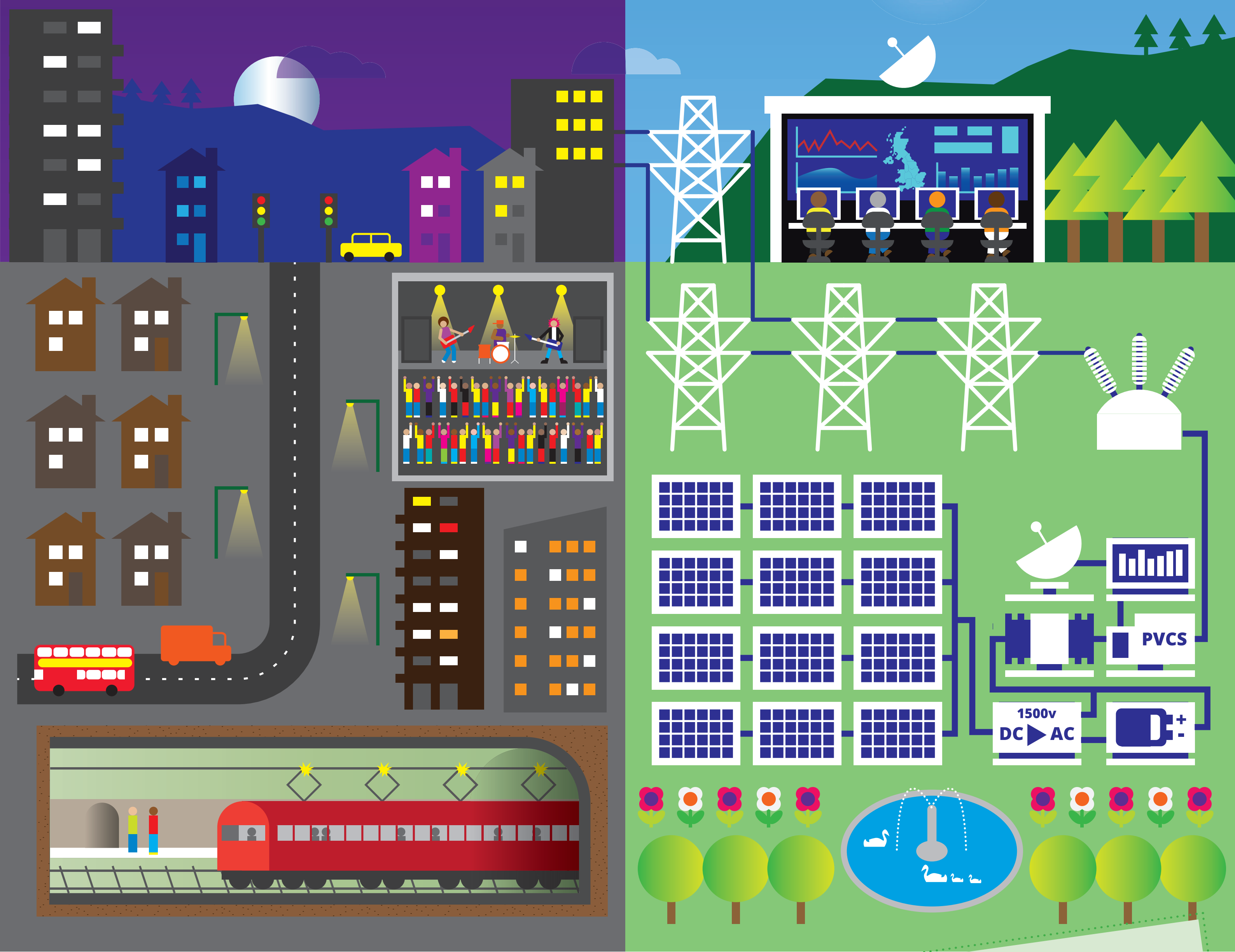
POWER PV TECH

Volume 04 | PV POWER PLANT TECHNOLOGY AND BUSINESS | September 2015

FUTURE PV POWER PLANTS

Technologies shaping the next generation in utility solar



SYSTEM INTEGRATION
Solar Star: Inside the world's largest PV power plant

DESIGN AND BUILD
Cutting costs and improving performance in commercial rooftop arrays

STORAGE AND GRIDS
How renewables and storage are being placed centre stage in plans to overhaul New York's grid

PLANT PERFORMANCE
14-page module performance special
- Rating module lifetime performance
- Which module materials offer most durability?
- Understanding power loss caused by module degradation in utility PV

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Introduction

For those in the utility solar business, 2015 has so far offered no shortage of landmarks. Since the start of the year, the record for the world's largest PV power plant has been both equalled and beaten, with the completion in the US of the Desert Sunlight and Solar Star projects respectively.

The industry has also notched up two important pricing milestones. In January 2015, news broke that a project in Dubai had attracted what was thought to be the lowest ever bid price for a solar project, of US$0.0585/kWh. That record proved short lived, however, when, in July, US firm First Solar revealed it had agreed to a price of US$0.0387/kWh for power from its 100MW Playa Solar 2 project in Nevada.

Although that price is not fixed and will go up over the project's lifetime, there can be no doubt that in an increasing number of regions solar, particularly at larger scales, has now firmly cemented its credentials as a low-cost power source. In our cover feature in this issue of *PV Tech Power*, one senior industry figure hails what he describes as the "utility-scale solar age". This would seem an apt term for the current era, in which larger and more sophisticated PV power plants are helping drive solar to levels of competitiveness scarcely imaginable 10 years ago.

And there would appear to be plenty of scope still for this to continue. Leaving aside the not-insignificant risks that regulatory, financial or political disruptions pose to solar's downward cost trajectory, confidence is high within the industry that on the technology side at least, the industry still has a good deal more to offer.

Our piece on future PV power plants (p.31) takes a look at some of the key constituents of utility-scale solar arrays and asks experts what technologies they think offer the most potential for driving utility solar to the next level. The broad consensus is that change will be incremental, but that in almost all of the major aspects of plant design and technology, there is much progress still to be made. And of course none of the observers we spoke to have a crystal ball: the possibility of a breakthrough piece of technology opening up new possibilities for PV remains within the realms of possibility, if not on most people's radars at the moment.

Elsewhere in this issue, we feature a series of in-depth articles looking at module performance (from p.65). In the first issue of *PV Tech Power* one year ago, we featured a report highlighting some of the shortcomings in the way the likely lifetime durability of modules is tested and assured. Here we present articles from three leading bodies examining various aspects of the module performance question and how the industry is gaining greater real-life insights into how modules behave in the field.

The Fraunhofer CSE and ISE research bodies kick the series off with an exclusive report on the latest phase of their long-running PV Durability Initiative (PVDI). This subjects leading module brands to accelerated stress testing to establish how quickly they wear out under various environmental conditions. The hope is the findings of the PVDI will help inform a new industry standard for module service life. The Fraunhofer piece is accompanied by briefings from skytron energy (p.73), looking at module degradation, and DuPont (p.78), which assesses which of the materials most commonly used in c-Si modules offer the best properties from a durability perspective.

With a detailed report on the realisation of the Solar Star project (p.62) and interviews with two of the figures helping reshape New York's power grid (p.88) we hope you find this issue of *PV Tech Power* an indispensible source of information.

Ben Willis
Head of content

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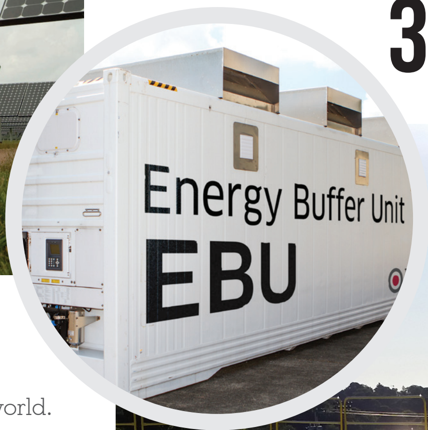


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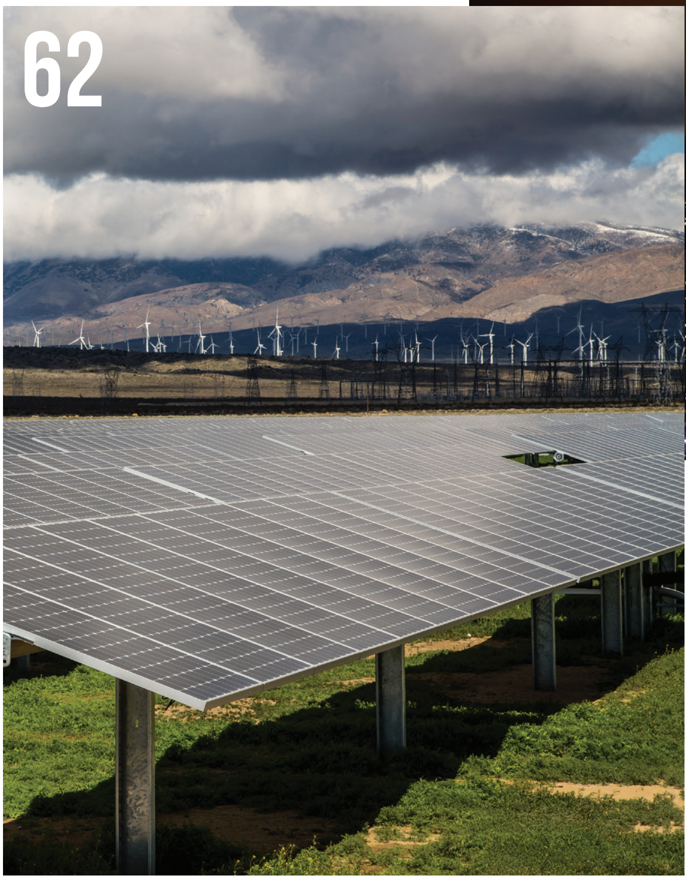

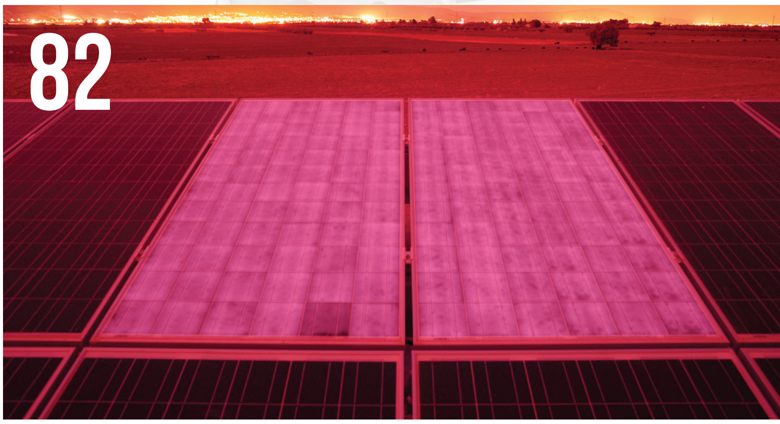

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REGULARS

EUROPE

Policy

Solar bears brunt of UK government subsidy cuts

The UK's Department of Energy and Climate Change outlined proposals including new cuts to solar subsidies in July, cancelling Renewable Obligation support for sub-5MW farms a year earlier than planned and hinting at additional cuts to the small-scale feed-in tariff (FiT). The proposed cuts came following months of speculation that the Levy Control Framework, the mechanism used to monitor the cost of subsidies passed onto customers, was on course to record an overspend. Energy and climate change secretary Amber Rudd confirmed that the LCF was set to go approximately £1.5 billion (US$2.37 billion) over budget by 2020, prompting significant cost-cutting measures to be enacted. DECC also stripped out grandfathering rights, meaning that sub-5MW solar farms without accreditation on 22 July 2015 will not be eligible for RO support which will wipe off as much as 4GW of solar capacity from the UK's pipeline. Reaction to the proposals has been forthright and damning, and the consultation responses are due to be released shortly after it closes on 2 September. Plans to cut the FiT to a more economical rate are also widely expected.

Amber Rudd, UK secretary of state for energy and climate change.

Storage

Spanish storage and self-consumption tax petition attracts record responses

More than 180,000 Spanish citizens signed a petition against plans to introduce a new tax on the use of batteries in combination with residential solar installations in Spain. The tax would apply to grid-connected solar PV systems of up to 15kW, with fees ranging from €8.9 (US$9.84) per kW for domestic consumers up to €35 per kW for medium-sized businesses. Fines of up to €60 million have been proposed for infringement, double the maximum fine for releasing nuclear waste. The new tax threatens to increase payback time for solar-plus-storage owners from circa 16 years to as many as 31 years.

Market

Photon CEO Georg Hotar condemns 'same old nonsense' from Czech minister

Czech Republic's environment minister Richard Brabec has called for an end to new ground-mounted solar farms by 1 January 2016, prompting strong criticism from Photon Energy CEO Georg Hotar. Brabec spoke to Czech daily *Mladá fronta Dnes* to discuss a new Green Savings Programme, which would subsidise rooftop solar deployment but look to phase out ground-mounted development, prompting Hotar to claim the Czech Republic is a "complete banana republic" on energy policy. Hotar also said Brabec's interview contained "the usual lies" about the level of state support PV has received to date, claiming the CZK45 billion (US$1.82 billion) figure cited by Brabec to be untrue.

Business

France's Solairedirect and ENGIE to merge

French solar developers Solairedirect and ENGIE are to merge after the latter acquired a 95% stake in the former in July. Financial details of the deal are undisclosed, however it follows a failed IPO by Solairedirect earlier this year. The deal will see ENGIE supplement its own 158.5MW portfolio with Solairedirect's 224MW operational capacity, which the company said would cement its position in France's PV market. ENGIE chairman and CEO Gérard Mestrallet said the company intended to "pool the expertise" of both firms to speed up development.

Market

Italian court backs feed-in tariff fight

Italy's constitutional court has backed the country's solar industry in challenging retroactive changes to the FiT. The case, which challenges proposals set out by the Italian government in June 2014, has been accepted by the constitutional court in Rome, however there is currently no timeframe as to when it could be heard. If passed, the proposals would see PV projects over 200kW either take a 10% cut in support or accept an extension to their term from 20 years to 24, effectively reducing the amount they receive each month. Investors heavily criticised the move and Agostino Re Rebaudengo, president of national industry group assoRinnovabili, said he hoped the Italian government would now overturn its decision.

Tenders

Second German PV tender three-times oversubscribed

Germany's Federal Network Agency revealed that its second round of tenders for ground-mount solar projects was over-subscribed more than three times its 150MW volume cap. A total of 136 bids were submitted in the tender round which closed on 3 August and the Federal Network Agency was still examining the admissibility of the bids at the time of writing. The tender programme has been established on a trial basis to encourage more PV projects after Germany witnessed a steady decline in added capacity in recent years. In June the Federal Network Agency revealed that just 95.5MW of new PV capacity was added in June 2015.

Policy

SolarPower Europe calls for tougher European Commission renewables stance

The European Commission must be tougher and establish biennial renewable energy targets for member states if it is to ensure that the 2030 energy and climate package is successful, SolarPower Europe said. The trade organisation said the Commission should take on a "more active watchdog" role and enforce the existing 2020 package more rigorously. SolarPower Europe also put forward plans to establish a European fund to attract more investment into renewable energy programmes in order for Europe to meet its target of deriving 27% of energy demand from renewables by 2030.

Tender

Juwi receives approval for 450MW Spain project

Spain's Ministry of Environmental Affairs approved a 450MW solar project which is to be constructed by Germany-based Juwi. The development, based in Mula, Murcia, is to cover 1,088 hectares and cost Juwi around €450 million (US$497.8 million) to construct. A spokesperson for Juwi said the latest approval was an "intermediate step" in the lengthy process towards the final green light, but represented an "important milestone". Juwi now hopes to gain administrative authorisation and project approval from the Ministry of Industry by Q1 2016.

AMERICAS

IPO

Sunrun IPO runs lukewarm

US residential solar installer Sunrun raised US$251 million following its flotation on the NASDAQ stock exchange on 5 August. Shares opened at the bottom end of the company's US$13-15 range however and before the bell were priced at US$10.77, down 23%. Solar firms were mainly up on the NASDAQ on that day. Sunrun follows its US residential peers SolarCity and Vivint Solar on to the NASDAQ, trading under the symbol 'RUN'. The company had hoped to raise as much as US$309 million. After deductions, the company's filing had estimated approximate net proceeds of US$221.8 million. The use of proceeds was listed as "general corporate purposes, including working capital, operating expenses and capital expenditures". In July, Texas-based developer Principal Solar postponed a planned IPO of its own, citing "market conditions" as the reason.

SunEdison

Busy quarter for SunEdison and its yieldcos

In another busy quarter, SunEdison said it had 1.9GW of projects under construction in Q2, a record for the company. Meanwhile, it also launched its second yieldco, Terraform Global, which will seek to acquire assets outside of North America, raising around US$675 million in an IPO. SunEdison also spun off its remaining 10.6 million shares in SunEdison Semiconductor in June and in late July confirmed that it will acquire major US residential installer Vivint Solar along with its already up-and-running yieldco Terraform Power. It also purchased UK energy firm Mark Group.

Chile

Chile continues to attract serious interest

Deployment of solar continues at pace in Chile, often pinpointed as one of the nations with most promise for PV in Latin America if not the world. SunEdison said at the beginning of August that it will spend US$1.5 billion on Chilean solar projects, while developer Pattern Energy marked its entry into the Chilean market with the start of construction of a 122MW PV plant, both taking place in early August. Meanwhile, on a far smaller scale but still significant, the world's largest bifacial PV plant reached "an advanced stage of construction" in early July. Similarly, Germany technical research institute Fraunhofer ISE opened a centre for solar thermal and PV at the end of May.

Trade

Revised US-China duties leave no clear winners

Revised US trade duties on Chinese solar panels, issued in early July, have created further ambiguity with SolarWorld welcoming the changes, even though the world's top two producers appear to have benefitted from the changes. The review of the 2012 tariffs increased the countervailing duties (CVD) to 20.9%. For many tier-one manufacturers, this increase was wiped out by decreases in the anti-dumping rates. The 2012 case deals with modules classed as Chinese while the 2014 case targets Chinese modules with Taiwanese cells. Any imported module is subject to one or the other set of tariffs. An investor note circulated by Deutsche Bank analyst Vishal Shah said the new changes to the 2012 duties were unlikely to impact Chinese firms' pricing in the US. SolarWorld Americas called the decision a "strong victory", although Shah pointed out that Trina Solar and Yingli, the number one and two module manufacturers by volume respectively, had had their rates reduced. "The Chinese will be able to use solar cells made in China and import them to the US under the new rates, following this review," Shah said.

Credit: Trina Solar

Trina Solar's HQ. The company has had its US trade duties revised.

Emissions

Solar a sensible fit for Obama's Clean Power Plan

US President Barack Obama and Environmental Protection Agency (EPA) Administrator Gina McCarthy released details of the Clean Power Plan – a set of measures designed to reduce CO_2 emissions by 32% from 2005 levels by 2030. The final rules also include a target for 28% of the country's electricity to come from renewables by 2030. Solar Energy Industries' Association president and CEO Rhone Resch said solar was the most sensible compliance option for states under the Clean Power Plan, while the chairman of E.ON North America called on US energy firms to embrace the plan, rather than fight it.

DATA WATCH

US$123.5m

The value of bonds released by SolarCity in August, secured against customer contracts

DATA WATCH

US$0.0387/kWh

The "lowest ever" price agreed for sales of electricity; from First Solar's 100MW Playa 2 project in Nevada to utility NV Energy

Brazil

Brazil opens up for PV business

The Brazilian Association of Photovoltaic Solar Energy (Absolar) has signed an agreement with the Brazilian Agency for Export and Investment Promotion (Apex-Brazil) to partner on attracting more foreign investment into the domestic solar industry. Opportunities for foreign companies in the Brazilian PV market reportedly exist for manufacturers, project developers, international financing institutions, multinational banks and development banks, among others. Brazil will continue to hold tenders for energy projects this year, including a solar-only auction at the end of August with a cap price of BRL349 (US$104)/MWh.

Largest plant

Canadian Solar completes Canada's largest PV plant

Canadian Solar Solutions, a wholly-owned subsidiary of Canadian Solar, has completed construction of the largest solar project in Canada, a 100MW PV plant in Ontario. The Grand Renewable Solar Project (GRS) included solar panels and inverters manufactured by Canadian Solar and SMA and the plant will produce enough electricity to power 17,000 households. Construction began on the project in September 2013 involving an average of 240 workers on site at any one time. Samsung Renewable Energy and the Six Nations of the Grand River partnered with Connor, Clark & Lunn to finance the project.

New services

Yingli launches US engineering and maintenance service

The US subsidiary of Chinese PV panel supplier Yingli Green has launched Amplify Energy, an engineering and maintenance company for PV plants. Yingli Green Americas opened the offices in San Francisco in mid-July. As well as assessing the value of PV plants, Amplify claims it can enhance production using engineering and software services that can analyse production and weather data and also offers inspection, testing and consulting services. Amplify launched officially at the Intersolar North America trade show.

Uruguay

Sky Solar secures US$85m loan for Uruguay projects

The Inter-American Development Bank (IDB) has approved US$55.7 million loan to finance the construction, operation and maintenance of six PV plants and their connected facilities in Uruguay for developer Sky Solar. The China Co-Financing Fund and the Canadian Climate Fund for the Private Sector, both led by IDB, will also offer additional loans of US$19.3 million and US$10 million, respectively. With a total installed capacity of 82MW, the plants, located in western Uruguay, will supply an average of 125.3GWh of electricity per year to the national grid.

ITC

ITC extension urged

The Solar Energy Industries Association (SEIA) urged its members in July to contact their senators to make sure the investment tax credit (ITC) for solar energy is extended. The ITC is pencilled in to expire at the end of next year. Tax credits for solar projects are currently scheduled to fall from 30% to 10% at the end of 2016. GTM Research has predicted that there will be almost no new utility-scale solar in the US in 2017 following cut, while tracker manufacturer Array Technologies recently boosted its manufacturing output in preparation for a surge in tracker installations ahead of the reduction.

Trackers

NEXTtracker bags 1GW deal

Single-axis PV tracker specialist NEXTracker has secured its second largest supply contract from US-based EPC firm, Blattner Energy. A year ago the start-up won a major 1.85GW three-year supply deal with SunEdison, catapulting the tracker firm into the mainstream. Since then, announced orders including the latest with Blattner Energy have exceeded 3GW. NEXTracker's single-axis systems amounting to over 1GW will be used with Blattner Energy's planned North American PV projects over the next two years.

MIDDLE EAST & AFRICA

Israel

EDF and partners power up 40MW plant in Israel

Israel-based PV developer Arava Power Company and EDF Energies Nouvelles Israel, a subsidiary of renewables company EDF Energies Nouvelles, have commissioned the 40MW Ketura Solar plant in Israel. Development began in 2009, with financial close reached in 2013. EGE and the Israel Electric Corporation were responsible for construction of the site, which lasted around seven months and involved 140,343 panels installed over 54 hectares. EDF Energies Nouvelles Israel is currently building another 50MW solar project named Zmorot. The firm already operates 10 solar plants in Israel with a total capacity of 110MW. Jonathan Cohen, chief executive of Arava Power, said that connecting the Ketura Solar project to the electricity grid raises Arava Power's current installed capacity to over 100MW.

Jordan

Martifer Solar to start work on four of Jordan's Seven Sisters

Martifer Solar, a subsidiary of Martifer SGPS, is to begin construction on four PV projects with a combined capacity of 57MW in Jordan. The projects were awarded power purchase agreements (PPAs) in Round 1 of Jordan's National Renewable Energy Plan. Three of the projects are 11MW and located near Ma'an in south-central Jordan at Al Ward Al Joury, Al Zahrat Al Salam and Al Zanbaq. The fourth 24MW project, Jordan Solar One, will be constructed near Mafraq in the North. Martifer Solar is responsible for engineering, procurement and construction (EPC) and operations and maintenance (O&M) for all the projects. The four plants are part of the International Finance Corporation's (IFC's) 'Seven Sisters' financing package, which provided US$207 million in debt financing for seven projects awarded contracts under Jordan's Round 1 tender.

Pipeline

SkyPower signs 1GW deal with Kenyan Government

Toronto-headquartered SkyPower Global signed an "historic" agreement with the Kenyan government to develop 1GW of PV. The company, which develops and owns solar energy projects, signed the deal with Kenya's ministry for energy and petroleum. "SkyPower's solar projects will help Kenya realise its electrification goals, support the development of the country's renewable energy industry and help the development of strong communities, generating a brighter future for all," said SkyPower president and CEO Kerry Adler. The US$2.2 billion agreement will see the 1,000MW of projects built over the next five years, SkyPower

Saudi Arabia

Deal agreed for 50MW plant in Saudi Arabia

The Saudi Electric Company (SEC) has agreed a deal to build a 50MW solar power plant with a power purchase agreement in place at a rate of 0.1875 Riyals (US$0.049). The unsubsidised plant, which was confirmed in an announcement by the state news agency, will be built by Taqnia Energy and co-developed by SEC and the King Abdul Aziz City for Science and Technology (KACST. The latter two will also develop a solar research facility. KACST and Taqnia are already cooperating on a solar desalination plant with a 40MW capacity PV plant driving the facility. The country has previously said it would invest US$109 billion in solar power to meet growing electricity demand and increase the volume of oil available for export. Progress has been slow however with responsibility for solar development passing between a number of organisations in the Kingdom.

Credit: Flickr freestock

Saudi Arabia is in line for a 50MW PV power plant.

said. SkyPower also signed an agreement in Egypt in March for 3GW of projects which the company likewise described as a "historic agreement". Through a JV with a Saudi Arabian company, FAS Energy, it has also signed a 3GW Nigeria deal.

World Bank

World Bank explores solar opportunities in Zambia

The World Bank's International Finance Corporation (IFC) is exploring the development of 100MW of solar in Zambia. The two 50MW projects could be developed under the IFC's Scaling Solar programme. They would be the first utility-scale PV projects in the country. Low rainfall has left hydropower reservoirs in the country low, creating a power deficit of 560MW. Zambian President Edgar Chagwa Lungu has ordered the country's Industrial Development Corporation (IDC) to develop 600MW of solar power. "The Zambian government is resolved to address the current hydropower shortages caused by low rainfall through active promotion and increased use of renewable energy technologies," said President Lungu, who is also chair of IDC Zambia.

Finance

Dubai's record low-cost project secures finance

The 200MW second phase of the Mohammed bin Rashid Al Maktoum Solar Park in Dubai has achieved financial close. The emirate's electricity and water authority, DEWA, confirmed the landmark in mid-July. Saudi power engineering firm ACWA Power and Spain's TSK Engineering won the tender process for the plant with a bid under US$0.06/kWh, believed at the time to be the lowest winning solar bid in an independent power producer project tender. The original procurement had been for a 100MW project but it was decided to double the size of the deal after bidding was complete. In March this year ACWA's CEO Paddy Padmanathan said the company had a 27-year loan agreement for US$344 million. The finance is being provided by Abu Dhabi-based First Gulf Bank and the National Commercial Bank and Samba Financial Group, both of Saudi Arabia. The interest rate is 4%, according to reports. First Solar modules have been selected for the project.

West Africa

Mali sets sights on region's first PV plant

Mali has joined the race to become home to West Africa's first utility PV power plant following the signing of an agreement between Norwegian firm Scatec Solar, Mali's energy ministry and main utility company. Under its agreement with Mali's Ministry of Energy and Water and utility Electricité du Mali (EDM), Scatec will build, own and operate a 33MW plant near the town of Segou in the south-east of the country. The project is being developed in conjunction with IFC InfraVentures, the project arm of the World Bank's International Finance Corporation, and local firm Africa Power 1. Electricity from the plant will be sold under a 25-year power purchase agreement between EDM and Segou Solaire, the local project company set up by Scatec Solar. Scatec Solar will own 50% of the project, IFC InfraVentures 32.5% and Africa Power 1, 17.5%.

ASIA-PACIFIC

Suspension

Hong Kong finance authorities suspend Hanergy TFP

The Hong Kong Securities and Futures Commission (HKSFC) formally suspended Hanergy Thin Film Power Group. The Hong Kong stock exchange had already halted trading in shares of the company but was ordered to suspend them by HKSFC, which had been investigating the company. Shares in Hanergy TFP surged in the first quarter of the year after a number of deals with other parts of the Hanergy Group were announced. The company's value reached a high that briefly made its chief, Li Hejun, China's wealthiest person. A subsequent collapse in share price was followed by the cancellation of a 900MW order for thin-film production equipment, the suspension of share trading and the investigation by the HKSFC. Hejun had originally denied that the company was under investigation. In response, Hanergy threatened to challenge the suspension in the courts.

Coal

India solar power investment could surpass coal by 2019/20 – Deutsche Bank

Deutsche Bank said investment in solar power in India could surpass investment in coal by 2019-20, with US$35 billion already committed by global players. The 'India 2020: Utilities & renewables' report said the focus on solar would be driven by prime minister Narendra Modi's ambitious target of deploying 100GW of solar capacity in the country by 2022. Deutsche Bank also raised its forecasts for solar capacity additions to 34GW by 2020, up 240% from its previous 14GW projection. Therefore, by 2020 annual solar power capacity additions could also surpass those in coal power projects, which are slowing down.

Exodus

BNEF highlights overseas exodus of Chinese PV producers

Bloomberg New Energy Finance (BNEF) figures suggested a mass overseas relocation of production capacity by Chinese PV manufacturers in response to increasingly hostile trading conditions. Chinese manufacturers are planning to build some

Australia

Australia agrees reduced renewables target

Australia's government agreed to set the renewable energy target (RET) at 33,000GWh, down from 41,650GWh, after 15 months of political wrangling. In August the country also pledged a 26-28% reduction in emissions from 2005 levels by 2030, which was criticised by environmental campaigners for falling behind other countries. Additionally, the Clean Energy Finance Corporation was told by Australia's pro-coal prime minister Tony Abbott that it can no longer invest in rooftop solar and wind projects. In an eventful quarter, the forthcoming end of regional feed-in-tariffs in New South Wales at the end of 2016 was cited as a major opportunity for the energy storage industry to help consumers maximise the use of solar panels on their roof, in the absence of incentives to feed into the grid. The country's Australian Renewable Energy Agency (ARENA), also under fire from the government, has revealed its new funding plan and proposed a 200MW large-scale solar auction. The competitive auction would be open to grid-connected projects between 10-50MW. Additionally, Australian utility AGL's 102MW PV plant in Nyngan, New South Wales, the largest in Australia, also reached full generation capacity and can power the equivalent of 33,000 homes per year.

Nyngan solar plant.

Credit: AGL

5.3GW of new production capacity in countries such as Malaysia and Thailand by the end of this year. The apparent driver for this phenomenon is the increasingly tough stance taken by the USA and European Union against unfair pricing practices employed by Chinese companies selling into those markets. This has forced Chinese companies to find alternative manufacturing locations to avoid falling foul of punitive import duties. Whether the strategy employed by Chinese firms to evade duties will be successful remains to be seen, however, Trina Solar did have its plans to build a manufacturing plant in Malaysia opposed by a Malaysian government agency.

Into India

Softbank's US$20 billion solar investment 'game changer' for India

Japanese telecoms provider-turned solar developer Softbank plans to invest US$20 billion to construct 'mega' solar PV plants in India. Softbank is also forming a joint venture to be named SBG Cleantech, with Taiwan-based manufacturing services provider Foxconn Technology Group and Indian business conglomerate Bharti Enterprises. SBG Cleantech will invest in solar and wind projects across the country and intends to participate in the 2015-16 round of solar tenders under the National Solar Mission (NSM) programme and state-specific solar programmes. The news was followed by a flurry of reports of foreign investment from companies including Sunpa, Canadian Solar, Hareon Solar, Rosneft, Hilliard Energy, Trina Solar, Risen Energy, SunEdison, Hanwha Q Cells and Gamesa.

Pakistan

Scatec Solar outlines 300MW Pakistan PV push

Norwegian developer Scatec Solar is entering Pakistan's nascent solar market with plans for up to 300MW of large-scale PV. Scatec Solar has joined forces with local developer, Nizam Energy, and together the two companies have agreed to develop, build, own and operate PV power plants over two 150MW phases. Development and financing of the first US$300 million phase will be complete by the end of this year, with construction slated to begin in early 2016. Together the two 150MW phases of the project are expected to generate up to 580GWh of power per year.

Low bids

Record low India solar bid from SkyPower

SkyPower Southeast Asia Holdings put in the lowest winning bid ever for solar projects in India at INR5.05 (US$0.080) per kWh for a 50MW project in Madhya Pradesh. The firm put in three bids all under INR5.3 per kWh for 150MW of solar projects in the state. The auction was oversubscribed by 1200%, with a record 100 companies putting in bids for a total of 3744MW capacity. There was also massive oversubscription for bids in the state of Telangana, for which SkyPower won four more projects, also with the lowest bid of INR5.17/kWh (US$0.0807/kWh). ACME Solar also won 460MW of projects in this auction. The low bids across both auctions sparked concern in the industry about the profitability of the projects at such low prices.

China

China installed 7.73GW in H1 2015, official figures reveal

China installed 7.73GW of solar in the first half of 2015 as it continued to chase its target of 17.8GW by the end of the year. Of the 7.73GW, 6.69GW was utility-scale solar and 1.04GW was distributed generation. Beijing-based solar industry consultant, Frank Haugwitz said the figures offered few surprises. Haugwitz expects China to deploy no less than 14-15GW and is optimistic that it could reach 16-17GW with his most bullish position at 18GW. Q2/15 witnessed the installation of 2.69GW. Slow uptake of DG solar in 2014 and the delay in grid connection of some projects completed towards the end of the year meant that the country installed 10.6GW of solar, short of its maximum quota of 14GW.

Philippines

Call for Philippines to quadruple 500MW FiT ceiling

Solar companies in the Philippines are planning to push the country's government to quadruple the amount of solar qualifying for its feed-in tariff (FiT) programme. The Philippine Solar Power Alliance (PSPA) wanted the current FiT ceiling of 500MW extended to around 2GW. The Philippines' FiT for PV has already been raised from an initial 50MW to the current level of 500MW, but the PSPA now wants to go further. The Alliance will draft an industry roadmap, which will be presented to the government as the basis of a proposal for an increase in the cap to 2GW. Market research firms such as IHS have tipped the Philippines as one of the emerging markets to watch in 2015.

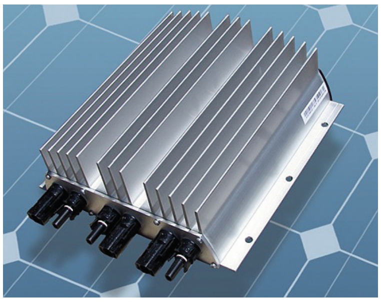
Product reviews

Balance of system | Ampt string optimizers lower 600 volt PV systems costs

Product Outline: Ampt has said that its patented String Optimizers are being deployed in 600 volt photovoltaic (PV) solar systems at installed costs in cents per watt that rival that of 1,000 volt systems. Ampt String Optimizers are designed to allow the use of 1000 volt inverters that are claimed to lower inverter cost by 40% and also reduce DC BOS costs by 50%.

Problem: 600 volt systems continue to be deployed due to application type (like rooftops) or code adoption cycles across local jurisdictions in the US market. In some cases, 600V systems are used to take advantage of significantly lower-cost 600V PV modules, or because they are grandfathered in under the 1603 Treasury Grant Program. However, lower cost and higher power from systems can be achieved when deployed with 1,000V inverters.

Solution: Ampt String Optimizers are DC-to-DC converters that are being deployed with 1,000V inverters at their full-rated power in 600V National Electrical Code (NEC)-compliant systems. These inverters are claimed to be delivering 60% more power translating to a 40% reduction in inverter cost. In addition, fewer inverters are used, so AC cabling costs and labour decreases proportionally and are claimed by Ampt to allow the removal of five to 10 US cents per watt in total system cost installations in the US market.



Applications: US residential rooftops deploying 600V (NEC) compliant PV systems.

Platform: Ampt's patented 'String Stretch' technology allows PV strings to be twice as long as in other NEC-compliant systems. Doubling the number of PV modules per string reduces the number of combiners, disconnects and associated labour by 50%.

Availability: Already available.

Tracker | BIG SUN's steel cable driven dual-axis tracker offers simplified and low cost operation

Product Outline: BIG SUN Group, a Taiwan-based PV manufacturer, has developed a commercial dual-axis tracker unit, 'iPV Solar Tracker', that uses a steel cable drive mechanism.

Problem: Dual-axis solar trackers are known to harvest more energy than other mounting structures. For mass deployment of dual-axis tracking systems, two conditions need to be met: simplifying the hardware structures to lower the capital and O&M costs, and also guaranteeing stability and reliability against adverse weather. Generally, solar tracking systems use linear actuators, ball screw or slew wheel drive systems, which are complex and carry high capital and O&M costs.

Solution: The iPV Solar Tracker drive mechanism consists primarily of an electronic control unit, two electric motors, shafts, ball bearings, cable reels, pulleys, anchoring bolts, springs and steel cables. The two motors are attached to a central pole and positioned perpendicular to each other. Each motor has a two-slot cable reel fitted on a rotation shaft. Steel cables attached to the diagonal corners of the module frame are wound on the reel slots; one clockwise direction and the other anti-clockwise. When the electric motor rotates the cable reels, the winding and unwinding of the steel cables pulls the module mounting frame into a rotational motion. The pulley connecting the anchor bolt diverts the horizontal force into vertical motion so that less force is used to pull the module mounting frame downwards.

Applications: Utility-scale PV power plants.

Platform: The tracking accuracy of the iPV Solar Tracker is managed by an electronic control unit based on astronomical algorithm. This enables a full 360 degree azimuth rotation and altitude tilt of -40 degrees to 40 degrees. The performance evaluation of iPV Solar Tracker power plants in Taiwan (23 degrees N) shows an average of annual energy gain of 30% compared to a fixed-tilted PV system.

Availability: Already available.

Products in Brief

WINAICO 300 W monocrystalline PERC module passes IEC certification tests by TÜV Rheinland

WINAICO's 300 W 60-cell monocrystalline PERC module passes IEC certification tests conducted by TÜV Rheinland, and is ready for shipping to all major markets worldwide. WINAICO is one of the first manufacturers in the world to implement PERC technology in PV modules, with more than two years of experience in optimising material combinations to minimise cell to module (CTM) losses during manufacturing. WINAICO's team is able to reduce the CTM losses to below 1%, a marked improvement over the 3.5%-5% experienced by competitors.

Trina Solar's polycrystalline modules UL1500V certified

Trina Solar has received UL1500V certification from Underwriters Laboratories for its TSM-PE05A and TS-PE14A polycrystalline modules. The UL1500V award certifies that the PV modules are allowed to be used in PV systems with a maximum system voltage of 1,500V, significantly higher than the existing 1,000V of most modules on the market. The higher system voltage modules allow PV systems with longer string length, reducing the number of balance of system components and thus the cost per unit of power (US$/W) of BOS.

Product reviews

Module | REC Solar's 'TwinPeak' PV module offers enhanced performance features with PERC

Product Outline: REC Solar's 'TwinPeak' multicrystalline module series combines a number of enhancements to provide 280Wp performance. The new module features 120 half-cut multicrystalline cells, four busbars, passivated emitter rear cell (PERC) technology and a split junction box.

Problem: Conventional multicrystalline and monocrystalline PV modules suffer from significant (2% plus) cell-to-module conversion efficiency losses. Reducing losses enables higher performance and lower cost, while improving overall energy yield from the same surface area.

Solution: TwinPeak modules use half-cut standard cells connected in series, in three

strings. The reduced loss of power in a half-cut cell produces a higher fill factor and higher cell efficiencies, resulting in better energy yields, especially at times of high irradiance. The improvements made in the reduction of resistance through half-cut cells add an overall around 4Wp per panel extra power output, according to the company. Panels with a higher fill factor have a lower series resistance meaning reduced loss of current internally in the cell. TwinPeak modules are split into two sections which generate electricity independent to each other, but combine again before the current exits the module. This helps them to continue producing electricity in the non-shaded section even at times of reduced irradiance on the module.

Applications: Residential, commercial, and industrial markets.

Platform: The PERC architecture improves the light absorption of the cell, boosting overall performance, and the addition of a fourth busbar increases the flow of current, improving efficiency and reliability.

Availability: Volume production Q1 2015.

Inverter | SMA Solar's the Sunny Tripower 60-US adds leading power density with easy installation

Product Outline: SMA Solar's Sunny Tripower 60-US PV inverter is designed for medium to large-scale PV plants. This 60kW inverter combines the advantages of a decentralised system layout with the benefits of a centralised inverter design.

Problem: Installers can require flexibility in offering different product offerings to best match system requirements when developing commercial and utility-scale PV plants, as well as high power density, easy installation, simple commissioning and low maintenance requirements, which all contribute to reduced system cost.

Solution: The Sunny Tripower 60-US is claimed to offer high-efficiency power density, easy installation, simple commissioning and low maintenance requirements. The system has a maximum efficiency of 98.8%, power density (60kVA at just 165 pounds) and DC input voltage of up to 1,000V. It also provides a scalable PV building block approach and full grid management features, making it ideal for medium and large commercial systems, as well as distributed utility-scale applications. For a complete system solution, the Sunny Tripower 60-US can be paired with the SMA Inverter Manager, Local Commissioning and Service Tool and a combiner box.

Applications: Commercial and utility-scale PV power plants.

Platform: The SMA Inverter Manager is the central communications and control interface for the entire Sunny Tripower system. It handles all important inverter and system management functions for up to 2.5MW in a single device. The Sunny Tripower 60-US benefits from a self-configuring inverter network with automatic IP configuration and device discovery, which eliminates manual setup.

Availability: Already available.

Products in Brief

Fronius introduces first string inverter to the project market

Fronius has introduced its first string PV inverter to the project market, by adding a 25.0 and 27.0kVA power category inverter its SnapINverter range. The Fronius Eco string inverter is claimed to deliver maximum yields, especially for large-scale PV projects into the megawatt range. The compact design ensures maximum average power density and maximum yields with a 98.3% CEC conversion efficiency. Its lightweight design (weighing just 35.7 kg) and tried and tested SnapINverter mounting technology make for quick and easy installation. Another highlight is the ability to connect up to six strings directly to the inverter, meaning that the system operator no longer requires additional DC or combiner boxes.

Shoals Technologies develops 1,500V 'SlimLine' combiner box

Shoals Technologies' 1,500V SL Combiner Box features 100% load break UL98B rated disconnects, surge suppression, and NEMA4X fiberglass enclosures. Further, the bussbars utilised are C1100 oxygen free that are precision milled to ensure optimum contact and long term reliability. Multiple off the rack and custom options are available up to 400A and 32 strings. Shoals first introduced the concept of 1,500V PV products over four years ago. The 1,500V SLCB is in production and commercially available now.

Product reviews

Operations & maintenace | meteocontrol delivering holistic monitoring solutions and quality assurance

Product Outline: meteocontrol has introduced the modular 'blue'Log X-Series' of data loggers, in combination with web portals and the SCADA Center, a flexible, high-performance solution for monitoring both small and large PV systems, as well as PV power plants.

Problem: Investors and operators of existing PV systems require professionally monitored and regularly maintained power plants to deliver the expected yield. Often yield losses are attributed to unrealistically high forecasts.

Solution: The blue'Log X-Series comprises the models X-1000, X-3000 and X-6000, specifically for PV systems in the utility-scale range. The new firmware for all X-Series models also offers expanded functions

such as power control in order to comply with legal requirements pertaining to grid feed-in management, power reduction in relation to on-site energy consumption (IPL, zero feed-in) and compatibility with other inverters and sensors. In conjunction with the blue'Log X-Series, seamless remote access to real-time values enables fast troubleshooting and operational efficiency.

Future plans call for opening the PV platform to additional energy providers and consumers. The development of the SCADA Center is meteocontrol's response to the demands of project developers who are looking for local operation management and control of PV power plants located at remote sites.

Applications: PV power plants

Platform: The SCADA Center is equipped with interfaces for all system components and third-party systems of grid operators and energy suppliers. Detailed options for the real-time visualisation of measured values and intelligent alarm management allow for quick identification of incidents or failures.

Availability: Already available.

System design | SMA Solar and Siemens to offer turnkey container solutions to PV power plants

Product Outline: SMA Solar Technology and Siemens are collaborating in the field of decentralised large-scale PV power plants. SMA Solar is contributing PV inverter solutions and system design capabilities, while Siemens is contributing transformers and switchgear for the high-voltage and medium-voltage range, including grid connection.

Problem: Coordinated project management and joint technological developments on a worldwide basis could support project developers and EPC contractors in rapidly realising large-scale PV projects.

Solution: SMA and Siemens will work either as separate project partners or as a consortium for technology and services in all areas of electrical engineering to best meet customer requirements. The portfolio of services ranges from planning and commissioning to maintenance of complex large-scale projects in the megawatt range. The high overall efficiency of the systems and the speed of implementation will also see customers save significantly on system costs, time and effort when it comes to

implementing their large-scale projects.

Applications: Utility-scale PV power plants.

Platform: The first product to come from the partnership is a new type of container solution that combines a 2.5MW central inverter from SMA Solar with a medium-voltage transformer and medium-voltage switchgear from Siemens as a turnkey solution in a standard container. The SMA Medium Voltage Power Station 2200SC/2500SC for direct voltages of 1,000/1,500 V can be used in large-scale and extremely large-scale PV power plants worldwide and is suitable for outdoor installation in all ambient conditions.

Availability: June 2015 onwards.

Products in Brief

Ideal Power grid-resilient 125kW power conversion system scalable to 1MW plus

Ideal Power has a new grid-resilient 125kW power conversion system, which is scalable to greater than a megawatt for large-scale applications for battery energy storage systems for peak demand management and PV-plus-storage applications. Ideal Power's patented PPSA provides transformerless isolation, dramatically reducing the weight and size of power conversion systems while increasing efficiency and overall performance. At one-quarter to one-eighth the size and weight of conventional power conversion systems, Ideal Power's systems are claimed to have lower installed costs than conventional solutions.

Mersen offering portfolio of 1500VDC components for growing solar PV market

Electrical specialist Mersen has introduced a portfolio of 1,500VDC components for the solar PV market. The product portfolio includes string and NH style fuses, supporting fuse gear, surge protective devices (SPDs), power distribution blocks (PDBs) and switches. The product portfolio also includes string and NH style fuses. By offering a complete portfolio of 1,500VDC PV products, Mersen has the ability to partner with customers for custom-designed and integrated systems supported by a single manufacturer.

Secure your solar investments by harnessing the power of true reliability and flexibility.

Introducing the new line of three phase string inverters: the Conext™ CL

The ideal solution for commercial buildings, carports and decentralized power plants.

Designed for high efficiency, maximum flexibility and easy installation and service:

- Detachable wiring box with multiple options to fit different installation needs
- Built-in Gateway to support remote monitoring and control features
- High conversion efficiency: 98.4% peak efficiency and 98.0% Euro/CEC efficiency
- Flexible mounting options: wall, pole, and a 10° minimum tilt installation
- Guarded by our electrolyte-free design and rigorous Multiple Environmental Over Stress Testing (MEOST) for superior reliability

Learn more and download our free solution guide, "Decentralized PV Systems Using Conext CL Inverters" at: solar.schneider-electric.com/conext-cl-learn-more

Schneider Electric

Product reviews

Inverter | Kaco's 1500kVA inverter matched to Ampt string optimizers

Product Outline: Kaco new energy's new 'blueplanet 1500 TL3' string inverter has been combined with Ampt's String Optimizers to enable a claimed 50% increase in rated output power, lowering the specific cost of a system inverter solution by 33%.

Problem: Inverter costs are reduced because Ampt String Optimizers put MPP tracking as well as voltage and current output limits on each string of PV modules. This enables KACO new energy's blueplanet 1500 TL3 inverters to operate with a higher and narrower input voltage range.

Solution: Electrical BOS costs are lower because of the voltage and current output limits of Ampt String Optimizers. This feature allows up to two times the number of PV modules per string compared to conventional systems. This reduces the number of strings and combiner boxes as well as the associated labour by 50%, according to the company. In utility-scale systems, the medium voltage AC network costs are reduced due to a smaller number of PV power stations. Increasing the size of a standard PV "block" from 2MVA to 3MVA reduces the number of medium voltage AC connections by 33% on a given PV project.

Applications: PV commercial and utility-scale systems.

Platform: The blueplanet 1500 TL3 with Ampt Mode is a 1,500kVA transformerless solar inverter with protection class IP 54/ NEMA 3R for outdoor use. The inverter is also available as part of a 3,000kVA integrated power station (IPS). The IPS 3000 TR3 with Ampt Mode includes inverters, medium voltage transformers and SCADA equipment mounting – as well as optional equipment, such as auxiliary power for tracker motors, and external DC and AC disconnects that are mounted together on a single base plate (or "skid") to create a ready-to-use utility-scale solution.

Availability: Already available.

Modules | Trina Solar launching smart solar 'safety' modules in US market

Product Outline: Trina Solar has launched it 'Trinaswitch' smart solar modules into the US market. The module provides new technology built into the junction box for additional safety and compliance.

Problem: To provide the best in PV system safety a module-level control device that can detect, interrupt and annunciate faults, and automatically be shut down to a safe level when needed is required.

Solution: Trinaswitch smart modules are constantly monitoring PV module parameters such as over-voltage, over-temperature and over-current. The smart module will enter PV-Safe mode if a safety hazard is detected and reported to the Cloud Connect. The Cloud Connect will decide whether there is a local threat that can be avoided by shutting down a single module, or if there is a potential system safety hazard and PV-Safe mode is needed for the entire system.

Applications: PV systems.

Platform: Trinaswitch modules are claimed to be the only smart module on the market with upgradeable functionality such as string flexibility and advanced optimisation performance features. Trinaswitch modules are NEC 2014 690.12 compliant. They meet the 2014 NEC Rapid Shutdown safety standards which is now required in more than 24 states. By 2017, nearly all US states will be required to meet this standard.

Availability: July 2015 onwards.

Operations & maintenance | Trimark offers remote SCADA access to PV power plant development sites

Product Outline: Monitoring and communications solutions firm Trimark Associates has introduced the Trimark Enterprise Network (TENetwork), a private, secure network that can be quickly deployed for monitoring, control and maintenance of SCADA systems and other computing systems located at distributed generation resources.

Problem: Project developers and contractors who need remote access to their sites often have to wait weeks or months for installation.

Solution: With the TENetwork, communications can be established within hours as it uses a cellular connection. It can be implemented at a significantly lower cost than other telecommunications options without the lead time required to install traditional, wired telecommunications infrastructure, according to the company. This means developers and EPCs can maintain construction schedules without waiting for a telecommunication company to install a separate line.

Applications: Utility-scale PV projects.

Platform: The TENetwork is a secure, private network that is dedicated to communicating control signals and operational data. Trimark partnered with Verizon to develop this service, which is delivered over Verizon's 4G LTE-based data network. Access is controlled by Trimark and restricted to sites and devices that have a business need to communicate within the network. Each user's traffic is isolated from all others to ensure privacy.

Availability: Already available.

Lessons from America's 50 power markets

Credit: White House/Pete Souza

State energy policy | Acceptance of solar in the boardrooms and living rooms of America along with President Obama's Clean Power Plan potentially put the US on the precipice of huge solar growth, but the patchwork of state solar policies remains a barrier. John Parnell and Tom Kenning look at some of the US' leading solar states and ask what others could learn

With 50 electricity markets buzzing away, countless lawyers and myriad regulatory frameworks, the US is a fertile breeding ground for inventive and original ideas around energy provision. It is also a great test bed for how to deal with some of the inevitable opposition that can arise when change is injected into an industry that has had the same business model for 100 years and more.

President Obama has set the country on a path to a cleaner energy future, one with a natural place for solar. There are several possible routes and a lot can be learned by other states and beyond by looking at what has worked so far.

"There is so much churn going on right now on all these different levels. It's a very dynamic time," says Amit Ronen, director of the George Washington University Solar Institute.

Ronen and his colleagues have been assessing policy progress in different parts of the country as part of their Interactive Map of Leading Solar States project.

"Lots of people are looking to see what the best steps are, it's hard to find one general trend and say this is the direction everything is going in. Here in the US we have essentially 50 state electricity markets," Ronen adds.

While many utilities are doing more than merely fulfilling an obligation to deploy solar, the majority are putting up more resistance. Working with them to overcome their inertia and promote the benefits they can reap is a big challenge for the industry.

Barack Obama's Clean Energy Plan is looking to up the ante on states to embrace low-carbon energy.

"There is a century of regulation and legislation geared towards a different system; a lot of these bigger firms have multi-billion dollar investments that they had assumed would amortise over 20 to 30 years," says Ronen. "They expected a certain amount of revenue and now with a shift to new resources, it's a stranded asset. They have to figure out who is going to pay for that. Things are changing so rapidly. We have never seen anything like this in the history of the utility industry."

Looking at what has already worked is one way to ensure these rapid changes are executed in the best possible way.

CALIFORNIA – MOVING PAST THE GOLD RUSH

With a huge installed solar capacity and as the base for many of the biggest domestic PV companies, California should always feel like home turf to the US solar industry.

An ambitious renewable portfolio standard (RPS) of 33% by 2020 has helped the state meet its voracious demand for power. With falling levels in hydropower dams and around a third of the state's electricity being imported, solar has provided the perfect solution.

Net metering, meanwhile, has given residential customers the ability to cut their power bills by receiving the full retail rate for excess power sent back to the grid. These two drivers have propelled the state to runaway leader position for solar power in the US.

"California has always been a leader on a lot of these solar policy issues since the 1970s. Obviously they have a large economy and population but they are by far the leader. They put in 4GW just last year, which was more than the entire country in the previous 30 years through 2011. They have over 10GW now," says Ronen.

Observers of markets in Europe and elsewhere cite the absence of direct subsidy as a boon for solar. Hamstrung markets in Spain and Greece look on with envy. But even California's supportive measures are under threat, despite the appetite for them, and their apparent success.

Net metering is under heavy attack with utilities proposing additional charges for participating customers and a reduction in the full retail payment for exported power. The anti-net metering lobby claims solar drives up the cost for residential customers, a claim repeated around the country and reinforced in TV ads by the Edison Electric Institute, which represents utilities.

With the approval of Governor Jerry Brown and the state senate, an increase to an RPS of 50% by 2030 is on the cards but it is not quite a done deal. California showcases the benefits of an aggressive pursuit of solar. Its next job could be to show emerging solar states how not to become victim to their own success.

NORTH CAROLINA – BACKING FEDERAL POWER WITH STATE POLICIES

On the opposite side of the country from California, North Carolina has quietly deployed more than, or just under, 1GW of solar power, depending on who you ask. Much of this was driven by its RPS and a series of state tax incentives for renewable investment that could be claimed on top of the federal investment tax credit.

"The latest number we have is 984GW," says Allison Eckley of the North Carolina Sustainable Energy Association (NCSEA). "That's largely down to the suite of clean energy policies that have been passed here in just the last few years. The RPS, Senate Bill 3, requires 12.5% of North Carolina's electricity to come from renewable sources by 2021."

The state has a monopoly utility, Duke Energy, which was part of the bipartisan talks that created the RPS (talks which lasted two years) and backed the proposals. "Duke was supportive and it has far surpassed the amount of solar that it was required to bring online," says Eckley.

"We're on about 6% of the 12.5% requirement, which is supposed to increase in the future but there is a bill on the table that would freeze it at 6%. Duke has not gone on the record to say it supports it or otherwise. I can't speak for Duke, but I can't see why they would be against the RPS at this time," says Eckley.

Ultimately, the story in North Carolina is similar to Europe. Where European countries want to wean themselves off feed-in tariffs, Eckley wants to see even tax incentives phased out and solar compete with other technologies. She believes the RPS is doing a good job at driving the levels of deployment required to ensure that happens.

Credit: FLS energy

North Carolina has quietly become one of the leading US solar states.

In the context of the Clean Power Plan, Eckley says North Carolina's existing policies should position it well for compliance while some nearby states that have been less supportive will face some "pain" when looking to match the requirements of the Clean Power Plan.

TEXAS – MARKET FORCES TAKING HOLD

While the best solar resources can be found in the south west of the country, one obvious candidate with lots of open space, large population centres and proven pedigree in the energy industry – albeit in the oil and gas sector – has remained relatively quiet on the solar front. With a deregulated electricity market, Texas offers tremendous opportunities for solar.

"Texas is coming on pretty fast," says GW University's Ronen. "You have incredible resources and it has always been a mystery why wind has been such a dominant player in Texas and no one has really looked at solar."

Developer OCI Power and First Solar have scored a number of successes in Texas including merchant PV power plants. A 10GW RPS target by 2025 was surpassed in 2010 (largely through wind) meaning the impetus for development is not linking to any impending deadline. The Renewable Energy Credits (RECs) traded between utilities provide additional project revenue and continue to encourage development even with the RPS fully realised. But with prices reaching record lows in Texas, the market is as bigger driver as any.

"Austin Power, a co-op, is always a leader in the state in terms of trying new and innovative things and trying to be greener. They recently signed a sub-four-cents PPA, which I think shocked a lot of people because there is really nothing that can compete with that on any level," says Ronen. "That's not even considering the additional benefits of solar."

Credit: Freepik.com

NEW YORK – VISION AND VULNERABILITY

New York has always had an ambitious RPS with an initial renewable energy goal of 25% by 2012, but it now has an RPS of 50% by 2030, which is one of the most ambitious goals of any state in the US. It is also targeting an overall 80% reduction in greenhouse gas emission by 2050.

All of the plants coming out of the state are now falling underneath the umbrella of its 'Reforming the Energy Vision' (REV) strategy, which aims for a clean, resilient and affordable energy system for all New Yorkers. The vision also proposes the Clean Energy Fund, a US$5 billion investment over the next 10 years in clean energy programmes.

The strategy, spearheaded by New York governor Andrew Cuomo and his so-called 'energy tsar' Richard Kauffman, also includes the US$1 billion NY-Sun Initiative, which has driven a strong market in the state for rooftop solar. The purpose of the NY-Sun initiative is to see a stable, long-term decline in the subsidies that the state provides for solar systems until they can rely on fundamental economics alone.

Solar in New York has grown more than 300% from 2011-2014, at twice the rate of solar growth nationally. A total of 314MW of solar was installed as of December 2014 and the ultimate goal for distributed solar is to have 3GW by 2023.

Jamil Khan, energy policy and electricity markets specialist at SolarCity, says: "The real spark to the powder keg came from Hurricane Sandy. It was a startling realisation by the administration and the people of New York that their energy infrastructure was completely outdated and not as clean as it could be with the addition of renewable energy. Hurricane Sandy really illuminated the fact that we rely on a large, central system that has a singular point of failure."

Khan says it resulted in New York moving towards actually capturing the value in renewable and distributed energy, instead of just handing out grants and incentives.

For further insight into the role of storage in New York's REV plan, turn to page 88.

Credit: Governor Andrew Cuomo ©

New York governor Andrew Cuomo has been a champion of low-carbon energy.

MINNESOTA – LAW AND ORDERS

In a landmark ruling at the end of 2013 an administrative judge in the US state of Minnesota ruled solar generation to be a better investment than natural gas for utility, Xcel Energy, to meet its 150MW capacity target.

The case may have set the tone for a boon in solar deployment, having received widespread national coverage in the media, but it was the policies in place ahead of that ruling that made it possible.

For example, Minnesota ordered environmental costs to be quantified and then included in planning back in the early 1990s. More recently it has brought in a renewable preference law, which means the State Commission cannot issue a certificate for a non-renewable project unless the utility has shown that it has considered a renewable project and that it is not in the public interest.

Minnesota also has a very aggressive RPS – 30% by 2020 for Xcel Energy, the state's largest utility, and 25% by 2025 for other utilities in the state.

The Aurora solar project, developed by Geronimo Energy, as a result of the Xcel ruling, could also be used to reach the state's solar energy standard.

Furthermore Xcel energy said it is working on solar plants at all scales in order to meet Minnesota Legislature's goal of 10% solar power on its system by 2030.

Betsy Engelking, vice president, policy and strategy at Geronimo Energy, says: "Solar has really exploded in the state of Minnesota. Aurora was the leading edge of it."

However she says legislation had addressed solar from the smallest to largest scales. It improved net metering by increasing the threshold from 40kW to 1000kW. It also included community solar projects, which allowed customers to participate in a programme of virtual net metering into a community solar garden of 1MW or less.

Engelking says that as a result, there was around 10MW of solar in the state in 2014, but by the end of 2016, the state is expected to have around 1GW of solar spread between utility-scale projects and community solar gardens.

Solar analysts on Obama's Clean Power Plan

Shayle Kann, senior vice president, GTM Research

The final rules are definitely a net positive for solar. There's a higher renewable energy target of 28% by 2030, up from 22%, and there is some language around the rules more rapidly creating a switch to renewables rather than encouraging coal-gas switching, which is disincentivised. That's got to be a good thing for solar but how that will be implemented remains to be seen. It's going to be a long-term impact not a short-term impact but we'd rather see big long-term requirements rather than earlier implementation.

Via the Clean Power Plan, states are going to have to ramp up their renewable energy significantly over the course of the next 15 years. One thing that would make it a lot easier to do that is if the ITC is extended. It places a lower burden on states to create mechanisms to get solar online if the ITC is extended on its own.

Finlay Colville, head of Solar Intelligence, part of *PV Tech Power* publisher, Solar Media

On the surface, there is probably not a solar industry globally that would not want to have a leader that gave a long-term vote of support to renewables, regardless of policy detail or the prospects for implementation. Imagine that occurring in the UK or Australia, for example.

There were certainly two parts to the speech however, and these should be considered separately. The first is based on "America leading the way forward". Has the rest of the world not been waiting for the US to participate in global climate change directives for years? It is hard not to remember the reaction in the US to the Kyoto protocol for example. But again, for the renewables and solar industries in the US, why should they even care about this?

The second part of the speech is simply about creating a more binding requirement on all states to cut emissions. Solar deployment in the US has until now largely been confined to states that have passed renewables targets, so potentially this could accelerate solar in the US significantly and across a much wider range of states.

Where next for UK solar?

Credit: Belectric

Solar support policy | The UK's solar industry has grid parity within reach, but recent proposals to cull various subsidy schemes threaten to pull the rug from beneath its feet. Liam Stoker asks whether the UK can embrace alternative forms of support to help solar achieve long-term freedom from subsidy

The UK's utility-scale solar sector enjoyed a booming start to 2015, installing 2.53GW of capacity in Q1 as the country cemented its position as one of the world's leading PV markets. But less than six months later, the industry is facing a cliff edge in deployment.

The recent proposed cull of no fewer than nine renewably energy subsidy schemes has alarmed numerous stakeholders and is the cause for considerable consternation amongst those who consider grid parity for solar PV to be within touching distance. It has thrust new importance on the UK industry to be creative and led many to come up with alternative methods of support that just might bridge the gap between now and 2020, when the industry has predicted it can operate subsidy free.

The UK's current malaise started with the UK Conservative Party's surprise general election victory in May, which acted as the precursor for a steady stream of subsidy cuts with onshore wind and solar in the government's crosshairs. The most notable casualty was the proposed closure of Renewable Obligation support for sub-5MW solar farms a year earlier than planned. Support for such projects could now cease as of 1 April 2016, exactly a year after the programme closed for projects larger than 5MW in size.

But while many have accused chancellor George Osborne and his government departments of making politically motivated decisions when it comes to energy, it is a fact that there are very real financial constraints that have to be tackled. The Levy Control Framework – the government mechanism used to control the cost of energy subsidies handed down to taxpayers – was revealed by energy and climate change secretary Amber Rudd to be on course for a £1.5 billion overspend by 2020/2021, leaving the Department for Energy and Climate Change (DECC) with no choice but to take drastic action.

While a 20% head room had been budgeted for in order to compensate for energy price fluctuations, that the spend was on course to reach £9.1 billion meant that without intervention, there would be precious little left in the pot for future subsidies, let alone additional Contracts for Difference (CfDs) rounds. Rudd's recent confirmation that the future of CfDs is now up in the air after just one round is evidence enough of the parlous state of DECC's finances.

Right-leaning think tank the Policy Exchange did not waste any time in sticking the boot in. It accused DECC of "reckless and wasteful" management of renewable subsidies and proposed

Despite a recent boom, the UK solar industry is now on an unexpected cliff edge following a number of government policy announcements.

a complete overhaul of various subsidy programmes. Richard Howard, head of environment and energy at Policy Exchange, authored a report examining the extent of DECC's mismanagement and said that while the government must "take its decarbonisation commitments extremely seriously", it was down to them to "meet energy and climate objectives at lower cost to consumers".

Wrong place, wrong time

The message from the Conservative government was simple. It did not want – and could not afford – anymore ground-mounted solar deployment in the UK, having seriously underestimated the technology until now. Rudd swiftly defended the decision, insisting renewables could not have a "blank cheque" paid for by people's bills, but many within the industry merely reiterated the importance of stability and certainty. "After delivering price falls of 80% since the introduction of the feed-in tariff, no-one is asking for a blank cheque, just a sensible, transparent and predictable transition to 'subsidy-free' solar by 2020/21," says Seb Berry, head of external affairs at UK-based firm Solarcentury.

But deployment of utility-scale solar is realistically still needed if the UK is to meets its decarbonisation targets. The

country is already behind in its efforts to do so and failure to deliver a consistent message at this year's COP21 summit in Paris will seriously undermine the country's commitment to the cause.

DECC's own impact assessment of its early RO closure proposals even reveal that it expects to incur costs of between £75 million and £115 million under the European Union's Emissions Trading Allowance scheme due to the extra reliance on power derived from fossil fuels caused by curtailing subsidy support a year earlier than originally planned.

Not only that, but simply culling subsidies without an alternative means of support also threatens to jeopardise the entire UK industry. Giving evidence at a recent select committee hearing, DECC permanent secretary Stephen Lovegrove insisted that it was during the period immediately after subsidies have been withdrawn that the "greatest innovations" emerge from within industries, but the solar sector has rallied to counter his view.

A recent report compiled by consultancy KPMG in collaboration with the Renewable Energy Association provided detail on three markets – Spain, Greece and Italy – which saw significant downturns in market activity just after subsidy support was withdrawn. "If there's no subsidy or no substitute for subsidy, then it's likely the industry will decline quite rapidly and there'll be lots of economic impacts as well, particularly slower decarbonisation and so on," says Robert Hull, director at KPMG and co-author of the report.

While it's true the UK did survive and subsequently flourish after a significant cut in subsidies in 2011, their complete removal without equivalent support, Hull says, would be altogether more damaging than before. Hull likens the effect to a cliff edge, and warns of the dangers the industry faces. "It is lower deployment rates, loss of jobs in the industry and slower installation of solar," he adds. For Solar BIPV owner and REA senior advisor Ray Noble the importance of bridging the gap between now and a time when solar can be subsidy free is starker. "With 35,000 jobs hanging in the balance as an industry we need to work with government to find an acceptable solution," he says.

Vision for the future

To avert UK solar falling off the cliff, and with the UK government seemingly unwilling and unable to change tack, KPMG has put forward a number of alternatives to support that could be capable of steering solar to grid parity. Utility-scale deployments could benefit from relaxed planning regulations – a significant development hurdle – but from a financial perspective various tax breaks or incentives could prove to be the way forward.

It's a mechanism used in other industries to support but not directly subsidise development, and would shift the financial burden from the creaking LCF to the Treasury. The UK's oil and gas industry in the North Sea has enjoyed similar benefits for several years now – Osborne confirmed an extension to this support for a further year during his summer budget in June – and Hull notes that a similar system has been introduced in other markets with tangible success. "I think the main [market] is North America, where a number of states have used tax credits to encourage solar development. There's huge growth in their solar industries and also at the same time, costs are falling very dramatically," he says.

Whether or not George Osborne would be willing to incur the costs involved with granting such incentives remains to be seen, particularly at a time when the Treasury is tightening its belt to reduce the UK's national deficit. But allowing large-scale projects currently in the pipeline that would otherwise fall off the subsidy cliff to access tax credits would not only help stimulate the market but also reinforce secure confidence. John Dashwood, director of energy and utilities at PricewaterhouseCoopers, says it is imperative for the UK to continue to earn the trust of potential investors, adding that recent policy decisions threatened to "create uncertainty at an important time".

A US-style net metering scheme, which would enable small-scale generators to sell electricity back to the grid for a pre-determined fee, could also be introduced and would stand to become popular with smaller developments favoured by community energy schemes, which the UK government is on the record for wanting to continue to support.

One other, altogether more contentious method of support suggested by KPMG would be a withdrawal from the European Union's minimum import price (MIP) undertaking, applied to Chinese modules sold in the EU. The MIP has created a market in which component prices are artificially inflated, effectively reducing margins on generated energy by increasing development costs. Allowing EPC firms to source cheaper modules would make solar farms cheaper to develop.

Repealing the MIP and its implications would be a political hot potato, and while it has been suggested as a potential alternative to subsidies, it is by no means touted as the right way for solar to achieve its goal of moving past subsidy and onto grid parity. "That's a government decision and it does affect the industry, and maybe a change in that could have a beneficial impact," Hull says. "That's certainly something the solar sector has lobbied to get changed, and what we've done is state that it exists and changing it could make a difference."

Hull believes it is this end goal that warrants the need for special action on solar's behalf. "My sense of the solar industry is that it recognises you have to move past subsidy, which not every industry does, and from what I've seen it is keen to find a solution that removes it from subsidy and makes sure there aren't barriers to being able to fit into energy markets and compete in open markets," he says.

The Conservative government has made it abundantly clear that, as far as the LCF is concerned, there is no more scope for extensive subsidy support for large-scale solar farms, but this does nothing to aid the industry on its way to a sustainable future. A failure to provide it with an alternative, far from Lovegrove's vision of innovation, only threatens to create the same kind of developmental cliff edge seen previously in other markets as well as the associated after-effects.

A number of meaningful alternatives have been put forward, and it is now up to UK solar as an industry to put its message across. Grid parity is a realistic goal, but not one that can be achieved without the necessary help. ■

If the tariff FiTs

While the proposed early closure of the Renewable Obligation for sub-5MW solar farms has stolen the headlines, hinted changes to the feed-in tariff also stand to have a significant impact on the uptake of solar in the UK. The feed-in tariff for standard domestic installations is currently set to fall to 4.28p/kWh on 1 October, but could be cut far lower if the "cost-cutting measures" alluded to on 22 July come to pass. The Policy Exchange has already condemned the feed-in tariff as "enormously generous" and average returns have swelled to around 12%. There is every expectation DECC will trim back the FiT to within the 5-8% annual returns originally forecast, but a worst-case scenario could see the small-scale FiT removed entirely.

Finlay Colville analyses the prospects for large-scale solar under the Contracts for Difference scheme overleaf

Uncertain future for UK large-scale solar power plants if Contracts for Difference scheme fails to deliver

Solar auctions | The proposed closure of the UK's Renewable Obligation programme to solar from next March would leave the Contracts for Difference programme as the only form of support for large-scale PV. Finlay Colville looks at the prospects for an auction-based system taking off in the UK

Credit: Lightsource Renewable Energy

The past few years have seen the UK's large-scale solar industry become of global significance, due exclusively to the Renewable Obligations Certificates (ROCs) on offer to solar. This incentive-based platform has seen the UK move to a multi-gigawatt market, with many overseas engineering procurement and construction (EPC) companies targeting the domestic market.

During 2014, the UK solar industry added 2.55GW, of which 1.85GW came from utility-scale projects. The contribution from ground-mounted ROCs was 1.83GW, highlighting the importance of PV power plants in the UK. In fact, during the first quarter of 2015 (Q1'15), a staggering 2.38GW of ROC-incentivised solar plants was commissioned, ahead of the ROC reduction level cut-off for 1.4ROCs/MWh on 31 March 2015.

However, the RO scheme – which has been in existence since 2002 – is due to finish on 31 March 2017, or 12 months earlier depending on the outcome of ongoing policy proposals, leaving the recently introduced Contracts for Difference (CfD) mechanism as the only incentivised route for large-scale solar power plants. Therefore, in terms of speculating on the long-term prospects for large-scale ground-mount solar plants in the UK, it is the CfD scheme, and not ROCs, that needs to be considered carefully.

Solar's contribution to the first CfD auction round

While the UK government's intentions to shift funding for renewables from ROCs to the CfD scheme have been known about for some time, few in the UK solar industry had given the CfD scheme much thought until 2014. This was due to the fact that, at the start of 2014, the RO scheme was expected to be available to solar, with no capacity cap in the size of solar sites, until 31 March 2017.

The continuation of the UK's recent large-scale solar boom has been cast into doubt by the early introduction of the action-based CfD scheme.

Therefore, solar plant developers, and asset holders, were imagining a period of another three years of being able to build, own and operate large-scale solar plants that would be financed through ROCs, so long as they were commissioned before 31 March 2017. Why bother about the more complicated and risky auction and capacity-limited CfD scheme, until it was the only option available?

But in May 2014, this all changed when the UK's Department of Energy & Climate Change (DECC) announced that solar plants above 5MW in size would no longer qualify for ROC incentives, if built after 31 March 2015. With the exception of some projects that qualified under 'grace' criteria, this effectively closed the RO scheme to large-scale solar plants (>5MW) some two years earlier than expected. Adding to that, in July energy secretary, Amber Rudd outined proposals to close the RO to sub-5MW projects from April 2016.

As such, the previously expected transition from RO to CfD for large-scale solar plants on 1 April 2017 was brought forward by two years, to 1 April 2015. Consequently, the first CfD auction, planned for October 2014, then became a somewhat premature and rude awakening for the solar industry.

Between May and October 2014, debate and discussions within the UK's solar industry regarding the first CfD auction process late in 2014 dominated many internal company agendas and trade meetings. Many speculated on how much solar would be included in the 2014 CfD round, when announced at the start of 2015, or what the split would be between solar and onshore wind.

The reality was very different. The first CfD auction came and went, and very little changed regarding the future prospects for solar plants in the UK. Confusion reigned both within the industry and across external stakeholders, when only a handful of solar sites/developers received letters of offer earlier this year. And even greater surprise was to be found in the very low strike prices offered by some developers, at prices that were clearly well below the break-even point of profitability.

So, what went wrong? To understand this, it is important to review the specific timing of the first CfD round, in relation to

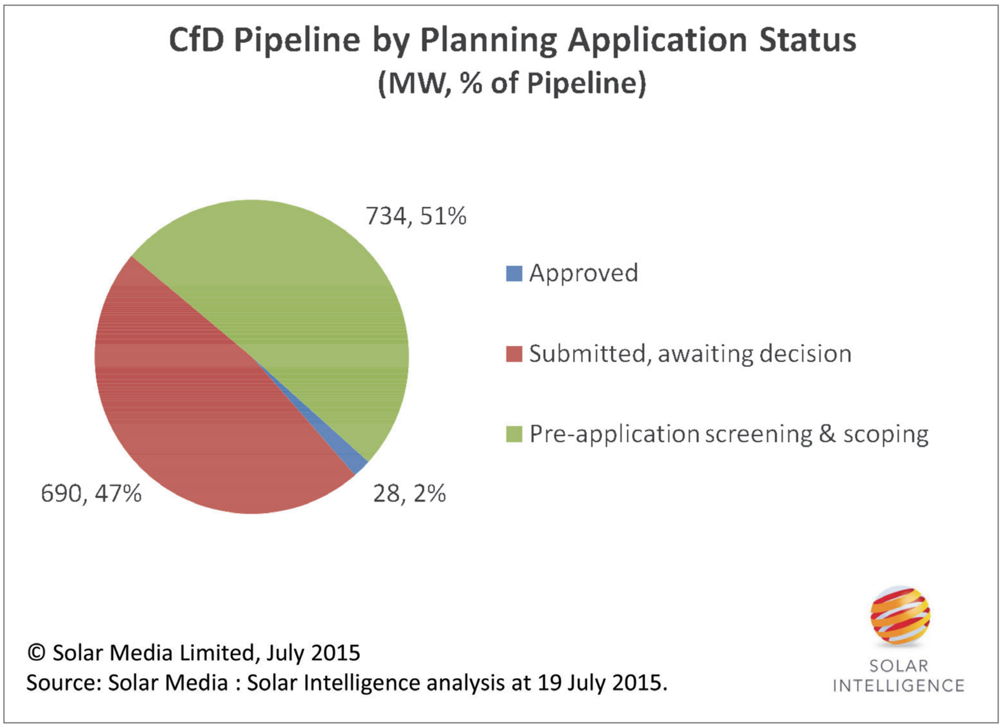


Figure 1: By the middle of July 2015, almost 1.5GW of prospective solar plants have been identified as likely candidates for possible submission within a forthcoming Contracts for Difference auction. Almost half of these have yet to be submitted to the planning process, with about 690MW awaiting local planning authority approval. Source: Solar Media Limited, 2015.

DECC's policy changes to large-scale solar under the RO scheme in May 2014. Simply to enter the CfD process, it is necessary to have several site-specific conditions satisfied, the most important of which is planning application consent.

Within this context, during the period June to September 2014, almost any large-scale solar plant that had received planning consent was almost certainly looking to build under 1.4ROCs (expiring on 31 March 2015) or during the subsequent fiscal year at 1.3ROCs. Furthermore, one of the key grace conditions imposed on the industry for large-scale solar plants above 5MW that could qualify for 1.3ROCs if constructed in the fiscal year ending 31 March 2016, was that planning applications were validated on or before 15 May 2014.

As a result, the vast majority of solar plants above 5MW that had come out of the planning application process during June to September 2014 had almost certainly been submitted to planning before 15 May 2014. So, in effect, the RO scheme was available to them, if the site could get built before 31 March 2016, based on 1.4ROCs before 31 March 2015 or grace-compliant 1.3ROCs before 31 March 2016. In short, why even bother putting these sites into a lowest-offer auction process in October 2014, if ROCs are still on the table – double-dipping across the RO and CfD schemes being prohibited?

The first CfD auction largely came and went for the UK solar industry at the end of 2014, and all focus was on building large-scale solar power plants during Q1'15 and if that did not work out, putting them in the bank for RO grace-compliancy during the fiscal year ending 31 March 2016.

CfD auction prospects

At the time of preparing this article, the next CfD auction looks likely to be pushed out to 2016, although the exact dates for applications are yet to be announced. At around the same as proposing to close the RO to sub-5MW projects, Rudd was unable to give any firm commitments to when round two would be. But assuming a second round is at some stage on the cards, how have things changed since the first CfD auction in 2014?

As it turns out, the landscape is actually much clearer, in terms of pinpointing the sites and developers that are lining up for CfD submissions. In simple terms, large-scale applications (nominally above 10MW) that have gone into the planning process from January 2015 onwards can only have one possible incentive route – CfDs. (A few anomalies exist related to multiple sub-5MW cluster site proposals and dual RO/FiT sites.)

So, let's look at the projects that are being earmarked for CfD submission. In contrast to the 2014 CfD round, where large-scale sites were being held back for ROCs, it is now thought that the CfD route is essentially favouring economy-of-scale in site size. So, only projects above 20MW in size are considered in the analysis below.

Figure 1 shows the breakdown of the CfD candidate sites, as of July 2015, lined up as prospective sites for auction submission. The pie chart contains 1.45GW of solar plants, across various stages of planning application status, including application approval (required for CfD submission), application submission, and pre-application screening/scoping.

Interestingly, right now, only one site above 20MW has got planning approval. Some 22 sites, adding up to 690MW, are still awaiting planning application outcome. Completing the 1.45GW are 18 sites adding up to 734MW that have been subject to pre-application screening and scoping over the past six months.

Therefore, while 1.45GW may sound a commendable capacity of CfD prospects, the reality is a much smaller submission stack. Taking the approved site, and half of the awaiting-decision applications, then there is potentially about 400MW of >20MW solar plants in the UK that could be entered into a CfD round in 2015 if – however unlikely – that were to take place in the next few months. With submissions having to bid on strike price and intended year of CfD allocation, this is certainly not sending out a great signal for CfDs being the natural successor for solar plants after the RO scheme.

Reliance on CfDs casts doubt over new UK solar plants

Given the somewhat lukewarm pipeline of CfD entries in 2015 in the face of ROs being phased out for large-scale solar plants in the UK, is there something else holding back developers from being proactive in stacking up application prospects? Why is the whole industry not starting to find a larger number of sites for the forthcoming CfD rounds?

The answer to this is rather complex and is more a consequence of the distrust that currently exists between the industry and a government that has yet to indicate its support for large-scale solar plants in the UK. The climate for solar and other renewables does not look good in the UK right now.

Therefore, perhaps the modus operandi of developers of solar plants is simply to build as much under 1.3ROCs as possible, and then anything else after 31 March 2016 is simply a bonus.

Moving to a capacity-based auction process, such as CfDs, has to be based upon the intent to add capacity in the first place. In the UK, however, this is far from the case. What becomes available from CfDs for large-scale solar plants may be greatly curtailed, based upon the solar industry's success in capitalising on the RO scheme. Both the ROs and the CfDs, in addition to the rooftop incentive vehicle for solar under the feed-in tariff, come from a single Treasury purse, capped by the Levy Control Framework (LCF). Runaway success in any of these funding schemes ultimately impacts the budget available for the others.

With the government currently under pressure to address potential overspend within the LCF, the automatic reaction would appear to be one of budget overspend recovery, as opposed to reviewing specifically why renewable energy was originally on the table in the first place. Upon re-election, the Conservative government is committed to show the electorate that cost savings within the government and the public sector are top of the election manifesto pledges. And in this respect, any budget overspend from the first (coalition) term is only going to be targeted as easy pickings.

So, uncertainty is by far the order of the day for future large-scale solar plants under CfDs within the UK. If ever the industry needed a champion within the government, that time is now. The next few months will be critical for potential deployment for solar plants in the UK, funded through CfDs, and central to this is the timing, scope and qualification criteria for submissions. The solar industry in the UK has successfully navigated frequent policy adjustments in the past, but the future is simply too hard to call. ■

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Two steps forward, one back for Australian solar

Policy | As one long-running policy saga finally draws to a close, a series of attacks on renewable energy support have offset any progress that had been made. Tom Kenning explores the latest setbacks and where the possibilities for progress may lie

Credit: Flickr/leard state forest

Australian PM Tony Abbott is accused of being under the thumb of the coal lobby.

The long-disputed saga around Australia's renewable energy target (RET) has settled at last, bringing to an end 15 months of political wrangling that thwarted the progress of the country's solar energy industry. Things appeared to be looking up with a 200MW large-scale solar auction on the horizon in the wake of the Australian Renewable Energy Agency (ARENA) revealing its new funding plan. Nevertheless politics couldn't leave the industry alone, with sudden restrictions enforced on the investment capabilities of the Clean Energy Finance Corporation (CEFC), whose very role is to mobilise capital investment in renewable energy. This piece questions key players in the Australian market and industry bodies on whether the outlook is positive for the industry in a nation of abundant solar resources, the 'sunburnt country', or whether it is still hindered by the incumbent Coalition government.

The RET agreement is a compromise, having been reduced around 20%, from 41,650GWh to just 33,000Gwh by 2020, and prime minister Tony Abbott made it clear that he would have liked to cut the target further. Yet industry members agree that the final resolution did result in a noticeable boost in sector confidence.

Jack Curtis regional manager, Asia Pacific at First Solar, which has developed PV projects in Australia, tells PV Tech Power that the RET agreement has improved investor sentiment, with the end of the uncertainty preferable to waiting even longer for an improbable higher target. However, one of the criticisms about the lower target was that it may not be large enough to accommodate both main renewable technologies; it could take around two years for solar to reach price parity with wind.

"One of the trends we are seeing is a much more active focus on trying to find a way for solar to comprise a larger percentage of the RET," says Curtis. "We've seen a lot more activity, not just from the usual suspects but also those that might have taken a less supportive view during the negotiations. We think that solar has a pretty credible price trajectory to make that interest worthwhile over the next two or three years."

Curtis also says that many projects, including some from First Solar were dependent on a deal being reached and a further six months of delays could have been the tipping point to abandoning those ventures.

This is backed up by Darren Gladman, policy manager at the Clean Energy Council (CEC), the body that represents the clean energy sector in Australia, who says that some members with projects stuck in limbo had reported suddenly being able to seal power purchase agreements and gain financial backing directly as a result of the RET agreement.

Indeed soon after the deal was made in June, CEFC chief executive Oliver Yates said: "The market should now benefit from lower risk premiums for financiers, which in turn can lower the overall cost of developing new projects."

Bloomberg even reported interest from Chinese wind giant Xinjiang Goldwind Science & Technology to expand into solar via co-location of wind and solar farms. It was also claimed that this came as a direct result of the RET agreement.

The outspoken chief executive of industry body the Australian Solar Council, John Grimes, says that the government acted to "purposefully" disrupt and delay the agreement, for example by trying to include the burning of native wood waste in the target and insisting on biennial reviews.

"Having said that, we are back in business," Grimes adds. "The problem is the attacks from the Abbott government just haven't stopped."

The assaults continued this July, when just as the CEFC agreed a AUS$100 million (US$77 million) deal to help the rollout of the utility Origin's rooftop solar leasing scheme for households and businesses, Tony Abbott told the financing body that it could no longer invest in rooftop solar and wind projects via a draft mandate that was passed over for consultation. The CEFC responded with a moderated statement confirming that it was seeking legal advice on the matter and reassuring investors that existing deals would not be affected.

The news of government meddling

was unsettling for the industry, which had breathed a sigh of relief when the RET agreement was passed. Grimes says that the new restrictions came on top of another directive two months earlier which mandated the CEFC to double the rates of return it achieves on its investments. This meant the CEFC would have to rely on financing more established technologies, such as large-scale wind and small-scale solar, which are in the "sweet spot" for getting a higher rate of return, says Grimes. But of course these established technologies are now likely to be off limits for CEFC financing under the newly proposed limitations.

Grimes adds: "This one-two blow is a cynical exercise – a stitch up – designed so that the CEFC will fail. They are loading up the saddle bag of CEFC so it is not possible to win the race. It underlines the fact that the Abbott Government is not going to stop and that is extremely concerning."

Australia has a "very risk averse" capital market, Grimes adds, and although it has been considering investment into this renewables asset class for the first time, the CEFC was playing an important role in terms of educating investors about the opportunities available.

Curtis says: "Anything that looks to impede or constrain or undermine what was an established policy platform is only a negative thing."

It sends a negative message that these kinds of programmes can be fiddled with in a "fairly haphazard fashion", he adds, although it remains to be seen whether the CEFC will actually accede to the new government directions.

The political upheaval over the CEFC also coincided with plans by ARENA to proceed with a new large-scale solar auction. It said it was planning to provide AU$80-100 million (US$59-74 million) in support through the competitive funding round, which was likely to open in September.

The Government's rhetoric, at the time of the CEFC limitations, also turned surprisingly towards support for large-scale solar. On local radio, environment minister Greg Hunt said an approved RET would result in "increased and enhanced support for solar, particularly large-scale solar". Leaked plans also revealed government intentions to write to the CEFC to ensure "significantly increased uptake of large-scale solar and energy efficiency". Nevertheless, industry members widely agreed that this rhetoric was heavily directed by an anti-wind campaign, with Tony Abbott branding wind farms as "ugly and noisy".

Bloomberg New Energy Finance analysis has estimated a further 8GW of large-scale renewables generation will be required to meet the 33,000GWh RET target, needing AU$15 billion of investment. Of this around 2.6GW (33%) is expected to come from large-scale PV.

Industry members say that utility-scale solar will be the most impacted by the RET resolution, with prices falling dramatically worldwide and more deployment required in Australia to replicate that. Utility-scale will emerge, Grimes says, and this is helped by the certainty around the RET and the CEFC not being prohibited from investing in large-scale solar.

"Crossbenchers really are demanding large-scale solar, which means that the prospects have never been better," Grimes adds, "but the issue remains – when will the price pressure be such that the customers are willing to sign power purchase agreements for large-scale solar plants?"

The commercial-scale solar sector (<100kW), on the other hand, has become a more healthy industry. Gladman says that two years ago almost all rooftop solar was residential, with utility accounting for just 5% by volume one year ago. It now accounts for 25% with the CEC expecting to grow strongly in the coming two years.

"Economic fundamentals have just gotten better over the years," says Gladman.

In contrast, Curtis says commercial hasn't quite taken off as a function of "general procurement bias" on behalf of those that pay low electricity rates.

He adds: "While some interest has been driven by Corporate Social Responsibility (CSR) and green branding, it does not really go mainstream until it starts to appeal economically."

Solar is reaching a crossroads at a distributed level, Curtis says, where consumers can be given AU$11-12 cents/kWh tariff levels, which can offset someone paying AU$12 cents/kWh.

One sector, which came out almost unscathed by the lengthy RET review was residential solar, for which public support is so strong that Grimes says it is widely regarded as "beyond the reach of politics". He adds that the economics are compelling, with the likelihood that consumers will pay around a third of their normal energy bill over a 20-year period through rooftop solar installations.

Curtis says: "There has obviously been a significant uptake of residential solar during the previous five years [although] that growth trajectory will start to taper off as a function of natural demand drivers and policy constraints."

Tony Abbott
Credit: Flickr/Global Panorama (2)

Looking at all three solar sectors, then, the outlook certainly appears to be positive in light of the RET review finally drawing to a close. What other government meddling may occur remains to be seen, however, Gladman cites the upcoming conclusion of the anti-dumping investigation in October, sparked by Australian panel manufacturer Tindo Solar, as a potential "spanner in the works" for the industry. The investigation was recently broadened beyond price margins and competition to include examining whether China's government policy constituted unfair support for its PV sector.

Gladman says: "Most of the panels used in Australia are brought in from China, and if there was a significant anti-dumping duty placed on panels, that could have a huge price impact on sales."

In any case, Grimes says a major story will be the rise of energy storage technology with 6kW LG batteries on sale for AU$6,500, providing an attractive option for consumers, especially those with larger systems, who in one state, will lose their feed-in tariffs (FiTs) at the end of the year.

While the Coalition government does not have a majority in the senate, which has thwarted its attempts to shut down ARENA and the CEFC, Grimes says there is a significant danger to the solar sector if the Abbott government is returned at the next election.

The biggest coal deposit in Australia has been discovered in Northern Queensland, the Galilee basin – an area roughly equivalent to the size of the UK – and Abbott is very keen for Adani Mining, a wholly owned subsidiary of India's Adani Group, to mine and export it to the world, says Grimes. With Abbott "completely captured" by the coal interest group, adds Grimes, he is doing everything he can to frustrate and retard the development of any alternative option and particularly renewable energy.

Much of Australia's coal is expected to be exported to India, but as a recent Deutsche Bank report suggests, reliance on India for imports could be foolhardy with total Indian investment in solar power expected to surpass that of coal by 2019/20.

Moreover, Grimes insists that Abbott's policies are doing political damage to the Coalition, given the strong public support for solar.

He adds: "The Australians have seen into the Prime Minsters heart and found it covered in coal dust." ■

Future PV power plants

Utility solar | Recent years have seen huge decreases in the cost of electricity from utility PV arrays. However, with PV's grid parity battle not yet entirely won, competition to drive out further costs is still fierce. Ben Willis looks at some of the technological evolutions that will shape the next generation of PV power plants

Earlier this year the leading solar research institute Fraunhofer ISE completed a study for German think-tank Agora Energiewende documenting the past and projected fall in the cost of solar-generated electricity. From PV's first space-based applications in the 1950s to the current generation of large-scale power plants, the study said the progress made by a once-marginal power source had caught many people by surprise, with costs falling much faster than expected.

In Germany, for example, the study recorded a fall from €0.40 (US$0.44)/kWh in 2005 to €$0.09/kWh in 2014 in the cost of power from large-scale PV installations. Although figures such as these already make PV a low-cost renewable energy technology – the lowest in some parts of the world – the study predicted it had the potential to go much further, falling in Europe to between €0.04 and €0.06 per kWh by 2025 and to as low as €0.02 to 0.04 by 2050 based on conservative estimates. Indeed such levels are already being reached in some sunnier regions, with US firm First Solar recently announcing a PPA price for its 100MW Playa Solar 2 project in Nevada of US$0.0387 per kWh.

Even for those responsible for the growth in utility-scale solar, the cost story is still one of some wonder. Matt Campbell, senior director of power plant products at SunPower, remembers how even as recently as 2008, PV's economic viability compared to its nearest rival, concentrating solar power (CSP), was still in the balance. "At the time the conventional wisdom was that CSP was the technology of choice for utility-scale solar and PV was for distributed solar, and there were a lot of people sceptical about the ability to reduce the cost of PV," Campbell says.

But then firms including SunPower and First Solar took a leap of faith, signing power purchase agreements (PPAs) for such mega-projects as the 250MW California Valley Solar Ranch and the 550MW Topaz solar farm. "We bet on the future and got these big PPAs, and that was the kick-off of what I would call the utility-scale solar age," Campbell says. "The market in '07 was let's say 12 to 14 cents. And today you see people in the US signing PPAs for less than five cents per kilowatt-hour. So you've got almost a two-thirds reduction in just seven years. It's remarkable."

The question now is how far this can go. As the Fraunhofer report highlighted, while some have pointed to PV's success in bringing down cost as evidence of a dawning "solar age", the flip side to that coin is that the price declines the industry has achieved in a short space of time could slow down, prompting a sudden bursting of the "solar bubble".

One of the biggest risks for the industry, one that could give some credence to this latter view, is the threat of regulatory or financial disruption. In many markets, PV is still reliant on support either through direct subsidies, as in many European markets, or fiscal incentives, such as the investment tax credit in the USA. As PV becomes increasingly competitive, the risk of political support for a technology that has begun standing on its own two feet being withdrawn also grows. This has already happened in countries such as Spain and Germany, with serious consequences for those markets.

Ultimately preventing this happening is only marginally within the industry's control. Where the solar sector does have more control over its own destiny, however, is on the technology side, and here there would appear to be plenty more room for driving down cost.

According to Fraunhofer's analysis, the cost of a PV system, a key component of the levelised cost of electricity (LCOE) metric used to compare the cost of power from different sources, still has some way to go. Based on various different scenarios and assumptions around market development and technological learning rates, the study forecasts system costs falling from €935-1,055 per watt peak in 2014 to anywhere between €280-610/Wp in 2050.

Credit: First Solar

SunPower's Matt Campbell says projects like California Valley Solar Ranch kick-started the "utility-scale solar age".

Campbell agrees there is still plenty of headroom for driving out cost. But he highlights the fact that in the seven years or so of the "utility-scale solar age", the industry has already largely achieved most of the easy wins on the technology side. Most of the cost reductions to come he believes will be achieved through methodical, incremental improvements to many individual details rather than some single breakthrough piece of new technology.

Nevertheless, he has high hopes of what the industry can still achieve. "I've never been more excited about our ability to bring new innovation to the power plants," he says. "We've already done the low-hanging fruit. We did a lot of things that were easy and they had a huge impact; now it's a little bit harder. But when I look at our pipeline for next-generation products, there's going to be a lot of things that will make an impact."

This article looks at some of the key elements of a PV power plant and canvases opinion on where the biggest hopes for innovation lie in the next-generation of solar power plants.

Cells and modules

The module is the engine of a PV power plant and reductions in module costs has played a large part in the driving down of PV system costs. In terms of future module price developments, the Fraunhofer study conservatively predicts that the so-called "experience curve" – the rate at which manufacturers collectively drive down module average selling price (ASP) in proportion to the amount of experience and therefore innovation gained through producing a product over time – will continue, but slow and not return to historical rates of around 20.9% until 2050.

The two key drivers of continued cost reductions in modules will be improved efficiencies in both performance and material usage. Although thin-film PV has two notable players – First Solar with its CdTe technology and Solar Frontier with its CIS variant – crystalline silicon-based cell technology is expected to dominate for the foreseeable due to its relatively low cost and potential for efficiency improvements.

"Thin-film was quite interesting in the times when silicon was getting expensive during the feedstock crisis. But nowadays, crystalline silicon is so cheap and there's still such high potential in there," says Radovan Kopecek, co-founder of the ISC Konstanz research institute in Germany and head of its advanced solar cells department.

Kopecek foresees an ongoing transition to passivated emitter rear cell (PERC) technology as a new industry standard in crystalline silicon PV, a process that is already well underway among many manufacturers attracted by the higher yields offered by PERC cells. After PERC, he expects its near cousin, PERT (passivated emitter rear totally diffused) technology to take off, with the likes of Belgium's imec research centre having achieved a 22.5% conversion efficiency in an n-type PERT cell.

One trend that has come to the fore in the past few months that many are backing as a sign of things to come is the growing prevalence of bifacial modules. The jury is still out on what benefits the ability of bifacial technology to absorb light on both front and rear sides will offer in yield and therefore cost terms. But the matter could soon be settled when a 2.5MWp plant in Chile, La Hormiga, is completed later this year.

This project is being touted as the world's largest bifacial system. It incorporates glass-glass modules containing bifacial 'BISoN' cells from Italian firm MegaCell, and claims to offer an LCOE of less than US$59/MWh per year. Kopecek believes the installation will settle the question over the benefits of bifaciality once ad for all.

"I think it will become a mainstream technology," Kopecek says, "and not because it's a cool technology but because people are going anyhow to bifacial cells and glass-glass modules. So you don't have to implement a new technology into your modules in future, but you can just use it on top."

Credit: MegaCell

New cell technology could offer a fresh round of efficiency gains for modules.

System design

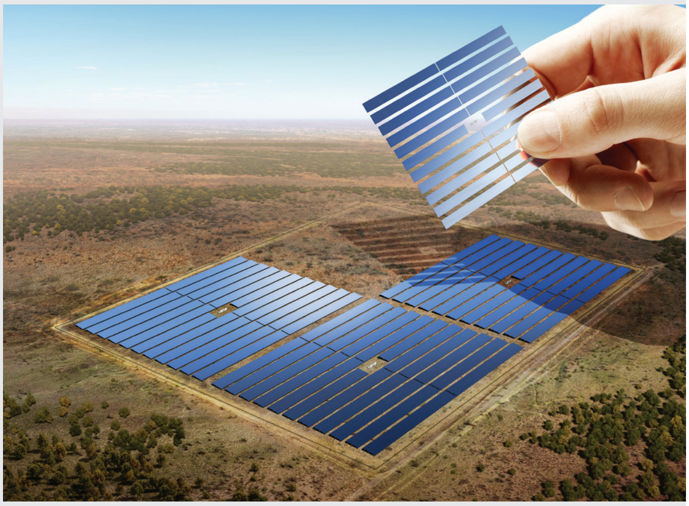
One of the key developments in the evolution of utility-scale PV plants has been the shift to modular design and construction that breaks plants down into a series of smaller, standardised units. SunPower's Oasis product is one example of this, a 1.5MW power block in which all the components are designed to function as a single system. As many of these individual building blocks as are needed can be deployed to make up a larger overall plant.

Campbell says the introduction of the Oasis approach has allowed SunPower to reduce its balance of system costs by more than half. "Its modular, integrated design ensures fast installation practically anywhere, reducing time to market," Campbell says. "At the recently completed 579MW Solar Star Projects, for example, we were installing up to 5MW per day."

Another prominent exponent of the power block concept is Germany's Belectric, which now offers its '3.0MegaWattBlock' as the standard building block of plants it builds. According to the company's UK managing director, Duncan Bott, the modular approach is one that the industry should now follow as standard.

"The PV industry needs to stop designing solar farms," he says. "We should just have a block – would you like a 1MW, 2MW or 3MW block sir? And then it becomes a modular approach; you don't need a million designs on every single piece."

Bott believes further developments around the power block concept are more than likely. In the past two years he says Belectric has been able to progress from a 2MW to 3MW block design largely as a result of collaboration with GE, whose 1500V inverter has been central to the concept's development.



Credit: Belectric

Belectric's 3.0MegaWattBlock concept is the basis of its modular approach to system design.

"GE developed that inverter, and that has enabled us to evolve from a 2MW block to a 3MW block. So therefore the cost of inverter by a per-MWp ratio has dropped, just because they have built a bigger and better design," Bott explains. "So will our 3MW block evolve? I would be tempted to say yes it will. How much to? That will depend on our inverter suppliers. But give us another year and I wouldn't be at all surprised if there's a 4MW block."

Inverters

If the module is the engine of the PV power plant, then the inverter is the brain. The biggest development here has been the 1500V model, which aside from such developments as Belectric's 3MW power block has brought with it a multitude of other benefits, including greater power densities and fewer AC connections, all of which mean cost savings in balance of system components such as transformers and wiring, and savings on labour.

Mahesh Morjaria, vice president of product management at First Solar, believes that just as the industry has largely moved from 600 to 1,000V plants in the past few years, a wholesale shift to 1,500V will be next. "The whole industry will move towards that for purely economic reasons," he says. "And we see in the industry there are more suppliers who are coming up with modules that are 1,500V and inverters that are 1,500V."

But he sees 1,500V as "just the next evolutionary step" for the industry, with even higher voltage ratings possible: "This will be dependent on a few other factors as well: usually it's pushing the standards to accommodate that and pushing the suppliers to have components that are capable of higher voltage levels. But I would not be surprised if we saw power plants at higher voltages as we develop the technologies to accommodate them."

Campbell however sees the move to 1,500V as less straightforward than the shift from 600V to 1,000. "We are pushing up against the voltage ceiling of commercially available IGBTs [switches] and BOS component technologies. Maintaining reliability will be the challenge as newer, higher voltage inverter topologies come to market, meaning that the ramp to 1,500V as the standard may take slightly longer than planned."

Aside from the trend to higher-voltage central inverters, greater emphasis on operational efficiency of PV power plants has also led to a move in the other direction for inverters – notably, the recent uptake in three-phase transformer-less string inverters on sub-10MW plants and even microinverters on sub-1MW commercial rooftops and a few ground-mount projects.

Credit: GE

GE's 1500V 'ProSolar' central inverter forms part of the emerging generation of higher-voltage PV equipment.

Key attractions are the inherent CEC power conversion efficiencies of above 98% and high MPPT granularity, while offering modular scalability and long lifetime reliability that can provide a meaningful LCOE reduction as they transmit power to a ~1MW DC-to-AC power converter and medium voltage distribution transformer.

How the battle between central and distributed inverter architectures plays out remains to be seen. "It will be interesting to see string inverters and central inverters face off in upfront cost, DC and AC collection costs, reliability, installation, and O&M," says Campbell. "All of these factors need to be considered when choosing an inverter architecture."

Storage and power control

One capability that the PV power plant of the future will need to be able to offer is the ability to provide so-called ancillary services that help stabilise the grid. Companies such as First Solar and others have developed control systems for PV plants that, in conjunction with increasingly sophisticated inverters, enable them to respond rapidly to voltage or frequency fluctuations on the grid.

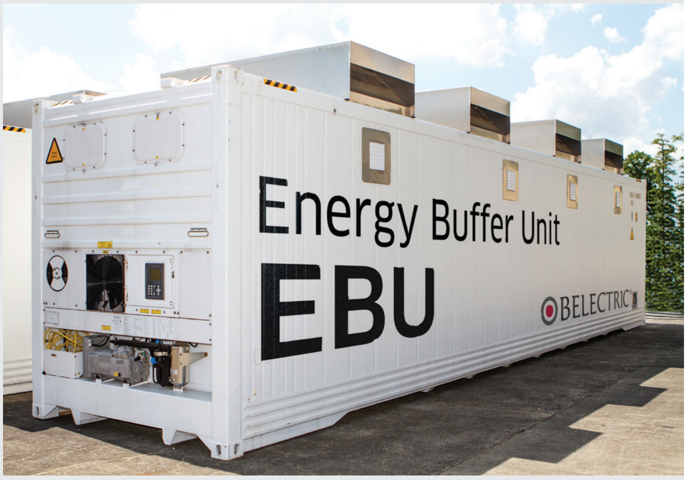
Such capabilities have so far not been a significant requirement for PV power plants given the relatively small proportion of PV on the grid. But with more PV plants being connected to the grid, that requirement will grow.

"As more and more PV plants come to the fore now, the utilities are looking for ways to stabilise the grid," says First Solar's Morjaria. "They expect the plants to perform somewhat similar to how conventional plants do in terms of providing ancillary services – things that are not currently sought after from PV plants but will become more and more important."

Much of the technology – through smart inverters, power conditioning units and sophisticated SCADA systems – already exists to enable plants to operate in this way. One particularly exciting development, however, is the coupling of these technologies to battery storage units to enable PV plants to effectively offer ancillary services night and day.

Belectric has been one of the pioneers of incorporating storage into utility solar through its Energy Buffer Unit system. This incorporates a containerised battery unit into a utility-scale PV array, allowing the array to respond rapidly to deviations in grid frequency and to sell power into the lucrative primary and secondary frequency response markets in Germany. The company is going a step further with a '3.0MegaWattBlock Hybrid', which combines all the attributes of its modular power block and EBU systems with a diesel or gas-fired generator, potentially opening up further commercial opportunities for PV.

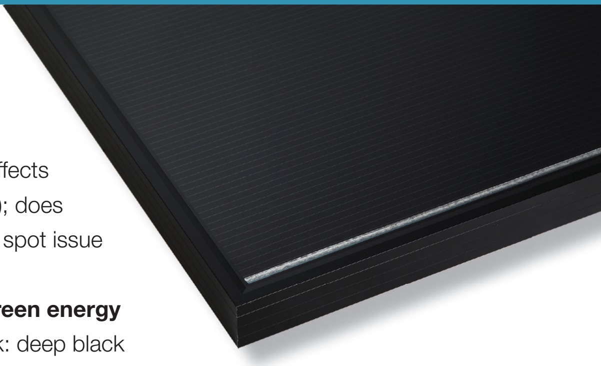
"Ancillary services are definitely key to where this industry is going to evolve to in the future," says Bott. "If you are an asset manager, what you are looking to do is to add additional business models to your standard subsidy. So therefore if you're going to be building solar farms in the future as the subsidies drop to zero, which is what's happening at moment, then you need to add additional business models."



Credit: Belectric

Belectric's Energy Buffer Unit promises to open up new commercial options for PV power plants.

Hulk Energy Technology takes Green CIGS module power to record 324 Watts



Hulk Energy Technology Co., Ltd. (HULKet), based in Taiwan and founded in 2011, has been devoted to equipment development, product design and key process improvement. Finally HULKet launches the world's most powerful (320W~330W) CIGS thin-film solar modules, the CIGS 3000 series, which was certified by Germany's Fraunhofer ISE at 324Wp. Its conversion efficiency reaches as high as 14%, breaking the long-existing business barrier of CIGS thin-film solar products and achieving a new record in mass production in the solar industry.

Because of its material and thin-film structure, the CIGS thin-film solar module additionally possesses a Power Gain Factor (PGF) that delivers a sizeable power boost when compared to crystalline silicon modules: under the same environmental conditions and based on the same labelled power, the CIGS solar module could generate additional electricity yield as high as 26%. The power output of the CIGS module with a conversion efficiency of 13.5% is equivalent to 16.2-17.01% in mono- and polycrystalline modules.

The Power Gain Factor is determined by the following

1. Better response to UV and infrared light (spectral response); good for cloudy areas and sunny areas
2. More heat-resistant (δ=-0.23%/oC of HULKet's product which is the lowest record of global commercial solar modules, certified by TÜV Rheinland); good for hotter areas
3. Better response to light with lower incident angle, scattered light and diffused light; good for early morning and before sunset
4. Positive light soaking effect (mono- and polycrystalline modules have negative light soaking effect); it might have 4-5% higher power generation than nameplate labelled.

CIGS has many competitive advantages compared to c-Si as follow:

1. Product reliability

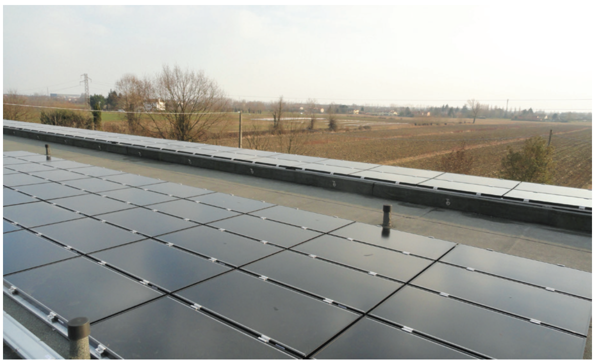
(1) No potential-induced degradation (PID-free); no power losses
(2) No light-induced degradation (LID-free); no power losses
(3) Absence of hot spots; no danger of consequences of hot spots ranging from fires to accelerated aging of encapsulant set.
(4) No snail trail problem; against module failure
(5) Rare existence of solder joint (as compared with hundreds of solder joints for mono- and polycrystalline)
(6) No glint/glare problem
(7) Low shadow effect (which affects electricity yield); does not induce hot spot issue

2. A vision for green energy

(1) A pleasing look: deep black colour, blends in with the environment easily
(2) Saving more energy and generating less pollution: production process does not include silicon purification and wafer processing
(3) Shorter energy payback time
(4) Lower carbon footprint
(5) Less consumption of raw materials and more environmental friendly

IRR/payback time is an important indicator for most investors when it comes to investment in the power sector. With the same labelled power, and assuming that price per watt is the same, because of the higher Power Gain Factor of the CIGS solar panel, the payback time for power plants using HULKet technology will be greatly reduced and IRR will be raised significantly, especially for high-powered (>320Wp) CIGS solar modules where the balance of system is relatively lower.

All HULKet's products are based on a new green design that replaces cadmium-sulfide (CdS) with a zinc-sulfide (ZnSx) buffer layer. As a result, HULKet obtained TÜV RoHS (hazardous substance) certification to ensure that HULKet's products are without toxic cadmium and without toxic lead. For four years, HULK Energy Technology has been practising sustainable manufacturing and has become a green innovator in the clean energy industry.



WORLD'S Most Powerful Green CIGS Solar Module

HULKet

- World's Lowest Power Temperature Coefficient,
  δ = -0.23% / °C (TÜV RL Certified)
- Lead (Pb) free, Cadmium (Cd) free, RoHS compliant
- Royal BLACK color

BoS less

IRR up

LCOE down

Power Gain Factor higher
(Yield more)

310Wp~330Wp

Cigs-3000 Series

NO.309
Solar Power International
09/15~17, 2015

NO.E30
Solar Energy UK
10/13~15, 2015

NO.E2-062
PVCEC 2015 Beijing
10/13~15, 2015

Hulk Energy Technology Co., Ltd. www.hulket.com

Trackers

Another big development in the PV power plant space is the rapid recent adoption of trackers, and this looks set to gather further pace. According to analyst firm IHS, 2014 saw a 60% increase to 4GW in the global tracker market. This year and next IHS expects 6GW of trackers to be installed in the US alone, as that market gears up for the expected deployment rush ahead of the ITC step-down at the end of 2016.

One company hoping to benefit from this is Array Technologies, which came top of IHS' 2014 tracker suppliers. The company has just launched the third version of its DuraTrack HZ product and expects to triple output this year compared to last.

Ron Corio, Array's chief executive, ascribes growth in the market to a realisation of how trackers can address the increased price pressures in the PV market. "There was more room for people to avoid the technological risk of a tracker and still make money on a PPA but as PPA rates have come down and as technology has matured, people have gotten smarter about what the benefits are of a tracker," he says.

"I think people are realising trackers work, they make sense, it's a more efficient utilisation of everything and a lower LCOE. It took a little time to prove the technology and have it follow the cost dive of solar systems in general."

Corio sees trackers as having a big future even in "marginal irradiance areas" because the incremental cost of installing a tracker he says is not that great in proportion to the benefits. "That's not just in terms of pure power production but the next step is the profile of that power production, the flatness of the power curve," he explains. "Peaking output at noon is ok but having a flatter output from morning to evening is much more desirable and most of the time that output is flatter and wider in the summer which is when [off-takers] really want to have that power."

Credit: Array Technologies

The next generation of trackers, such as Array Technologies' v3 DuraTrack, offer better performance for only marginally higher cost.

Mounting

Mounting – or racking – is probably one of the less discussed aspects of PV power plant design, but even here there is room for innovation. John Klinkman, vice president of engineering at US-based supplier, Applied Energy Technologies, says that although mounting manufacturers have driven out cost "dramatically" in recent years to around US$0.10-0.15 per Watt, the aim of driving those figures down further is a daily concern.

Klinkman says one consequence of this has been a return to standardisation in the design and manufacture of mounting products. When the industry was still young, Klinkman says few specialist racking suppliers existed. "Racking for solar was sort of taking those off-the-shelf products that maybe existed for construction or building," he says. "We then saw a lot of companies enter the market with custom shapes, adding a lot of features to try to help save installation costs or to set themselves apart. And we still have some of that, but we're also seeing a return to a lot of the common standard sections again. And cost is the driver for that."

Belectric's Bott echoes this, revealing that substructure design is the "next major step forwards" for Belectric. "Once you've standardised your block you then need to simplify the amount of fixed steel in the design," he explains.

Without divulging much detail, Bott says Belectric is developing what it calls the peg system, which he says will reduce the substructure costs by a "significant amount". "We are testing that and hoping to take some significant steps forward," Bott says.

Credit: Applied energy technologies

Racking is one area where Belectric's Duncan Bott sees further room for improvement.

The wild card

Many of the technological developments outlined above will, as Campbell puts it, offer incremental improvements to the performance and costs of future PV power plants. However, the Agora Energiewende/Fraunhofer study cited at the start does leave the door open to a future breakthrough in costs that could herald a much higher level of deployment.

As things stand, the consensus seems to be that disruption of this nature is not yet in sight. The technology currently generating most buzz is perovksite, which offers potentially much higher photovoltaic conversion efficiencies than any of the incumbents. But at its current state of development, the best prospects for perovskite appear to be using it as a tandem technology with, say, CIGS or CdTe technology, to boost their performance.

Nevertheless, in the context of what some projections have indicated PV is capable of achieving as a player in the global energy market, there is clearly hope that some wild card technology is out there that could take the industry to the next level.

"If you look at the projections of where we could be in 2050, we may be 16% of global electricity," says First Solar's Morjaria. "That's a very small number, but even to reach that number we would have to install 150GW, which we have done to this date, every year. And that's a huge challenge in terms of scaling up the business. It can be done, but it's a huge scale-up. To get to that number we are just at the baby steps in this business."

Additional reporting by John Parnell and Mark Osborne. ■

Warranty claims management from an IE perspective

Warranties | PV module manufacturers, O&M companies, owners, insurance companies and financial stakeholders employ independent engineers (IEs) to conduct plant surveys at critical milestones, such as impending plant warranty expiration (e.g. EPC warranty), or on a periodic basis. The result of the plant survey is a status report that identifies improvement potential and, in the case of specific failures or failure indicators, their corresponding root causes. Mitigating actions are mediated by the IE with all the involved stakeholders. Bill Shisler and Matthias Heinze of TUV Rheinland describe a procedure and a sample case for identifying and investigating the performance and possible safety shortcomings of PV modules, triggered by an impending asset sale

Warranties and insurance policies provide cover for various aspects of a PV system's components and life cycle. Warranties must be managed to ensure that plants are built with the specified performance and that production targets are met during operation, as well as to ensure that the system is safe under normal operation. A PV power plant consists of many elements and components, and while all contribute to production, their relative importance varies. Inverter and module warranties are the most critical, with terms ranging from 7 to 10 years for inverters, and from 20 to 25 years for modules (typical). Although inverters have shorter warranties, they often have self-reporting features that enable the operator to apply specific scheduled and unscheduled maintenance procedures. PV module power, on the other hand, generally has initial out-of-the box degradation, then begins a slower, less noticeable, descent from the moment of installation until the end of system life. Dramatic failures of PV modules are typically found during installation, but material degradation can become a reliability issue over time.

Warranty terms set the trigger mechanism, i.e. when the warranty is invoked. Thus a proper warranty contract is essential in asserting the asset value and risk. In addition to covering manufacturer defects that result in total loss of performance or in safety issues, it is essential that warranties and insurance policies be analysed for early detection of 'degradation beyond specification' resolution. PV module warranties often fall into two categories – workmanship and performance. Workmanship includes such aspects as modules being clear of defects and material issues resulting from manufacturing mistakes, material wear-out, or glass cracks not resulting from impact within typically 5 or 10 years. Power output guarantees are often listed as 90% power at 10 years or 80% power at 25 years from the date of purchase – each based on the lower tolerance limits of the module's rated nameplate power, or on more-specific terms of the contract. In the example project discussed in this paper, the guarantees given for the PV modules were five years for materials and workmanship, 90% power at 10 years and 80% power at 25 years.

"A proper warranty contract is essential in asserting the asset value and risk"

A warranty assessment model was developed by TUV Rheinland, on the basis of research performed at Arizona State University, and modified for practical use on large-scale utility-grade power plants [1]. The plant in the example project was commissioned 5 years ago. It had not been certified by an accredited IE, and DC-side health had not been properly established

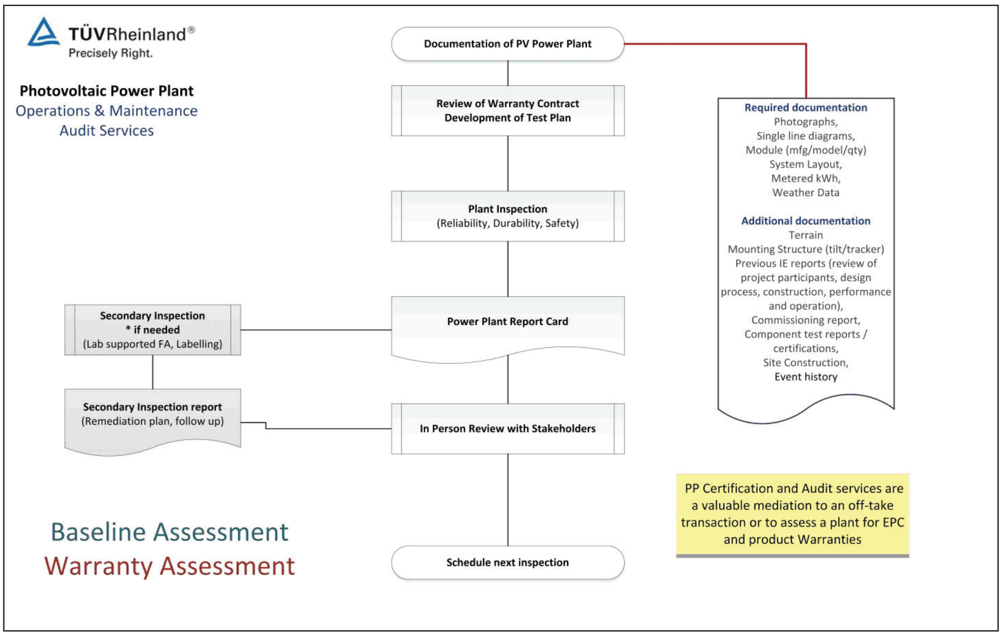


Figure 1. Baseline assessment and review of existing documentation.

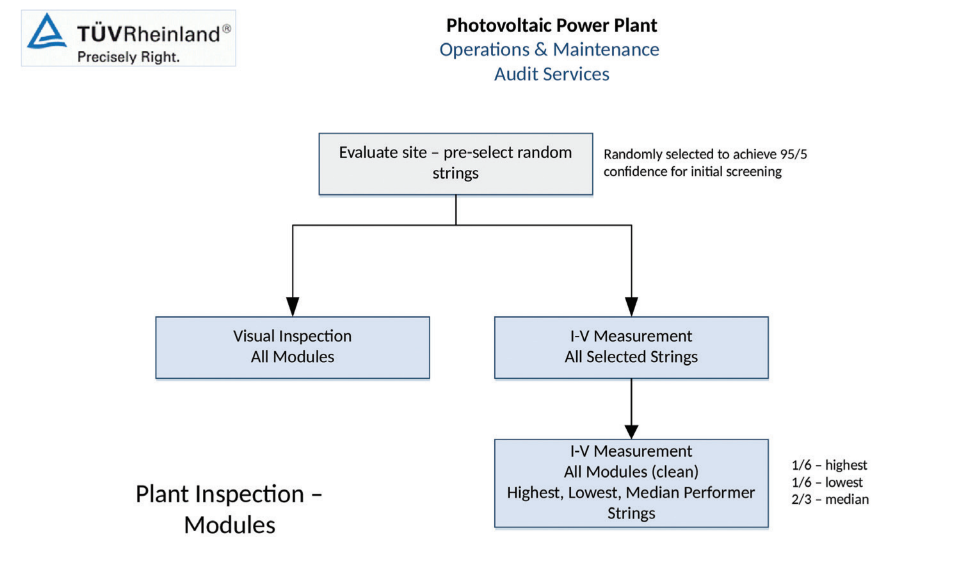


Figure 2. Screening evaluation for warranty claims.

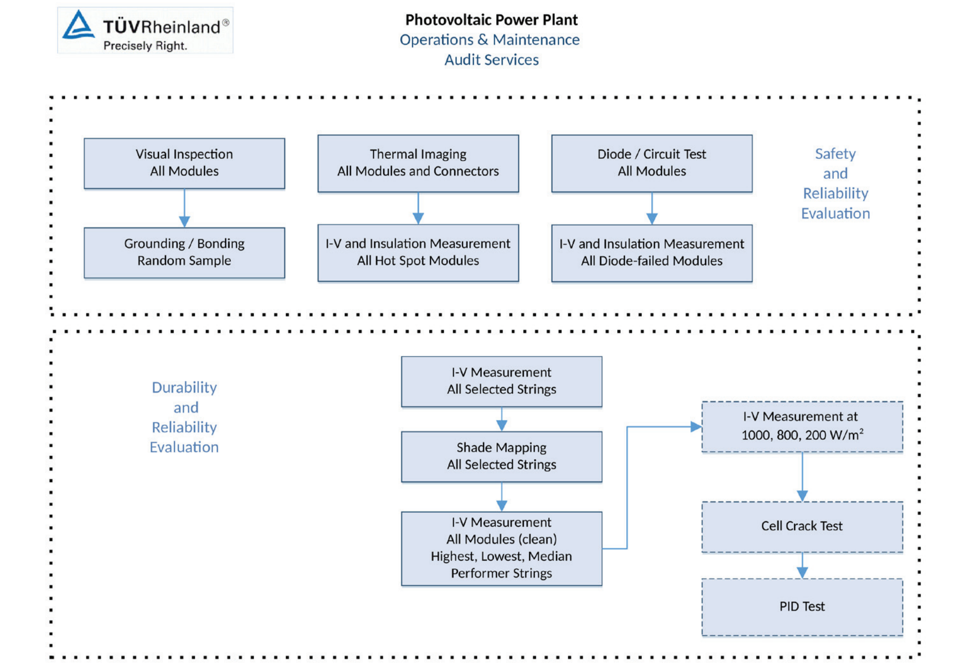


Figure 3. Detailed chart of the resulting audit.

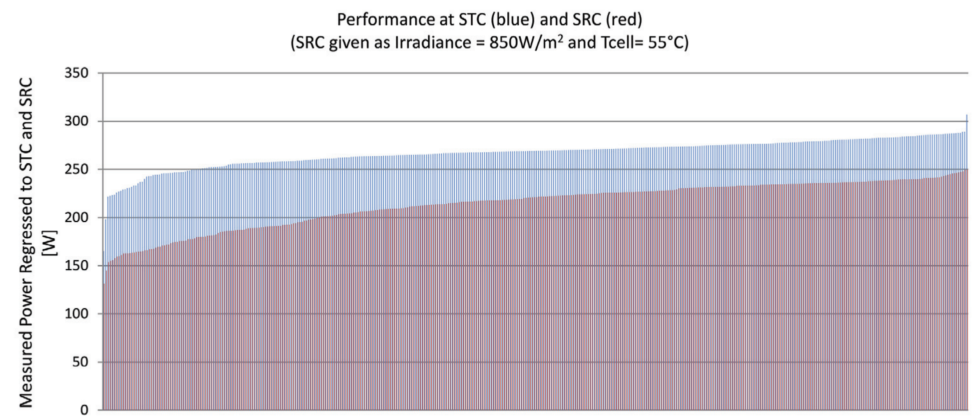


Figure 4. Translation of SRC into STC.

at Year 0 or Year 1, so a baseline assessment and review of the existing documentation had to be conducted (see Fig. 1).

Plant production guarantees are associated with utility metered AC performance. For older systems, monitoring systems do not always include the monitoring of detailed DC performance. Even if historical DC data were available, these would still only represent one-third of the relevant information necessary for determining PV module health with respect to warranty – the other information would have to be obtained through physical inspection (visual and infrared) and selective *I–V* curve traces.

In this example, a 95% statistical confidence level is utilised for performance, and a visual inspection was performed at a 100% level – even if this meant a large initial effort for the plant (see Fig. 2). Note that one-sixth of the modules must come from PV strings in the bottom one-sixth of distribution, one-sixth of the modules must come from strings in the top one-sixth of distribution, and two-thirds of the modules must come from strings in the middle two-thirds of distribution.

> "The temperature coefficients of modules change over time, which means that they must be re-evaluated periodically"

A detailed chart of the resulting audit is given in Fig. 3.

When complete original DC-side health data is not available, assumptions must be made in favour of the module supplier in terms of original performance versus current performance (i.e. degradation rate). The lower tolerance limit of the nameplate, along with the negative side measurement tolerance from the IE, was assumed at the plant's commissioning. For the sake of convenience, a 100W ±5% nominally rated module is used as the example:

100W nominal
– 5% (nameplate lower limit)
– 2.5% (measurement tolerance)
= 92.5W assumed baseline power

Although PV modules typically do not operate anywhere near the standard test condition (STC) of 25°C cell temperature when the solar irradiance is 1,000W/m², as identified on the product nameplate and datasheet, the performance guarantees are nevertheless associated with these values. This means that IEs might choose to remove several modules from the field and send them back to the lab, or use an expensive flash tester on site. Each of these options has its own issues: flashers do not present the true solar spectrum and operating condition of the modules, and shipping presents a risk of breakage. Neither of these options is necessary, however, if proper control and high-precision instruments are used for taking measurements of the PV modules – even when the modules are still operating on the mounting racks or trackers.

An assessment of the actual operating DC power of the PV modules is essential in order to understand the performance over time on the basis of site conditions, and ASTM E 2939 methods provide guidance on determining the expected capacity of a site in terms of reporting conditions (RC). Reporting conditions for a site are dictated by the local geographical environment, and consist of total global irradiance, ambient temperature and wind speeds at the site.

TUV Rheinland has taken the same approach for the characterisation of PV modules, the major difference being that the site reporting conditions (SRC) use module cell temperature instead of local ambient air temperature. The SRC can then also easily be translated into STC for comparison with the nameplate ratings (see Fig. 4), and is a useful tool for understanding the degradation of the modules as they age in actual operation.

The temperature coefficients of modules change over time, which means that they must be re-evaluated periodically in order to properly regress the sample population to the STC warranty rating. In this case a limited set of modules across the sample distribution must be evaluated for coefficients, so that the new values can be applied in the assessment. A few modules were therefore removed and taken back to the lab in order to work out the proper temperature coefficients, though far fewer modules are needed for this than for performance measurement. (It is understood that some technologies have seasonal behaviour, so it is important to schedule the periodic assessments at the same time of year for a given power plant.)

PV modules are also sensitive to the

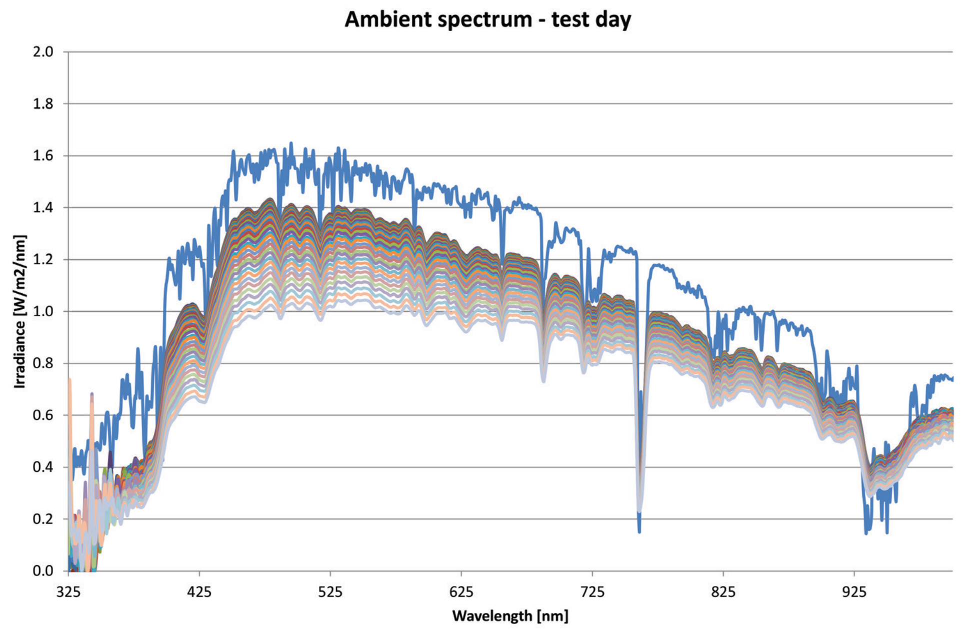


Figure 5. Measured spectrum vs. the spectrum in the ASTM standard.

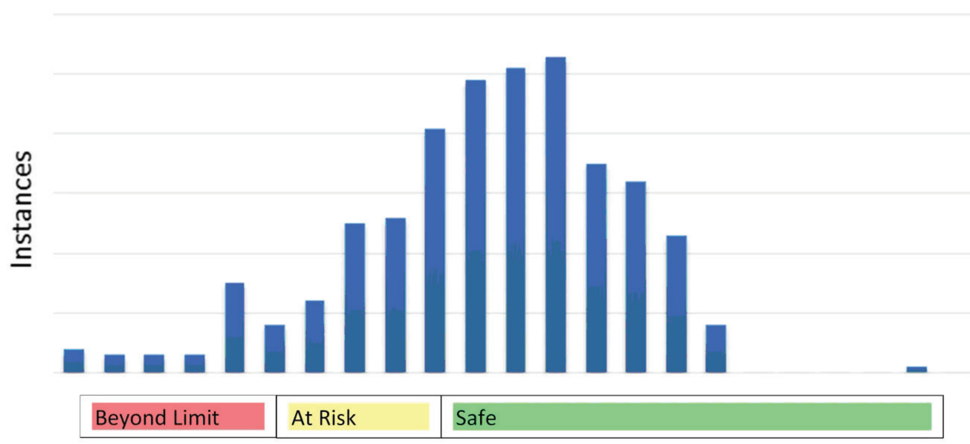


Figure 6. Deviation from the nameplate lower limit after five years of operation.

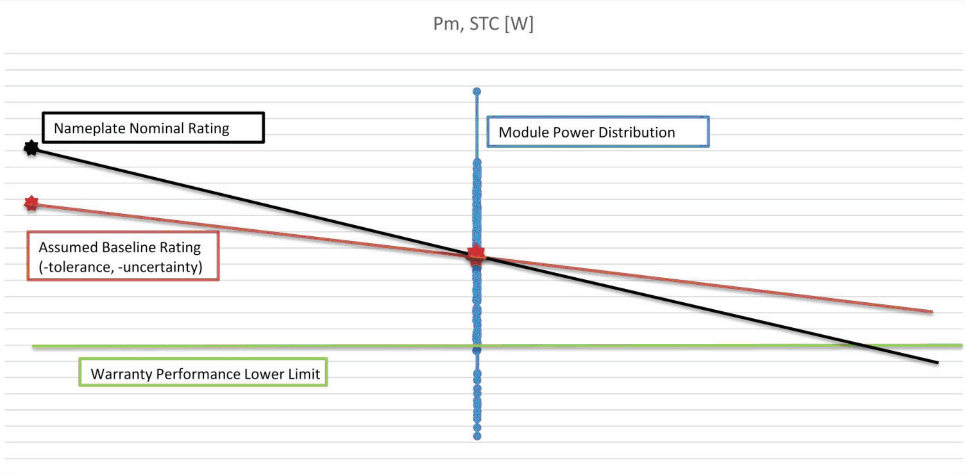


Figure 7. The challenge to commonly held assumptions.

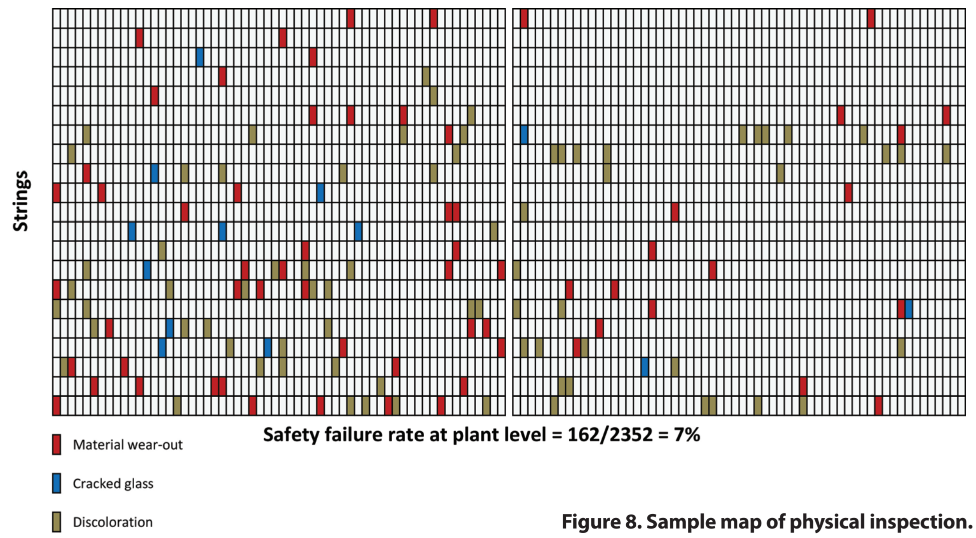


Figure 8. Sample map of physical inspection.

solar spectrum. Fig. 5 shows the measured spectrum versus the spectrum described in the ASTM standard. The coloured lines represent measurements at different times of the test day. Because it was a clear sky day – verified through spectral measurement – the amplitude of the current could be corrected by means of the corrected irradiance via a direct relationship.

Measurements in this example were taken and regressed to STC. All tolerances were calculated in the manufacturer's favour. A summary of the result (corrected to STC and taking into consideration all measurement tolerances) is given in Fig. 6.

The measurements conducted in the field and in the laboratory resulted in a linear regression of degradation that fell outside the extrapolated tolerance limit. The paradox here is that initial measurements (at commissioning) would have shown higher than planned production on the DC side, as opposed to the assumed lower limits. The inverters also clipped at the upper performance end (the AC performance would therefore remain stable for several years, even as the modules continually degrade).

Fig. 7 illustrates the challenge to commonly held assumptions. Whereas the red line shows the expected degradation at the lower limit as specified, and the green line shows the absolute design life limit, the black line represents a linear regression without warranty remediation. The difference is the understanding of when the modules are projected to fall below the warranty limit. The actual projection might be at a higher negative slope than the assumed rate. And even more likely, the module degradation during the first year was probably higher and has levelled off since. With two or three data points by this time (at commissioning, at the 1-year anniversary and after 5 years) the owner of the power plant can properly evaluate the DC health, better employ O&M and prepare for contingencies with the supplier.

Power output guarantees represent one-half of the warranty assessment. The safety and reliability evaluation means that additional modules might be identified as 'critical' candidates for warranty replacement. The overlapping of those modules identified as critical during inspection and measurement means that the total is not simply the sum of the two processes, although the two issues are compounded. The sample map of physical inspection is presented in Fig. 8; the different colours here represent different criticalities of defect.

In the example project, the nominal loss as a result of module degradation and safety/inspection failures amounted to more than 5% of production as of the day of measurement. The cumulative loss without correction (i.e. warranty invoked) for a plant of more than 40MW could be in double digits of millions of US$ over the plant life.

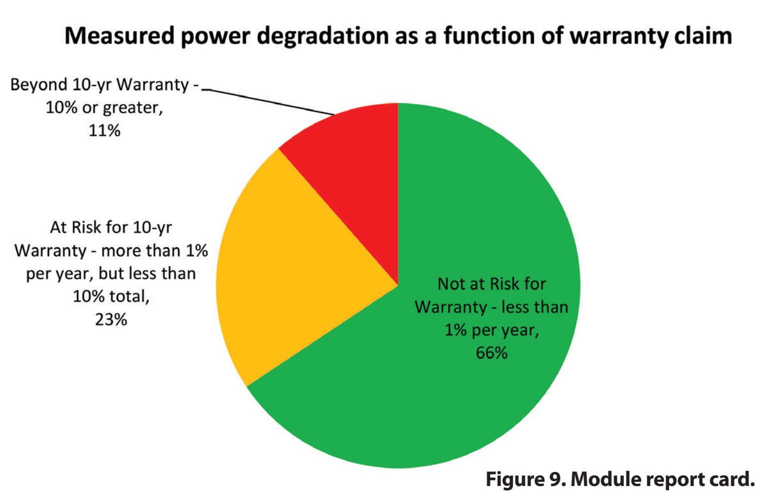


Figure 9. Module report card.

Summary

The determination of root cause required careful statistical analysis and then a combination of in-lab and on-site experiments by the global science team. The result for the plant owner is the recovery of long-term performance by having the IE mediating the warranty terms and module issues with the EPC and manufacturer. One would also surmise that better due diligence would have detected any issues much earlier. It is advisable that O&M utilise qualified IE audits at key milestones, to ensure forward-looking asset performance. Related to the root cause analysis for this sample project, specific detection procedures were designed and recommendations given for preventing recurrence in future plants.

Authors

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Innovative PPAs: Small print, big impact

New solar finance | Innovation in the solar industry is not limited to labs and fabs, with some creative financial engineering increasingly proving its worth. John Parnell looks at how power purchase agreement innovation can bridge the gap between cost-competitive and 'nearly' cost-competitive solar

In the dizzying world of finance, power contracting and project investment, words like 'nearly', 'almost' and 'roughly' are unlikely to make the final cut of any contract. Nor do they make a convincing pitch. So with solar 'nearly' cost competitive in almost all the most advanced markets, how can an end customer be utterly convinced they'll pay roughly less than their current arrangement?

This is the challenge thrown up for solar in a variety of scenarios, in the absence of a major utility willing to lock in a price for 25 years, where local spot market offers the chance to exploit any volatility in energy pricing and potential financiers are looking for something with more security.

Changing the rules with new contracts can bring more potential investors as well as more potential off-takers. So what are the options? One route is what is often referred to as a synthetic PPA.

A common element is an agreed threshold price or price range for electricity from the project. If the market price drops below this level, the buyer's missed savings are returned, if the market price is over this level, the seller is compensated for what they could have sold the power for on the open market.

Ray Hudson, global solar service leader at DNV GL, says a better definition comes through what a synthetic PPA is trying to achieve rather that any given aspect of its mechanics.

"There isn't a standard definition of what a synthetic PPA is. On the highest level it's an attempt through contract language and using financial engineering to create a more financially stable situation where the power is being sold on the market a merchant way and to make that more attractive to the financiers," Hudson says.

The US has not had the same price guarantees and top-up tariffs that Europe and other markets have enjoyed; stability has to come from other sources. Hudson points to the very different market dynamics as another reason why PPA innovation has typically started in the States.

"Here in the US market it's been [dominated by] very firm PPA contracts. Typically that was with a utility so that's a very bankable, very creditworthy off-taker for the energy. That's a really solid contract. At the far extreme you have projects selling just at the merchant spot price, in the places where there is a spot market, and that has a lot of price volatility. A synthetic PPA is to try to go between the two extremes, between a fully defined PPA and the pure merchant market," explains Hudson.

Just a few short years ago, cost-competitive solar felt like a long way off but the closing of that gap has also brought the two extremes described by Hudson closer together. It is largely for that reason that the synthetic PPA has become a more important tool for those on either end of the contract.

"I think what is really important in the overall context of this is that the cost of solar-generated electricity has dropped so much that you can really talk about solar being competitive on the merchant market. A few years ago that wasn't the case and now that it is competitive in many areas, and almost competitive in others, these additional assurances that are in the contract language help a broader range of entities that are providing financing to come in," explains Hudson.

"It allows entities with different appetites for risk to participate in the solar industry and help with the financing of solar projects.

The growth of synthetic PPAs in solar is a sign of the industry's maturity, according to DNG GL's Ray Hudson.
Credit: DNV GL

It's interesting that the financiers of solar have a wide range of risk appetite. Some are very comfortable with high risk and are looking for appropriately high returns. Some really want low risk. And again, this too allows different entities to come in – non-traditional financial institutions, not just banks but also insurance companies, hedge funds and other kinds of investors. It also lets in individual load users who are interested in purchasing solar energy. This mechanism can help them be comfortable with the price they are paying for the solar energy."

Even with state-wide renewable portfolio standard (RPS) obligations on the wane, demand is still growing. Demand from new corporate players beyond the utilities that were subject to those requirements is also growing.

The Environmental Protection Agency's Green Power Partnership, which monitors how much power firms source from renewable generation, includes Intel, Unilever, Wal-Mart, Sprint and Lockheed Martin to name a few. Anyone doubting the appetite of large corporates for solar energy in particular need only look at the US$850 million PPA Apple signed with First Solar in February. Or the 180MW healthcare firm Kaiser Permanente signed in the same month.

Bringing in corporate interest also opens the door to firms looking to exploit on-site renewables but Hudson says but capturing the additional benefits of those installs would help further.

Utilities are by no means done with solar, however. Even beyond the investment tax credit cut in the US, there is a future for solar demand from the big power firms, as long as one criterion can be met.

"The utilities don't just have to pay a relatively high PPA as part of firm contracts to make their RPS obligations," Hudson says. "We're right on the cusp of the cost of solar being competitive for generation and the utilities being interested in having additional renewable generation for economic reasons, not just for 'green' reasons or the RPS requirements. Now we are moving down the [cost] curve where we are getting into generation parity and at that point you are competing fully against other generation sources."

Lack of standardisation

Roll together the increase in distributed generation projects, synthetic PPAs and projects forming part of bundles securitising bonds and it could appear that the paperwork per megawatt is only increasing.

"Just like the engineering of solar plants can be complicated the legal and financial engineering that is going into these agreements is also, frankly, quite complicated – sophisticated might be the word!" says Hudson.

This sophistication could mean that emerging markets with tighter margins might not be able to make the best use of synthetic PPAs just yet but Hudson sees scope for that to change.

"I think you'll see it first in the places in the world where there are already lots of lawyers like the US and I think the details will be worked out in ways that it can be articulated and then spread out to other places in the world. We're seeing some of the other things happening elsewhere in the world like securitisations, like yieldcos that have really followed what happened in the US. I think the same thing will happen here," he predicts. "The challenge right now is that these contracts are new and not very standard, so you end up with more legal work, reviews and frankly expenses to do these. So these are not simple contracts and you do have to have an investment in the legal and financial review. We do think that over time they will become much more standardised."

> "I think you'll see it first in the places in the world where there are already lots of lawyers like the US"

There is, of course, more than one way to skin a cat. Don Lord is CEO of UK Sustainable Energy (UK-SE), which helps industrial and commercial clients fit renewable energy and efficiency measures into their business. It built what it describes as the UK's largest "zero cost" solar farm for telecoms giant BT.

BT takes 8MW of power from the site with a simple contractual clause that ensures all parties are happy with the PPA.

"We say to all our clients, and we're doing an awful lot of these with very big energy users across the UK, have a 60-day termination clause," says Lord. "That way that enables us to fix a low cost of energy that is index linked and the client can just terminate if it feels it's necessary. That's the way they like it rather than having a complex hedge structure."

Lord stresses that a hedge structure is great in some situations but many corporate clients are looking for the simplest option.

"They know that this option is available but it is highly complex; people have enough complications between carbon accounting and price fluctuations so anything for an easy life. And it is not just an easy life, it also makes the best financial sense to be honest."

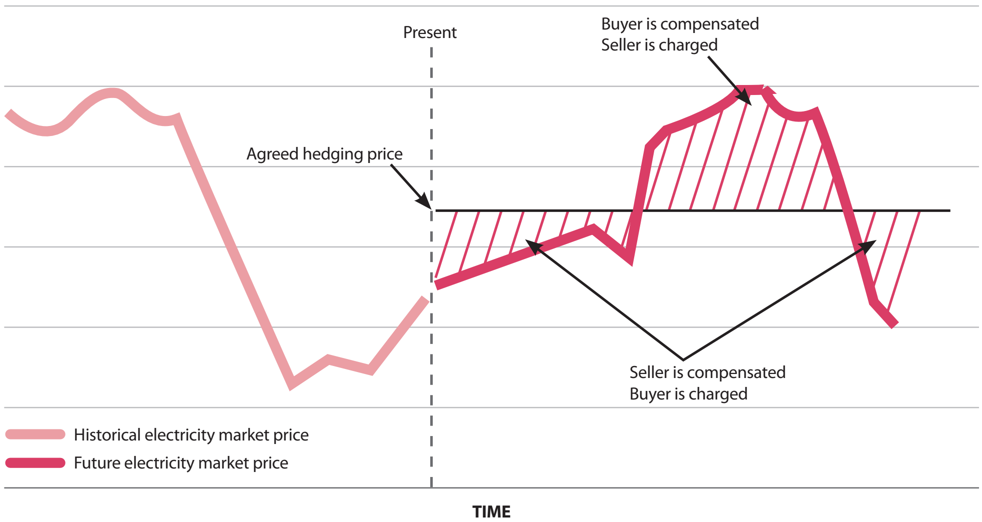
UK-SE funds its projects on the worst-case scenario that the client cancels. This means that, given that no-one has cancelled at the time of writing, the company receives a bonus from the PPA on top of what it modelled with its backers. On the client-side, they are safe in the knowledge that they can exploit any dramatic downward shift in the market price of power by invoking their 60-day termination.

Lord says the company has a healthy 300MW pipeline of safe bets and much bigger pipeline in earlier stages of progression. While they are focusing on the UK for the moment Lord acknowledges that there are plenty of places with high, volatile power pricing where the comfort of the 60-day cancellation could appeal.

The fact that the solar industry is able to find multiple solutions to its problems and continue to bring new sources of demand and fresh investment into the sector is worth celebrating. Hudson points to the solar market in Texas and California where some of the most sophisticated contracting work is at play. It's no coincidence that these are also two markets where solar is highly competitive.

"I think this is just one of the mechanisms that is helping with the competitiveness of solar. I think the industry could certainly do a better job of talking about the advances it has made," Hudson says. "This type of structure and dealing with these sorts of issues is not new to the finance and legal industry. Bringing it to solar shows that the industry is maturing, certainly it has matured technically and economically. It has improved and it's getting into these really competitive situations and that's what I find really exciting."

Use of index in hedging



A PPA hedge guarantees the buyer does not pay over the odds should the market price rise, while the seller is protected by a floor price should the going rate drop below the contracted price.

Motivation for single axis solar trackers versus fixed tilt

Trackers | The economic argument for trackers is increasingly compelling. Matt Kisber, president and CEO of Silicon Ranch Corporation explains why the technology's use is increasing and examines the benefits of opting for single axis tracking systems

Tracker technologies in photovoltaic solar power plants have been increasingly utilised as plant owners strive to reduce the cost and produce more energy per unit area by tracking the sun throughout the day shown in Figure 1. Although single-axis tracker technologies can provide up to 10-24% more power compared to fixed tilt systems, a tracker design may not always make financial sense to use [1]. In regions where there is high Global Horizontal Irradiance (GHI) and relatively low Diffuse Component (DHI), the increased energy output from a single-axis tracker typically compensate for the additional material and O&M costs.

Global Horizontal Irradiance (GHI), measured in Wh/m2 is the sum of direct and diffuse solar radiation. Direct Normal Irradiation (DNI) is the amount of sunlight received directly from the sun, and Diffuse Horizontal Irradiance (DHI) radiation is the sunlight that is reflected and transmitted at an angle through the Earth's atmosphere. Areas with high GHI and relatively low DHI tend to be the best locations for single-axis trackers due to little to no weather interruption.

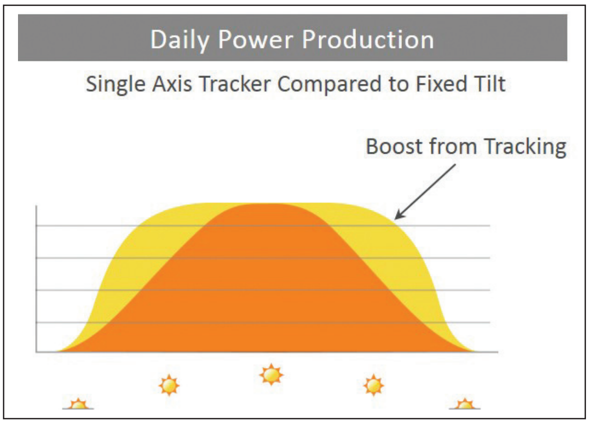


Figure 1. Additional energy output from tracking systems.

As shown in Figure 2, the annual GHI values for the desert in the Southwestern United States are on the order of 2100-2200 kWh/m^2. In comparison, annual GHI values for a Germany/UK region has GHI values on the order of 1100-1300 kWh/m^2. GHI and especially DNI are important metrics when considering a mounting system, as the energy gain from the tracker has to compensate for the increased system costs relative to a fixed tilt system.

Brief history

Historically, prior to the dramatic cost reduction of PV modules over the past five years, both single and dual axis trackers were installed in PV sites. Dual axis trackers were used at great expense to extract every last kWh from a PV module by rotating in

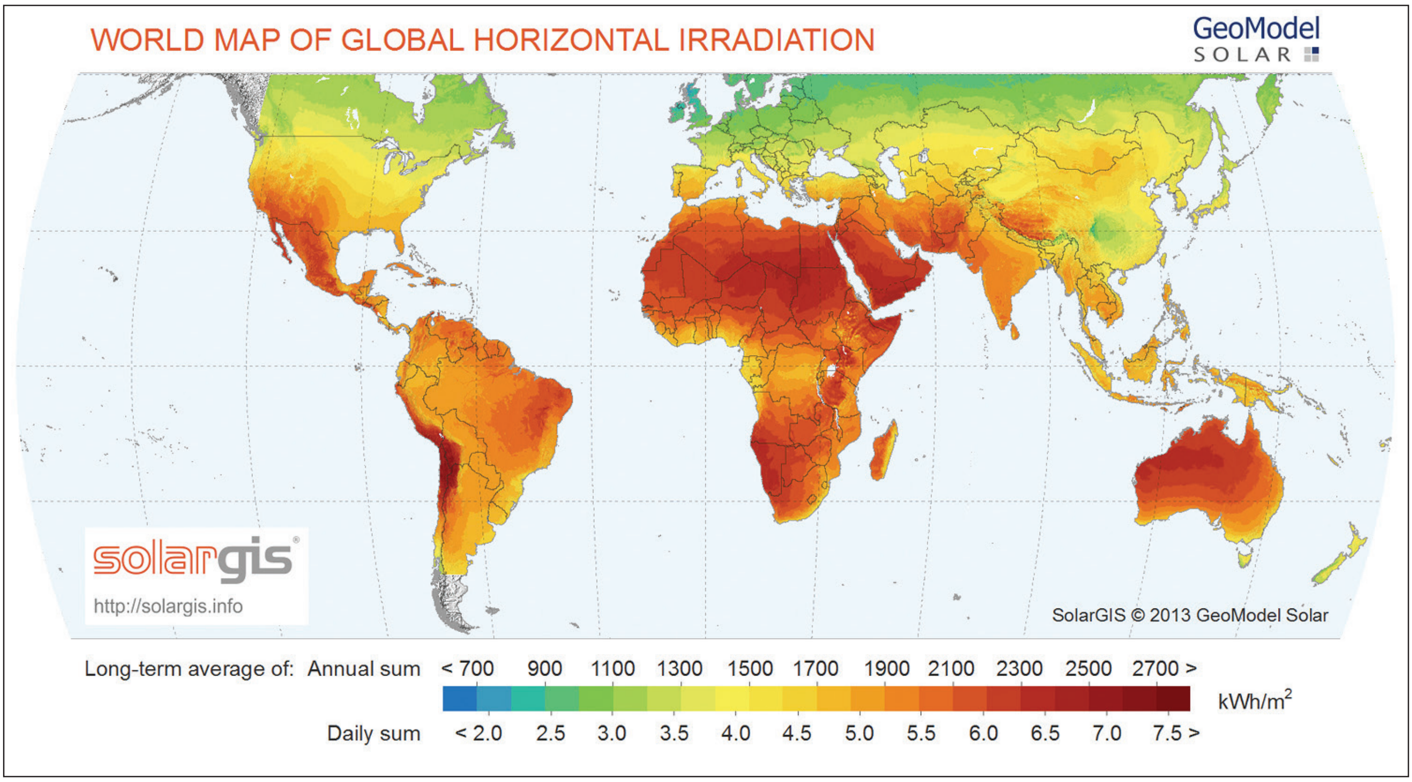
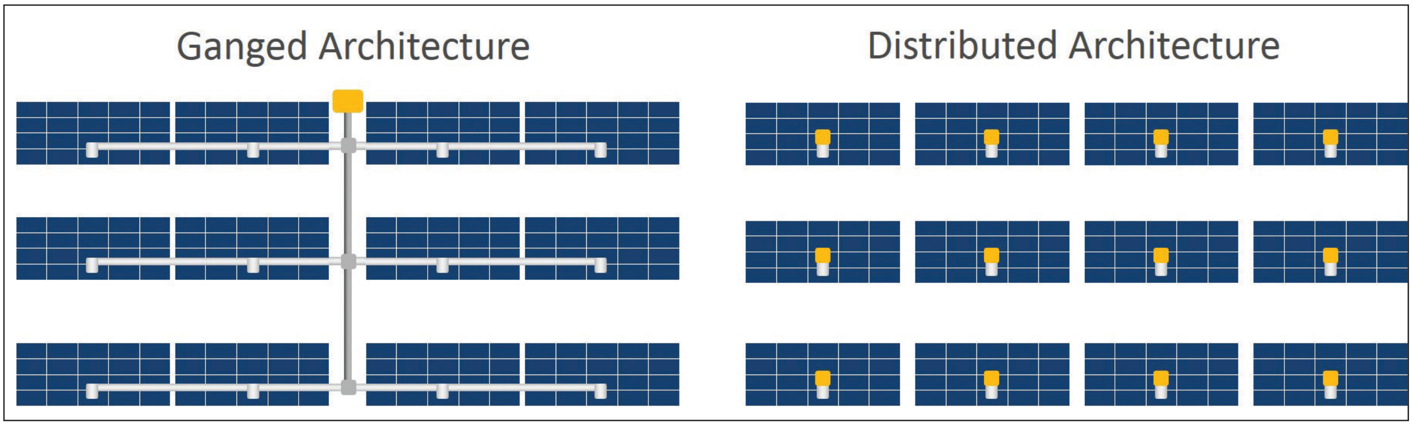


Figure 2. Global Horizontal Irradiation. Credit: SolarGIS© 2015 GeoModel Solar.



two degrees of freedom that are typically orthogonal to each other. Single axis trackers rotate around a horizontal (or close to horizontal) axis and track from east to west during the day. Unless trackers are located close to the equator, they don't point the module directly at the sun like a dual axis tracker, but they do track far closer to orthogonal compared to a fixed tilt system. Dual axis trackers have higher energy output per installed watt (kWh/kW) compared to single axis trackers, but require much more land, are more prone to mechanical failures, require higher than normal routine maintenance and have significantly higher capital costs. Due to the disadvantages regarding reliability, bankability and ease of installation, the vast majority of utility-scale tracker systems have migrated to single axis trackers.

Single axis tracker architectures

Single axis tracker systems can be categorised into either ganged or distributed architectures, shown in Figure 3. Both architectures rotate the modules using controllers and motors, but fundamentally differ by how many modules are controlled by each motor.

Trackers with ganged architectures are systems that primarily use a single motor (depicted in yellow) to drive multiple rows of modules. Typically, a single motor in a ganged system can drive more than twenty rows in common systems.

Conversely, a distributed architecture system contains one or more motor/actuator assembly per row. Essentially, it's a trade-off between extra mechanical components of a ganged system (e.g. drive shafts, gearboxes, universal joints) and extra electrical components of a distributed system (e.g. actuators, wiring). The primary differences in these designs impact site layout, installation processes and O&M costs.

Site layout

To date, the majority of the utility-scale PV plants in the US have enjoyed level and open terrain, allowing for relatively less-flexible array designs (i.e. large rectangular arrays). There is a clear trend toward smaller, more-irregular sites that require more complex array designs. Sites with irregular shapes and/or sloped grounds can lead to design challenges that should be taken into consideration before committing to a tracker technology. Distributed architecture systems allow for a minimum space requirement of a single tracker unit, which can be as small as 480ft^2. By contrast, ganged systems may require minimum rectangular areas of up to an acre or more.

Different wiring permutations are available with small tracker pixels which allow for layouts that maximise coverage of imperfect sites, shown in Figure 5. Additionally, due to the small footprint of the distributed architecture, sites with slopes and/or rolling hills can utilise a tracker system. In contrast, ganged architectures have a large footprint, which require open topography for an efficient layout and may require more site grading and site prep costs.

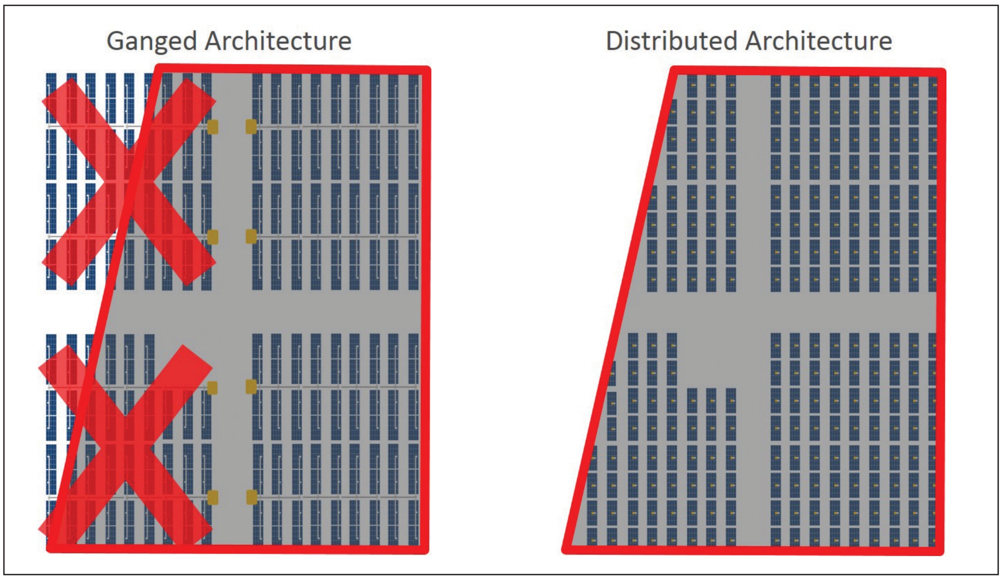
Figure 3. Tracker architectures.

Figure 4. Distributed architectures can maximise irregular site arrays.

Trenching for DC wire can be costly, and trenching is different based on site design and tracker topology [Figure 5]. In a typical large-scale tracker array the inverter is placed in the centre with the DC collection from the PV modules in trenches along the main East/West access road. In a distributed architecture these trenches also carry all the tracker control wiring to minimise cost. Depending on the configuration of a ganged architecture system, there may be a need for further trenching in a North/South direction to provide power to the large DC motors, shown in Figure 5.

AC/DC plant optimization

The distributed tracker approach provides more flexibility in design to find optimal DC/AC power ratios. The larger mechanically driven trackers see significant price increases if the tracker does not have the maximum number of tracker rows per drives. This happens because one of the larger cost components for mechanical trackers is the drive motors and controls. As a result, the cost per Wdc of a mechanical tracker increases significantly as rows are reduced. In contrast, the smaller sizes of



distributed trackers do not have this cost impact. The tracker cost per Wdc is consistent, regardless of the number of trackers. The distributed approach provides PV system designers the opportunity to search for the best DC capacity to match with any number of inverters without significant tracker cost impacts.

Optimising plant layouts and the DC/AC capacity ratios is one of the best opportunities for solar EPCs to bring additional value to customers. By manipulating the DC capacity, designers are able to find the best balance between capital investment and long-term plant performance.

Operation and maintenance

O&M costs are necessary to consider during design. Over the 25-30 year lifetime of a PV power plant, trackers will require repairs and maintenance. Common failure modes of tracker systems are motors, gearboxes, and controller electronics. Distributed architectures balance the higher volume of failures with the fact that each failure has less impact on the overall output of the plant and the fact that replacing parts is easier as they are generally smaller. There are essentially no "emergency" repairs, since a failure impacts so few modules. For ganged systems, a failure can result in full blocks ceasing to track, causing more impact to the output of the plant. Furthermore, overall O&M of a distributed system is made easier by the fact that there are no east-west drive shafts causing obstruction to travel through the site in a north-south direction. Complications like this can add significantly to down time and costs.

Since the widespread deployment of utility scale tracking systems has only happened in the last 3-5 years, O&M estimates and failure predictions were previously the single tools that tracker suppliers could use to determine what typical O&M costs and rates would be. Today, with several gigawatts of trackers installed in the US, suppliers can more accurately determine what costs are associated with O&M, shown in Figure 6. The amount of spare parts in inventory and number site attendants are now well defined to maintain a low O&M cost.

Efficiency during installation

With falling material costs, the cost of installation is becoming a larger fraction of the overall system cost. Installation of ganged and distributed architectures are notably different. Distributed architectures require more electrical labour due to additional actuators, controllers and wiring while ganged architectures have a more complicated mechanical arrangement which requires extra alignment and positioning.

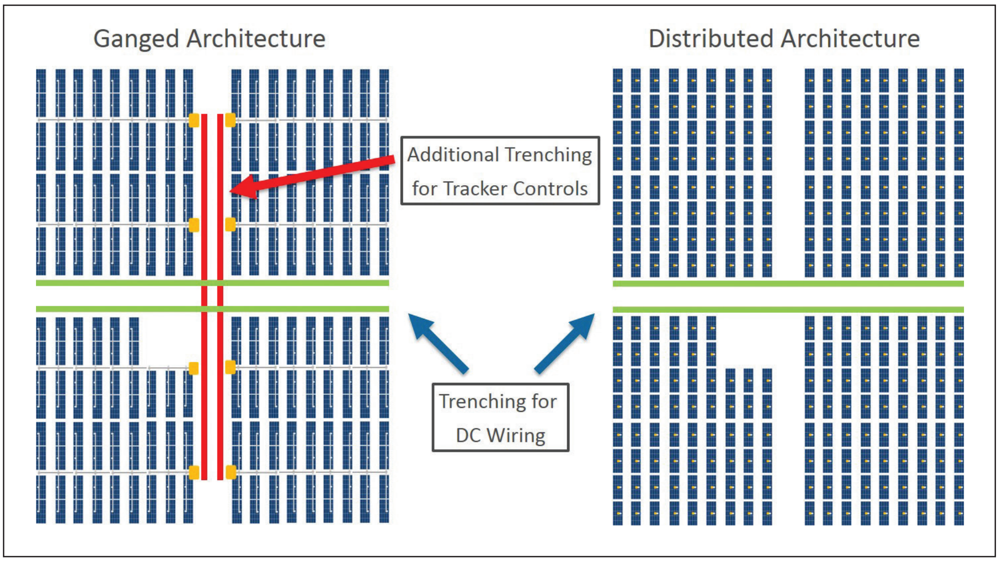


Figure 5. Trenching comparison for both tracker architecture blocks.

Design features such as open-top bearings to allow easy installation of torque tubes, pre-fabricated wiring harnesses and factory assembled components can realise substantial cost savings in the field. Simplified design of larger structural members like torque tubes enable supply chain efficiency by allowing shipment directly from steel mills without post processing.

New/future developments

As the US utility solar market continues to shift from fixed tilt to tracker based systems, improvements continue to be rolled out giving trackers a steeper cost reduction rate compared to fixed tilt systems. A number of new suppliers have gained traction in the past 12 months fueled by high demand as we approach the reduction of the federal solar investment tax credit (ITC) in 2017. Larger arrays are becoming more economical as inverter sizes are increasing, developments in tracker controller design have allowed for fewer controllers per array, and module efficiencies are rising.

Advances have continued in the calculation of wind forces on a tracker structure aided by more sophisticated wind tunnel studies. This new knowledge enables features such as wind stowing, a way of minimising the forces on structural members, giving more efficient use of material and lower costs.

Tracking algorithms continue to be optimised to extract more energy from ever improving modules. Examples include tailoring the movement of the tracker to suit the module technology (like "Backtracking" for C-Si and "Truetracking" for CdTe modules [2]), and creative ways to maximise the cleaning effect of rain by adjusting the tracker as weather systems pass by.

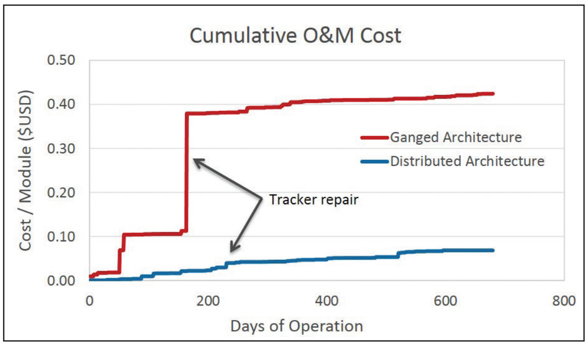


Figure 6. Example of ganged versus distributed O&M costs in desert south-west US.

In summary, tracking systems are in continuous development to reduce costs and enhance reliability. The systems are becoming more competitive in more locations and will continue to gain traction globally as new markets mature and get comfortable with the bankability of utility scale tracker-based solar PV plants.

Author

Matt Kisber is the President & CEO of Silicon Ranch Corporation, a developer, owner and operator of solar energy projects in the US. McCarthy Building Companies and First Solar contributed to this column.

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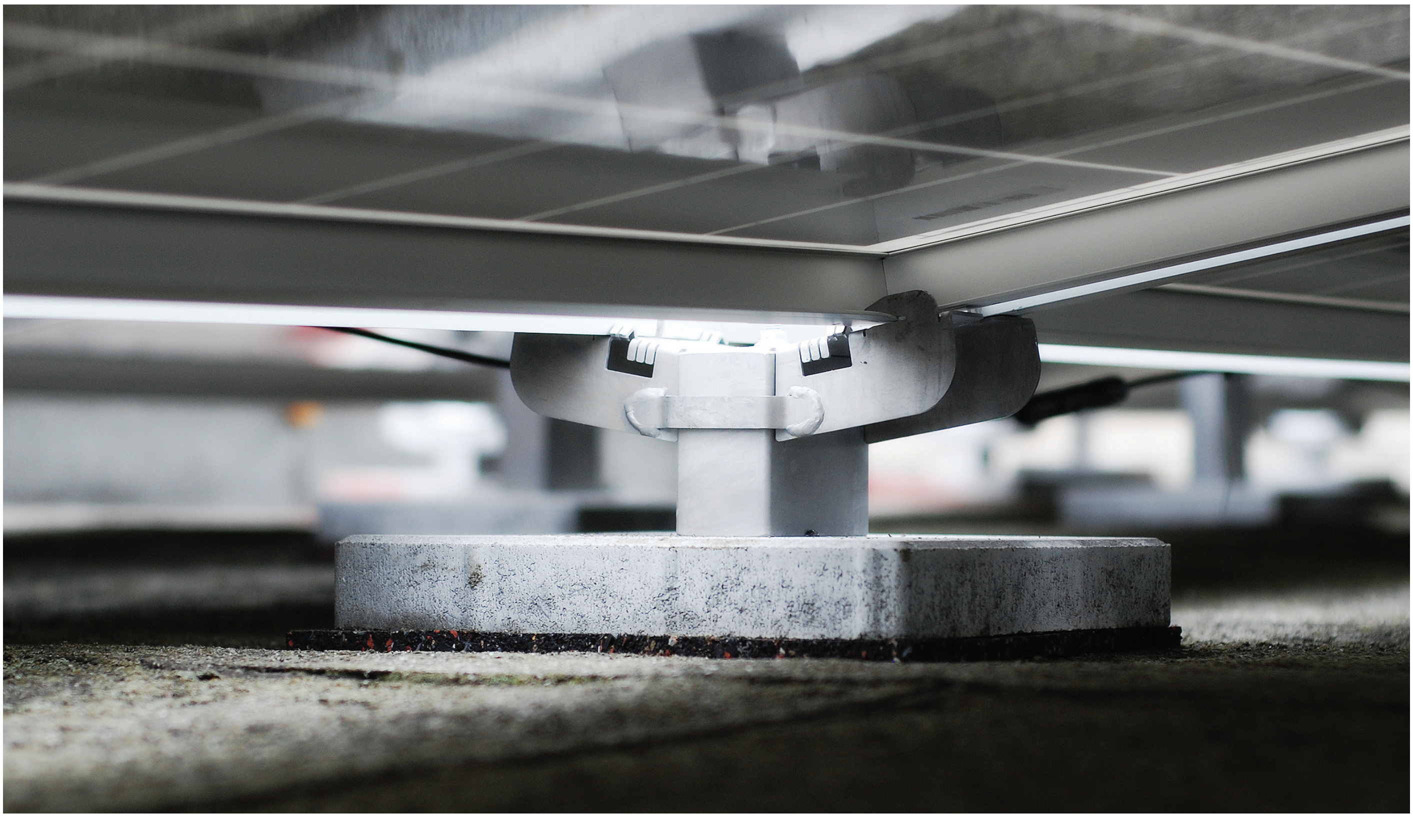
Top of the world

Commercial rooftops | Innovations in commercial rooftop PV mounting systems are offering new possibilities for installers as they seek to drive down costs. Andy Colthorpe looks at some of the key developments that are helping breathe life into a segment that has so far been slow to take off



Credit: Renusol

The global rooftop PV market, combining both residential and commercial applications, "has grown tremendously" in the five years between 2010 and this year, according to MJ Shiao, director of solar research at GTM Research. GTM's findings show the total rooftop market was about 1.4 times bigger in 2015 than it was in 2010, split fairly evenly, around 52% to 48% in favour of commercial systems. However, the past five years have also seen a decline in the share of the total PV market that rooftops enjoy, losing out to ground-mount in various incentive-driven markets, Shiao says. While hardly surprising for anyone following the past few years in PV, putting a figure on the fact that the share has slid by as much as 40% in that time from 70% of the market to just 30% puts that slide into sharp relief.

Banks are becoming more comfortable lending for large-scale solar and homeowners and tenants have a multitude of options open to them for financing rooftop arrays. For commercial rooftop arrays, however, the business case has been less clear cut, exacerbated by bureaucratic red tape, investment risk and other non-technical barriers such as long decision-making processes.

"In the US we look at the commercial space with a little bit of disappointment because it's not growing nearly as quickly as the utility sector or residential," MJ Shiao says.

Tipping point

However, a tipping point may have been reached. In July, SolarCity launched an offering to enable small and medium-sized businesses (SMBs) to go solar.

"The vast majority of commercial buildings in the US house SMBs, so it's a very large underserved market for solar and the challenge has been financing and cost," the company's vice president of communications, Jonathan Bass, says.

Smaller companies lack the investment-grade credit ratings of bigger firms, or consumer credit risk scores that can be leveraged by households. To put it very simply, by taking advantage of changes in property regulations and structuring a commercial lease blended with a PPA, the company hopes to take this "underserved market" to new heights.

Reducing weight, installation time and cost have all been key objectives for commercial rooftop mounting suppliers.

Bass says SolarCity followed a strategy it always has in identifying a new market opportunity – as with residential and large commercial before it, the company waited until it could see an opportunity to undercut utility prices for customers. While the finance and regulatory aspects became favourable, however, it also necessitated serious cost reduction and innovation on the technical side to work, according to Bass.

Cost cutters and yield maximisers

In SolarCity's case, leveraging the know-how of Zep Solar, a US mounting systems maker it acquired in 2014, gave it the final

Credit: SolarCity

SolarCity's mounting subsidiary Zep Solar has helped the US installer gain a foothold in the commercial segment.

push it needed on cost to make the SMB commercial solar proposition attractive.

"Zep Solar have been working on their commercial solution for some time, they had not rolled it out when we acquired them," Bass says. "Now we're able to bid the vast majority of our commercial projects with their flat roof solution, ZS Peak."

ZS Peak incorporates the Zep Groove, the proprietary technology that put Zep Solar on the residential PV map. Adding a standardised groove to the mounting structure allows the installer to snap the module into the frame with relative ease. The groove also allows for easy grounding and can carry wires and other components.

The other key selling point of ZS Peak is the east-west orientation that it is designed for. Commercial rooftop solar is often about maximising the onsite self-consumption of the yield from PV. This is especially the case in Europe's challenging market. When the FiT is the main driver for PV, users simply want to generate as many kilowatts as possible – hence a south-facing orientation works best. However with commercial installations in the post-FiT era, especially in regions such as Germany that restrict how much can be exported to the grid, matching load to generation as closely as possible will get the best results in offsetting the cost of power.

"If you have a south-facing system, the efficiency is higher, because you direct the modules in the direction of the sun. So the overall gain for these systems is higher," Stefan Liedtke, head of German mounting systems manufacturer Renusol says.

"So you have a huge peak during lunchtime and a little bit more efficiency, but with east-west, you have a flat generation curve over the day. So if you want to use your own energy and you have machines that are running the whole day, it's better to have an east-west system."

Additionally, Liedtke says, when placing a system in the east-west orientation, more modules can be fitted to the roof, an assertion Zep Solar would appear to agree with, claiming that ZS Peak can put 20% to 50% more PV modules over a typical south-facing installation.

Optimum sizing

Renusol, acquired in 2014 by US commercial and utility-scale mounting system maker RBI Solar, has rolled out its own east-west commercial rooftop product, ZS10, to the UK market. Zep Solar too is preparing for a UK commercial rooftop rollout later this year.

Meanwhile, MJ Shiao of GTM Research says that more generally, sizing a system optimally is also an art that manufacturers and installers are learning more about.

"The marginal cost of installing solar has gotten to a point where it's economical. Adding another 50kW, another 100kW, is already going to be economical. So what you're trying to do is reduce some of the fixed costs: all the cost that goes into permitting – and this is especially true in the US – that goes into financing; all the transactional costs," Shiao says.

"If you can amortise those over a larger system, then you can reduce the resulting dollar-per-watt [cost] of the system significantly. You're paying a little bit more in hardware costs to generate the same amount of electricity but at the end of the day you will offset a bunch of fixed costs, transactional costs and you'll end up looking a lot better overall."

It's not just fitting more modules in a better layout, Shiao says. As well as being able to potentially use a smaller size inverter for a less 'peaky' output, there is the question of how much strain a rooftop PV system – and rooftop – can handle.

"Wind loads are the big thing that contributes to structural costs. Obviously you don't want the system to fly off the roof but you also don't want it to weigh too heavily so that the structure of the building can't support it. So having more elements to deflect the wind and also not let the wind underneath the panels and things like that could also lower the amount of materials that are needed."

Increased modularity of the system, being able to fit it to different roofs with different obstructions such as air vents without having to redesign the entire array, is another winning innovation, according to Shiao.

"When you get up there, you'd love for [a roof] to just be this flat, open space but in reality there's a lot of stuff that's up there in terms of roof obstructions, in terms of vents, things that basically you need to avoid as you're placing the system. [A] degree of modularity allows the installers and EPCs to not have to worry about things like cutting the rail to the exact length you need".

To rail or not to rail

In every PV industry segment, what works in one country might not work in another. Clenergy, a Sino-Australian company which specialises in mounting systems as well as branching out into power electronics and downstream project engineering, has experience of this first hand. The company has supplied mounting solutions to projects including a whopping 24MW rooftop installation in China's Hainan province, completed in 2013.

Thomas Gertsch, Clenergy's chief technical officer, says wind loads are also one of those key differences, along with the differences in type of roof structure.

"As an example, in Europe, where wind speeds only reach around 32 metres per second, aerodynamical ballasted systems are the way to go as it requires very low ballast and no penetration. In Australia, or Southeast Asia, with cyclonic wind speed up to 70 metres per second, ballasting is not an option and the design of the fixing and the capacity of the roof becomes key."

Indeed, just as Clenergy has adapted from the Chinese and Australian markets to go elsewhere, European and US rooftop commercial systems are increasingly being deployed, as with Renusol's FS10, without rails, using ballasts instead. As well as innovating towards success, the industry has had to learn from harsh previous experience.

"If you tell a roofer there is a flat roof and that you want to run a rail five metres long on it, he would say you are crazy! Because a roof is never flat, it's impossible. If nevertheless you put on a rail, it wears on the roof and it takes one, two, three years, and the roof is not watertight anymore," Renusol's Liedtke says. "Then there is thermal extension and contraction and these things [systems built on rails] are just crawling down the roof".

As well as these general rules, Gertsch of Clenergy adds: "Every roof is different and every mounting system has its own design rules. So all commercial roof projects have to be designed in close collaboration between the mounting system engineers and the developers."

Clenergy's modus operandi on commercial rooftops involves working "based on the most accurate site inspection [possible]", with the company helping installers with site inspection forms, calculations and other 'soft costs'.

Labour days

The final part of the puzzle is physically getting a system running on a roof. Every company will inevitably make claims on ease of installation or labour costs saved over competitors' offerings that are hard to verify and depend on a multitude of factors. Yet all the manufacturers *PV Tech Power* spoke to are in agreement that cutting installation time can lower costs dramatically. Bass says SolarCity recently completed a 300kW installation in two days, as opposed to the three weeks it would have taken, pre-ZS Peak. The ZS Peak system also has a handy 'snap-together' locking method for construction, which Zep Solar UK engineer Keith Harrison explains is what automatically grounds the system and makes it safe.

Clenergy's Thomas Gertsch says: "In countries where labour is expensive like Japan or Australia for example, pre assembly and innovative design are key to reducing the time installers spend on the roof."

Stefan Liedtke says that with Renusol's product 80 modules can be fitted onto one pallet for installers to carry, making their logistical task easier and trips up the roof less hazardous, while Renusol makes similar 'we're the fastest' claims on speed of installation to Zep Solar.

GTM's Shiao says that there will be limits to how far manufacturers can outcompete – once an installer has selected its supplier of choice, there is a certain amount of loyalty to a trusted brand that is hard for a rival to win over, as well as the costs of re-training staff to use new systems, however well designed. The race to cut costs will also have its inevitable share of casualties as consolidation kicks in, Shiao says, especially as the US' federal investment tax credit (ITC) is planned for step down in 2017. Nonetheless, Shiao says, as much as 8% of a commercial rooftop PV installation's system costs can be found in the mounting structure, which comprises the bulk of structural balance of system (BoS) costs.

Better relationships between manufacturers, installers and customers will help companies build brand loyalties and a clear understanding of what each product can do as markets mature, according to MJ Shiao. On the technical side, there is still scope for more to be done. Material innovations, such as the replacement of the more expensive but corrosion-free aluminium with better forms of galvanised steel are already moving at pace, for example, the analyst says.

Whatever the future holds, it's certainly true that for BoS, as with modules, costs are certainly falling at speed and are there to be used to the best advantage, Shiao says: "One of the things that we see in the next five years is that while we think that the cost of the BoS will fall, even as much as 10% a year, there are still tremendous things that could happen within this space." ■

Future developments in BIPV and energy efficiency in the fight against climate change

BIPV | Building-integrated PV has yet to live up to its promise, remaining a niche sector of the solar industry. However, as Silke Krawietz writes, European and international climate and energy goals, and a chance of reviving the European PV manufacturing industry, all offer BIPV the opportunity of becoming a mainstream technology

Buildings represent the largest energy-consuming sector in the global economy, account for over one-third of global final energy use, half of global electricity and about a fifth of all greenhouse gas (GHG) emissions. In Europe, buildings account for around 40% of total energy consumption and 36% of CO2 emissions and therefore present a huge potential for energy efficiency and incorporation of renewable energy technologies, in particular PV and building-integrated PV. Under business-as-usual projections, global energy use in buildings could double or even triple by 2050.

As such, the relationship between buildings and energy must by necessity form a core element of discussions taking place towards the end of this year at the United Nations' COP21 climate talks. Although buildings at the moment are key GHG emitters, the development of low-carbon and energy efficiency technologies, in particular PV and BIPV, offer huge potential for meeting energy efficiency and renewable energy deployment goals, and therefore the deep cuts the international community must agree to in December.

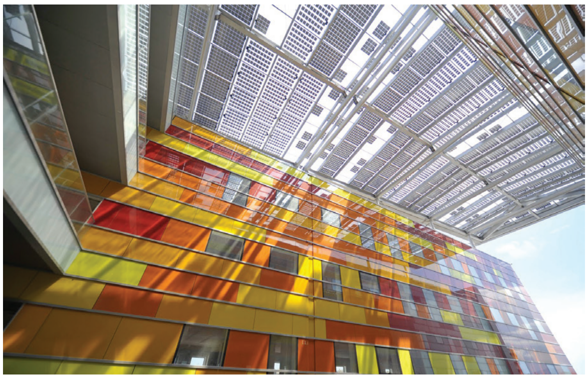
In a report published earlier this year, *Energy and Climate Change*, the International Energy Agency (IEA) underlined the importance of the talks: "The importance of the 21st Conference of the Parties (COP21)... rests not only in its specific achievements by way of new contributions, but also in the direction it sets. ….The overall test of success for COP21 will be the conviction it conveys that governments are determined to act to the full extent necessary to achieve the goal they have already set to keep the rise in global average temperatures below 2 degrees Celsius (°C), relative to pre-industrial levels."[1]

According to the IEA, under the pledges so far made by nations in advance of COP21, the Intended Nationally Determined Contributions (INDCs) Scenario, growth in global energy-related GHG emissions slows, but there would be no peak by 2030. The link between global economic output and energy-related GHG emissions weakens significantly, but is not broken. Renewables become the leading source of electricity by 2030, as average annual investment in non-hydro renewables is 80% higher than levels seen since 2000.

The IEA report proposes a so-called 'bridging strategy' that could deliver a peak in global energy-related emissions by 2020. A commitment to target such a near-term peak would send a clear message of political determination to stay below the 2°C climate limit. The peak could be achieved by relying solely on proven technologies and policies, without changing the economic and development prospects of any region. Two of the key measures in the IEA's 'bridge scenario' would have a key bearing on the ongoing deployment of energy efficiency and renewable energy measures, presenting huge opportunities for BIPV and energy efficiency in buildings:

- Increasing energy efficiency in the industry, buildings and transport sectors.
- Increasing investment in renewable energy technologies in the power sector from $270 billion in 2014 to $400 billion in 2030.[1]

BIPV also has a potentially central role to play in helping the European Union meet its energy efficiency and low-carbon energy goals. Energy efficiency is one of the main pillars within the newly created Energy Union (02/2015), which states as one of its aims "…fundamentally rethinking energy efficiency and treating it as an energy source in its own right so that it can compete on equal terms with generation capacity". [2] The Energy Union will ensure that renewable energy is mainstreamed and fully integrated into a fully sustainable, secure and cost-efficient energy system.



Credit: Laurent Lacombe, Wikimedia Commons

BIPV and energy efficiency measures in buildings offer options for policy makers seeking to reduce global emissions.

Meanwhile, the EU's Strategic Energy Technology (SET) Plan aims to accelerate the deployment of low-carbon technologies by encouraging greater cooperation on research and development between EU countries. Together the SET Plan and the Energy Union, through energy efficiency measures and the integration of renewable energies, lead the way to Nearly Zero Energy Buildings (NZEB) and possible future energy-plus buildings.

And the recast directive on the energy performance of buildings (EPBD) also stipulates that all new buildings constructed within the European Union after 2020 should reach nearly zero-energy levels.

This means that in less than five years, all new buildings must demonstrate very high energy performance, and their reduced or very low energy needs will be significantly covered by renewable energy sources. BIPV is clearly an excellent option in achieving this goal.

Collaboration needed

In the context of these international and European energy and climate objectives, BIPV looks particularly attractive. In Europe, the potential development of BIPV from a niche market as it is today into a mainstream one could also bring the additional benefit of reviving the continent's ailing PV manufacturing industry, which has been in decline for a number of years.

For this to happen, however, close collaboration between the PV industry, the building industry, including architects and engineers, will be crucial to ensure the creation of innovative, competitive BIPV products; so far, despite the huge potential of BIPV to play a role in meeting European and international objectives, this level of cooperation between the building industry, architects and the PV industry has been the missing ingredient in bringing BIPV into the mainstream.

The building industry is making huge progress with the implementation of energy efficiency measures, new technologies and innovations in building and construction; the PV and BIPV industries should now consider using the enormous possibilities outlined above, in supporting the achievement of European and international climate goals, to spur closer collaboration with the building industry in the field of innovation, new materials and the development of highly energy-efficient building components through the integration of renewable energies, in particular BIPV.

Collaboration among the above mentioned sectors is crucial for enhancing the innovation and competitiveness of the industry and research and development sectors related to energy efficiency and renewable energies. The positive factors are the creation of jobs and rise of competitiveness in the world market of European industry and research institutes.

The building industry, which is rapidly developing, and the BIPV industry, which is following a slower path, have common issues: energy efficiency in buildings and production of renewable energies in the buildings, in order to reach the EU and international goals. This scenario presents an important opportunity and challenge and strengthens the market opportunities for energy efficiency business and BIPV towards to NZEB and energy-plus buildings.

Unlocking the potential of BIPV

Unlocking the immense energy saving potential of buildings requires not only ambitious legislative frameworks and policy programmes, but also the continued research and development of innovative building techniques and technologies, and the dissemination of learnins from real-world best-practice projects. To address the challenges of transforming the energy use in buildings and to allow for their better integration into the future energy systems, a long-term and multi-dimensional perspective is required.

Today both sectors are disconnected, and insufficient collaboration is happening between the two industries and the various stakeholders. The disconnection can be seen in the development of both industries, but not the creation of new innovative products of BIPV based on common research initiatives. The collaboration today is not happening.

One positive step forward for BIPV and energy efficiency in buildings would be the creation of a dedicated task force, to initiate this closer collaboration among the described stakeholders and policy makers. Such a body is needed for the realisation of the goals of the Energy Union and to reach the international climate targets.

It would function as a forward-looking alliance for international collaboration, to define and develop the requested business strategy further and to stimulate investment in the concrete development of measures and products for advanced energy efficiency with renewable energy integration into buildings.. The task force would, together with the various stakeholders, identify barriers to market development and initiate work on issues of common interest, leading the way to NZEB and possible future energy-plus buildings. The energy efficiency and BIPB task force is being initiated by SETA Network, an international consulting firm, based in the UK, specialised in energy efficiency in buildings, renewable energies and, in particular, BIPV.

The existence of such a body would help join up the dots between the various disconnected elements of the BIPV industry and help instigate the needed paradigm shift within the PV industry that makes full use of the huge market potential of BIPV and to develop new innovative products, in close collaboration with the building industry, architects and engineers. The SETA Network and other stakeholders are intending in the near term to propose the task force to the European Commission and Energy Union figures, as well as to the European Investment Bank for support. The intention is as soon as possible to establish it as the 'Energy Efficiency and BIPV Alliance'.

Opportunities for BIPV innovation to drive the PV market

Besides supporting European and international energy and climate goals, the further strong development of BIPV technologies and products, developed in close collaboration possibly with the building industry, could also be an important driver for the PV market generally, following the well-known problems and downturn of the European PV industry and research facilities in recent years. Therefore BIPV offers huge potential for the European PV sector overall.

The forthcoming COP21 talks, the path to NZEB and energy-plus buildings in Europe by 2020 and the opportunity to reverse the European photovoltaic industry's recent downturn all offer huge potential for BIPV to develop from a niche market into a future large-scale market of the photovoltaic industry, creating innovative products and jobs with the necessary financial support.

Crucial for this are the close collaboration of the PV industry with the building industry and the creation of innovative competitive BIPV products to promote NZEB and possibly future energy-plus buildings. The potential for collaboration between the building industry (in the frame of enhanced energy efficiency) and the renewable energy sector (in particular the PV and BIPV industries) is enormous and could help put the world on a more sustainable path. ■

Author

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Diminishing the glare that obscures

PV panel reflection | The increasing deployment of PV systems in dense urban areas has drawn attention to the issue of glare and the public discomfort arising from the sun's reflection on the PV panels. Licheng Liu, Yong Sheng Khoo and Thomas Reindl of the Solar Energy Research Institute of Singapore (SERIS) and Julius Tan of Sunseap Energy discuss ways of fine-tuning system designs and alleviating visual discomfort, while not compromising on the energy yield of PV systems

The steep decline in prices of solar PV modules in recent years has catalysed the adoption and deployment of solar PV systems globally for private, commercial and industrial uses, all the way to utility-scale installations of several hundreds of megawatts. Grid parity for solar electricity has been reached in many countries, including Singapore. In other words, the levelised cost of energy (LCOE) generated from PV is equivalent to, or less than, the price of electricity from the power grid, which has made investments in PV systems financially attractive, even in the absence of monetary support schemes, such as feed-in tariffs. In early 2014 the Singapore government announced the SolarNova initiative, led by the Singapore Economic Development Board (EDB) to encourage the adoption of solar PV in the public sector. The target is to achieve 350MWp of installed solar PV capacity on the rooftops of government-owned buildings by 2020.

With the increasing adoption rate, one relatively rare issue related to solar PV installations has started to surface: glare from PV modules. The smooth glass encapsulation on the front side of solar panels can cause glare effects through the optical reflection of direct beam irradiance.

Sunlight reaching the earth comprises a direct component and a diffused component. *Direct sunlight* is the portion of solar radiation that is not blocked by clouds when it passes through the earth's atmosphere, whereas *diffused sunlight* is experienced when the incoming solar radiation travels through clouds or is reflected off matt objects, such as white walls. Because of the tropical nature of the weather conditions here (high moisture content in the air, frequent cloud formations), the solar radiation experienced in Singapore has a relatively high share of diffused irradiance (55–60% on average). The potential glare effects are therefore inherently lower than in other locations that have a higher percentage of direct sunlight.

Glare (a continuous source of bright light) is one of the two potential impacts of optical reflections; the other is *glint* (a brief flash of light), which can result in momentary loss of vision (flash blindness). The impact of glare on individuals typically depends on several factors, including background luminance and the distance and luminance level of the glare source. A glare effect is normally experienced when there is a sharp contrast between the intensity levels of the background luminance and the glare source. If the intensity level of the background luminance is very high, for example during broad daylight, the sensation of the glare impact would be reduced. The distance of the glare source and the solid angle also influence the degree of attenuation of glare, as does the luminance level of the glare source, which, in the case of solar modules, is a function of the reflection level of sunlight.

Generally, there are two types of reflection, namely specular reflection and diffused reflection. *Specular reflection* from a surface is the case where light from a single incoming direction is reflected into a single outgoing direction, whereas *diffused reflection* is the reflection of light from a surface where an incident ray is reflected at many angles. The luminance of a specular reflection is usually higher than that of a diffused reflection. As the surface of the glass encapsulation of most solar panels is smooth, the reflection off them is usually specular, which may result in glare under certain conditions, as described in detail below.

There are several indices for evaluating the level of visual discomfort brought on by glare, such as the British glare index (BGI), the discomfort glare index (DGI), the Cornel glare index (CGI), and the discomfort glare probability (DGP). However, the different indices are typically applied in very specific scenarios and are often limited in other situations, especially since they also involve a number of subjective measurements. It is therefore difficult to isolate a specific index to evaluate the glare from PV systems.

In the following sections, the severity of reflection from solar panels is discussed, followed by recommendations for system designs in order to ease the discomfort from glare. Analyses of the reflectance and glare arising from PV systems have been performed for various module tilt angles and orientations in order to derive a balanced solution to the issue of glare. The solution is further reinforced with simulation models that provide a comprehensive visualisation.

Reflection from a solar PV module

Sunlight reaches the surface of the earth as packets of energy, commonly known as *photons*, with which different materials interact differently in terms of reflectance, transmittance and absorptance. Fig. 1 shows the AM 1.5 solar spectrum, which graphically describes the distribution of solar energy received on the earth's surface as a function of different wavelengths. It can be seen that at low wavelengths of less than 400nm (ultraviolet light), not much solar energy reaches the earth's surface. The highest fraction is in the wavelength range of visible light (400–700nm); from around 500nm the solar energy decreases with increasing wavelength.

A solar cell is designed to absorb as much sunlight as possible and convert it into electricity, and any photon reflected off a solar cell is in fact an undesirable loss in

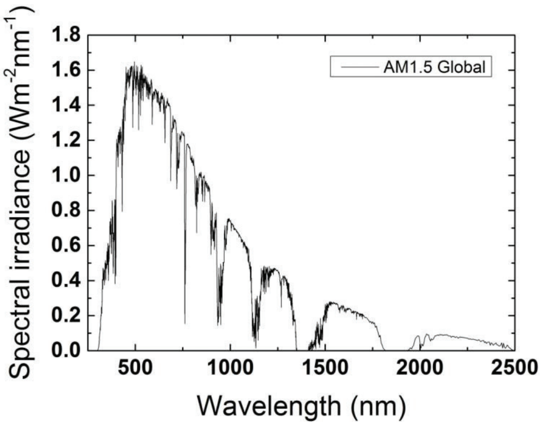


Figure 1. Standard solar spectra at AM 1.5 (IEC 60904-3).

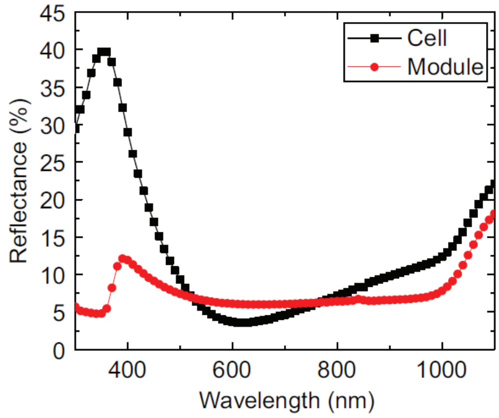


Figure 2. Wavelength-dependent reflectance of a typical solar cell (black squares) and module (red circles) [1].

the energy yield. In order to maximise the energy yield, a layer of anti-reflection (AR) coating is therefore deposited onto the front surface of a typical solar cell to minimise the reflectance. However, it is not economically viable to reduce the reflection of the cell surface over the entire solar spectrum; in consequence, the refractive index of the AR coating is tuned to minimise reflection in the visible light spectrum range in order to cover the largest portion of the solar energy reaching the earth's surface.

Fig. 2 shows the wavelength-dependent reflectance of a solar cell with an AR coating as well as the reflectance of a solar module, i.e. after packaging the cell into a durable panel with a glass surface. Although the refractive index of the AR coating is designed to minimise the reflectance of light in the wavelength range 400–700nm, it can be seen that the reflectance at wavelengths of less than 500nm increases (with a peak below 400nm), i.e. in the blue, violet and ultraviolet (UV) ranges; this explains why typical

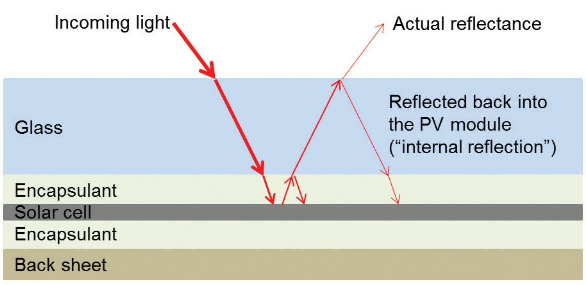


Figure 3. Schematic of light paths in a solar module.

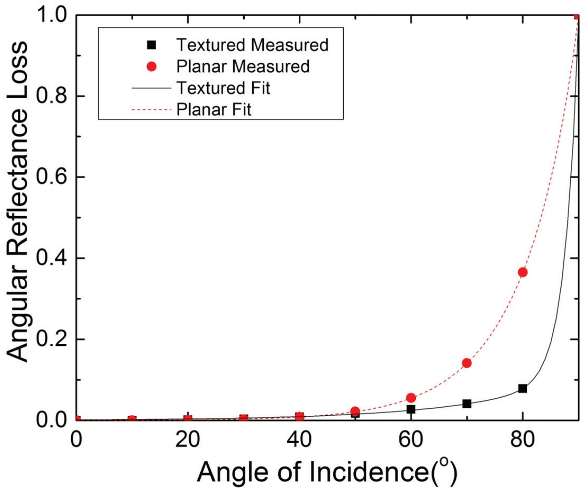


Figure 4. Angular reflectance loss of a solar panel [2].

solar cells appear blue in colour. When solar cells are assembled and encapsulated into a solar module, the reflectance of high-energy light in the UV range decreases significantly because of the 'light-trapping' effect of the glass encapsulation in a solar module.

Fig. 3 demonstrates this light-trapping effect by outlining the possible paths of sunlight when it reaches the surface of a solar module. The sunlight is refracted through the glass and the encapsulant before arriving at the surface of the solar cell, where it encounters a certain degree of reflection. The fraction of high-energy light which is not immediately absorbed by the solar cell, and hence reflected from the solar cell surface, will then encounter internal reflection again at the encapsulant–glass interface, as well as at the glass–air interface, back to the solar cell. The energy of such reflected light is partially reduced, which enhances its absorption by the solar cell thereafter.

Thanks to the light-trapping effect, the weighted average reflectance (WAR) of a solar module is reduced to below 10%. This is comparable to the reflectance of typical window glass (6–10%) and significantly below the reflectivity requirement of the Singapore Building and Construction Authority (BCA) for reflective surfaces on buildings, which is 20%.

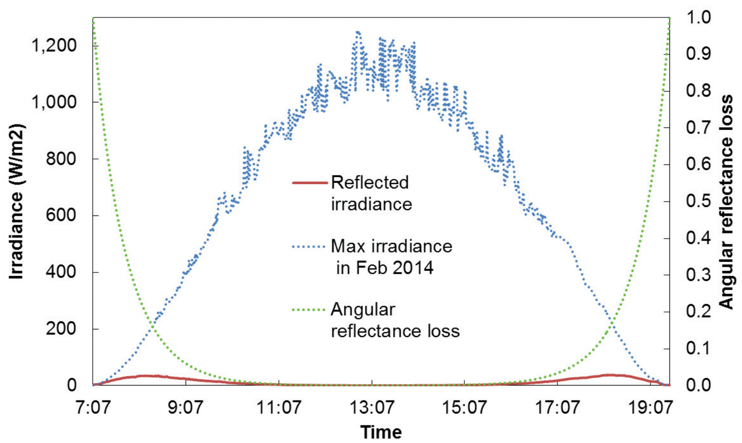
As with any reflecting building element, there are, however, possible situations and scenarios in which glare from a solar panel can potentially occur. The reflectance measurements for the solar cell and solar module as shown in Fig. 2 are taken at a normal (0°) incidence, i.e. the incoming light is perpendicular to the solar cell and the solar module. Fig. 4 shows the angular reflectance losses, relative to normal incidence, of typical solar modules with a textured glass and a planar glass (for a solar module, such reflectance reduces the absorption and the yield and is hence considered a 'loss'). It can be seen that the angular reflectance loss starts increasing dramatically when the angle of incidence goes beyond ~70°.

For a horizontally installed solar panel, such high reflectance at high angles of incidence can occur only in the early morning or late afternoon hours, when the sun is close to the horizon. However, as the solar irradiance is low at those times, the energy of the reflected light at that point in time is also low, as shown in Fig. 5. The blue dotted curve describes the worst-case irradiance profile when plotting the maximum observed irradiance at 1min intervals in the case of Singapore (taken in February 2014, which was particularly dry and hot). The red solid curve represents the reflected irradiance obtained by multiplying the irradiance profile by the angular reflectance loss. The maximum reflected irradiance under such circumstances is calculated to be only 37W/m², which is similar to the amount of light emitted from a light bulb used in residential applications.

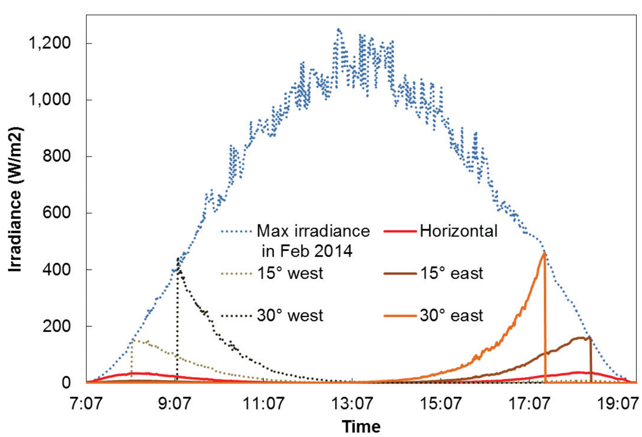
Solar modules are typically installed at tilt angles close to a location's latitude. In the case of Singapore, this suggests near-horizontal installation, but they are in reality installed rather tilted at an angle of 10–15° to facilitate the so-called 'self-cleaning' effect, which helps to clean the surfaces from dust and dirt through natural rainfall. Many PV systems in Singapore are installed in an east–west orientation, which helps to generate a slightly higher energy yield compared with a north–south orientation [3], and hence allows the harvest of solar energy to be maximised in a space-constrained location like Singapore.

It can be seen from Fig. 6 that the maximum reflected irradiance increases with larger tilt angles of the module, because the high reflectance at high angles of incidence occurs later in the morning or earlier in the afternoon, when the solar panels are tilted towards the west and the east respectively. This could then increase the level of discomfort brought on by glare from the PV system, as the relative irradiance levels are higher. For a PV system with solar panels tilted at 15° to the west and east, as an example, the maximum reflected irradiance would be ~160W/m² at 8:10am (W) and 6:20pm (E), compared with a horizontally installed PV system, which reflects only 37W/m².

If the tilt angle of the solar panels is further increased to 30° to the west and east (which would only happen if a PV installation has to follow the given larger tilt angle of the underlying roof, e.g. on private residential buildings – see also 'Private residential buildings' section below), the maximum reflected irradiance would be ~450W/m² at 9:10am (W) and 5:30pm (E). Such higher levels of reflected irradiance

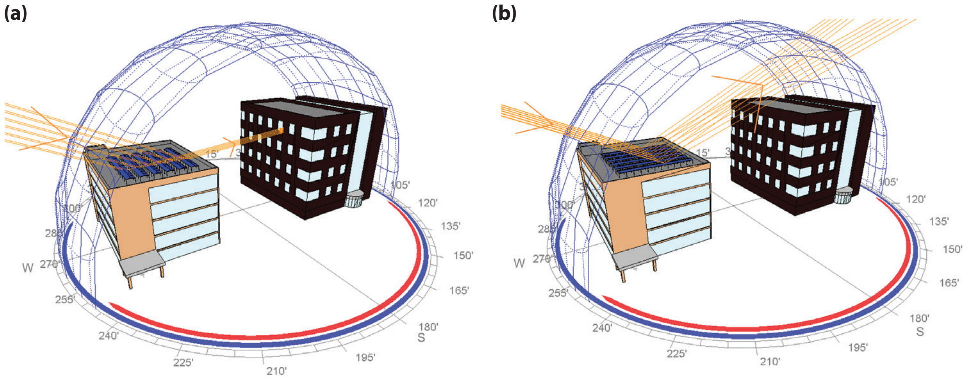


▲ **Figure 5. Plots of maximum irradiance, angular reflectance loss and reflected irradiance for Singapore in February 2014 with respect to time.**



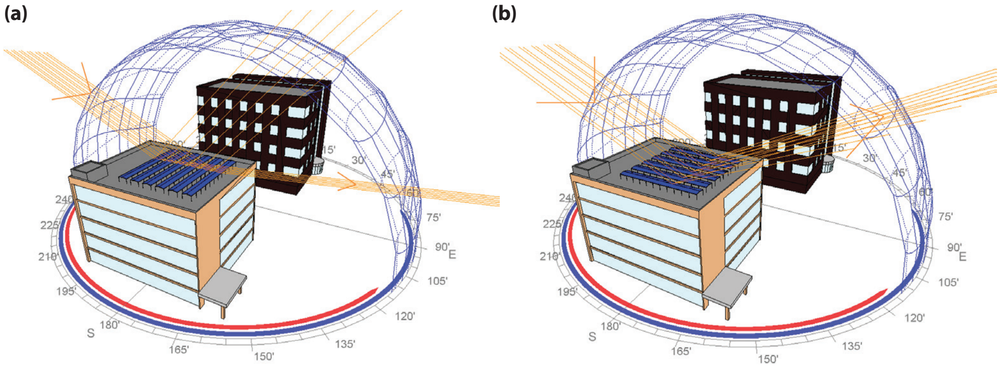
▲ **Figure 6. Variation in the reflected irradiance profile with module tilt angles and orientations.**

(a) (b)



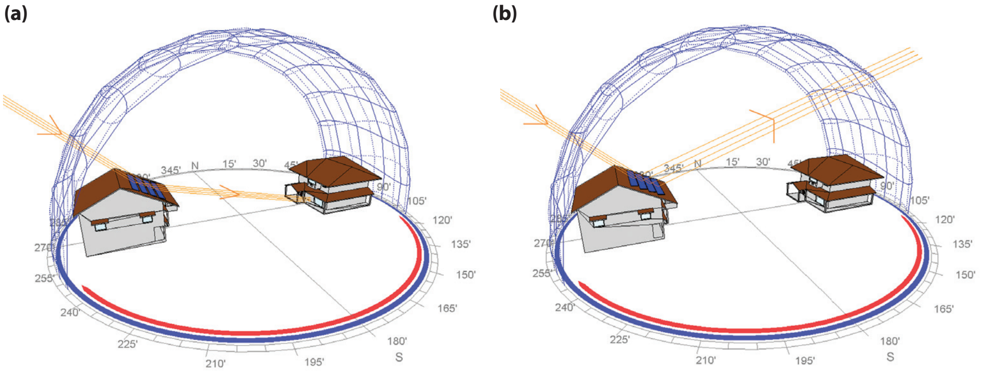
▲ **Figure 7. Model of a PV system tilted at 10° on a commercial/industrial building. The buildings are positioned in an east–west orientation at a distance of 25m. The PV system is installed in (a) an east–west orientation, and (b) a north–south orientation.**

(a) (b)

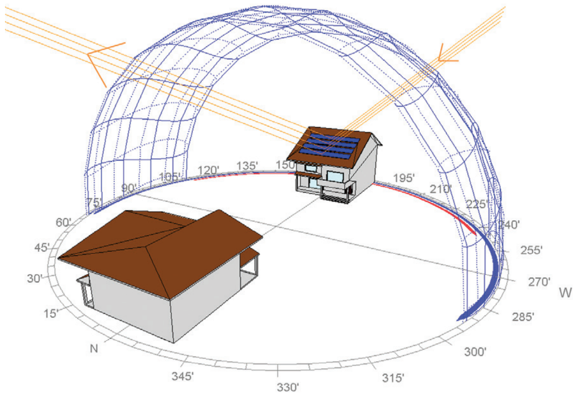


▲ **Figure 8. Model of a PV system tilted at 10° on a commercial office building. The buildings are positioned in a north–south orientation to each other at a distance of 25m. The PV system is installed in (a) an east–west orientation, and (b) a north–south orientation.**

(a) (b)



▲ **Figure 9. Model of a PV system on a private residential house: (a) system tilted at 25°, following the tilt angle of the pitched roof; (b) system tilted at 10° by adding mounting structures. The two houses are positioned in an east–west orientation to each other.**



◄ **Figure 10. Model of a PV system on a private residential house, where the system is tilted at 25°, following the tilt angle of the pitched roof. The two houses are positioned in a north–south orientation to each other.**

can then possibly result in visual discomfort. Nevertheless, from ~20° onwards, the yield of a PV system in Singapore starts to drop significantly; hence the vast majority of PV installations here will be tilted between 10 and 15°, to prevent both losing yield and reflecting too much irradiance. Since the issue of glare from a PV system becomes more prominent when the panels are installed at high tilt angles in an east–west orientation, the most straightforward way to mitigate the problem is through adjustments to the system design by changing the tilt angle and/or orientation of the PV panels. This is discussed further in the next section.

System design

Although it has already been established in the previous section that the maximum reflected irradiance increases with increasing tilt angles of the solar panels, it should be assessed in more detail under what circumstances this could cause glare. For that, it is important to visualise the effect of the reflected irradiance from a rooftop PV system onto the neighbouring buildings. Rooftop PV systems in Singapore are predominantly installed on two types of building: commercial/industrial buildings and private residential houses. Case studies for both types were therefore carried out using Ecotect software to simulate the paths of the incoming sunlight and the reflected light. For each type, a PV system was modelled on one of the buildings. The orientation and tilt angle of the solar panels were varied under different building orientations to investigate the effect of glare from the PV system on the respective neighbouring buildings.

> "Potential glare issues can be avoided by assessing the situation of neighbouring buildings during the system design stage and by taking proper measures to avoid glare in the first place"

Commercial/industrial buildings

In the installation of PV systems on

reinforced concrete (RC) rooftops, the solar panels are usually tilted bidirectionally in a wave-like manner. In other words, if one row of solar panels is tilted towards the east, the next row is tilted towards the west, and so forth.

When designing the orientation of a PV system on a commercial/industrial building, it is essential to know the relative orientation of its neighbouring buildings. In the worst-case scenario, when two buildings are positioned in an east–west orientation, which coincides with the sun path, then there is indeed a possibility that the nearby building will be subjected to a glare effect, depending on its height and the distance from the PV installation. One possible (and easy) solution would then be to tilt the solar panels away from the neighbouring building, possibly all the way to a north–south orientation. This may not always be possible, though, for slightly tilted metal roofs.

Fig. 7 shows a model in which a commercial/industrial building and an office building are positioned in an east–west orientation at a distance of 25m. It can be seen that if the solar panels are tilted at 10° in an east–west orientation, the reflected irradiance will hit a certain row of windows of the neighbouring building in the late afternoon, which might result in visual discomfort of the occupants of that building (Fig. 7(a)). Under such circumstances, it is advisable to tilt the solar panels away, for example in a north–south orientation. This would result in the incoming sunlight being reflected to a much higher location (above the office building), and therefore not dazzling the occupants of that neighbouring building (see Fig. 7(b)).

If the buildings are positioned in a north–south orientation, as shown in Fig. 8, the orientation of the solar panels does not matter, since the orientation of the buildings does not coincide with the sun path of the reflections from the PV system.

Finally, for vertically installed PV systems on the facade of a building, the glare effect is no worse than that of any glass curtain wall, which is commonly used in many buildings in Singapore.

Private residential buildings

In the case of the installation of PV systems on the pitched rooftops of private residential houses, other than the dependence of glare on the orientation of the houses, the tilt angle of the solar panels usually follows that of the pitched roof. As a result, some PV systems are tilted at 30–40°, which has two possible effects. First, as mentioned earlier, the overall irradiance received by the PV modules is lower because they will not be able to receive direct sunlight before or after a certain time of the day, depending on the orientation (the so-called 'internal shading' effect). Second, the maximum reflected irradiance will also be higher and could possibly increase the level of visual discomfort to neighbouring buildings (again, depending on the orientation).

Similarly to flat-roof or low-angle installations on commercial/industrial buildings, the potential glare effect is higher if the buildings are oriented east–west with respect to each other. In this case, if technically possible, it would be advisable to employ a smaller tilt angle for PV systems on the roofs of private residential houses. This can be achieved, for example, through special mounting structures to adjust the tilt angle downwards to ~10°; such a measure, however, may be subject to aesthetic considerations.

A model of two private residential houses in an east–west orientation is shown in Fig. 9. The pitched rooftop of the house on which the PV system is installed has a tilt angle of 25°, and hence the tilt angle of the solar panels is also 25°, as shown in Fig. 9(a). It can be seen that the reflected irradiance directly strikes the front window of the neighbouring house at 4:15pm for ~20min, which might result in a certain level of visual discomfort. This can be avoided, for example, by using mounting structures that decrease the tilt angle of the solar panels, as shown in Fig. 9(b). At a resulting lower tilt angle of 10°, the path of the reflected irradiance is well above the roof of the neighbouring house, thus eliminating the effect of glare.

Similarly to the case of commercial/industrial office buildings, if the private residential houses are positioned in a north–south orientation, then glare is not an issue, because the reflected light does not come into contact with the neighbouring house, as shown in Fig. 10.

Conclusion

It can be seen from this study that the reflectance of solar panels is ~10%, which falls within the same range as normal window glass and is significantly lower than Singapore BCA's reflectivity requirement for reflective surfaces on buildings (which is 20%). The vast majority of PV systems in Singapore have been, and will be, installed at tilt angles of around 10–15° in order to maximise the yield and to ensure regular 'automated' cleaning through rainfall.

In rare cases, however, it is possible that neighbouring buildings experience glare from PV systems during certain times of the day, depending on the actual tilt angle and the relative orientation of the two buildings. It has been demonstrated through calculation and modelling that such potential glare issues can be avoided by assessing the situation of neighbouring buildings during the system design stage and by taking proper measures to avoid glare in the first place.

The rule of thumb is to ensure a low tilt angle for the solar panels, in the range 10–15°, to minimise the reflectance. If the buildings are positioned in an east–west orientation, and if there is freedom to vary the system orientation, it is advisable to tilt the solar panels away from the neighbouring building, possibly all the way to a north–south orientation. In the case of any uncertainty, SERIS has the capability to carry out simulations to determine a site-specific possibility of the occurrence of glare. ■

Authors

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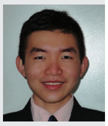

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Inverter performance problems in PV power plants

Power oscillation | In the last few years the power rating of PV power plants has risen very quickly to values reaching several hundred megawatts. This means there are hundreds, or even thousands, of inverters operating in parallel in these plants. Furthermore, these large-scale PV power plants are often built far away from cities and are therefore connected to the grid via long transmission lines. This leads to weak grid conditions in the power plants, and these conditions give rise to the risk of electrical instabilities within the plant, or instabilities of the plant within the grid. Roland Singer of Fraunhofer ISE explains how these electrical instabilities can be detected and counteracted

There are many aspects to consider regarding the performance of inverters in PV power plants. Inverters should be highly efficient at converting PV energy from DC to AC. They have to follow the maximum power point (MPP) of the PV generator very precisely, under various conditions, and all requirements of the local grid codes have to be met during the operation. All these functions must be delivered in a very reliable way over many years of operation, with as little maintenance as possible; often they have to be fulfilled under very harsh environmental conditions, for example very high temperatures and dusty air in desert regions. The requirements for an inverter mainly focus on maximising the power output over its lifetime, thereby minimising the costs and maximising the economic return.

In view of all these factors, inverter manufacturers optimise their products during the development phase and perform tests to establish inverter performance. Often these tests are performed by third-party organisations to convince the customers of the quality of their product through independent test results. All these tests are done with single inverters, and during the design of the inverters the manufacturers focus on the optimisation of a single inverter too.

Undesirable oscillations of the currents and voltages are referred to as *instabilities* in power plants. Often these oscillations are not recognised during the commissioning and the normal operation of the plant; this is because they cannot be measured by typical monitoring systems, as will be explained later in this paper. The instabilities often result in malfunction of the inverters and poor yield from the power plant, or even lead to failure of the inverters or other components of the plant.

During the building of a PV power plant the typical approach can be described as 'build and forget'. After the commissioning of the power plant, apart from some minor maintenance work, the plant should 'run itself'. Instabilities are therefore not recognized until serious problems arise, such as a high failure rate of the inverters or significant deviations in yield compared with expectations. Even after serious problems have been detected, oscillations are usually not recognised directly, because often the failures could also have been caused by other, more common, problems. In general, the instabilities therefore remain undetected for a long time during the troubleshooting.

This paper is based on the article by Dötter, G. et al. [1].

Electrical instabilities

The majority of transmission systems in the world are operated at a rated frequency of 50Hz or 60Hz; however, other frequencies are always present in the voltages and are mainly parasitic and mostly limited by the local grid code. To characterise voltages and currents with different frequencies present, the spectral representation in the frequency domain is used. Each single frequency present in a signal is expressed by a frequency, amplitude and phase angle; the superimposing of frequencies using this method is exploited and illustrated in this paper. When oscillations appear, they are described as *electrical instabilities*; their amplitudes are higher than stability thresholds and therefore endanger the normal operation of the PV power plant or neighbouring systems. The frequencies of these oscillations can be above or below the rated frequency of the system.

For an oscillation to occur in an electrical system, the presence of a resonance point is necessary. The resonance of a system is defined by the energy-storing elements in the system. These elements are inductive and capacitive in nature, and in a PV power plant many such elements are present – they are partly parasitic and therefore their values are not precisely known. Depending on their values, arrangement and number, there may be one or several resonances present in the system.

"Undesirable oscillations of the currents and voltages are referred to as *instabilities* in power plants"

In the control algorithms of PV inverters, additional 'virtual' energy storage devices are also present; these are integral to typically used PI (proportional and integral) controllers. The calculation of the system resonances must therefore not only take into account the typical electrical components (such as cables, transformers, filter chokes and capacitances), but also consider the control algorithms of the inverters.

Moreover, whether or not the system will oscillate at the resonance frequency depends also on the excitation and the damping: in electrical systems the ohmic parts or loads attenuate the oscillations, and control algorithms can have a damping, neutral or even exciting action. Oscillations can also be triggered by load steps, switching operations in the grid, nonlinear loads or other events. If the frequency is not damped properly such events can cause long-lasting oscillations.

Typical frequency spectra of grid voltages or inverter currents

In the first step the frequency range can be separated into two parts: 1) the range below the rated frequency (e.g. 50Hz) – frequencies in this range are called *subharmonic oscillations*; 2) the range above the rated frequency – this is the *harmonics* range.

A qualitative example of a typical frequency spectrum of the output currents of a central inverter is shown in Fig. 1. The indistinctness in the colours of the spectral lines represents the typical range of the specified oscillation frequencies. In the following discussion the sources and behaviour of the different frequency components are explained, and possible problems are highlighted.

Switching frequency

Central inverters on the market currently use switching frequencies in the range 2kHz to 5kHz. The power electronic switches of an inverter are controlled with this frequency, so this frequency and its multiples are always present in the spectrum of the output current. When multiple inverters of the same type (same switching frequency) are operated in parallel, these frequencies often superimpose in a destructive manner as a result of the changing phase angle between the inverters [2].

The changing phase angle is caused by small differences in the switching frequencies between the inverters, for example because of tolerances in the frequency sources inside the inverters. This gives rise to a slowly changing amplitude of the switching frequency in the overall current of the power plant. The main problem caused by the switching frequency is the violation of emission thresholds. However, there have been no reports of problems in PV power plants as a result of this 'beating' of the switching frequency, or any reports of instability problems due to frequencies above the switching frequency.

System resonance

The system resonance is typically within the range of the harmonics; during the design of an inverter the value is usually set in the range of one-half to two-thirds of the switching frequency for systems with single inverters under normal operation conditions. In PV power plants, because of multiple inverters operating in parallel and weak grid conditions, the system resonance is lower [3], taking a value of around 1kHz. The system resonance is formed from all elements in the electrical system of the PV plant, including the grid impedance, the transformers and cables in the plant, the filter elements in the inverter, and the behaviour of the inverter's control system.

The system resonance can occur at any arbitrary frequency; the frequency of oscillation that can be measured thus often occurs at a harmonic frequency. Harmonics are multiples of the rated grid frequency, and these frequencies then act as the excitation of the oscillation. Harmonics are often present in the grid voltage and are introduced by, for example, nonlinear loads.

If the system resonance lies in a frequency range within which the phase margin of the control system is very low, then the control of the inverter can excite the oscillation too. Oscillations at the system resonance cause increased losses in the inductive components of the power plant (chokes, transformers), which in turn lead to a decrease in conversion efficiency. These increased losses can also result in higher temperatures of these elements and therefore accelerated ageing. The ageing of capacitive elements can also be accelerated by higher currents. In extreme cases, even inverter failures can be caused by the oscillations, because of over-voltages or over-currents. Another problem can be excessive harmonic emissions of the power plant and hence problems with the grid operators.

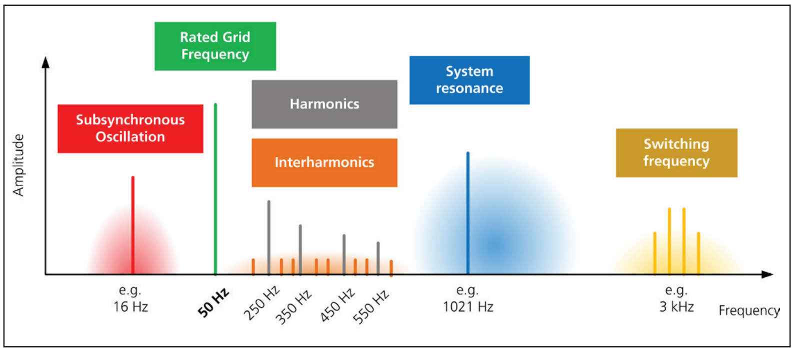

Figure 1. Classification of oscillation frequencies.

Subsynchronous resonance

The reasons for this phenomenon in inverters have not been investigated to the same extent as the above-described harmonic effects. Some inverter manufacturers have reported that changes in control parameters could result in damping of subsynchronous oscillations in PV power plants. These oscillations cause the output power of the inverter to vary over a wide range, so the MPP tracker may no longer operate, causing a reduction in the harvested energy of the power plant. Another problem can be violation of flicker limits in the grid.

Measurements of instabilities in PV power plants

Oscillations in large PV power plants have been measured by Fraunhofer ISE on several occasions. There have also been several reports by inverter manufacturers and park operators of oscillations in large power plants. These measurements and reports again show that such oscillation problems can be distinguished by oscillations in the frequency ranges above (harmonic) and below (subsynchronous) the grid frequency.

Harmonic oscillations

For the measurement of the oscillations, illustrated in Fig. 2, the grid impedance for the power plant was artificially increased by adding a grid choke of a low-voltage ride-through (LVRT) test container. The oscillation in the voltages and currents can be seen in the figure. The frequency of this oscillation is 850Hz, which is the 17th harmonic component. This was also present in the voltage outside the PV power plant but had a much smaller amplitude; however, because the system resonance was only a few hertz below this harmonic component, the oscillation was excited at 850Hz.

Subsynchronous oscillations

The measurements seen in Fig. 3 were taken in a PV power plant with more than 100 central inverters operating in parallel; a high-precision measurement system which was distributed in the power plant was used. The sampling of the measurement system was synchronised via a GPS signal. In Fig. 3 the AC voltages and currents of an inverter with a subsynchronous oscillation of 25Hz can be seen. Fig. 4 shows the

simultaneously measured DC voltages of 10 inverters at a plant consisting of more than 100 inverters. It can be seen that all inverters are oscillating at the same frequency, and that they are also no longer operating at the MPP.

Summary of all measured and reported oscillations in PV power plants

To illustrate that this problem is not associated with just a few low-quality manufacturers, all the problems known by the author with oscillations in PV power plants are illustrated diagrammatically in Fig. 5; the colour scheme is similar to that used in Fig. 1. Two accumulations of oscillation phenomena are observed: at system resonance and in the subsynchronous range. In this diagram a distinction is made between reliable external sources, external sources without detailed reports, and measurements taken by Fraunhofer ISE. It can be seen that problems with electrical instability are not focused on a specific power range of the plant or on a specific manufacturer; with the rising number of power electronic generators, instability is a widespread phenomenon.

Accounts of electrical instability in other technologically related areas have also increased in recent years. For example, oscillation has been known to occur in railway technology, where more and more generators and loads are being replaced by power electronics. Moreover, oscillations were reported during the commissioning of the offshore wind farm BARD Offshore 1 in Germany [4,5].

Detection and counteraction of instabilities in PV power plants

Monitoring systems are typically installed in PV power plants to monitor the correct functioning of all components in the plant and sound the alarm if a fault occurs. In order to reduce the amount of data, averaging intervals of more than one minute are typically used for these measurements. The oscillations described above, however, cannot be detected in these average measurement values, because of the filtering effect of the averaging process. Although any differences in performance might be observed from a comparison of these values with the results from other PV plants, the detection of oscillation is not possible.

If the oscillation leads to a temporary stoppage of an inverter, the monitoring system will signal the alarm; however, inverter error messages do not usually

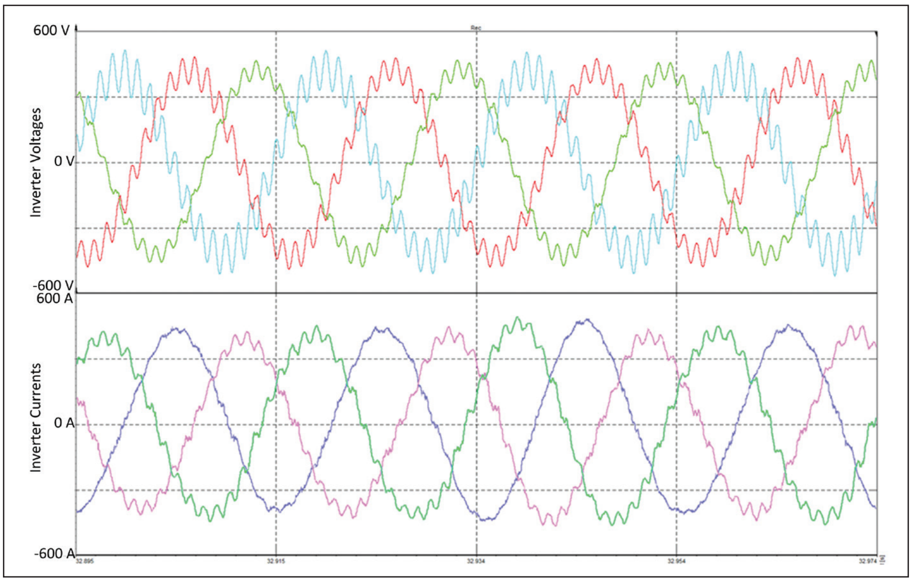

Figure 2. Harmonic oscillation at a frequency of 850Hz: instantaneous values of the inverter voltages (top) and currents (bottom).

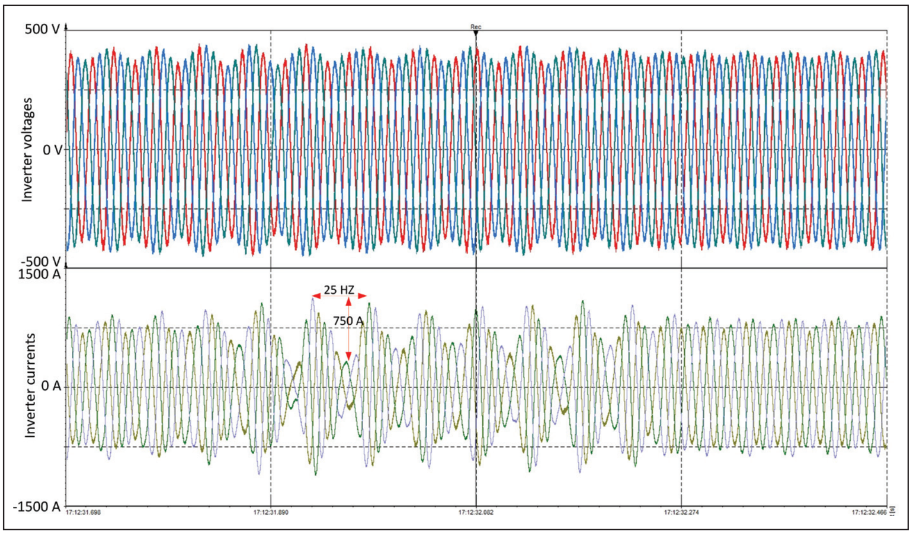

Figure 3. Subsynchronous oscillation at a frequency of 25Hz in a PV power plant with more than 100 parallel central inverters: inverter voltages (top) and currents (bottom).

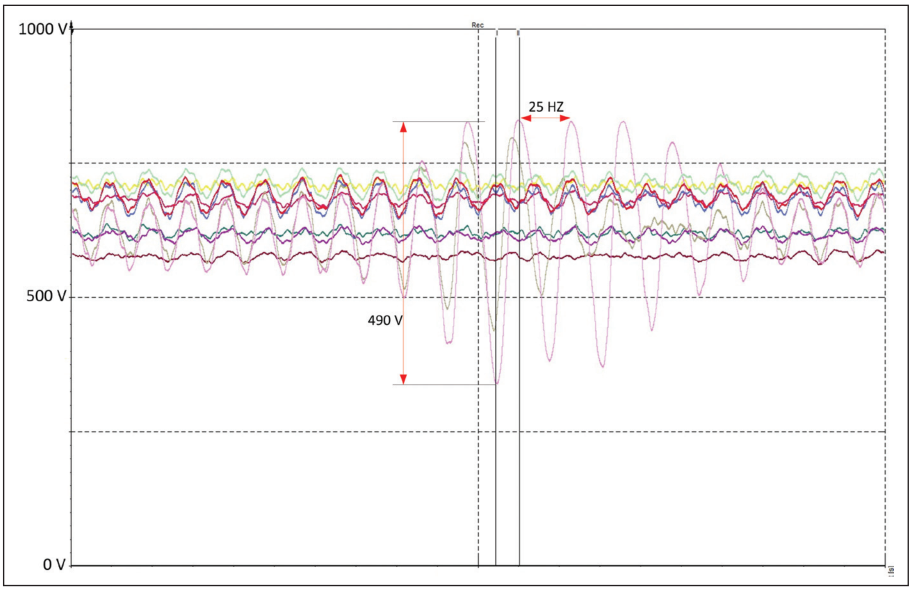

Figure 4. DC voltages of 10 inverters in a power plant with more than 100 central inverters, with the presence of a subsynchronous oscillation of 25Hz.

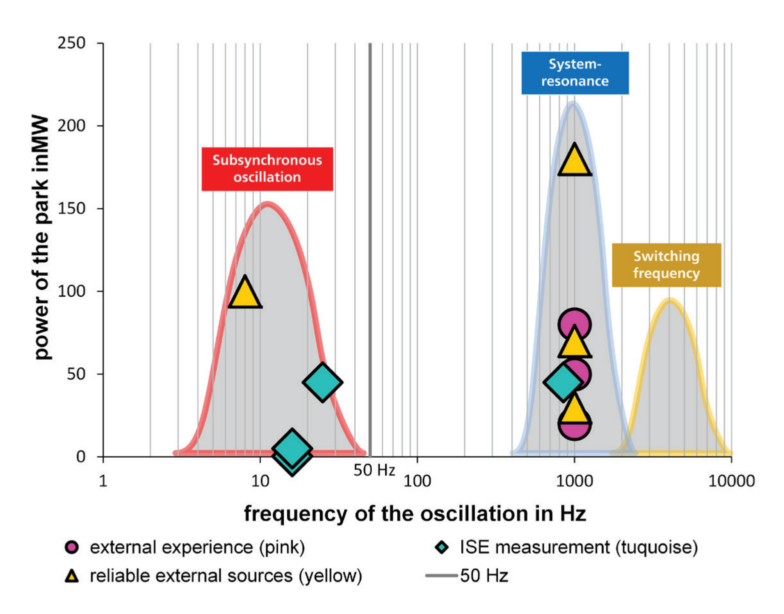

Figure 5. Overview of electrical instabilities in PV power plants.

indicate that the cause of the problem was oscillation. Generally, the disconnections of inverters cannot therefore be linked to oscillations in the plant.

One possible way of detecting instabilities is to install a power-quality measurement system at the plant; this system will recognise increased harmonic content in the grid voltage if an oscillation occurs at a high frequency, such as the system resonance. In the case of oscillations in the subsynchronous range, the flicker values will be increased. The flicker measurement evaluates voltage variations in the low frequency range between 0.05Hz and 35Hz (for 50Hz systems), with a weighting filter that has its maximum sensitivity at 8.8Hz [6].

If oscillations are detected in a PV power plant, several methods for damping are possible. For example, the oscillation can often be damped by changing the control parameters or the control algorithm of the inverters. This method, however, frequently presents problems regarding the certification of the inverters in compliance with the local grid code, because of the fact that as a rule the certification is only valid for one set of control parameters. Moreover, this method is also sometimes restricted as a result of the lack of processing power of the processor used in the inverter. In addition, restrictions of the hardware can limit the effectiveness of changing the control parameters or algorithm; for example, the sinusoidal filter or the switching frequency can limit the effect on the oscillation in the PV power plant. Nevertheless, an advantage of this method is that no additional components have to be installed at the PV plant, which saves time and money.

If it is not possible to damp the oscillation by changing the control parameters or algorithm of the inverter, additional passive filter elements can be installed at the power plant [7]. After instabilities are detected, these filters are specially designed for this specific oscillation problem. Another possibility is the use of active damping elements, which can be adjusted in a fast and flexible manner for all kinds of oscillation. The disadvantage of both of these methods, however, is the need for additional components, which add to the cost and require time to set up.

An expansion of the grid could also be a possible solution to the problem: the system resonance would increase to higher values and, therefore, typically uncritical ones. This solution is very costly, though, and needs a long time to put into action.

All the solutions described above are methods for combating instability after it has already occurred in the PV power plant. In the future, the goal should be to establish policies during the actual planning of the PV power plant to prevent these problems from happening in the first place. For large power plants in particular, during the planning one should anticipate these issues and consider possible actions to address them. There are, for example, ways of determining the system resonance of a planned power plant [8], which can give an idea of whether or not there is an increased risk of instability. However, detailed information about the structure of the power plant, and especially of the control system of the inverters, is necessary, which cannot always be provided by the manufacturers because of know-how protection.

Summary

In this paper, some problems with often-undetected instability problems in PV power plants have been described. The different oscillation phenomena observed in PV power plants have been classified and their possible effects on the performance of the plant discussed; moreover, possible reasons for the oscillations have been given.

Measurements of oscillation phenomena in real PV power plants have been presented. An overview of oscillation problems in PV power plants (depicted in Fig. 5) indicates that it is a widespread problem in power-electronic-dominated grids. The reasons why oscillations are often undetected are explained, as well as how it might be possible to increase the likelihood of detecting these oscillations more quickly. Possible countermeasures which can solve oscillation problems in existing PV power plants have been proposed.

To save time and money in implementing countermeasures in commissioned power plants, however, in the future the potential for electrical instability problems should be taken into account during the planning and construction phases of a power plant. ■

Author

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Project briefing

SOLAR STAR: INSIDE THE WORLD'S BIGGEST SOLAR PLANT

Project name: Solar Star
Location: Kern and Los Angeles counties, California
Project capacity: 579MW
Site 1,295 hectares

Covering a 1,295-hectare estate mostly of fallow farmland, the world's largest solar plant sits in the Antelope Valley straddling two counties of California. The Solar Star project has been supplying its full 579MW of capacity to the grid since May this year and it will be announced as officially complete before the end of 2015. *PV Tech Power* explored the designs behind this mammoth installation near Rosamond, California, to investigate what key factors had to be considered when creating a solar plant that can supply electricity to more than a quarter of a million homes.

BHE Renewables, a subsidiary of Berkshire Hathaway Energy (BHE), previously known as MidAmerican Energy, owns the project, which was developed, constructed and maintained by PV developer SunPower. Construction began less than three years ago and was completed around six months ahead of schedule. Meanwhile two 20-year power purchase agreements (PPAs) were signed with the utility Southern California Edison back in January 2011.

No development of this scale could be accomplished without overcoming a range of environmental and local community issues. Strangely, in this case, one of the biggest barriers stemmed from previous attempts by PV developers to build projects in the same valley, some without success.

Bryan Whitcomb, general manager, Solar Star project, BHE Renewables, tells *PV Tech Power* that other projects in the valley had had to grade much of the land to make it level enough to install solar modules, but this had created a lot of "fugitive" dust, which concerned locals. However, SunPower's Oasis Power Plant technology, with its 'light on land' approach, minimised the amount of grading required for the Solar Star, because the panels could be installed above the ground to alleviate problems with curvature of the land including hills and bumps.

"Our goal was not to touch the ground as much as possible because of our experiences with other solar sites in the valley," Whitcomb says.

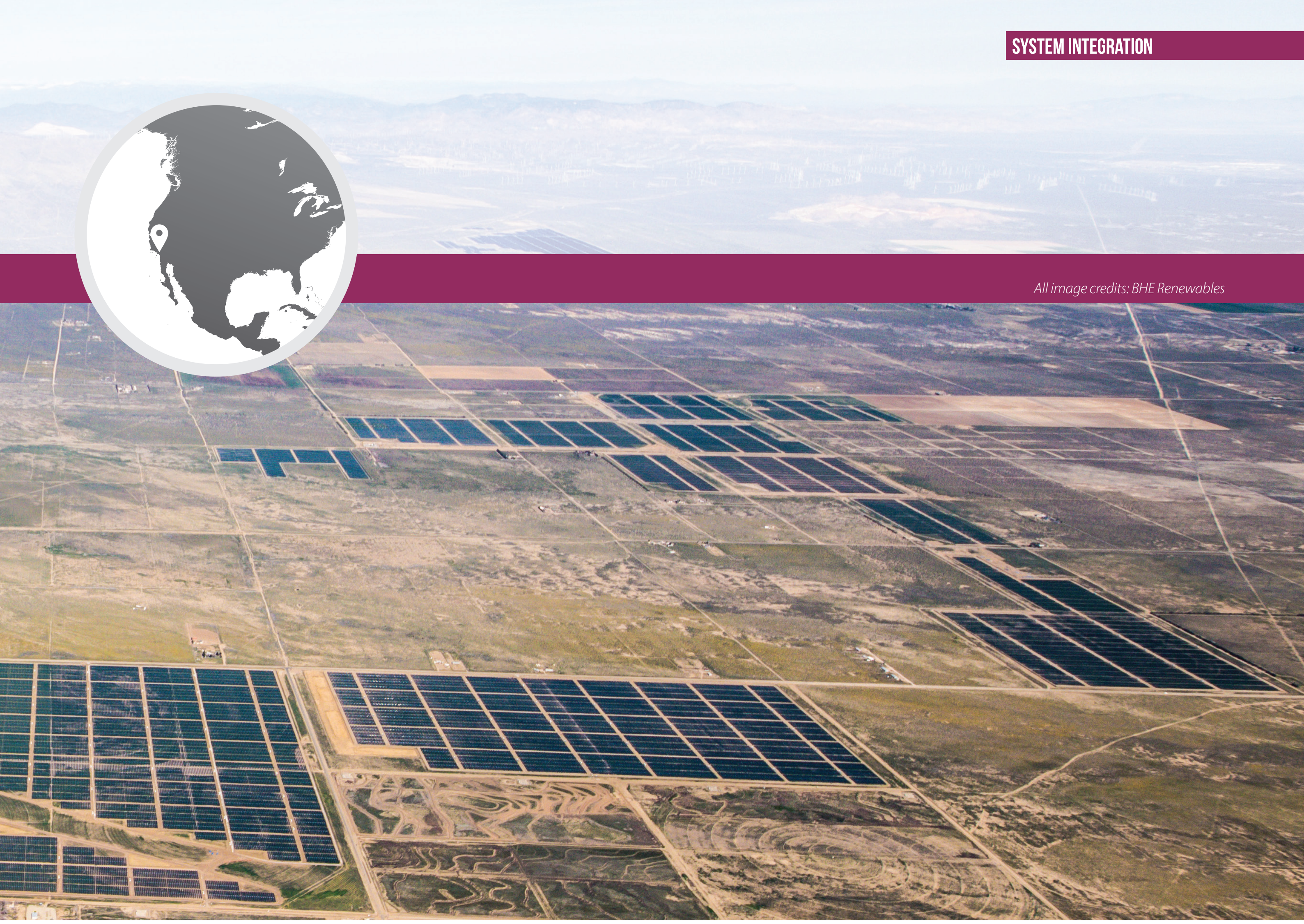
This off-the-ground approach is also cost-effective because it requires less heavy equipment on site, Whitcomb adds. The location is subject to strong winds, evidenced by the fact that it neighbours the largest wind farm in America, the 1,320MW Alta Wind Energy Center. These winds can exacerbate any dust issues.

The construction team pre-seeded the ground before installing so there was plant growth ahead of the build. Meanwhile ground was only graded in order to build roads for access to the plant inverters.

Looking from an aerial perspective, various segments of the plant appear oddly spread out. Whitcomb says this split came down to availability of land issues, because other PV projects in the middle of the site had never come to fruition. "One of the biggest challenges was splitting the design within the land we had and then getting the power to the grid," he says.

There were a few landowners with more than 100 acres and others owning five acres, which meant BHE Renewables had to buy several separate plots of land. This also contributed to the site not appearing as one continuous installation and being split up across the valley.

"The neighbours were still upset about what happened at other solar projects in



All image credits: BHE Renewables

the valley where they created a lot of dust. We spent a lot of time convincing them that we were going to do it the right way and we did – so we really have a good relationship with all of our neighbours and the local community," Whitcomb says.

The hardware

In terms of solar technicalities, the project team picked up publicly available data about the site's irradiance levels from Federal Emergency Management Agency (FEMA) flood maps and topographic maps, before installing metrology stations to verify the data.

The project uses approximately 1.72 million SunPower modules, which BHE regards as being able to deliver up to 75% more energy over 25 years than conventional panels. The panels use SunPower Maxeon cells, which have a copper foundation to make them stronger and more durable and to minimise corrosion. Cells with a weaker foundation are susceptible to cracks and can lose power when exposed to temperature swings, claims BHE.

SunPower also offered a 25-year combined power and product warranty, with a degradation rate of 0.4% a year after the first five years. The result is an 87% power level at the end of 25 years.

SunPower's Oasis technology installs the modules in high-density, cost-optimised power blocks. Using these standardised 1.5MW blocks, a kind of 'cookie-cutter' approach, allows a developer to use one template and multiply it to install a plant as large or small as required, but with a minimal time of construction. This also reduces field wiring and costs of labour, SunPower claims.

The Solar Star projects also use SunPower's C1 Trackers, which can produce up to 25% more energy than fixed-tilt systems by using GPS to follow the sun, according to BHE. Solar Star's panels are not tilted to the south so at high noon it experiences a dip in energy production compared to fixed-tilt systems. Nevertheless due to its tracking of the sun throughout the day, Whitcomb says it picks up energy far earlier in the morning and later in the evening, and maintains that level for some time. This gives a smoother energy input to the grid. The late-afternoon energy is also particularly valued because there is a strong load on the grid at that time of day as a result of demand for air conditioning within California.

The Oasis system also uses a mix of smart inverters from ABB and some from SMA, which feature voltage ride-through, curtailment control and solar reactive power, which enhance the plant's grid interoperability.

Whitcomb says that as technology has improved and interconnection requirements have increased, the plant has the capability to supply reactive load to the grid although it cannot do this at the same level as a giant thermal power plant or nuclear plant. Recently, inverter companies have had to meet several interconnection requirements put forward by the Federal Energy Regulatory Commission (FERC) and this is reflected in the plant's new capabilities.

"We can do voltage control. We can ramp up and down from zero to max output, and if voltage varies on the grid and dips we can actually ride through that. In other words the inverters won't shut down. They will just keep on putting power down and keeping up with it," he explains.

The Solar Star inverters are also assisted with larger capacitor banks, allowing the operators to switch capacitor banks as necessary when power factor requirements change.

The SunPower Tracking Monitoring and Control System (TMAC) is used to anticipate storm conditions and protect the array. The operators also use a supervisory control and data acquisition (SCADA) system to visualise the plant's operation, with rapid commissioning and historical data reports. This also helps the plant meet the requirements of the grid.

Back in 2011, when Southern California Edison signed up for the two PPAs relating to the Solar Star the utility remarked that it was advances in technology and economies of scale that would enable such a large solar project to be cost competitive. Furthermore the location within Kern County, which is recognised for its leadership in permitting solar energy deployments and the project's proximity to the major Southern California Edison substation, were also factored into the utility's evaluation of the levelised cost of energy (LCOE) offered by the plant.

Whitcomb says that it was easy to set up in Kern County which is a "very strong energy county" with plenty of oil and gas exploration alongside its renewable energy developments. Furthermore, Los Angeles County also has a large proportion of pro-solar locals. For example, it is illegal to build a new house in the nearby Lancaster area unless it includes solar panels on the rooftop. "That is the atmosphere of the environment we are working in here," Whitcomb says.

Grid connection

In terms of power evacuation, the Solar Star projects were located just four miles from a large substation, which is critical for a plant of this size. The Whirlwind 230/500 kV substation ties directly into the grid that supplies power to Los Angeles.

Whitcomb says: "That is what made it realisable because you cannot just put a project like this anywhere. You have to have good access to a large grid network."

The team minimised the amount of overhead lines being used by sharing poles with other local projects already in operation. There are several wind projects to the north of the site for the solar plant to share poles with, along with one other solar plant. Future projects located nearby will also share in this way. Whitcomb says putting up such giant poles is very difficult and using ones already installed alleviates a potential bottleneck.

In terms of grid connection, the project's distribution system is underground within the arrays. Medium voltage cables transition from underground to above ground poles with air switches. Overhead lines then carry the collected energy at 34.5kV to one of the three substations where the electricity is stepped up to 230kV on three separate lines, which connect the Solar Star projects to the Whirlwind Substation.

There are nearly 400 inverters of 1.5MW used at the Solar Star, hence the requirement of the significant medium-voltage (34.5kV) distribution network to transfer the energy to the three substations with minimal loss.

It is clearly a significant operation, but one made easier by strong local support for renewables. For the community at large, BHE Renewables says it is possible to be a good neighbour by being active in the community and supporting local events, serving on local boards, and hiring local workers who have the necessary skills.

There were around 650 construction jobs created during the three-year period, and several BHE staff will remain on site now that it is connected. It is also estimated to bring in around US$500 million for the regional economy.

The company already owns what was previously the world's joint-largest solar plant, the Topaz solar project in the San Luis Obispo County of California, developed by First Solar and which stands at 550MW. Another First Solar-developed project, Desert Sunlight, in Riverside County also stands at 550MW. BHE is also a minority owner of the 290MW Agua Caliente solar plant in Arizona, again developed by First Solar. Now the Solar Star site is yet another unprecedented project in terms of scale and it begs the question of just how big solar can go.

With the investment tax credit (ITC) for large-scale solar projects in the US currently scheduled to fall from 30% to 10% at the end of 2016, there are a lot of projects around the 100-200MW ranges that are rushing to get finished but there are no projects larger than the Solar Star visible on the horizon.

Neither Topaz nor Desert Sunlight were able to hold onto their crowns for longer than seven months, but for the moment Solar Star will remain firmly the world's largest solar farm. ■

Fraunhofer PV Durability Initiative for solar modules: Part 3

Module performance | The potential for PV modules to fail before the end of their intended service life increases the perceived risk, and therefore the cost, of funding PV installations. While current IEC and UL certification testing standards for PV modules have helped to reduce the risk of early field (infant mortality) failures, they are by themselves insufficient for determining PV module service life. In this paper, teams from Fraunhofer CSE and Fraunhofer ISE present the results of the Fraunhofer PV Durability Initiative's third round of testing, which now includes 10 module types

Current IEC and UL certification testing is done on a pass/fail basis: assessment of the relative reliability risk, and the guidance provided to manufacturers for improvement, are therefore limited [1–5]. The tests also lack standard protocols for comparing the relative durability risks between different module designs. Without these benchmarks, financial models must instead depend on a patchwork of methods to create predictions for relative durability. This makes it difficult to quantify which solar modules are best suited to a particular installation. The uncertainty creates confusion that increases perceived risk, delays financing and ultimately raises the cost of building PV power plants.

First announced in 2011, the PV Durability Initiative (PVDI) is a joint venture between the Fraunhofer Institute for Solar Energy Systems ISE and the Fraunhofer Center for Sustainable Energy Systems CSE, with a goal of establishing a baseline PV durability assessment programme. The aim is to create an open-source durability assessment protocol that will eventually form the basis for an international industry standard. The first round of testing included five module designs [6]; data for three more module designs were reported in the second round [7], and another two module designs are reported here for the third round.

PV modules are rated according to their likelihood of performing reliably over their expected service life. Modules are subjected to accelerated stress testing intended to reach the wear-out regime for a given set of environmental conditions; in parallel with the accelerated tests, modules are subjected to long-term outdoor exposure. The correlation between the accelerated tests and actual operation in the field is an ultimate goal of the PVDI programme. As understanding of PV module durability grows, the test protocols will be revised as necessary. The regular publication of durability ratings for leading PV modules will enable PV system developers and financiers to make informed deployment decisions. This paper provides summary data for ten module types from the three rounds of testing to date.

> "The correlation between the accelerated tests and actual operation in the field is an ultimate goal of the PVDI programme"

PVDI's accelerated test component is an extension of familiar reliability stress tests [8–12]. Since the acceleration factors of most stress tests are not yet known, the protocol combines accelerated testing with long-term outdoor exposure testing. Until the acceleration factors for various stress tests are identified, the comparison of modules remains the best means of assessing (relative) module service life. To enable a comparison of different module technologies to be made, performance is converted to a rating on a scale of zero to five (see Table 1), and the modules are rated for performance. Modules in group 1 (potential-induced degradation) are rated based on their performance at the end of the test, following light exposure, whereas modules in the remaining groups are rated based on their 'weighted normalised performance'. The weighted normalised performance is the performance in each test interval, weighted by the final performance value and normalised by the initial value. Weighting by the final performance value is intended to give a higher rating to modules that show the least degradation under the tests with combined stress effects. In the years ahead, outdoor measurements of the modules under test will be used to allocate the proper acceleration factors for the accelerated test sequences.

The programme requires that, where possible, commercial modules be purchased on the open market, to avoid selection bias. If the module design is not available on the open market, the module ID label is annotated by an asterisk to indicate how the modules were acquired.

The manufacturers of modules tested in the programme have the option of withholding their identity from reports; however, the data generated remain (an anonymous) part of the dataset, for ongoing comparison with the rest of the field. As the PV Durability Initiative continues, a record of previous results will be available for comparison with the recent additions. To date, testing to this protocol has been completed in three rounds, on ten commercial module types. The manufacturers of four modules have attached the following identifications to the results:

- PVDI01*: SunPower E20 module
- PVDI06*: Aleo (Type S18) module
- PVDI09*: First Solar Series 3 Black (FS-395-Plus) module
- PVDI10*: First Solar Series 4 (FS-498/497) module

The PVDI01*, PVDI09* and PVDI10* modules were tested at Fraunhofer CSE / CFV Solar Test Laboratory, Inc., and the PVDI06* modules were tested at Fraunhofer ISE.

The PVDI test protocol comprises five different tests, which are discussed in detail in the following sections; a summary of the test results for each group is given. The performance of the modules tested in the third round of PVDI is presented together with the results from the previous two rounds of PVDI for comparison purposes, for each of the test groups. Any changes to the testing procedures from the first two rounds have also been indicated where applicable. Finally, the results of all the modules tested in all three rounds of PVDI have been summarised (see Table 2), and the modules have been given a rating according to their likelihood of performing reliably over their lifetime.

Test sequences and results

The test protocol is broken down into five test groups (Fig. 1). A minimum of fourteen modules is currently required to complete the tests. Modules are initially characterised, then assigned to a particular test sequence. The modules assigned to the control set are stored in a temperature-controlled environment and are used to confirm the consistency of the power measurement systems. As each module progresses through its assigned test sequence, it is repeatedly characterised: for example, in group 4 each module is characterised after every set of two hundred thermal cycles.

At each interim test point, electrical performance is determined, and electroluminescence and infrared images are collected. In some instances, wet leakage current and insulation resistance are also measured.

Initial characterisation and stabilisation

Commercial modules purchased on the open market arrive at the test facility in their standard shipping container and will have undergone some stress associated with the shipping process. The modules are unpacked and visually inspected for any manufacturing defects or for damage suffered during shipping.

Following the visual inspection, the modules undergo light-soaking to allow any light-induced degradation to occur, if no manufacturer-specific preconditioning procedure is in place. During light-soaking, the modules are maintained at their maximum power point, and *I-V* curves are collected periodically. Light-soaking is terminated once the modules have reached a stable performance level. Stability is determined by taking measurements from three consecutive periods to see if they satisfy the condition $(P_{max}-P_{min})/P_{mean} < 2\%$. Light-soaking requires a minimum of 60kWh/m², and may take upwards of 600kWh/m² to complete. The time to complete this preconditioning is technology dependent: thin-film technologies generally take longer to stabilise than crystalline or polycrystalline silicon technologies. PVDI09* and PVDI10* are thin-film modules, which are known to exhibit a transient behaviour as a result of dark storage. Measurements of modules affected by dark storage that are taken without following the proper conditioning procedures will not provide a true power characterisation. A First-Solar-specific preconditioning procedure was applied.

Once stabilisation is complete, the initial characterisation is performed, consisting of light current–voltage (LIV) measurements at standard test conditions (STC), electroluminescence imaging, infrared imaging, and measurements of wet leakage current and insulation resistance.

> "Some module designs will recover their power performance when the high electrical bias is removed or reversed"

The initial performance data are used throughout the test sequence to normalise successive performance measurements; the data are also used in the comparative analysis of the nameplate performance ratings.

Group 1: potential-induced degradation

The group 1 test sequence is designed to assess a module's ability to perform under the stress of high electrical potential. The class of degradation mechanisms caused by a high potential between internal and external components is collectively referred to as *potential-induced degradation (PID)* [13,14]. Since PV modules may be installed where the electrical potential between the module and the earth ground can be positive or negative, modules are tested at both positive and negative electrical biases. The magnitude of the electrical bias during testing is set to the module's rated maximum system voltage.

The test begins by mounting the module in a vertical orientation (to reduce condensation accumulation) in a heat and humidity chamber. The electrical leads of the module are shorted together and connected to the biasing power supply. The opposite polarity of the power supply is connected through a sensing resistor to the frame of the module or to other conductive mounting points. Since the most common PID mechanisms occur under negative bias,

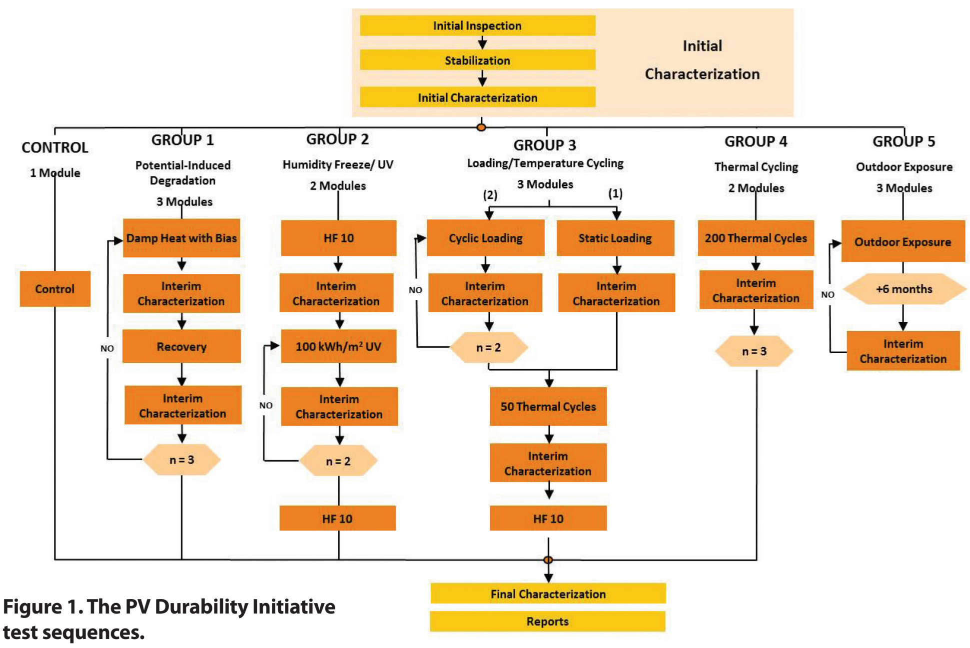
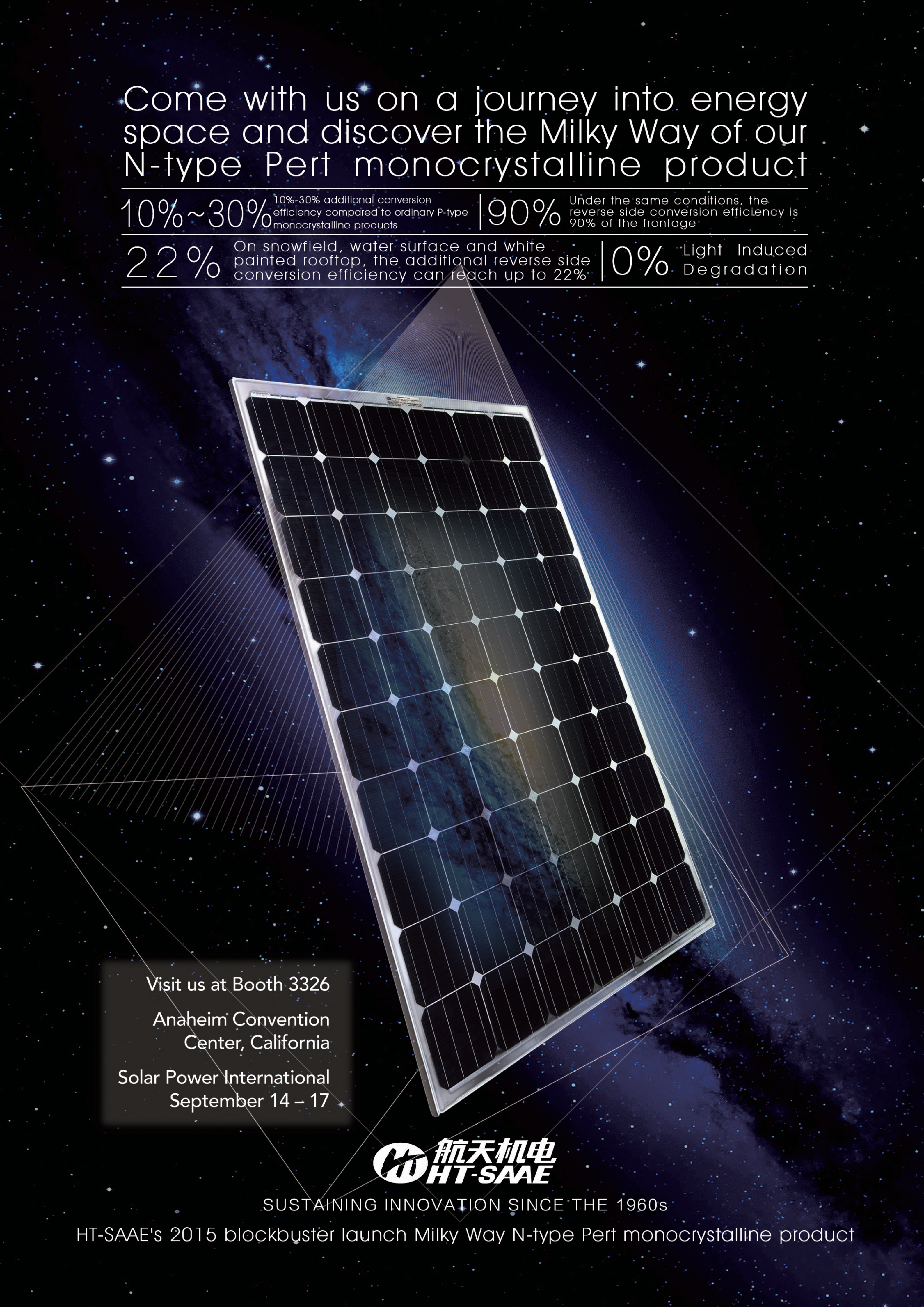


Figure 1. The PV Durability Initiative test sequences.



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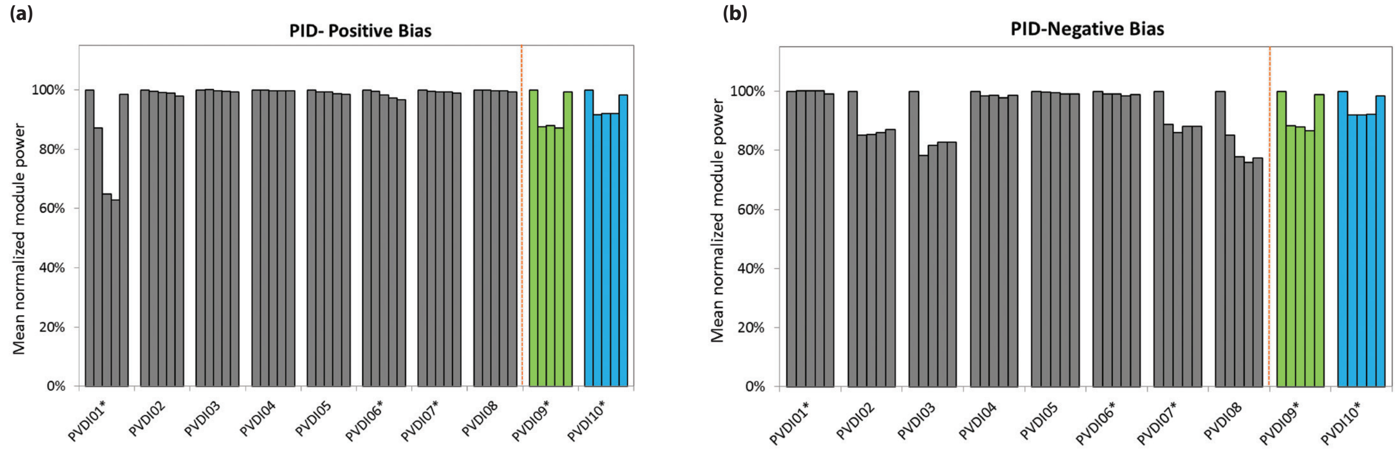


Figure 2. Mean normalised performance degradation of all modules of a test group in PID testing under (a) positive bias and (b) negative bias. To determine the PID rating, the final performance value after light-soaking/conditioning is used. (If the module design was not acquired on the open market, the module ID label is annotated with an asterisk.)

the current procedure requires that two modules be negatively biased and one positively biased. In order to represent operating conditions, a light bias (illumination) should also be applied during voltage biasing. Since the configuration of most heat and humidity chambers precludes this, the modules are currently exposed to light-soaking after heat and humidity exposure, to assess for recoverability of performance.

In the case of PVDI09* and PVDI10* modules, the manufacturer-specific procedure was applied. It should also be noted that, for the third round of PVDI testing, the PID testing protocol was modified on the basis of the new draft IEC62804 TS. In this round the modules were subjected to 288 hours of PID testing, and interim measurements were taken at 96, 192 and 288 hours and after a recovery step.

Depending on the module design and the failure mechanism involved, some module designs will recover their power performance when the high electrical bias is removed or reversed. Other modules have exhibited resistance to, and recovery from, PID when operated near their maximum power point under light exposure [2] or by raising the cell temperature to the normal operating cell temperature. For such modules, PID is not expected to have an impact in operation.

The results of the PID testing are summarised in Fig. 2. PVDI01*, as well as PVDI09* and PVDI10*, showed power degradation before a recovery conditioning procedure. These three types of module have a low probability of exhibiting PID degradation under field operating conditions, because they demonstrated recovery, which would probably also be the case in the field. To date, four out of the ten tested modules designs exhibit PID under negative bias.

Group 2: humidity freeze (HF) and ultraviolet (UV)

The group 2 test sequence is designed to assess a module's susceptibility to moisture in the presence of freezing conditions caused by sub-zero temperatures after the module has been saturated by humidity, and at high levels of UV radiation. In the first two rounds of PVDI testing, the damp heat UV sequence was combined into a single test sequence to provide a means of assessing the effects of UV on modules in damp environments. However, no distinction between different module designs was possible, which led to a change in this test group 2: the intention was to make the testing regime harsher in order to induce detectable degradation, as the PVDI test protocol aims to reach the wear-out regime of modules. In the third round, the test was therefore modified to combine humidity freeze with UV.

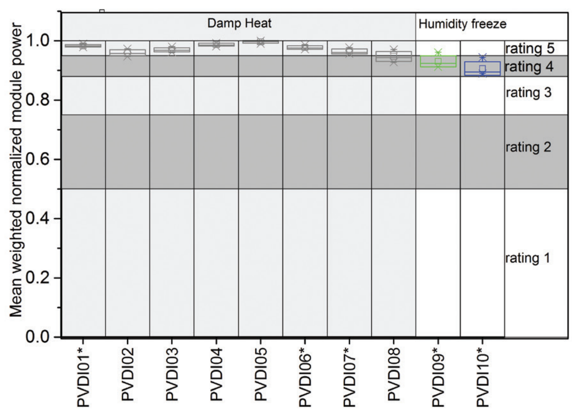
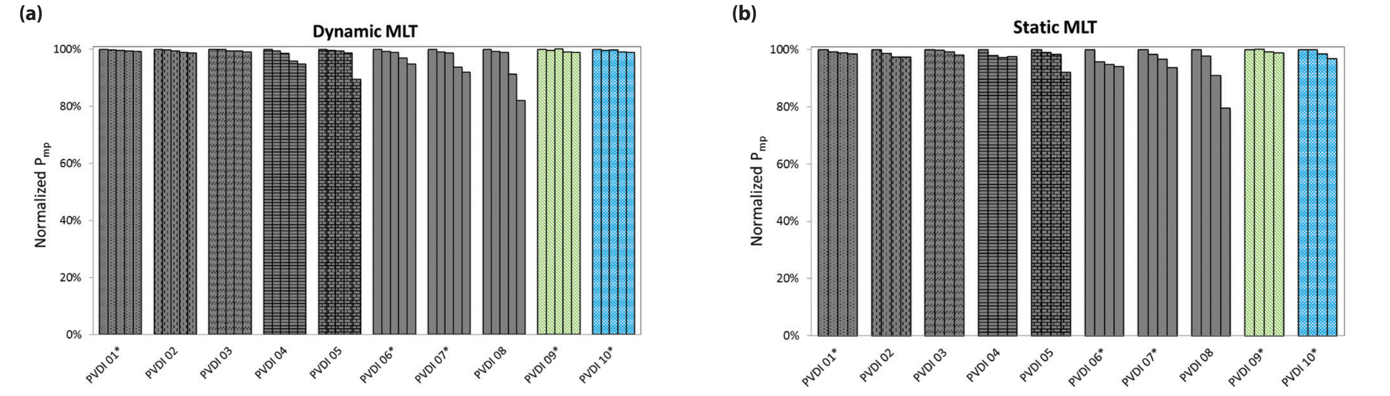


Figure 3. Mean weighted normalised module power (see Equation 1) of all modules of a test group after damp heat and 100W/m² UV exposure for PVDI01*–PVDI08, and after humidity freeze and 200W/m² UV for PVDI09* and PVDI10*.

The HF 10/UV sequence ('10' signifies 10 cycles) was combined into a single test sequence to provide a means of assessing the effects of UV on modules in the presence of moisture that forms ice crystals at extremely low temperatures. The HF 10 conditions represent a harsher environment, which is expected to accelerate degradation because of UV exposure; the sensitivity of module interfaces – such as junction box/back glass, edge seal/glass and interlayer/cell and glass – under low-temperature conditions and UV exposure is tested.

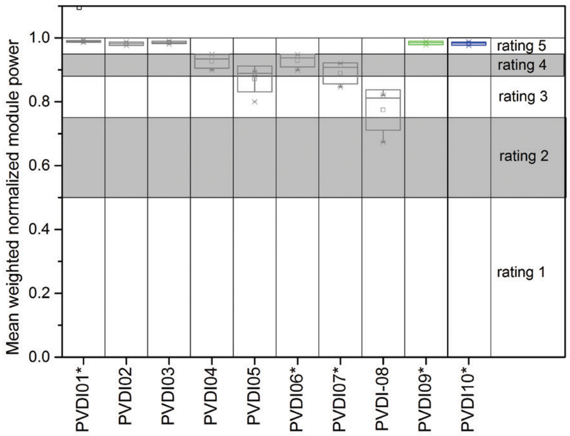
The test begins by mounting the module in a vertical orientation in a climatic chamber. Each module has a temperature sensor attached to either the front or the back surface in order to monitor and record the temperature of the module during the test. After 10 complete cycles, the modules are placed in a UV chamber, where they are subjected to high-intensity UV light for a total dose of 200kWh/m², which is double the UV dose in the previous rounds of testing. The exposure is carried out in two steps, with characterisation and re-saturation of the modules after each iteration. After a recovery time of 2–4 hours, the HF 10 and UV tests are repeated.

In the previous PVDI rounds one and two, the damp heat UV testing sequence did not demonstrate significant degradation in any of the modules tested (Fig. 3). The wear-out regime for these conditions had therefore not yet been reached, and no conclusions could be drawn with regard to relative susceptibility to damp heat and UV stress. This test was hence

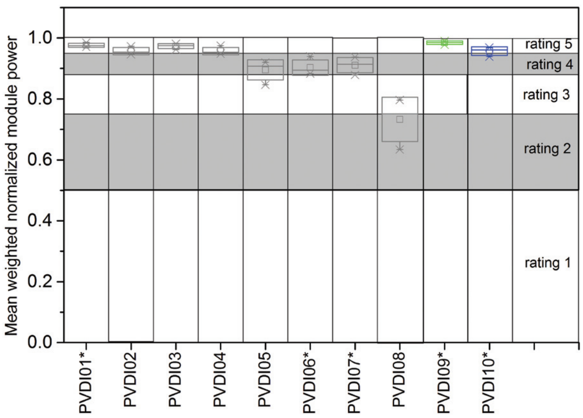


▲Figure 4. Normalised average performance degradation at the various test intervals of all modules of a test group in the case of: (a) dynamic loading; (b) static loading. The specific intervals are: initial, after loading, after 50 temperature cycles and after 10 humidity–freeze cycles.

revised in order for the wear-out regime for UV exposure to be reached, by replacing damp heat with humidity freeze and doubling the UV dose. Both the module designs PVDI09* and PVDI10* exhibited some degradation after the second round of UV testing: the module power output decreased by 5.1% in both cases. After exposure to the second HF 10 testing, however, the power recovers somewhat.



▲Figure 5. Mean weighted normalised module power (see Equation 1) of all modules of a test group after dynamic loading.



▲Figure 6. Mean weighted normalised module power (see Equation 1) of all modules of a test group after static loading.

Group 3: static and dynamic loading, thermal cycling, and humidity freeze

The group 3 test sequence is designed to assess the effect of both static and dynamic loading on a module's performance and package integrity.

A module's ability to withstand static mechanical loads for prolonged periods is significant primarily for regions where snow loads are present. The static test is performed at a temperature of –40°C and the dynamic test is performed at –30°C in order to increase the stress in and between materials [15,16]. To perform the static test, the module is loaded in a downward direction (i.e. the side that is usually exposed to the sun faces the ground in this set-up) by a force of 5.4kPa, for three one-hour periods, with a rest period between these loading periods.

The dynamic loading portion of the test is designed to assess the effects of intermittent loads, such as wind loads. This test is carried out at a low temperature, at which the effects are expected to be the most severe. The encapsulant modulus will increase dramatically as the module temperature approaches the encapsulant's glass transition temperature. This stiffening of the encapsulant results in greater stress transmission to the cell and interconnections, which may result in cell cracking and interconnection failure, for example.

The dynamic loading, with a maximum force of 2.4kPa at a frequency of 1.0Hz, flexes the module normal to the surface, in directions both positive and negative with respect to the plane of the module at rest. This is performed for two sets of 500 cycles each, with an interim characterisation to record any change in performance and to inspect for the appearance of cell cracks and damaged interconnects.

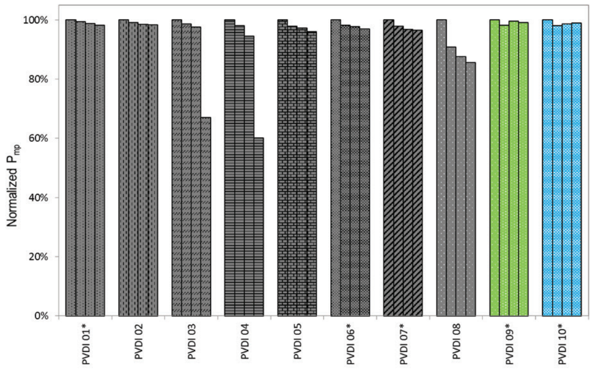
Following load testing, the modules are subjected to thermal cycling and humidity–freeze stresses: this is done to amplify crack propagation initiated during the load tests (Figs. 4–6). PVDI09* and PVDI10* did not exhibit any significant degradation after mechanical load testing or after thermal cycling and humidity–freeze tests. The likelihood of degradation due to static or dynamic mechanical loads is therefore very low for these modules.

Group 4: thermal cycling

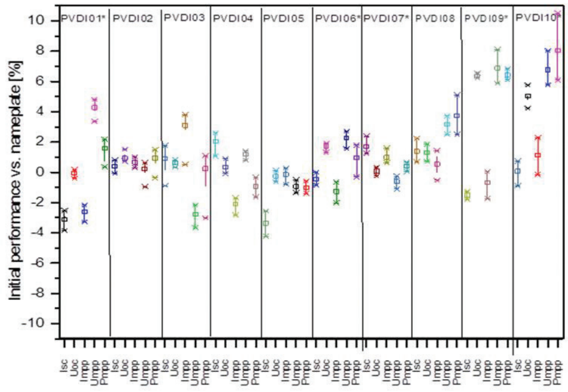
The group 4 test sequence assesses a module's ability to withstand the effects of shade-induced, diurnal and seasonal temperature changes. Under normal operating conditions, a module will be subjected to daily temperature excursions as well as more rapid temperature changes due to transient cloud cover. When temperature transients occur, stresses can be induced inside the modules as a result of the different thermal expansion characteristics of the various materials [17].

To simulate the heating effects due to current flow under normal operating conditions, the modules are biased with a current equivalent to their short-circuit current. The chamber is cycled between –40°C and +85°C at a constant rate, with a dwell of 10 minutes at both temperature extremes. Each module undergoes a total of 600 cycles; characterisations are performed after every 200 cycles.

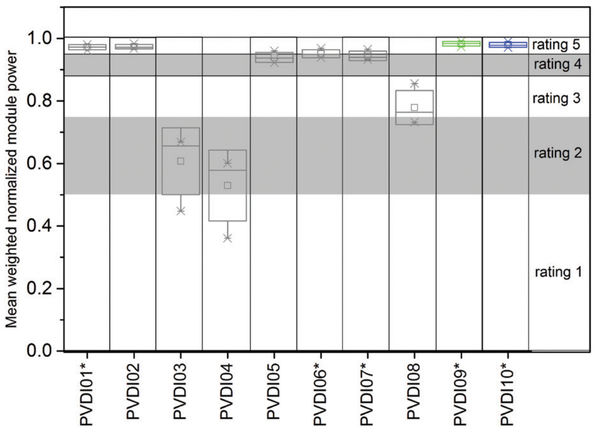
The results of the thermal cycling are shown in Figs. 7 and 8. Both PVDI09* and PVDI10* modules did not show any significant degradation in performance, even after 600 thermal cycles.



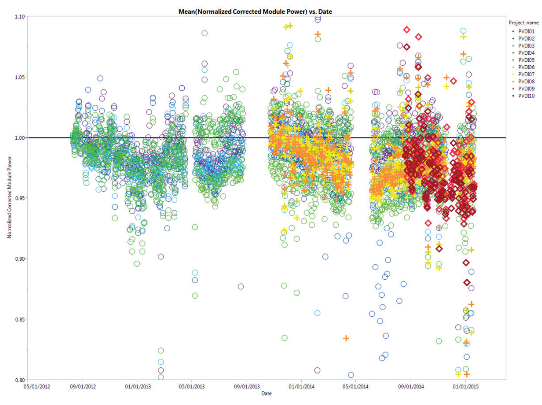
▲Figure 7. Normalised average performance degradation at each interval of 200 cycles of all modules of a test group after thermal cycling.



◀Figure 10. Baseline performance parameters with respect to nameplate rating.



▲Figure 8. Mean weighted normalised module power (see Equation 1) of all modules of a test group after thermal cycling.



▲Figure 9. Normalised module power for all modules subjected to outdoor testing.

Group 5: outdoor energy performance

The group 5 test sequence is designed to assess a module's performance under real-world (non-accelerated) operating conditions [18]. Three modules of each type are installed on an outdoor test station and monitored for long-term degradation effects. One module is instrumented with a power supply that maintains the module at its maximum power point and sweeps *I-V* curves at preset intervals; these data are used to calculate the performance ratio of the module. The other two modules are maintained at a fixed load near the maximum power point.

"All of the module designs are within the manufacturers' specified power tolerance limits"

All three modules are removed from the test rack at six-month intervals, visually inspected and tested at STC, then returned to the outdoors. Modules will be monitored on an ongoing basis for several years. The outdoor data will be compared with the accelerated test data, as well as with outdoor data from analogous module designs at other sites around the world. The ultimate goals are to understand long-term wear-out, identify new failure modes and determine the acceleration factors that are necessary to correlate the accelerated test results to outdoor operating lifetime. Fig. 9 shows the plot of the normalised module power for all the modules from the different rounds of PVDI over the entire duration of the PVDI programme so far.

Nameplate rating comparison

Fig. 10 illustrates initial module (STC) performance relative to the nameplate rating. Manufacturers may intentionally rate their modules below their expected initial performance to provide a performance buffer and reduce the risk of warranty claims. The results indicate that all of the module designs are within the manufacturers' specified power tolerance limits.

Module performance ratings

The module's performance is based on the measured electrical performance at STC. For the rating, a mean of the weighted normalised module power *P* is used:

$$P = \frac{\bar{P}_{n,n}}{n} \cdot \sum_{i=1}^{n} \bar{P}_{n,i} \qquad (1)$$

where *n* is the number of performance measurements within a test sequence, and $\bar{P}_{n,i}$ is the mean power, normalised with regard to the initial measurement, of all modules in a test group at the measurement step *i*. In the determination of *P* for test group 1 (PID), only the values of the initial and final measurements are used – this is because of the recovery process after the PID stress test.

There are four main rating categories for each of the testing groups:

1. **PID:** This category indicates a module's probability of surviving in an environment where there are large potentials (600–1000V_{DC}) between the active circuit of the module and ground.

2. **Humidity–freeze and UV:** This category indicates a module's probability of surviving and performing as specified in environments with high temperature and humidity as well as sub-zero temperatures.

3. **Static and dynamic mechanical loads:** The static load category indicates a module's probability of surviving in an environment where it will be regularly subjected to static mechanical loads, such as heavy leaf-fall, snow or ice. The dynamic load category indicates a module's probability of surviving and performing as

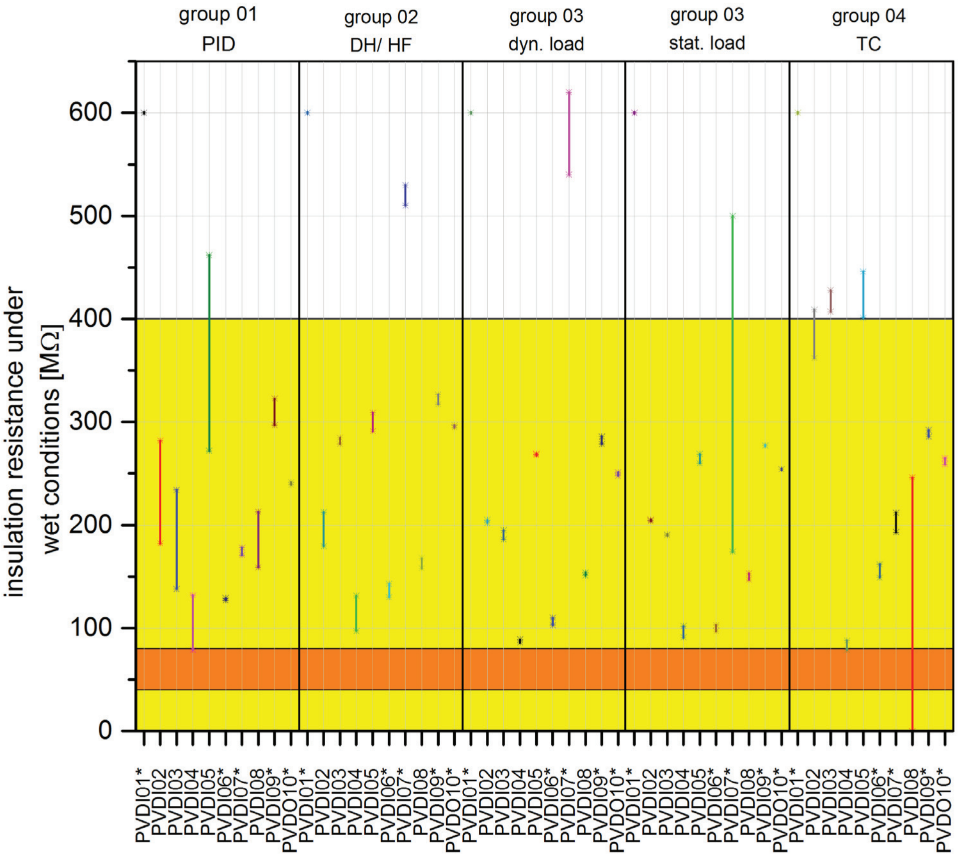
specified in environments where it will be subjected to constantly changing mechanical loads, such as wind.

4. **Thermal cycling:** This category indicates a module's probability of surviving and performing as specified in environments where there are temperature extremes and an expectation that the temperature will vary widely diurnally and annually.

Table 1 summarises the performance rating criteria, and Table 2 lists the performance ratings for the modules tested.

Rating	Rating criteria
5	$P \geq 0.95$
4	$0.88 \leq P < 0.95$
3	$0.75 \leq P < 0.88$
2	$0.50 \leq P < 0.75$
1	$P < 0.5$
0	$P = 0$

▲**Table 1. Module performance rating ranges.**



▲**Figure 11. Wet leakage resistance results for all modules by project and test group.**

	Environmental conditions					
ID	PID	DH/UV	HF/UV/UV/HF	Dynamic load	Static load	Thermal cycling
PVDI01*	5	5	N/A	5	5	5
PVDI02	4	5	N/A	5	5	5
PVDI03	4	5	N/A	5	5	2
PVDI04	5	5	N/A	4	5	2
PVDI05	5	5	N/A	3	4	4
PVDI06*	5	5	N/A	4	4	5
PVDI07*	4	5	N/A	4	4	4
PVDI08	3	5	N/A	3	2	3
PVDI09*	5	N/A	4	5	5	5
PVDI10*	5	N/A	4	5	5	5

▲**Table 2. Module performance ratings based on mean weighted normalised power measurements.**

	Wet leakage [MΩ]			Wet leakage [MΩ•m²]		
ID	Min	Max	Mean	Min	Max	Mean
PVDI01*	9,999	9,999	9,999	16,308	16,308	16,308
PVDI02	180	409	258	293	668	421
PVDI03	138	428	260	206	639	388
PVDI04	79	132	98	131	218	162
PVDI05	260	462	338	423	753	551
PVDI06*	97	162	128	154	257	202
PVDI07*	171	620	333	287	1,040	559
PVDI08	0	246	163	0	402	267
PVDI09*	277	327	300	200	235	216
PVDI10*	239	297	259	172	214	186

▲**Table 3. Wet leakage results for different modules tested under PVDI.**

Wet leakage results

The wet leakage current test is performed to evaluate the integrity of the package, which determines the safety of the module. Package integrity is determined by the leakage resistance density at the conclusion of a test sequence.

The magnitude of the leakage resistance density is dependent on the voltage applied, the area of the module and the resistance of the module's insulating materials. To normalise the leakage resistance for the comparison ratings, the measurements are normalised by area to yield resistance per square metre. The resistances are then binned according to the IEC leakage resistance limits and an equivalent resistance for the OSHA ground-fault leakage current of 5.0mA [19]. The equivalent resistance at 5.0mA is 200kΩ for a system voltage of $1kV_{DC}$. This method ensures that no module receives a rating above zero if it has a leakage current greater than 5.0mA. The wet leakage resistance results for all the PVDI modules are summarised in Table 3 and Fig. 11.

Authors

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Understanding module degradation in utility-scale PV plants

Power loss | The highly accurate module efficiency certified by accredited laboratories right after module production is at odds with the very rough estimate of the module's long-term efficiency stated by the manufacturer for its expected lifetime, through a commonly accepted and industry-standard power warranty. Agustin Carretero of skytron energy presents an innovative method for calculating module degradation by using string-monitoring systems, and compares the results obtained for a case study with the module manufacturer's power warranty statement

The potential for photovoltaic energy to be a major contributor to the world´s future energy mix is heavily dependent on the improvements being made in the energy conversion efficiency of the photovoltaic cells and modules. Manufacturers are constantly researching and applying new materials, always seeking to improve on the market-leading efficiencies, so that they can capture the attention of investors and decision makers. However from an investment perspective, just focussing on a module's efficiency directly after production could be misleading. The long-term stability of module performance is often not given the consideration it deserves. The high accuracy module efficiency figures cited by module manufacturers, taken directly after production and certified by accredited laboratories, contrast strongly with the very rough estimates quoted for their long-term efficiencies, usually through an industry-standard power warranty that is common across makes. Accurate and reliable long-term efficiency figures are still lacking in today´s module datasheets. In this article, following a description of the procedures commonly used to quantify long-term module degradation, an innovative method for calculating degradation using string-monitoring systems is presented. This can serve as a means of comparing actual results from a plant against the module manufacturer's power warranty statement.

The state of the art

Accurate prediction of long-term module performance under real environmental conditions is a topic that still involves certified laboratories and research institutions. For such an analysis, two main procedures are commonly used; however each has its advantages and drawbacks.

Module flashing under standard test conditions (STC)

The usual procedure for determining the rate of degradation of installed PV modules is to dismount a number of them periodically and then re-measure them in an accredited laboratory. By comparing the module power with that declared by the module manufacturer in its datasheet, the long-term module degradation can be determined. The main advantages of this method are that it is module-specific and that it is always done under exactly the same, ideal conditions. However, only a small number of modules are used, which may not be significant enough. This is especially true of utility-scale PV plants, where the exposure conditions and design parameters can vary across over the entire field. Besides this, the dismounting and remounting of individual modules of the PV array causes not only temporary energy losses, but also requires the intervention of the maintenance team. So the already expensive cost for producing flashing reports is inflated by contingencies for technical risks and other maintenance charges.

Plant performance analysis under real conditions

The second procedure for determining module degradation is to take advantage of the monitoring equipment that is often installed in large PV plants. Here, remotely monitored system data and measurements of the weather conditions can be used to systematically analyse and evaluate the systems and their components. In contrast to the module flashing approach, the results here are based on real operational conditions, and are statistically significant since all the modules in the plant are considered. However, a source of error comes from inaccuracies in the plant monitoring equipment being used. For analysing plant performance, energy measurement data from the utility energy meter or the inverters have commonly been used; the accuracy of these is typically ±5%. Further, this equipment is not always connected directly to the target modules, thus bringing in additional factors that have nothing to do with module degradation (inverter efficiency, balance-of-system losses, etc.). For the detection of such low, long-term module degradation, high-accuracy monitoring equipment is required with a low time resolution and which is mounted as close to the modules as possible. In contrast to the flashing procedure, no additional intervention is required from the maintenance team, so making it much more cost effective.

Proposed solution

By merging the main advantages of both previous procedures and taking advantage of high-accuracy string monitoring, a new methodology for detecting long-term module degradation has been developed: Simulating Module Flashing under Real Conditions. It is based on string power measurements to a minute's resolution, based on current and voltage samples every 100 milliseconds (then averaged over a minute), but only those where the weather conditions are close to STC. Next, this real measured power is compared with the string STC power, normalised to the selected STC-like conditions. By applying this analytical procedure based on historically monitored data to a utility-scale PV plant, module degradation can be obtained to string level in a cheaper, faster and more practical way [1].

To understand module degradation, the model shown in Figure 1 can be used, where (a) is the nameplate power tolerance and (b) is the annual rate of degradation. The solution outlined here:

- Uses a precise time-filtering algorithm to search for clear-sky conditions. The calculation is then performed only under these conditions.
- Analyses the annual deviation of the radiation sensor due to ageing and compensates the measurement data accordingly.
- Simulates the string power by normalising its STC power to the measured weather conditions after compensation.
- Calculates a measurement for string power by multiplying current and voltage measurements from the combiner boxes, taking advantage of both its ±0.5% measurement accuracy over full temperature range and its one-minute time resolution.
- Obtains a figure for string power deviation by comparing the measured power of each string to its simulated version.

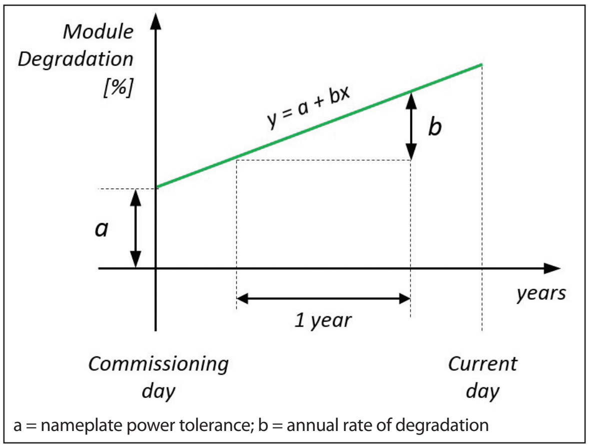
More about each of these aspects is explained in the following paragraphs.

Time filtering

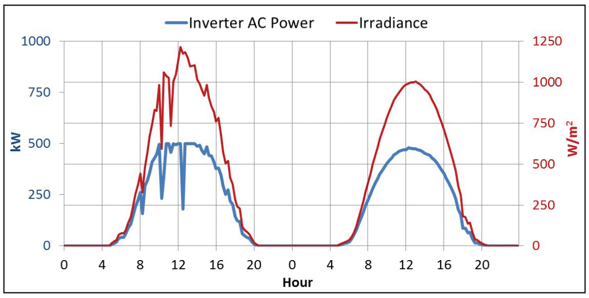
In order to obtain a trend-line such as that in Figure 1, each day of the whole monitored history of the plant is assessed consecutively, so as to find those with clear-sky conditions. A time window of one hour, centred on the solar noon, is chosen for each day, according to the change of the solar azimuth angle over the year. Next, the power output of the inverters is checked over the selected time window to ensure that none has reached its nominal power (inverter clipping, Figure 2). Notice how the inverters will clip on days with intermittent sunshine, because on such days the modules are cooler and perform better.

Thirdly, the thermal stability of the modules is evaluated by checking that the irradiance level remains high and stable over the selected time window. The irradiance measurements for two almost clear days have been plotted in Figure 3.

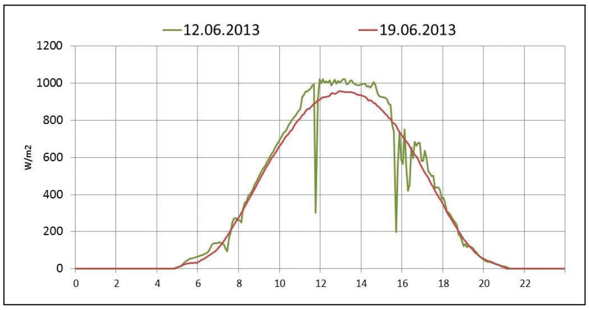
From the figure, it can be see that the selected clear-sky day is not the one with the highest irradiance at noon, but that with the most stable irradiance.



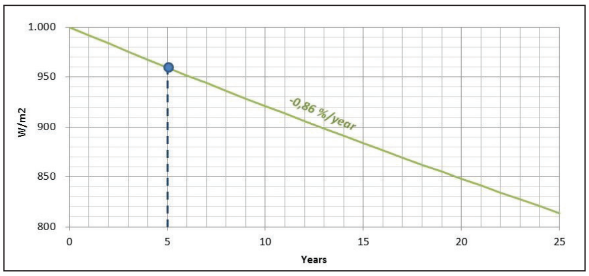
▲ **Figure 1. Modelling module degradation.**



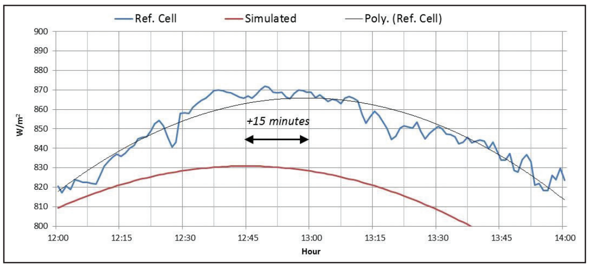
▲ **Figure 2. Effect of inverter power clipping.**



▲ **Figure 3. Intensity and stability of irradiance.**



▲ **Figure 4. Sensor ageing deviation.**



▲ **Figure 5: Misalignment of sensor orientation.**

Irradiation sensor ageing compensation

To calculate the ageing of the irradiation sensor, the variation in irradiance between a sensor measurement and a simulation of the clear-sky irradiance is analysed for each clear-sky day. To assess the impact of the sensor time resolution, four different resolutions have been analysed, and by sketching the progression of the variation over time, different sensor annual deviations due to ageing can be obtained:

Time resolution	Annual deviation
15min	–1.11%
10min	–1.15%
5min	–0.96%
1min	–0.86%

Impact of measurement time resolution.

For this case study, the manufacturer specified an annual deviation of <1% for the radiation sensor. It can be observed that a time resolution under five minutes is necessary to detect this. Taking the manufacturer´s initial sensor calibration, the deviation of the sensor's irradiance measurement due to aging can be plotted as in Figure 4.

After five years of monitoring, and without any recalibration over this period, the measured value under STC conditions was found to be 960W/m², i.e. 40W/m² less than the initial measurement. The resulting annual deviation is **8W/m2/year**. This annual deviation can be used to adjust the calculations for module degradation.

Besides the ageing of the sensors, any misalignment in the orientation between the reference cell and the modules can be

"Accurate time filtering is necessary in order to select both the optimum time window and the clear days for which the power deviation calculation should be performed"

determined and taken into consideration (Figure 5).

When the two curves are compared, a time shift can be seen between them. This has been used to further improve the accuracy of the final results.

String power deviation

The module degradation can be defined as the ratio of the measured power to the simulated one. For this to be valid, both must be related to the same environmental conditions. The procedure for normalising the STC string power to the Measured Weather Conditions (MWC) so as to calculate the final string power deviation is shown in Figure 6.

Once the string-measured power (Pstring) has been obtained as the product of the string current and the voltage, the string-simulated power can be obtained by:

$$P_{STC}^{T_{mod}} = P_{STC} * [1 + \gamma * (T_{mod} - 25°C)] \quad (1)$$

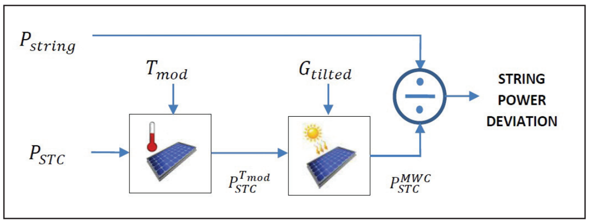
$$P_{STC}^{MWC} = P_{STC}^{T_{mod}} * \frac{G_{tilted}}{1000W/m^2} \quad (2)$$

Here, γ is the module-power temperature coefficient (%/K) obtained from the manufacturer´s datasheet. The final string power deviation is then calculated as:

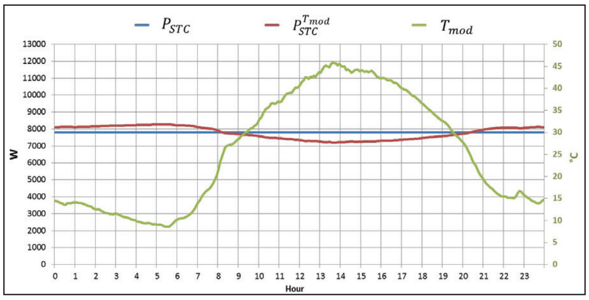
$$Deviation_{MWC}[\%] = \left(1 - \frac{P_{string}}{P_{STC}^{MWC}}\right) * 100 \quad (3)$$

To illustrate these normalisation steps, a real string of 40 modules @ 195Wp has been taken as an example. Its STC power is 7,800Wp, and the power temperature coefficient (γ) of its modules is -0.37 %/K. Measurement data has been taken from a selected clear-sky day. Its simulated power under the measured module temperature has then been calculated by applying equation 1 (see Figure 7).

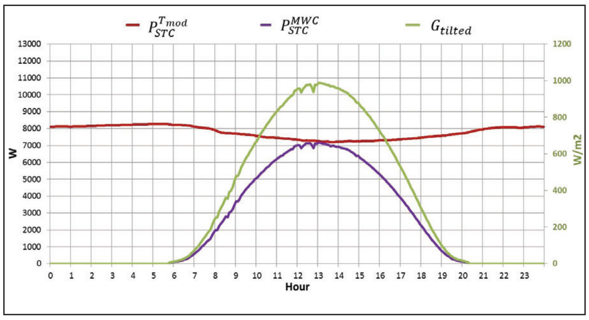
The temperature-normalised power, i.e. the result of normalising the STC power



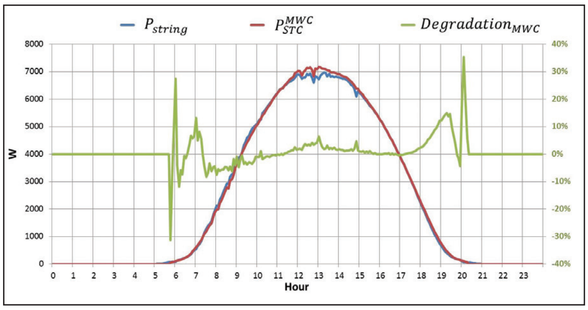
▲ **Figure 6. Power normalisation.**



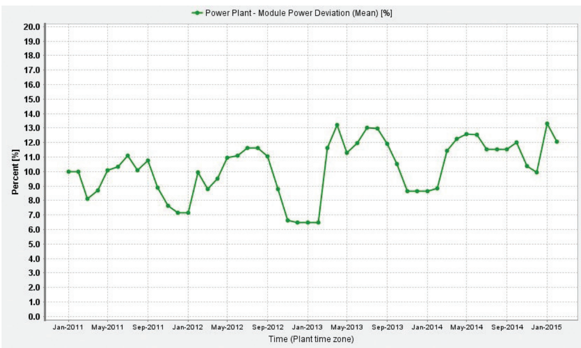
▲ **Figure 7. Power temperature normalisation.**



▲ **Figure 8. Power irradiance normalisation.**



▲ **Figure 9. Power deviation calculation.**



▲ **Figure 10. Monthly plant power deviation (PVGuard).**

(blue) against the measured module temperature (green), has been shown in red. The next step is to normalise this against the measured irradiance, by applying equation 2 (see Figure 8).

The temperature-normalised power (red) is then normalised against the measured irradiance (green) to give the final normalised power, shown in violet. The next step is to calculate the string power deviation according to equation 3 (see Figure 9).

Examining Figure 9 shows that valid results can only be obtained within the central hours of the day. Therefore, accurate time filtering is necessary to select both the optimum time-window and the clear days for which the calculation should be performed.

Results

To assess the proposed solution, measurement data from a utility-scale PV plant has been analysed using the supervision platform PVGuard. Operational data at string level was available for the plant's entire life since commissioning.

Module annual degradation

After determining the power deviation for every string of the plant for every established clear-sky day, the plant power deviation was obtained by taking their average. By calculating the mean value for each month, the chart in Figure 10 was then obtained.

This shows considerable fluctuations, even between consecutive months. This could be caused by:

- Non-linear behaviour of the module power temperature coefficient (γ), in dependence on both the seasonal irradiance level and spectral variations. This study has assumed the constant values given in the datasheets.
- Variable amounts of module soiling either due to rain (that lower the deviation) or high amounts of dust and pollen (that increase it).

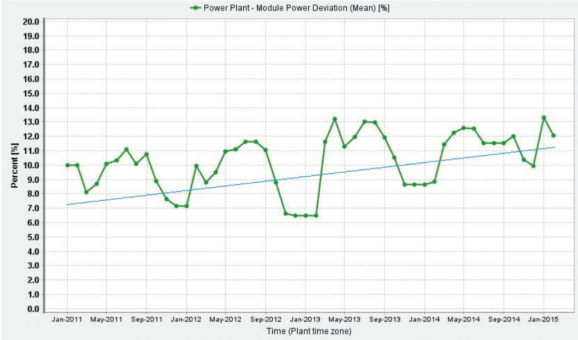
The next step in obtaining the module degradation is to determine the trend line across all the plant's power deviation values, as plotted in blue in the graph in Figure 11.

The trend line shows that there is a slight increase in the deviation over time. Dividing the absolute difference by the number of operational years of the plant results in a final figure for annual degradation of around 1%.

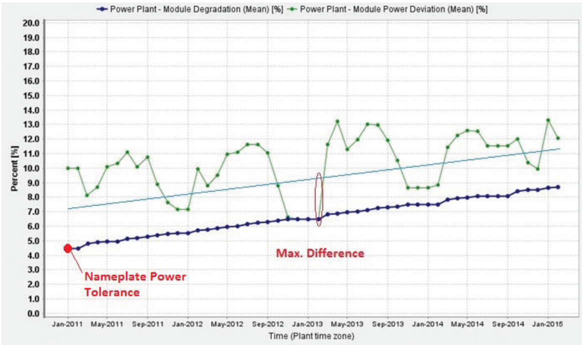
Module nameplate power tolerance

In order to obtain the module degradation line, a final step has to be made by taking the seasonal fluctuations derived from soiling and spectral issues into account. Therefore, the trend line shown in Figure 11 has to be shifted down by the amount found on the clear-sky day where the difference between the trend line and the plant power deviation is a maximum. The resulting module degradation line, shown in Figure 12, represents the module nameplate power tolerance and in this case results in the final figure of around +4.5%

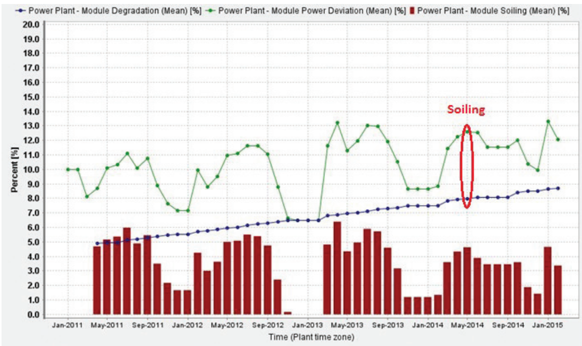
"Module degradation figures for single strings can be obtained and used to determine which strings are more affected by degradation than others"



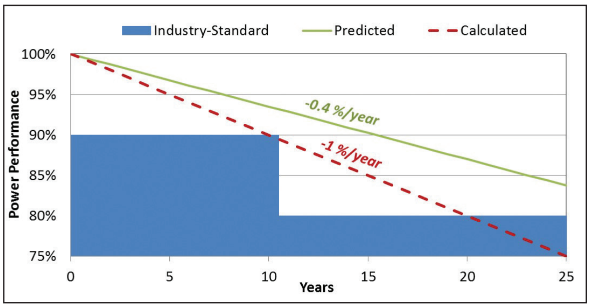
▲ **Figure 11. Trend line for the plant power deviation (PVGuard).**



▲ **Figure 12. Shifting down trend line (PVGuard®).**



▲ **Figure 13. Module soiling (PVGuard).**



▲ **Figure 14. Module performance over time**

Module soiling

One last result, the module soiling, can be derived from the module degradation line, by calculating the difference between the plant power deviation and the module degradation line (Figure 13).

Module annual degradation versus industry standard

By converting the rising degradation trend line back into a falling power performance trend line and drawing it together with both the module manufacturer´s industry-standard power warranty and a typical yield report prediction, the chart shown in Figure 14 can be plotted.

Neither nameplate power tolerance nor initial degradation has been considered here. However, the annual module degradation rate is still well adrift of that predicted in the yield forecasts. Obviously, if the initial degradation is taken into account, the industry–standard power warranty would not be achieved either at the tenth or after the twentieth operational year. So once the initial degradation is known, the characterisation of the module can be enhanced and yield predictions improved correspondingly.

Conclusions

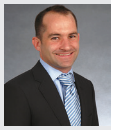
An innovative method for a precise calculation of module degradation has been presented. Based on an assessment of string power measurements over a long duration under specific measured weather conditions, the results could satisfy the need of investors and decision makers for reliable information about the long-term performance of modules outside the laboratory.

In order to obtain accurate and reliable results, it is essential that power measurements are taken as closely to the modules as possible, so as to minimise the losses due to cabling or other intervening equipment. Ideally string monitoring should be used, so that the results are only affected by the DC cable losses. In addition, the ±0.5% measurement accuracy of the string monitoring system and a time resolution down to a minute are crucial. Measurement accuracy of inverters is commonly stated as being around ±5%. This can be shown to be inadequate for such a precise calculation.

The long-term deviation of the measurements from the irradiation sensor due to its ageing process has been calculated precisely by comparing them to simulation of clear-sky irradiance with a one-minute resolution. The result has been used to compensate the final degradation results and so to increase their accuracy.

Figures for module degradation in individual strings can be obtained and used to determine which strings have been more affected by degradation than others, consequently providing a valuable source of information for the maintenance team.

Author



While studying his MSc. on Global Production Engineering in Solar Technology at the Technical University Berlin, Agustin Carretero joined skytron energy GmbH in 2012 where he has developed algorithms for plant performance engineering. Module degradation and soiling detection together with energy loss calculations are some of his recent scientific contributions.

Reference

[1] A. Carretero / H. Hoffmann, "Where are my Watts gone? Five Years of Utility Scale Power Plant Monitoring", 28th EU PVSEC Proceedings (pp. 4045 – 4050), September 2013.

Materials can be key to differences in module durability

Defect assessment | DuPont Photovoltaic Solutions recently completed a five-year study of commercial crystalline silicon PV systems, amassing a wealth of new information about PV system field experience and PV module defects. Principal investigator Alexander Bradley discusses the findings, which, in addition to supporting the company's ongoing analysis of materials performance, are expected to provide benefits across the industry. Building on the industry knowledge pool contributes towards the standardisation of performance expectations across the solar industry, enables the development of more stringent risk mitigation techniques, and helps purchasers of solar power systems make educated and informed materials assessments

Testing solar modules in a laboratory setting provides valuable information, but the most representative performance data can only be achieved by measuring solar module performance under real-world conditions, in different climates and settings, and over an extended period of time. In turn, these real-world results help researchers develop realistic and representative methods for conducting accelerated durability testing in the laboratory.

The DuPont study, presented recently at the IEEE Photovoltaic Specialists Conference [1], was extensive. More than 60 global solar installations were reviewed, ranging in size from 1kW to 20MW projects, representing 1.5 million solar modules and a total power output of over 200MW.

Modules at sites of all ages were examined, from brand-new installations to those with over 30 years in service. The study surveyed residential, commercial and utility-scale installations, roof- and ground-mounted, across Asia-Pacific, the European Union and North America. In addition, over 400 modules, from 45 different module manufacturers, were analysed in the lab. Selected modules were subjected to non-destructive and destructive testing in the lab, to provide more information about the chemical and physical changes to the solar module materials.

Visual inspections of solar module defects becoming more important

Two recent developments contribute to the increasing importance of identifying defects in solar modules. As the solar industry shifts its focus from the 'design and build' stage to the operation and maintenance of systems, including asset optimisation and energy harvest, visual defects are becoming key markers, along with the evaluation of safety and power output, in determining the value of a PV system.

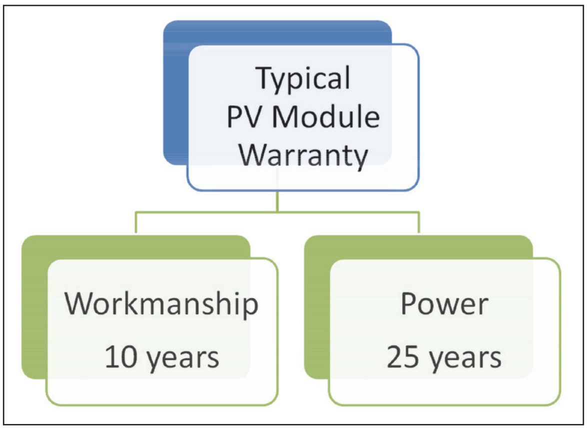


Figure 1. Warranty coverage breakdown: typical warranties cover both workmanship and power output. Visual defects, including yellowing and cracking, are potential workmanship defects, since they may lead to electrical safety hazards.

> "Visual defects are becoming key markers in determining the value of a PV system"

Another development is the extension of most module workmanship warranties to ten years (an increase from two years), exposing manufacturers to the possibility of claims for workmanship defects, and also for unsatisfactory performance/power output (Fig. 1). These developments are putting the spotlight on visual defects, as well as on performance and safety degradation.

In addition, the growing secondary market for PV assets dictates the need for an evaluation, based on numerous criteria (including visual inspection), to determine the value of modules and systems. Defects that require replacement, or more frequent inspections, will add operational

Subcomponent	Visual defect
Superstrate	Broken, etched or hazed glass
Encapsulant	Discoloration or delamination
Cell/Interconnection	Corrosion, hot spot (thermal non-uniformity), broken interconnection, snail trail, crack, burn mark
Backsheet	Cracking, yellowing, delamination

Table 1. Description of visual defects for each subcomponent category.

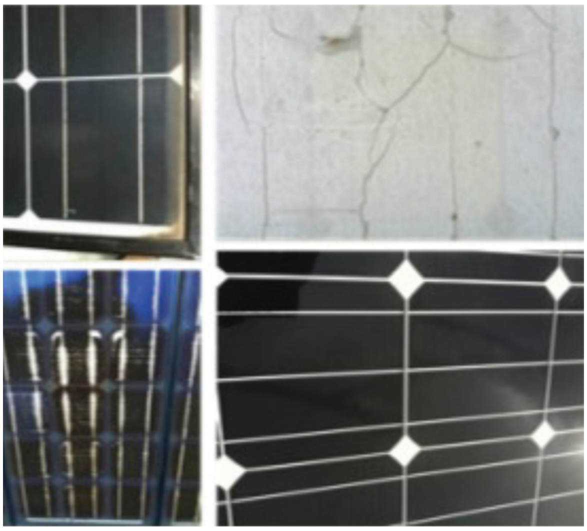


Figure 3. Representative visual defects (clockwise from top left): etched glass, cracked backsheet, snail trails and encapsulant discoloration.

expenses and drive up the cost of ownership, as well as reducing the secondary value of the PV asset.

For this study, module defects were identified via visual inspection using industry-accepted definitions, combined with the use of a thermal camera. Any PV module that deviated from a 'perfect' module was defined as *defective*. A PV module with a defect might not have a safety or power loss, but it differed in some way from a perfect module.

Survey results

All of the identified defects relate to one or more of the four major subcomponents of a PV module: superstrate, encapsulant, cell/interconnection and backsheet (Table 1). In many cases, the interactive effects of the subcomponents were responsible for the visual defect.

As part of the data analysis, degradation modes were combined into a small number of distinct categories. Out of all the modules surveyed, 59% had no defects; Fig. 2 shows the breakdown for the 41% with defects. In many instances, the defects were not uniform across all modules in a particular installation.

The superstrate accounted for only 2% of defects (Fig. 2). Twenty-four per cent of defects related to the cell, including hot spots (identified via thermal camera), visible corrosion, burn marks at interconnections, and cracks (identified by snail trails.) Encapsulants accounted for 4% of defects. While this percentage is low, it represents an important cause of defects, because of the resultant loss in transmission, as well as a shift in the transmission spectrum, which allows a shorter wavelength of light to penetrate the module.

The cell may be the most valuable part of a module, but the discoloration of encapsulants and backsheets can also exact a heavy price (see Fig. 3). Discoloration can cause embrittlement of these two electrical insulating components; this in turn can lead to delamination and the loss of mechanical properties, which can compromise electrical insulation. These issues are also grounds for potential workmanship warranty claims.

Backsheet material is key

The drive to reduce component costs has led some manufacturers to turn to alternative backsheet materials. The problem with many of these materials is the lack of in-depth, long-term performance testing, resulting in expensive field

"The discoloration of encapsulants and backsheets can exact a heavy price"

failures. Removing and testing modules part-way through their expected 25-year lifetime is expensive. Since operations and maintenance (O&M) is usually not always a fixed cost, it can increase significantly over a system's lifetime.

The study highlighted the critical role that backsheets play in the performance of solar modules. The following materials for backsheets were investigated:

- **Polyvinyl fluoride (PVF)** film is used extensively as a backsheet material in solar module construction. It has proven to be reliable and durable in protecting solar modules for more than 30 years, even in harsh environments.
- **Polyethylene terephthalate (PET)** film is widely used in very low-cost solar modules. There is little standardisation between PET films, leading to inconsistent performance in the field and a high rate of early field failures, such as yellowing and cracking.
- **Fluoroethylene and vinyl ether copolymer (FEVE)** coating is a newer, relatively unproven material. No long-

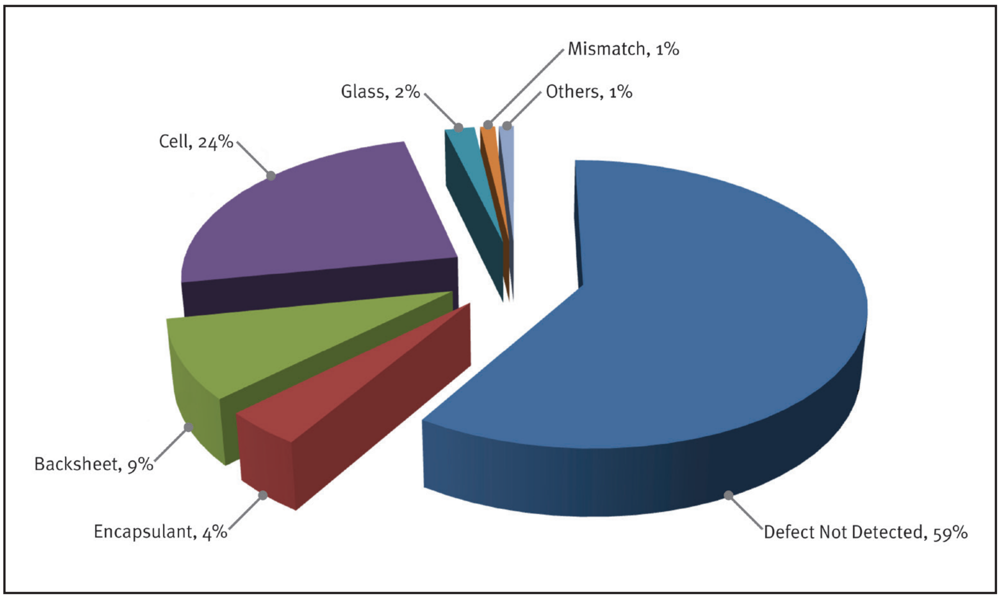


Figure 2. Subcomponent visual defect percentages.

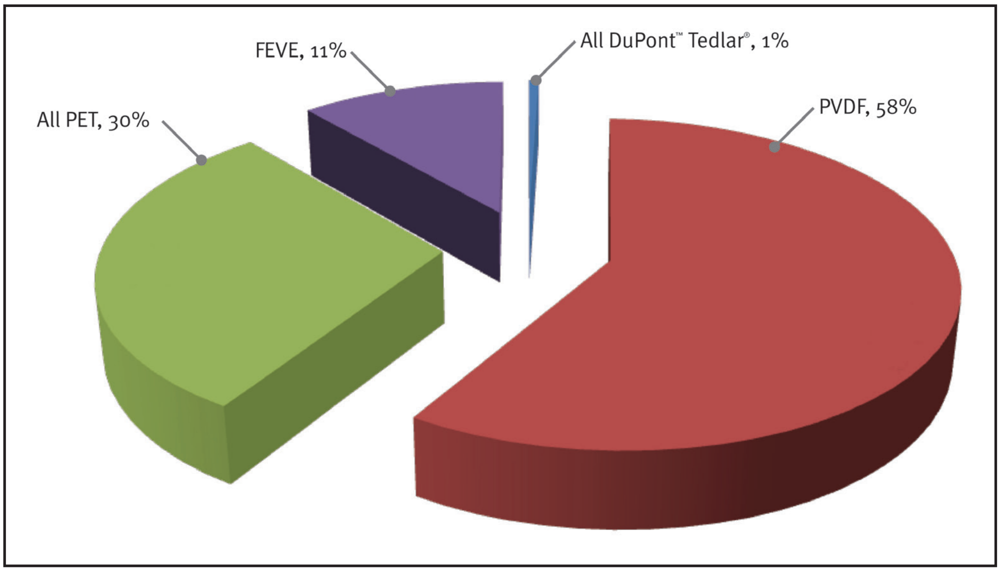


Figure 4. Backsheet visual defect percentages for different backsheet materials.

term studies have been completed on its performance in the field; recent studies, however, have shown evidence of issues, including cracking, within as little as three years of outdoor exposure.

- **Polyvinylidene fluoride (PVDF)** film is promoted by several manufacturers as a lower-cost alternative backsheet material. In the field, single-sided backsheets made using PVDF have demonstrated issues of yellowing, cracking and delamination.

Backsheet defects accounted for 9% of the total defects, and researchers found a significant variation in the percentage of defects across different backsheet materials (Fig. 4).

With the help of Fourier transform infrared (FTIR) spectroscopy, the outer surface of the backsheets were compared with reference backsheets, which provided a more detailed categorisation of the backsheet defects. The comparison also allowed a more specific categorisation of the defects relating to backsheets.

The most common backsheet defects found by the researchers were:

- **Yellowing:** discoloration of the backsheet material, caused by prolonged UV exposure, high temperatures and environmental stresses. An early indicator of serious mechanical integrity issues (including delamination and cracking), yellowing can compromise the backsheet's electrical insulating properties. Severe yellowing is frequently observed in modules with PET-based backsheets.

- **Abrasion and delamination:** visible cracking (macrocracks) in the backsheet's outer layer, along with outer layer separation from the backsheet structure. The abrasion and delamination defect presents safety issues, because it represents severe degradation of the backsheet's protective function, and exposes the inner PET core layer to the elements.

"Tedlar film outperformed all of the alternative backsheet materials"

- **Delamination and bubbling:** cracks in the outer layers of the backsheet. This defect has the potential to expose the core backsheet layers to the elements and compromise its structural integrity. Delamination can also result from hot spots (a bubble caused by the separation of the backsheet or encapsulant layers) or increased series resistance.

PVF outperforms all other backsheet materials

The study highlighted a significant performance advantage for solar modules constructed using Tedlar PVF film-based backsheets. As the only backsheet material demonstrated to protect solar modules for more than 30 years in the field, Tedlar film outperformed all of the alternative backsheet materials; the latter have not been proven to last over the expected lifetime of a solar module, since they have been in use in the field for only approximately half as long as PVF film-based backsheets.

New data shares benefits across solar industry

As the findings demonstrated, the long-term reliability and performance of a solar installation depend on the materials used in its construction. The most favourable system value based on the levelised cost of electricity (LCOE) is achieved when modules perform precisely as expected, delivering a high lifetime power output along with a long operating lifespan. Proven materials specified at the outset of a project can result in a higher system value and lower LCOE for the end user, as they help assure the longevity, durability and performance of solar modules over a system's lifetime. This fulfils the expectations set out in project plans and evens out financial returns.

Quantifying the range of defects found in PV modules, across installations and regions, will also provide benefits throughout the industry. A greater knowledge of solar module defects allows the solar industry to establish control plans relating to scheduled maintenance. It also enables insurance companies to more accurately anticipate replacement rates, as well as providing more comprehensive data for asset management companies for valuations of solar assets.

DuPont makes recommendations on the industry-standard bill of materials for solar panels on the basis of its extensive studies of material performance, and provides module manufacturers with materials technology that will best match power output and expected lifetime goals of solar installations.

Author

Dr. Alex Bradley is a principal investigator for DuPont Photovoltaic Solutions. He has studied and analysed PV systems for more than five years as part of an intensive field and laboratory research programme assessing the long-term performance of solar panels and materials in diverse service environments.

Reference

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Testing times


Credit: PI Berlin

On-site testing | PV project owners are becoming increasingly conscious of the need to understand how their plants are performing in the field. Ben Willis explores how mobile testing units are emerging as an important tool in the early detection of faulty module equipment

Towards the end of last year, the financial backer of a 4MW PV project in Italy called in engineers from the testing house Photovoltaik-Institut (PI) Berlin to investigate what it believed were underperforming modules at the plant. PI Berlin, a specialist in module and plant quality assurance, had developed a new system for on-site module testing, and in less than three weeks, according to the institute, its engineers were able to test over 12,000 of the plant's polycrystalline modules.

"It was at the initiative of the bank that had financed the project," explains Steven Xuereb, head of the PV systems business unit at PI Berlin. "They knew there were issues in the plant, and they wanted to know the extent and what action they could take against the supplier or the EPC. It identified cracking."

The test set two criteria – one at a cell level, measuring the amount of cracking within one cell, the other at a module level. "Eighty percent in our hard criteria [at cell level] failed," says Xuereb, "but to say you're going to exchange 80% of the modules would have been very drastic so we agreed with the bank and the owner and module supplier that we would use the soft criteria, which was at the module level. And there a third of the modules were then replaced."

Instances of underperforming modules being replaced at such a scale reaching the public eye are a comparative rarity in the PV industry. But that is not to say this isn't happening; plenty of anecdotal reports circulate within the solar industry of mass module failure, but they rarely, if ever, see the full light of day as they are usually hushed up in non-disclosure clauses.

One clear indication that the performance of modules in the field is an issue about which the industry is becoming increasingly aware, however, is the growing number of mobile testing labs becoming available. PI Berlin's system is just one of a number of similar services now being offered to the market as a means for plant owners and investors to keep tabs on their asset and to ensure it delivers what it has been promised to deliver.

PI Berlin's system supplies modules with current at night for electro-luminescence tests.

The circumstances in which mobile testing facilities are brought in are varied. For PI Berlin, there are usually two main reasons for a call-out to the field, explains Xuereb: "The first would be if the asset manager or owner has noticed some kind of issue with the power, so they see some degradation when they're comparing the theoretical and performance; they're seeing there's some kind of funny thing going on there and they don't know what it is. That's on the one side.

Suncycle's flexEL system in operation.

Credit: Suncycle

"On the other maybe they see something going on during installation, they're concerned about how the modules were transported or they were supervising the construction and saw some things that were abnormal. And because they know they've got a limited warranty either with the EPC or the module supplier, then they're concerned and want to get a second opinion."

Romain Elsair, UK project manager for the Spanish consultancy firm Enertis, which also operates a mobile testing lab, agrees that plant owners are becoming more vigilant of potential module problems emerging in the field and increasingly asking for on-site inspections.

"When clients first come it's usually because they have highlighted something or seen some cracks if they've done infrared, thermographic inspection," says Elsair. "Because this is not enough to claim or this is not enough to have a good idea of the behaviour of the modules, we can also do infrared, we have drones as well, and also electro-luminescence (EL) testing we can do by hand without dismantling the modules.

"So after these preliminary surveys have been conducted by clients they usually come to us and say can you check the actual performance of the modules. And usually it's about six months to two to three years after the plant has been installed."

Testing without dismounting

The big advance offered by some of the more recent mobile testing technologies offered to the market is the ability to test modules without dismounting them – a costly and time-consuming process that of course risks inflicting handling damage to modules that may have been in perfectly good condition in the first place.

Germany-based firm Suncycle has recently added a system known as the flexEL to its mobile testing laboratory. Its full mobile lab system offers a wider range of tests than just EL, but because it is certified to test equipment under certain standard conditions, it requires modules to be dismantled. The flexEL on the other hand is fully portable, allowing modules to be inspected either individually or as part of a string without having to be removed from their fixings.

"The flexEL is for mounted systems where you do have some damage assumption and then you use the flexEL so you don't need to dismount," says SunCycle's managing director, Mischa Paterna. "So that puts less stress on the module and is cheaper. And it has the same kind of throughput as with the mobile lab so you can do quite a high volume."

The company claims it can process up to 200 modules a day using its technique. A further advance offered by the system is that it can be used in daylight hours, when reflected sunshine can cause problems for the quality of EL image. "If you do [EL testing] during the day, you can cover the module, but you still get light through the backsheet," Paterna explains. "So that's a difficult task and we solved it through some software technology that filters out specific wavelengths of light. Through that technique we can get a crisp and clear picture even during daylight."

The PI Berlin system has also sought to improve the throughput of modules being tested by removing the need for dismantling. It limits testing to night time, to minimise operational impacts and claims to be able to process 1,000 modules a night by testing them at a string level.

"Being able to do EL testing in the field without dismounting the modules, not having to disrupt the operation because it's done at night, that was something that became very attractive to the operators," says Xuereb.

"Our test set-up allows us to take high-resolution electroluminescence images of several modules at once, thus saving time," adds Xuereb's colleague, Dr Juliane Berghold, head of module technology and research at PI Berlin. "These images are then analysed and automatically evaluated by our software, which is based on our years of experience with error analysis of PV modules in power plants. This expertise also helps us to evaluate these results very quickly and recommend specific courses of action for solving problems in the plant."

Fault detection

According to SunCycle's Paterna, EL testing is useful for identifying a range of different types of damage to cells and modules. Its particular strength is in detecting so-called "critical cracks", which can become larger over time and ultimately cause power loss in the module. It can also determine how a cell has been damaged by the kind of shape or pattern of the cracking.

"A typical story is if you have a hailstorm you might want to check what the modules look like afterwards," he explains. "When you look at hail [cracking] you have a little star pattern where you can see the big hail hit in the middle. Or if it's just pinched at a certain point it's probably a handling issue; perhaps when the module was taken out of the box it hit the frame of another module. So you can have a hint of what the problem is."

In the case of the Italian plant, says

Xuereb, the suspected cause of the widespread damage found was transportation. But further inspection in the laboratory raised question marks over the mechanical stability of the modules themselves, he adds.

"As part of what has led to this recent drastic reduction in module costs, suppliers are trying to cut costs everywhere," says Xuereb. "And part of that is even the thickness of the cells and the wafers, which makes them less stable and more susceptible to cracking through lighter loads. So when you're talking about transportation and maybe things weren't packaged optimally, then they're more and more susceptible to that."

Asset protection

The scenario outlined by Xuereb is one that perhaps adds most weight to the case for mobile module testing. The PV manufacturing industry's recent drive to squeeze out cost along the whole supply chain has undoubtedly been successful in doing this, to the benefit of solar's overall penetration. But there are concerns that in the long term, this could prove to be at the expense of product durability.

This clearly underlines the need for ongoing quality control measures such as in situ module testing, and emerging evidence suggests the industry is beginning to recognise this too. For example, Enertis' Romain reveals that in the first six months of 2015 his UK team has had the same number of testing contracts as it had in the whole of 2014. He concedes that this is partly because more and more companies such as his that offer quality assurance services are out in the market persuading investors and plant owners to be vigilant. But he also believes it an essential development in the market if investors are to make absolutely sure they will get the returns they are anticipating over the next 20 years.

Xuereb agrees that it is the holders of the purse strings that will have the most interest in making use of mobile testing facilities. "As often happens, the banks are the drivers," he says. "We saw that in the wind industry when the first gearboxes started to break down. That's when they started to take notice, so did insurance companies, and asked for some extra testing to be done on that particular component. So that's where it's coming from. You'll see it from a lot of the banks now asking for some sort of batch testing of modules in laboratories and also some sort of testing upon completion. That's where we see the pressure coming from."

Ultimately, as Xuereb points out, although modules have come down in price significantly in recent years, they still represent a hefty proportion of overall project costs and should on that basis alone warrant special attention from a quality assurance perspective.

"You're still looking at 30-40% of your investment on the modules," he says. "So it makes sense to spend a bit of money up front and to keep an eye on the process from the production [of modules] through to installation and then throughout the operation of the plant." ■

How PI Berlin's system works

PV Tech Power caught up with PI Berlin's Juliane Berghold for a closer look at the organisation's new on-site module testing system.

***PV Tech Power*:** How is the system able to process the claimed 1,000 modules a night?

Juliane Berghold: First of all we do not apply the current for the generation of the electroluminescence signal to every single module, but on a string level. For imaging we use a mounting hardware with two cameras allowing for picture capture of up to 10 modules at once.

***PV Tech Power*:** A key part of the speed of processing offered by your system is the software that sits behind it. How does the software work in analysing each module and identifying faults with them? And how does the analysis rank the severity of any faults it detects in individual modules so that investors are able to form a view on whether equipment requires replacing?

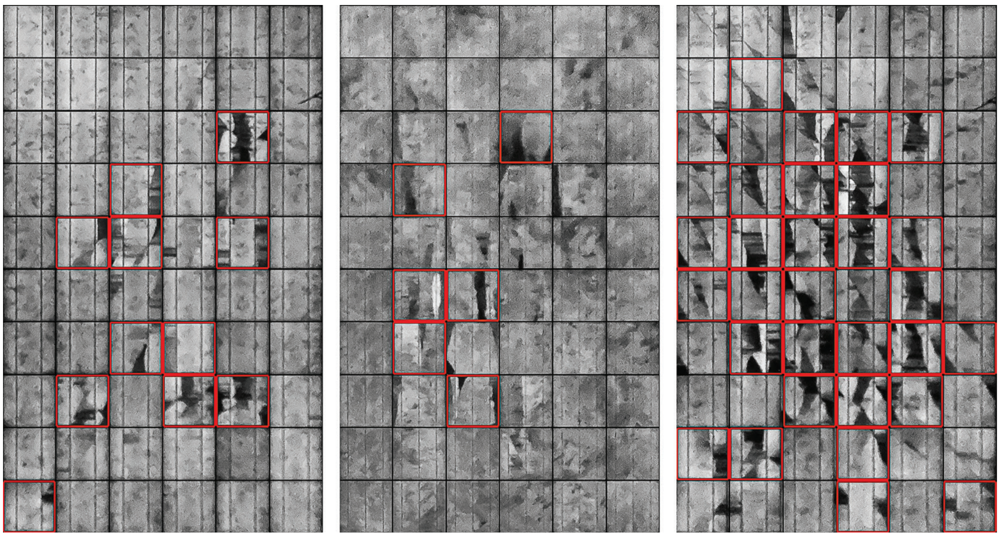
JB: For the moment, the focus of our software is on the detection and counting of heavy, isolated cracks. Cracks can cause significant power losses and resulting issues like hotspots. For the future the software will be extended to evaluate other failures such as potential-induced degradation (PID). The software analyses the EL images of the examined modules. Power-relevant failures such as isolated cell cracks are detected and counted. Therefore, it is possible to differentiate the modules in plant in 'pass' and 'fail' modules with respect to agreed criteria, allowing defective modules to be localised and replaced in plant. The final test reports help investors and operators to back up their claims to EPC contractors, module manufacturers and insurers.

***PV Tech Power*:** You have highlighted the example of a project in Italy that experienced a high failure rate and needed a large proportion of its modules replacing. How common would you expect such high rates of failure to be in PV power plants, or was this a one-off?

JB: This is not a one-off. Generally, the better the monitoring and the investigation tools to be used onsite become, the more modules are and will be identified as being 'low quality' or defect modules. As the warranties from the manufacturers are usually on module level, the testing and failure identification needs to be done on a module level. This means high-volume investigations in plant. This means also that more claims with high-volume module exchange will emerge. We see high volume module exchange claims also connected to PID and thin-film-related defects.

***PV Tech Power*:** Generally, how much demand are you expecting to see for your system as investors look to gain a better understanding of possible failures in module equipment?

JB: There is certainly an increasing need for high-volume EL investigations from investors and banks – also in the secondary market. We have inquiries for the investigation of plants that are known to be in bad shape. Our investigations are meant to estimate the technical risks of these plants.



Credit: PI Berlin

Electroluminescence testing can be used to detect cracking and other faults such as PID in modules.

A global approach to solar O&M

Operations and maintenance | The distribution and growing size of PV fleets mean new approaches to plant operation and maintenance are needed. Florian Danner, Jens Kahnert and Bjarn Röse of Conergy Services outline the key ingredients for cost-effective O&M in a globalised industry

Credit: Conergy

Solar O&M practices are adapting as the industry expands its global footprint.

In the past, the solar industry thought about operation and maintenance (O&M) providers the way most of us think about doctors: we only see them once a year for a check-up or when something is wrong.

Now with nearly 178GW of solar installed globally, O&M is much less of a reactive service and more of a preventive one. To continue the metaphor, O&M providers are more like your personal trainers, your nutritionists, or even your hairdressers. Today, O&M providers don't just fix solar power systems when something goes wrong; they make sure solar power systems are always performing optimally — and looking good.

This is particularly important in the context of the global geographic expansion of solar. Fleets are becoming too large and dispersed now for O&M providers to run them effectively on a purely reactive basis. To keep costs down for O&M providers and keep profits high for solar asset owners, a preventative approach is needed.

Conergy's O&M team has identified some of the key building blocks of an effective process. Here we distil the key capabilities of the modern, global O&M team:

1 – Monitoring software expertise;
2 – Re-engineering expertise;
3 – Cost-effective cleaning and snow removal methods; and
4 – Efficient scheduling practices

Monitoring technology expertise

In the past decade, the solar industry has gone from serving largely individual investors to largely institutional investors, who have a greater demand for detailed, reliable, real-time data on their PV systems for the purposes of financial modelling. Conveniently, the key to reliable data is the same everywhere: a great monitoring technology and expertise reading its data.

To start, you need a stable, reliable, and profound monitoring system — an in-plant SCADA — that collects and delivers all necessary data from all devices of the plant. Second, you need an automated data acquisition tool, normally embedded in a sorting data warehouse, to put them into a framework and make them ready for analysis. This is the crucial part of all O&M software, as nearly all the bigger O&M providers have a fleet, which consists of completely heterogeneous structures.

Third, you need your team to master the usage of the software. Service technicians cannot only be electricians anymore, but also need to be software engineers, network analysts and experts in electronics. You can only control your PV plant if you have a robust, flexible datalogger and SCADA system. This optimises full integration of the complete scope of O&M.

Conergy Services sees firsthand how modern technology reduces our costs significantly. We still maintain PV plants which were installed back in 2002 and are still working analogue. When we switch these older systems to modern technology, however, our manual labour and manual failure analysis needs reduce and our costs decline by roughly 20-30%. Today, while the old devices are still working, Conergy Services is making a big push to integrate these older PV assets into a modern IT landscape.

Ability to reengineer old plants

There are a lot of old PV plants that are not producing at their optimal capacity. At the same time, these older plants are at the end of their loan agreements, and customers have some freed up cash to invest in their solar PV system in new ways.

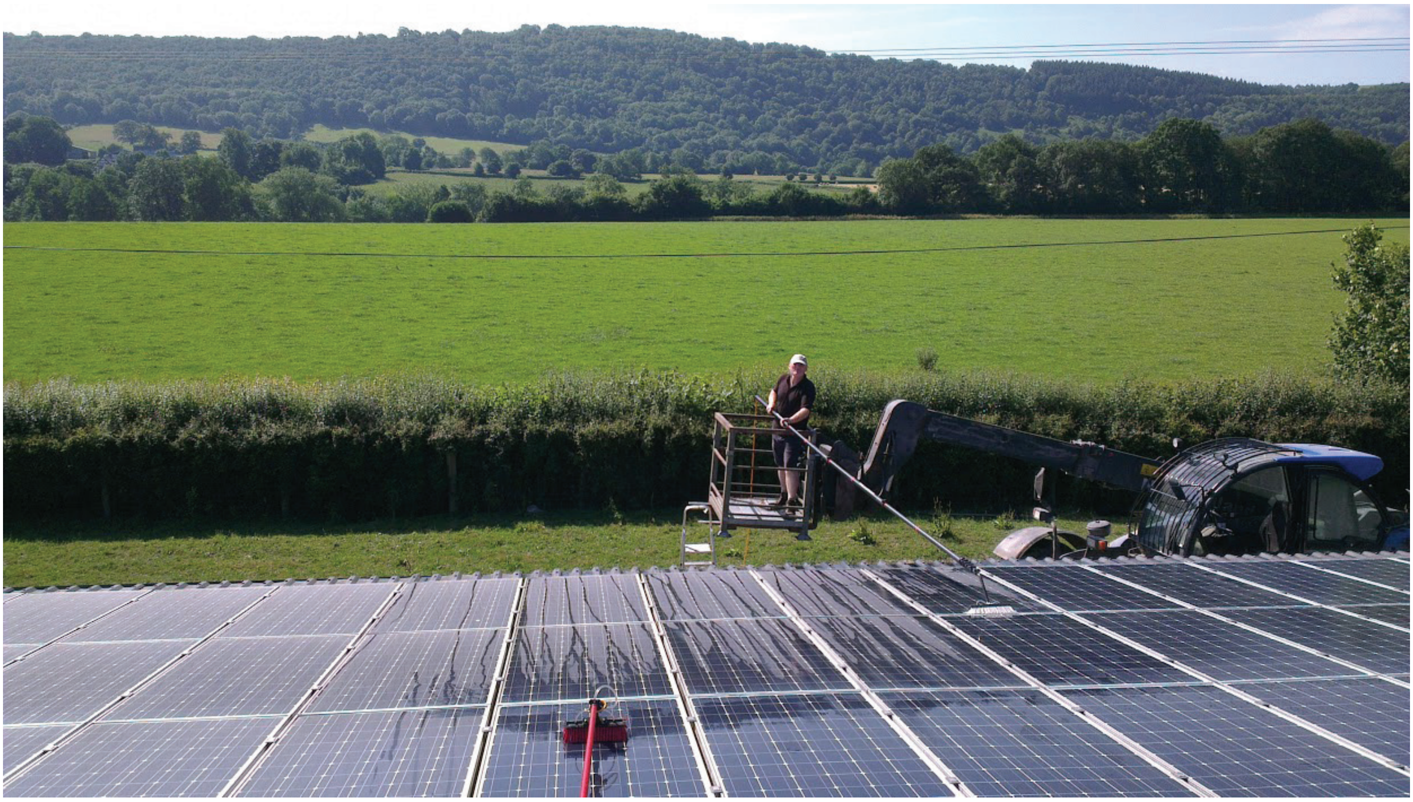
A modern O&M provider should be able to provide full re-engineering capabilities, to dive deep into the electrical setup and find possibilities for modification and optimisation of the plant's output.

There are a lot of possibilities to gain more yield. One is to exchange the equipment (modules or inverters). Conergy Services has developed complete new spare parts for existing old-fashioned central inverters. These small additions create a higher yield without the need to replace the whole inverter. Additionally, with new hardware, the service intervals will become longer, which will allow not only for better cost efficiency but also a higher yield of the entire service plan. Another possibility is to install a proper monitoring system, as mentioned above. There is no one solution to re-engineering an older power plant; each plant is unique and each solution must make sense for a given customer from the cost perspective.

It is critical, given the need for customisation and good judgement in the re-engineering process, to have an in-house field force of top service engineers. These engineers will know your systems inside out and are both backup and quality managers for your service partners.

Cost-effective cleaning and snow removal

Data-driven, system-specific cleaning can make or break the profitability of your O&M business. To start, you should always test your system by experimenting with two reference cells. One of them should be



Credit: Clean Clear Solutions

cleaned monthly and the other one should be left uncleaned. As soon as the (constant normal) deviation between both increases to more than 5%, due to the soiling effect, panel cleaning should begin (the soiled reference cell should be cleaned as well).

Moving forward, all production and irradiation data should be evaluated before and after cleaning to gain knowledge regarding the individual site concerned. This allows the frequency of cleaning to vary, which will benefit your time and costs spent. If you start to see that panels are getting soiled very frequently, you must identify the source and take all necessary steps to block this soiling.

For example, PV plants close to railway tracks and railway stations, industrial sites or on agricultural lands can suffer from excess emissions or dirt and need special attention. Regular controls on the soiling sources and steps to prevent this are mandatory for running any solar PV system profitably. New pressurised air technologies can also reduce costs, especially in dry parts of the world, where water is expensive or just not available. Snow removal is only needed in regions with long-term low temperatures below 2°C, where snow does not melt during the day. In these regions, it makes sense to remove the snow coverage with the same data-driven process you would use to clean your panels.

Efficient scheduling

As mentioned at the start, O&M is now a preventative maintenance practice as much as it is a reactive one. This is the industry standard now and most EPC and O&M contracts include the complete scope of work for maintenance services and the frequency they ought to be performed, similar to manufacturer warranty conditions.

To avoid unnecessary production losses, many tasks should be done during low-irradiation times. These are transformer and HV-switchgear maintenance during the winter season, preferably in the early morning or late afternoon. For health and safety reasons, these works (mandatorily including HV-switching) must not be executed during the night. Another task is inverter maintenance. This should be scheduled for March/October and executed in the early morning, late afternoon, or on days where the weather forecast predicts cloudy conditions. These are the times when disruption to production is lower, but irradiance is still sufficient for monitoring purposes.

For I-V-curve measurements, on the other hand, high irradiation is needed in order to obtain reliable results. These tasks simply can't be done early or late in the daytime. Production losses are inevitable. In order to keep those as low as possible, a spot check of 10% of the strings should be sufficient, unless the permanently monitored performance ratio of the site implies serious problems initiated by the strings/panels.

System-specific cleaning can make or break the profitability of O&M activity.

From the whole range of different maintenance tasks, only a few, like transformer thermal imaging or maintenance work on the energy meters, require a partial or complete shutdown of the site. Those have to be identified and all necessary preparations need to be completed prior to execution.

Modern solar O&M is becoming an increasingly competitive business and cannot continue be regarded as something done only when a plant malfunctions. An approach to O&M built around these four key areas will help providers optimise their practices and solar project owners ensure they will be maximising the value of their asset over its full lifetime.

Authors

Florian Danner is managing director of Conergy Services, the O&M business unit of Conergy. He has been with Conergy since 2006 and has a decade of experience in "after-sales" operations and customer care.

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Evolution or revolution?

New York's grid transformed

Credit: Dan Nguyen/Flickr

Hurricane Sandy in 2012 caused a blackout in a large swathe of New York, shown here in area behind the Empire State Building.

Grid investment | An ambitious plan is being drawn up to overhaul New York's electric grid infrastructure, an exercise that some have priced at US$30 billion. Andy Colthorpe looks at the efforts underway to ensure renewables and energy storage are a central part of bringing the state's power system into the modern age

In most developed nations, the grid infrastructure was built decades ago in the conventional "hub and spoke" model, with centralised generation in the middle. Adding more distributed resources including solar and managing a more complex flow of electrons around the network has brought the old-fashioned model of the grid as we know it into question.

From adding renewables, allowing energy storage to provide grid balancing, using demand response to match supply and demand, to building megawatt-scale micro-grids, distributed energy resources (DERs) add not only a new set of technical questions as to how the grid works, but also economic ones in terms of how the market around it should operate. For a network to rely increasingly on distributed resources at the "grid edge", those resources – including PV and storage – will need to be supported in finding a market-based, sustainable solution to their continued deployment, one free from subsidy and incentives.

'Revolutionary, dramatic change'

New York's governor Andrew Cuomo launched New York's Reforming the Energy Vision (REV) programme in April 2014, to "fundamentally transform" the way the state not only generates, transmits and distributes, but also values and monetises electrons on its network. A convergence of motivating factors inspired this decision, according to William Acker and John Cerveny, executive director and resources director respectively of NY BEST (New York Battery and Energy Storage Technology Consortium).

"One is that New York State has an ageing grid infrastructure, and estimates of the investments that need to be done just to maintain what we have are very, very large," Acker says. This could be in the order of US$30 billion over the next 10 years. The state, he says, recognised that for that amount of spending, "you've got to do better than just maintaining the status quo".

Second, Acker says, is the fact that New York has in place ambitious goals on both greenhouse gas emissions reduction and for increasing its share of power generated by renewables. New York's recently issued State Energy Plan calls for renewable generation to make up 50% of the state's energy mix by 2030.

"To do that on the grid really requires flexible assets like energy storage," Acker says.

Along with improving the status quo and accommodating more clean energy, grid resilience is also a big motivator in a state which has previously been badly hit by storms; memories of the power outages caused by the 2012 Hurricane Sandy still linger. Added to these three major motivators are the aims of maintaining cost-effective electricity and creating long-term stability to the distributed energy resource networks that will be created.

"One more aspect that I think is important, particularly from an energy storage perspective, is the ratio of peak power to average power," Cerveny adds.

"The Public Service Commission (PSC) in its documents pointed out that the top 100 [peak] hours in New York state cost it between about US$1.2 and US$1.7 billion dollars a year and so they've been very heavily targeting how we flatten the very top peaks here, and that's part of this process". Among other things, storage-shifted solar could be used to mitigate these peaks (see box).

Track tensions

The REV programme has sought the input of as many stakeholders in the network as possible. NY BEST, which Cerveny has previously described as part technical trade association, part development agency, was among the organisations invited to join working groups that built the REV framework.

"The PSC put out an initial concept…and then formulated a whole series of working groups that met in the spring and summer of 2014," Acker says.

The input from these groups looked at a system enabling distributed generation "from the point of view of technology, from point of view of market design, from the point of view of customers and economics", and other factors, he says. This led to the issuance of a 'Track 1 Order' by the PSC, a document which laid out the basic principles of REV. While many changes are expected as the process continues, that order created a specific new set of rules for utilities that has underpinned continuing discussions.

"One of the key tenets is that the utilities will – in addition to their role as utilities – create, serve as and eventually have a separate entity known as a distributed system platform provider (DSPP) and that entity [will control] the marketplace for DERs at the edge of the grid," Acker explains.

"...It is tasked with creating a transactive market for DERs, meaning that in the very long run, it really is the market maker that allows people to trade energy, energy services, to buy and sell energy services."

One topic we are forced to revisit often in reporting on solar is how tensions play out between distributed resources and established incumbents of centralised generation such as utilities. Solar companies, especially those with an interest in grid-connected storage, have long been at pains to point out that they do not see utilities as the enemy.

Writing utilities into the fabric of the future electricity market seems like a good way to ensure utilities are encouraged to move to a new business model. Yet it was not taken for granted at the beginning of the REV process that this would be the case, William Acker says, laying out the role of DSPPs.

"The concept of the DSPP is that it enables the DERs to interact on the electricity grid, it does not own or control them, except for in special circumstances. For the most part the DSPP is creating the mechanisms of interaction, owning the wires and creating information flow platforms and the way that the market works, but not owning the DERs or controlling them."

John Cerveny (left) and William Acker of NY BEST.

So what's in it for the utilities, which in terms of infrastructure are traditionally used to operating on the basis of being rewarded for levels of capital investment in the network?

"That's actually one of the key things being sorted out," Acker says, explaining that in theory, as a DSPP the utility would be "acting as a stock exchange, as the people who are market makers in this process. They're also responsible for maintaining infrastructure".

At present, New York utilities are paid for what they put on to the network. So, for example, while using batteries could be cheaper than upgrading a substation, this does not necessarily translate into a saving for the bill-payer. Modernising the utility business model requires as much thought as modernising the grid itself.

"Right now we have this rather perverse situation that the utility could be incentivised to do the more expensive option because they get return on capital investment. They don't get returns on the cheaper option," Acker says.

An ideal future

Next, Track 2 of REV will attempt to deal with these and other questions through tariff design. It will be a challenging part of the REV design process, as, to simplify the issues massively, in a distributed grid marketplace there will need to be more interaction between the retail and wholesale electricity markets. For instance, the Federal Energy Regulatory Commission regulates the wholesale electricity market at a national level, as well as high-voltage transmission lines, while the Public Service Commission (PSC) regulates the interests of ratepayers and will therefore, it is assumed, also be responsible for overseeing the DSPPs. Once DERs are selling power through DSPPs, the question remains whether that would constitute wholesale electricity sales.

This is just a glimpse of the level of complex questions that the transformed network will have to answer, unpicking details and balancing the sometimes differing aims of stakeholders, from the average citizen footing the bill to transmission and distribution system operators, to the utilities and their shareholders, and on and on.

So how is NY REV going to evolve a new set of rules for New York and what does NY BEST see as the ideal resolution for storage and for renewables?

"We have a few strong desires with respect to how this process is planned through," Bill Acker says, "including a plan that values all of the different services energy storage can provide to the electricity grid".

NY BEST would like to see energy storage valued "in a way that is fair and accurate, including both locational and temporal considerations", meaning that where and when electricity is generated, as well as where it is going to, should partly determine how it is priced. This would of course have obvious ramifications both for storage and solar.

Some of the documents informing Track 2 will be published over the coming months. Though REV may take a long while after that before being finalised and implemented, Acker and Cerveny seem to be both fascinated by the process and excited to be involved, applauding the programme's ambition and scope. As Cerveny previously pointed out, Audrey Zibelman, chair of New York's PSC, was once head of a demand response firm and is knowledgeable about many of the issues at hand, which is just as well, because as Acker points out, for PSC, "…it's not their normal day job to rewrite the rules on how the grid works!" ■

What REV could do for solar

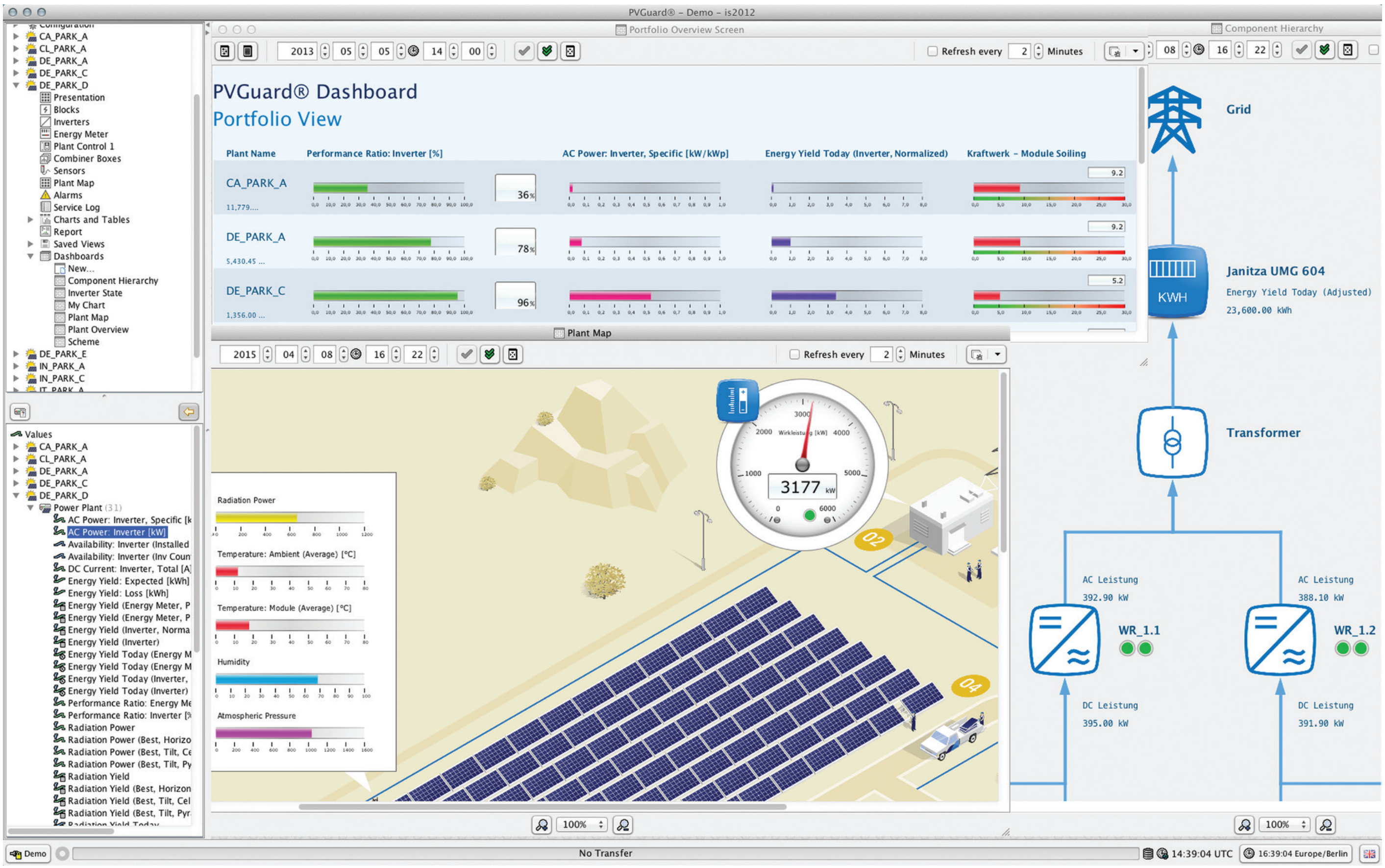
In addition to extensively re-evaluating the grid, other branches of New York REV are already funding and supporting clean energy and energy efficiency. Along with a range of other REV-related measures, in 2014 governor Cuomo launched NY-SUN, an initiative which is deploying large-scale solar and community 'shared' schemes for renewables in a bid to reach 23GW of deployment in the state by 2023. Building on a record which has seen solar installations grow by more than 300% between 2011 and 2014, according to official figures, NY-SUN consolidates all of the state's solar support programmes into one.

On a related note, when John Cerveny of NY BEST previously spoke to PV Tech Power (Vol.1), he said that with net metering schemes for residential solar in place, New York did not appear to be fertile ground for a solar-plus-storage market at that scale. However, this time he says that net metering's role as a market "shortcut" could be revised.

"It seems likely, given the goals of REV and the design and the desired outcomes, that that [role] will change, but it also seems likely that there'll be a [new] marketplace that decides, if you have PV that's feeding into the grid at times of peak demand, you're going to get paid premium price for it. I think it will change the nature of [the utility] for both PV and PV coupled with storage…it's going to open up a whole lot of opportunities and the work of REV is to make sure the value is appropriately there."

Big data for big solar

Plant control | SCADA technology enables PV plant owners to maintain their portfolios more efficiently and respond to increasingly stringent requirements from grid operators, yet avoid information overload. Sara Ver-Bruggen looks at the state of the art in SCADA systems as PV systems and fleets grow in size



Credit: skytron energy

Supervisory control and data acquisition (SCADA) systems, typically consisting of hardware components such as sensors and data loggers, as well as advanced software, have traditionally been developed to be used with one PV power plant, with each new PV plant being built needing its own SCADA system.

Nowadays, the leading operators and owners of utility-scale PV plants typically own portfolios of many individual plants, or assets, scattered across more than one geographic region or market. This trend this has driven advances in SCADA systems.

Key performance indicators (KPIs) of PV plants are identified in terms of the different pieces of equipment or components, such as strings and inverters, and the output of the plant. These raw measured values are processed, providing operators with an in-depth, real-time analysis of the plant's performance.

Maintenance

As well as measuring PV plant yield and performance, advanced SCADA systems perform critical monitoring for maintenance. It would be expensive and inefficient to employ teams of several people at every PV plant site in a portfolio to check for faults in inverters, cables or panels. SCADA systems pinpoint faults and problems and allow operators to decide how to address these, and schedule in maintenance and repairs, and despatch technicians where needed.

Enertis is a Spain-headquartered engineering and consultancy firm offering services in PV project development through to operations and maintenance (O&M), often working with large operators, mainly in the US as well as Latin America, including Chile and Guatemala. The company's own SCADA system, which it developed with a software company, forms a core part of Enertis' O&M services.

SCADA platforms are invaluable for O&M as well grid-side control of PV power plants.

The SCADA platform is designed to harness data from a multitude of PV plants and presents key information to clients about their PV portfolio. Clients can access the web-based program, but it is owned and managed by Enertis, as opposed to being sold as an off-the-shelf product.

"One of the issues that we often face is working with clients that have acquired an operational PV plant, which usually has an existing SCADA system in place, perhaps chosen by the project's developer. Some legacy SCADA systems may not be equipped to adequately address the complexity and range of tasks that operators may need," says Luis Collazo Garcia, a consultant at Enertis.

"In some cases a monitoring system was never installed in the first place. Sometimes, operators may need a system that can work with their entire fleet or want to exchange their existing system if the plant is failing to generate the optimum or desired output," says Jörgen Klammer, managing director of skytron energy, a large provider of SCADA technology, which is now part of First Solar.

Increasingly, according to Klammer, investors are looking to have an independent provider of monitoring and supervision solutions to keep their data separate from the developer.

Driven by scaling back of incentives, where in many markets, energy suppliers and utilities have negotiated hard on power purchase agreement (PPA) prices, reducing the levelised cost of electricity (LCOE) of a PV plant is the goal for many operators, which means rationalising and squeezing costs out of every aspect of costs related to operational expenditure.

"An advanced SCADA system supervising 250MW of assets lets you retain a core team of two or three technicians. You can coordinate how you despatch technicians to assets for repairing faults or dealing with issues, which the SCADA system has been able to detect. This has become a much more efficient way of pinpointing problems or maintenance actions, rather than deploying teams of technicians to check plants and look for failures, especially as plants have grown in size and fleets have grown in size," says Callazo Garcia.

Lightsource Renewable Energy in the UK, which has emerged in recent years as one of Europe's largest PV plant portfolio owners, has been investing in developing its SCADA platform, driven by the company's growing fleet.

"With an increase in fleet size there is definitely greater need for the automation of the calculation of the various KPIs across a large fleet. The manual downloading and checking of data usually inherent in fleet-wide reports becomes too time consuming with hundreds of plants," says Mike Day, a spokesman for the company.

The company is moving towards integrating the monitoring of its own internal SCADA platform, Lightsource Performance and Asset Management (LAMP), with other large data tools to help with this.

"In addition, greater user visualisation of things like inverter availability or string outages is needed as with large fleets it becomes time consuming to 'dig down' into individual sites to check these," says Day.

"Ease of use is imperative. Whilst SCADA systems can have great amounts of data available to the user, there is no point in having any of it unless it is easy to access and download"

While SCADA deployment can run from tens of thousands of euros into several digits more, good SCADA systems, worth their salt, can reduce O&M costs over the plant's lifetime and enable operators to manage a portfolio of assets from one single location, as opposed to manage each plant as a separate entity.

Companies, like skytron energy and Enertis, have developed SCADA platforms able to handle large portfolios. All plants can be integrated into one data management centre, which clients can operate from their own control rooms from any part of the world.

Too much information

However, as SCADA platforms take on more complexity, recording and processing data from every single balance of system (BoS) component in a PV plant across every single asset in a portfolio, too much information and data can be a hindrance.

"Ease of use is imperative," says Day. "Whilst SCADA systems can have great amounts of useful data available to the user, there is no point in having any of it unless it is easy to find, access and download the exact data that the user is looking for. Some of the platforms that exist have great technical attributes, but if the end user cannot work them quickly and easily then they are redundant."

"Good, effective SCADA systems don't just generate data on performance; they can indicate the best action that must be taken, based upon technical and financial inputs. They have become critical tools which influence what decisions are made. This is as important for a company operating several multi-megawatt PV farms or several hundred individual rooftop installations and aggregating these together into a single fleet," says Callazo Garcia.

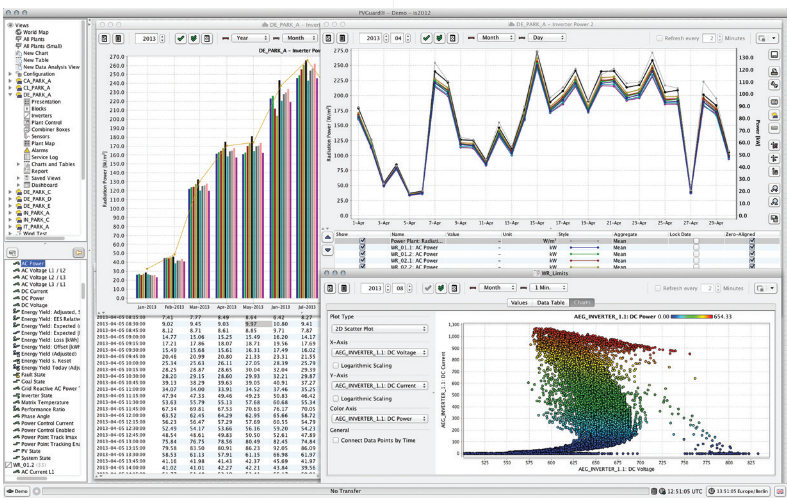
Beefing up security

Another growing area of importance that providers of SCADA systems have been addressing is cyber security and data protection for clients. Hive Energy, a UK developer of PV plants that is expanding into operating its own assets, is investigating different SCADA offerings and options; cyber security, along with the system's ability to meet the requirements of the National Grid, is high on the list.

"Cyber security is becoming more important. It's not just a question of data security but to avoid power plants being shut down or externally controlled by cyber-attacks," says Constantin Wenzlik, CEO and co-founder of Padcon, which has been providing PV plant developer and operator Belectric with SCADA and web portal platforms since 2008.

Enertis' security strategy has involved the company investing in servers in Canada, which, along with Switzerland, has some of the most watertight data protection and security laws of any jurisdiction.

"There is information bound up in SCADA systems, which plant owners do



Credit: skytron energy

Advanced systems offer a wide range of monitoring and control functions for single or multiple plants.

not want to risk getting into the wrong hands, so we have invested heavily in keeping it secure," says Collazo Garcia.

Klammer says: "Two areas where we have invested has been in network speed/ data transfer so that increasingly large packets of data can be handled while still enabling operators to see their fleets operating in real-time and also cyber security for safe and secure handling of data. This is a growing issue, as a PV plant operator with hundreds of megawatts of capacity across its portfolio, which are connected to the grid or several grids, needs to ensure that this sensitive data cannot be accessed or breached by outside parties.

Operators can either store SCADA data, which includes historical data, on their own servers, or – and this is the more common approach – have skytron energy manage the data on its own servers, including virtual servers. In either case, the data belongs to skytron energy's customers and only they have access to it.

Grid-side control

As opposed to simply feeding power into the grid when the sun is shining, PV plants must respond to grid requirements, which vary among different markets.

Skytron energy developed its Skycontrol power plant control system. The interface lets utilities curtail or manage the output from PV plants, partly by pulling together data from multiple blocks or inverters so that this is represented as one single generator to the grid operator.

According to Klammer: "For market integration requirements, which are increasing, skytron energy provides specific interfaces that allow energy trading. In the case of the grid requirements in certain markets, additions to the Skycontrol platform allow PV power plants to act like dispatchable resources on the grid."

He cites Romania as an unusual example of this. "In Romania PV plants over a certain size have to be constantly operated below the maximum possible energy output. In case of a ramp down command, the active power reserve is used to fulfil the grid operator requirement. Otherwise, the PV plant without energy storage can only provide negative regulatory energy."

More generally, the Skycontrol platform offers reporting packages, required for grid curtailment, for instance, where generators are paid not to send power to the grid, so it is important for operators to keep track of these instances.

How a PV plant portfolio owner uses SCADA

Lightsource RE is the largest PV asset owner in the UK, with a portfolio in excess of 700MW, making it one of Europe's biggest PV players. The company has grown its asset base rapidly in recent years, thanks in part to good subsidies for large-scale ground-mount PV plants in the UK and access to financing through its main stakeholder, Octopus Investments. The company has been investing in its own bespoke SCADA-based platform – Lightsource Asset Management Platform (LAMP) – for its monitoring needs as its portfolio has grown.

The platform differs slightly from a traditional SCADA system in terms of control functions, but monitors multiple parameters from the main components of the balance of plant of every single Lightsource site. Data is recorded from every part of the system: the export meters, G59 relay, pyranometers and weather station, transformers, inverters, DC combiner box, down to the individual strings. LAMP monitors the main aspects of these components, and not just basic performance parameters like energy and power.

The system also monitors inverter temperature, power factor and Buchholz relay in the plant's transformer. The LAMP teams use it to complete monthly reports on performance and availability and generally check on plant health. The platform is also the source of data for any calculations made by any department.

The company's monitoring and O&M teams also use the LAMP platform to actively monitor the health of the various parts of the plant. It has an alarm and event system built in that helps in this, flagging up issues as they occur.

Credit: Lightsource Renewable Energy

Lightsource has developed a bespoke SCADA system for its growing fleet of PV plants.

The reporting software packages are flexible so that operators, which in some cases own fleets in different geographic locations, can fulfil local requirements, and are also provided in different languages. Markets include Japan, Europe, the US, Latin America, the Middle East and South Africa.

SCADA investments

The cost of investing in SCADA technology for operators depends on a range of factors, such as the size of the PV plant or asset portfolio and also on the local grid requirements, which dictate the level of monitoring that is going to be required.

Klammer says: "For example, in Germany when the PV market started years ago, there were no grid requirements; power from PV plants was fed directly into the grid. Now, PV plants in Germany have to provide reactive power ancillary services to the distribution grid network, to compensate for voltage drops."

In newer PV markets grid systems are often weaker compared with those in western Europe. In Chile, for example, grid integration requirements are stricter, demanding that PV plants provide various ancillary services to help stabilize the grid. More controls for PV being fed into the grid are needed, so SCADA system investments tend to be more complex and, therefore, costly.

The PV market is continuing to evolve. Systems need to be able to meet the legislative requirements of different markets. So too must SCADA technology, showing owners what they can expect to generate from each of their plants under different financial models, with portfolios often spread over different markets and regions, while helping to optimise O&M activities to further drive down the cost of electricity. ■

Author

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Is China ready for 20GW in 2015?

So far in 2015 Chinese domestic PV deployment has outstripped last year's rates and a possible 20GW has been mooted for the year. This would set a benchmark for China's new five-year plan for solar development due to come into effect next year, writes Frank Haugwitz

During a national PV conference held late July in Beijing, representatives of various governmental entities conveyed the message that the deployment of 20GW in 2015 appears to be within in reach. The National Energy Administration (NEA) set a truly ambitious target of 17.8GW in mid-March, which itself, if successful, would translate into a 70% increase year on year from 2014's 10.6GW; 20GW would push that figure even higher to almost 100% year on year.

Indeed, in terms of quarterly installations, Q1 witnessed 5.04GW, which itself is more than all first quarters from 2012 through 2014 combined. Q2 also looked to be strong, with an estimated 2-3GW according to official NEA figures. Simple mathematics suggests China is just shy of needing 12-13GW to be deployed between July and December, which would be more than the entire installations in 2013 and 2014. Against this background, according to AECEA's market data, in the past years, demand in the third and fourth quarters has always been strongest, although not close to the anticipated 12-13GW.

However, 2015 differs from previous years in various aspects. One factor is that the former hard target policies were abolished, so there is no longer any cap for any type of installation, although authorities are encouraging the prioritisation of distributed PV. A monthly monitoring scheme has been introduced, allowing the government to have a clearer visibility in terms of actual implementation and clear deadlines developers are expected to meet or risk being suspended from applying for future projects. Other favourable signs include an improved financial environment, an approved project pipeline significantly exceeding this year's target and, last but not least, the anticipation that from 2016 onwards a reduced feed-in tariff will become effective. According to AECEA's monthly demand analysis, the first half of 2015 was the strongest ever so far and as of today doesn't show any sign of slowing down.

Despite strong momentum, China's domestic market is not free from challenges. One concern, for example is that the once-promising "agro-PV" projects, in which solar modules are deployed on agricultural greenhouses or put on mounting structures within fish ponds, could significantly slow down. The former is related to food supply concerns, because apparently in too many cases arable land has been converted into a project site not only pushing farmers out of business, but also undermining the national government policy to maintain a high degree of domestic food supply. The latter is apparently because of safety issues encountered during maintenance and operation of such plants.

Another area for concern is the prevailing grid curtailment in various western and southern provinces. Depending on the location, the amount of power grid operators are unable to take is in the high double-digit range. Further challenges include the various administrative hurdles that appear to be causing a negative impact on developers' cash flow in particular. But given the overall picture, to date, AECEA is still cautiously optimistic and estimates 14-15GW (baseline), 16-17GW (optimistic) and 18GW (bullish) to be installed in 2015.

If China's downstream sector is rather bullish, so is the upstream sector. Output of polysilicon and modules increased year on year by 15% and 26% respectively in the first half of 2015. Estimates suggest that in 2015 approximately 40GW of modules could be produced, thanks to an increase of imported polysilicon and the commissioning of new poly plants. At the same time the average capacity factor of 40 module manufacturers slightly increased from 77 to 80% in 1H/15 (YoY). In order to meet surging global demand, established manufacturers have been outsourcing to local third parties instead of adding production capacities, though new capacity plans are now beginning to emerge. Hence, one reason why small- or medium-sized manufacturers stay in business. According to the China PV Industry Association, Q4 2015 could even witness a minimal increase in module ASPs, due to the anticipated global demand growth of above 20%.

Credit: ReneSola

China has made a strong start towards a possible 20GW of PV in 2015.

During the above mentioned conference, a number of representatives stressed the point of maintaining and ensuring a high quality along the entire value chain, from materials through module manufacturing to installations. Accordingly, the national government plans to step up efforts to ensure that only high quality products go into export or are domestically deployed.

Overall, China is not only further cementing its position as the global manufacturer for solar PV, but also as the number-one investor for local installations at the same time. If China indeed manages to install 20GW this year, this achievement could possibly be used as a benchmark or reference for the drafting of the 13th five rear plan for solar development (2016-2020) scheduled to come into effect in March 2016.

This is an edited version of a blog post that first appeared on www.pv-tech.org

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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.


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