stay connected for the duration of the specified dips.

For the time after the fault, active and reactive power supplied by the EUT must return to their corresponding pre-fault values within 5s, according to FGW TR3. In contrast, CEI 0-16 specifies a time of 400ms.

Laboratory experience

Fraunhofer IWES operates a testing laboratory for PV inverters of up to 3MW. In this section the laboratory is briefly described, and specific challenges in testing central inverters for utility-scale PV installations are discussed.

SysTec – testing laboratory for grid integration

At its SysTec test centre (Fig. 5) for smart grids and electromobility, Fraunhofer IWES is developing and testing new equipment and operation strategies for smart low- and medium-voltage grids. In addition, investigations regarding grid integration and grid connection of electric vehicles, as well as of PV systems, wind energy plants, and storage and hybrid systems, are carried out under realistic conditions on site [10].

The main equipment of the testing laboratory for grid integration comprises:

- LV network simulator 1MVA, 100–900V @ 650A (100–450V @ 1300A), frequency range 45–65Hz
- programmable DC source, 3MW @ 1000V (DC)
- MV (medium-voltage) / LV (low-voltage) tap transformer 1.25MVA, 254–690V
- programmable LV RLC loads: 600kW, 600kvar (ind.), 600kvar (cap.)
- mobile 20kV LV-FRT unit up to 6MVA

The dynamic requirements are tested by using a mobile LV-FRT container, which is connected in series between the DER unit (EUT) and the public MV network and generates network faults (voltage dips) at the MV level. Both three-phase faults and two-phase faults can be simulated. A more detailed description is given in Schäfer et al. [11] and Geibel et al. [12].

Specific challenges

Challenges for testing laboratories regarding utility-scale PV installations are related to, for instance, LOM detection, the coverage of large power ranges, and non-standardised voltage levels. On the basis of experience gained at Fraunhofer IWES [13], a description of selected challenges is presented next.

The main complication originates from the wide variety of PV inverters with specific electrical data: the wide operating ranges of rated AC and DC voltages, as well as of maximum power point (MPP) voltages, in addition to the increasing rated power, are all challenging.

- Non-standardised AC voltages may occur, as individual 'power park voltages' can differ from common LV distribution grid voltages; therefore, the AC network simulator and the corresponding MV/LV tap transformer have to allow operation over a wide operating range in terms of both voltages and currents. Low AC voltages may pose an extra challenge, since the resultant high AC currents necessitate significant efforts with regard to cabling.
- The DC source has to cover a wide operating range of DC voltages and related currents. Tests should be possible over the full MPP voltage range of the tested PV inverter, but at

least for the maximum and minimum MPP voltage. Typically, MPP voltages range from 600 to 1000V, but higher MPP voltages do exist. Covering these wide operating conditions poses a big challenge to the dimensioning of the DC source. At the SysTec testing laboratory, the answer to this challenge is a series operation of single units of the DC source.

- The requirements for the AC interconnection depend on the topology of the tested PV inverter. High phase-to-ground voltages may require a galvanic separation, as the AC network simulator and the corresponding MV/LV tap transformer may not be able to withstand the stresses caused.
- Testing of the capability of *Q*(*U*) control is possible only with network simulators and can be very challenging for the equipment. The abruptly activated under-excited/over-excited operation of the EUT may have an impact on the AC voltage at the terminals of the EUT; this effect on the AC voltage must be compensated by the AC network simulator.

Regarding LV-FRT, in general the voltage dips applied to the EUT can be produced at the MV or LV level. Fraunhofer IWES has testing facilities for both, generating voltage dips at the MV level (using a mobile 20kV LV-FRT unit) and at the LV level (using a highly dynamic 90kVA AC network simulator). Both approaches possess advantages and drawbacks.

Testing at the MV level features very realistic test conditions but gives rise to some challenges:

- Because of its electromagnetic nature (inrush current), the use of the MV/LV tap transformer is very demanding on the performance of the inverter.
- The grid impedance seen by the PV inverter during the test is significantly increased by the decoupling impedance of the medium-voltage LV-FRT unit, which may lead to stability problems in inverter operation.

Challenges faced during LV-FRT testing at the LV level are:

- The testing at this level with an AC grid simulator does not reproduce the effect of an MV/LV transformer at all.
- Owing to the usually lower rated power of the AC grid simulator, the tests are limited to smaller inverters.

In general, highly dynamic AC network simulators, suitable for testing LV-FRT, are not currently available for testing very large central inverters. Affordable AC network simulators with higher power ratings usually do not allow the voltage drop/rise times specified for LV-FRT testing or asymmetrical faults. With a medium-voltage LV-FRT unit, however, realistic LV-FRT testing of large inverters with a rated power of several hundred kVA to a few MVA can be performed at affordable cost.

"A laboratory infrastructure for testing utility-scale PV inverters must be very flexible and should be based on a modular design concept that will allow future extension"

Outlook

The active participation of DER installations in regular network operation will increase. Advanced functionalities are defined in the grid codes and will be demanded by the network operators. For testing these functionalities a systems approach needs to be developed, comprising the communication path, the response of the device and the possible mutual interaction of diverse demands. For these reasons, a laboratory infrastructure for testing utility-scale PV inverters must be very flexible and should be based on a modular design concept that will allow future extension. ■

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Wolfram Heckmann has been working at Fraunhofer IWES in Kassel since 2007 in the area of grid integration of renewables and international testing laboratory networks. He is involved in the IEA task ISGAN/SIRFN (Smart grid international research facilities network).

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Solar plus storage goes large

The combination of storage technology with larger scale solar projects is an emerging science. Andy Colthorpe speaks to PV power plant pioneers, Belectric, about a project completed at the end of 2014 to install battery storage at a utility-scale solar installation in Brandenburg

When coupled directly with solar, energy storage has obvious benefits – the opportunity to increase self-consumption of PV-generated electricity, as well as adding uninterruptible backup power supply, especially at smaller scales. However, the use of larger scale storage to contribute to grid stability offers an interesting 'twofer' (two-for-one) driver for PV and other renewable energy that is being explored at a 67.8MW solar farm in Germany by PV power plant specialist, Belectric.

First, and most important from a bigger picture point of view, it can help render arguments against the variable nature of PV somewhat redundant, as stable grids can accommodate greater penetrations of renewable energy. Second, as in the case of the latest project from BELECTRIC, grid storage batteries could provide additional revenue streams, from playing in the market for ancillary services to the grid, such as frequency regulation.

The solar farm itself, Alt Daber, was completed on a former military airfield in Brandenburg, in the north of Germany. Alt Daber has a nameplate capacity of 67.8MW, to which the addition of the 2,000kWh lead-acid battery system, Energy Buffer Unit, was announced in February last year. Connection of the battery system was marked with a ribbon-cutting ceremony in November.

Belectric's UK managing director Duncan Bott and Tim Mueller, chief executive of Belectric's solar research and innovation subsidiary, Adensis, spoke to PV Tech Power about the project.

PV Tech Power: Alt Daber is a pretty big solar project. Can you tell us about some of the thinking behind the installation of a 2,000kWh energy storage facility once the solar portion of the project was completed?

Tim Mueller: We started Alt Daber as a PV power plant and began building in 2011 and it was also completed that year. We were thinking it would be very nice to add a storage system to this power plant. We came to this idea because the Transmission Network Operator (TNO) which was connecting the Alt Daber PV plant was having a lot of problems getting the energy away from this PV plant.

We were thinking – how could we aid this problem, how could we help? The first idea was always storage systems and we had started maybe three years before with the design of a storage system which would be suitable for PV power plants in stationary applications. So we were thinking, why not apply it to our power plant in Alt Daber?

PV Tech Power: When it comes to solar coupled directly with storage, a lot of the talk we have heard has centred on 'load shifting' applications, often conferring the direct benefit or value on to the owner of the PV system rather than using the batteries for grid stabilising. Why is the Alt Daber project more concerned with using storage for grid stability?

TM: The more we got involved in [looking at storage for Alt Daber], the more we found out that to store energy to shift it from one hour to another, or to shave the peak, would be a nice idea but would not be profitable. So it's not the time yet to do that – for business models to shift energy from one hour to another, using electrical storage systems. But in the end we thought, well, it should be something we have to do, or have to construct within the next couple of decades, otherwise we will not have a higher penetration of renewable systems at some point. We were thinking, what would be possible commercially and what would also be necessary?

We found out that for the moment the biggest problem is not to shift energy, rather to stabilise the grid; this is something that is a bit ahead but we will need that in the next couple of decades or even the next few years.

PV Tech Power: That's the technical side – what are some of the market drivers for this kind of grid-stabilising project, specific to Germany, which made the Alt Daber project possible?

TM: Frequency regulation is one of the main regulatory possibilities to stabilise the grid. This is done by conventional power plants, which are more and more being pushed out in Germany and Europe. At the same time, we also need grid stabilisation capacity. In order to not stop the trigger for the building of PV power plants we need to replace that grid stabilisation technology; we need to replace conventional power plants wherever they go out of

Credit: Belectric.

Belectric's Energy Buffer Unit allows utility PV power plants to offer grid stabilisation services.

business. So this is what we did in Alt Daber.

We installed the storage system, the battery plant, with the purpose of doing frequency regulation, commercially under the German grid regulation market. There is a weekly tender and you offer your power, your frequency regulation or frequency response power and you are awarded, or not, depending on the price you offer. We have done a lot of talks with National Grid [responsible for the high-voltage transmission network in the UK] and they're doing very similar things.

PV Tech Power: So there were some economical barriers to the addition of peak shaving capabilities, even though you say the technology can already do it. What has the regulatory response and support been like to the development of such battery systems in Germany?

TM: In Germany, we feel ready now, on the side of the government, on the whole because they've deregulated the German energy market over the last five years; they opened up possibilities for newcomers to enter this market, be it production of energy, be it transmission of energy or grid regulation.

There are still a lot of barriers, like the regulation market was custom tailored for fossil fuel power plants; it was never meant for batteries to be part of it. For example, for somebody awarded frequency regulation for one week's time, it is assumed you are able to deliver regulation services, where you deliver energy into the grid, for the whole period of the tender. That means in theory one week, 24 hours a day, you shall be able to deliver. In reality in frequency regulation that's never the case because you either deliver or you draw out of the grid. In practice, a battery is perfectly suited for this job, because it delivers and it takes out energy, it's always discharge and charge so it's pretty perfect.

PV Tech Power: So what needs to change?

TM: It was just two years ago that they accepted a battery to take part in this regulation market, and not with the right conditions [for batteries]; you still need a fossil power plant in the background, [with a long period of delivery] to back up the battery. This is handled by pooling fossil and battery-based frequency response providers. This was one of the main achievements of the deregulation or unbundling of the energy market.

If they were to award this on an hourly basis we could get rid of the backup power plants, we could auction our storage systems for one hour and if it's still full we auction it for one more hour, otherwise we take it out and charge it. We would get rid of the necessity for the backup power plants. On the other hand we could also combine more peoples' services, by let's say shifting load during daytime and doing frequency response at night-time or something. That would enable a lot more business models. For the moment, the art of marketing the battery will, in the near future, be the art of combining different business models. Refinancing the battery with one business model, for example frequency response, will become more difficult because more and more batteries will come onto the market in my belief. So we have to be able to combine different business models.

PV Tech Power: Do you think these kind of devices, storage in combination with solar, could make large-scale solar more attractive to governments and electricity network operators? The theory would suggest it should but as we know, the politics and economics behind these things do not always follow the science and technology as closely as we would hope!

Duncan Bott: The various network operators around the world are starting to progress towards the recognition that, historically, it was thought that renewable energy was disruptive to the network and now that's starting to shift towards a recognition that actually, renewable energy can offer solutions to stabilising the national networks and we are progressing towards recognising how that is achievable.

Belectric is a technology provider, that is what we are positioning ourselves as, and so as subsidies come down in all the various new markets in the world for technologies such as solar, investors and owners of power plants and also developers of solar farms, we all need to realise and learn to innovate. So through the innovation of technologies, we can now add additional business models to what was once just this simple model of produce, export and sell energy.

Using Energy Buffer Units, we can not only do frequency control but also voltage control of the network, and what we're preparing ourselves for is, in the future when new battery technologies come to the market, we will then start doing shifting of energy from one hour to the next.

So I guess what we're doing here is demonstrating that it's not just about the battery in the box. There's a lot more behind the hybridisation of solar and these technologies, and solar and these business models, to enable us to make that step forward in the future into the world of either lesser subsidies or no subsidies. ■

Credit: Belectric.

The Alt Daber power plant in Brandenburg, Germany.

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USA needs ITC, if it's going to back PV

In early February President Obama threw a lifeline to the solar industry by proposing an extension to the crucial investment tax credit. Welcome as it is, it's far from a done deal, writes John Parnell

Credit: Flickr/White House/Pete Souza

The inclusion of the investment tax credit (ITC) in President Obama's 2016 budget is of course good news but it is the beginning not the end of the debate. The ITC has a powerful friend in the President of the United States but it may not have enough friends to win the argument.

"The solar ITC has been a tremendous boon to both the US economy and our environment. The proposal presented by President Obama would extend this proven, successful policy for years to come," said Rhone Resch, president and CEO of the Solar Energy Industries Association (SEIA) in the wake of the publication of the president's budget request.

"The ITC has changed America for the better. The solar industry employs nearly 175,000 Americans, pumps US$15 billion a year into our economy and offsets more than 20 million metric tons of damaging carbon emissions. In the past four years, employment in the solar industry has increased by more than 85% – and last year alone, we created one out of every 78 new jobs in America. This remarkable progress is due, in large part, to smart, effective public policies like the solar ITC," said Resch.

But let's remember that this is the president's budget request. While you don't get if you don't ask, the continuation of the ITC is far from a done deal. For the next few months, the entire budget proposal will be scrutinised before the Republicans – who now control the House and the Senate – will offer their own version of the budget. And so the horse trading begins.

The jobs angle picked out by the SEIA could prove key. States like Arizona, Texas, Utah and the Carolinas, have burgeoning solar energy sectors and Republican representation in Washington. These states could be susceptible to being ITC-friendly.

Shayle Kann, VP of GTM Research says he understands the optimism that some are already expressing. "This budget is far from final but is by no means insignificant. It's a strong indicator of where the Administration's values lie and what they care about. It's the first set of bargaining chips," he says.

But can the ITC win enough support across the political spectrum?

"We'll see. The ITC is one of a million things that are going to be debated in this budget proposal. It's a mixed bag for the Republican congress. Republicans tend to like solar in general, it has a fair bit of bi-partisan support and, increasingly at the state level, even Tea Party support," says Kann, adding that often the problem is not solar itself but the perception of the ITC subsidising solar.

SunEdison founder and clean-tech investor Jigar Shah has suggested to PV Tech that fighting for the ITC is part of the politics but the end result of budget negotiations could be to trade it for "something better". He suggests full access to real estate investments trusts (REITs) and master limited partnerships (MLPs) to avoid double taxation in yield cos, federal net metering legislation, more grid interconnections and the ability to sell power directly to consumers could be considered.

But Kann is adamant that the most important federal-level policy for solar is the ITC.

"It's the single largest and most important federal policy for solar. If you are lobbying at the federal level for the solar industry, you should be laser-focussed on the ITC," he says.

The ITC is currently scheduled to fall to 10% at the end of 2016. Without explicitly detailing the 30% rate in the budget, the assumption is that that level is the starting point for negotiations.

Utility-scale solar has been predicted to fall of a cliff in 2017 if the ITC falls to 10% and as such, Kann says that sector is more exposed than its residential counterpart. An extension of the duration for a 30% ITC, or even a more gradual wind-down, would buy the industry valuable time to lower its costs and boost their competitiveness with conventional power sources.

With solar on the brink (or better) of competiveness in many states, any concession could prove highly valuable. Deutsche Bank told investors it was a broadly positive development, even if the numbers in the Senate and the House looks unfavourable on paper. "Whether or not the ITC gets extended beyond 2016 still remains to be seen, but the analysts believe this proposal certainly increases the chances of some sort of a positive outcome compared to the current step down of ITC to 10% beyond the 2016 timeframe," it said in a research note.

Getting the full 30% in perpetuity would be a great result for the industry. If Obama's budget does nothing else but increase the chances that 10% would be a hard sell for its detractors, it surely still counts as a victory for solar.

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