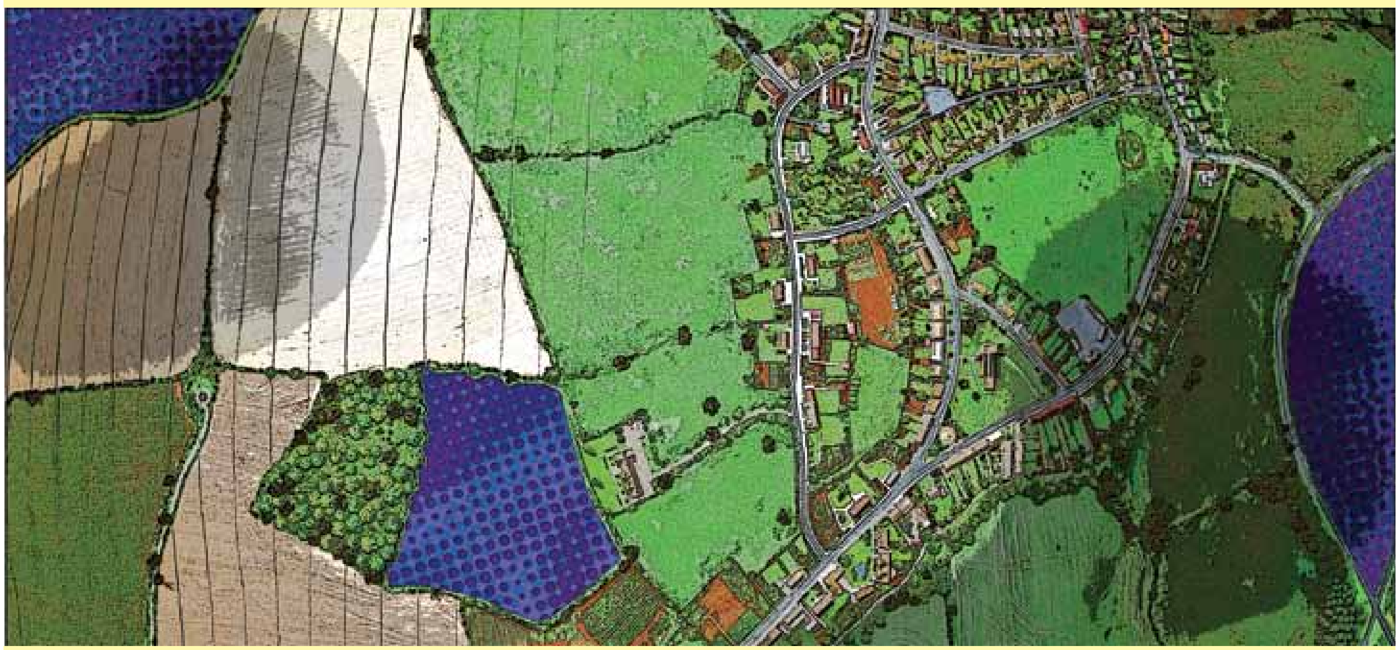
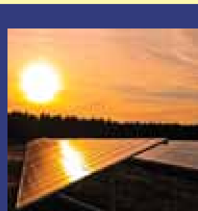
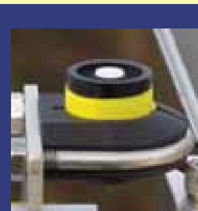
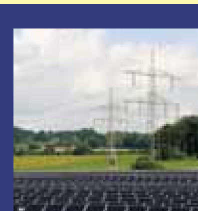
Photovoltaic Plant Output and Cloud-Induced Variability

Issues and Opportunities for Enhancing Plant Productivity and Grid Integration

December 2011




As photovoltaic (PV) installations spring up across the globe, addressing the variability in solar energy output—particularly that attributable to cloud passage and shading—is becoming increasingly important. Resource characterization and project siting, design, and implementation create opportunities to maximize productivity and better plan for and manage the effects of solar variability on grid integration. This white paper reviews the current state of knowledge, ongoing research, and future priorities in these areas. It is designed to assist electricity providers in understanding key factors that may influence the ability of central-station PV plants to deliver high-value power and be effectively integrated within the larger electricity infrastructure as penetration levels increase.

Executive Summary

PV technologies convert sunlight into direct current (DC) electricity and employ inverters to supply grid-compliant alternating current (AC) power at distribution and transmission levels. They are capable of generating useful amounts of renewable energy almost everywhere, and they produce no pollutant or greenhouse gas emissions during operation. They may be deployed in rooftop or ground-mounted arrays, at scales designed to serve on-site needs or supply bulk power to the grid. When solar energy is available, they produce electricity as designed, and they operate with high reliability and require minimal maintenance over lifetimes exceeding two decades. PV technologies also offer improving conversion efficiencies, declining costs, increasing bankability, and breakthrough possibilities.

These characteristics—bolstered by renewable energy mandates, investment and production incentives, and other government support mechanisms—are driving rapid capacity expansion and positioning grid-connected systems as increasingly important in meeting the world's energy needs. Because PV technologies operate on a diurnal cycle and generate variable output in response to cloud shading and other factors, concerns about grid integration also are growing (Figure 1). This is particularly true in areas that have experienced or are projected to see significant levels of deployment.

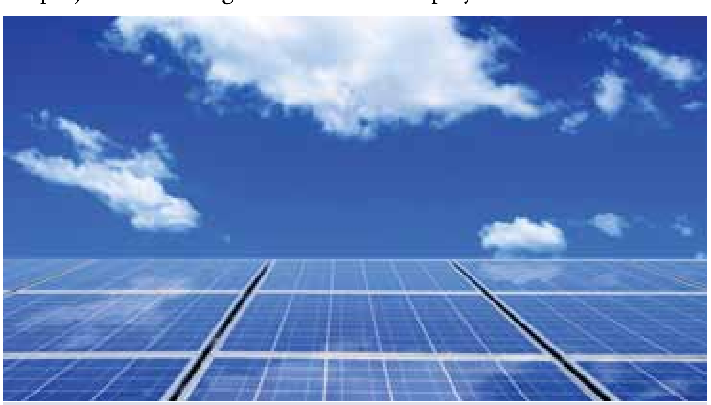


Figure 1 – Passing clouds produce immediate changes in irradiance and in PV plant output, creating ramps that pose grid integration challenges.

PV systems transform solar radiation—referred to as irradiance or insolation—arriving on their surface into electrical energy. Irradiance is defined as the instantaneous power available over a given area, typically in watts per square meter of surface (W/m^2). Direct normal insolation (DNI) is defined as the solar energy, in kilowatt-hours per square meter (kWh/m^2), that impinges upon a plane perpendicular to the path followed by the Sun's rays. Global horizontal insolation (GHI) is that which impinges upon a plane at the Earth's surface, and it includes DNI, diffuse light dispersed by clouds, aerosols, and other airborne constituents, and reflected light from buildings, water bodies, and other sources.

Flat-plate PV technologies based on crystalline silicon and thin-film materials make use of both the direct and diffuse solar resource and thus may be installed almost anywhere exposed to the Sun. They dominate the commercial marketplace, are being rapidly deployed in areas with a range of GHI values, and represent the focus of ongoing efforts to understand output variability. Concentrating PV technologies, addressed briefly in this white paper (see box, p. 15), are in the early stages of commercialization and have narrower applicability because they only are able to make effective use of DNI.

Solar variability encompasses both gradual changes in overall output over hours, days, months, and years and faster rates of change,

Table of Contents

Solar Variability & Integration • • • • • • • • • • • • • • • • • 4
Cloud Shading • 6
Geographic Smoothing • 9
Characterizing, Modeling & Forecasting Variability • • • 11
Addressing Variability in Project Planning & Design • • • 14
Addressing Variability in Grid Integration • • • • • • • • • • 19
Conclusions & Implications • • • • • • • • • • • • • • • • • • • 20

This white paper was prepared by Chris Powicki of Water Energy & Ecology Information Services under the direction of EPRI's Cara Libby, with cover art and layout by Liz Hooper at ehooperdesign.com.

which are caused by clouds and other sources and are experienced by the grid as ramps. From an integration perspective, the inherent variability of PV systems offers some advantages relative to that of wind turbines. Their diurnal output profile is closely aligned with load shape, helping meet peak needs. Further, morning and evening ramps and seasonal variations are predictable.

Cloud-induced variability poses some unique integration challenges (Figure 2). Formations and individual clouds change the irradiance available to be converted into electricity. This may produce immediate and large ramps in solar generation because of the way solid-state PV cells operate and are assembled into modules and arrays (see box, p. 5). By contrast, changes in turbine power output caused by shifts in wind speed and direction are dampened by the inertia of a spinning rotor. As a result, both the magnitude of PV transients (as a percentage of project output) and ramp rates (in capacity per second) often are more dramatic than those of wind-powered generators.

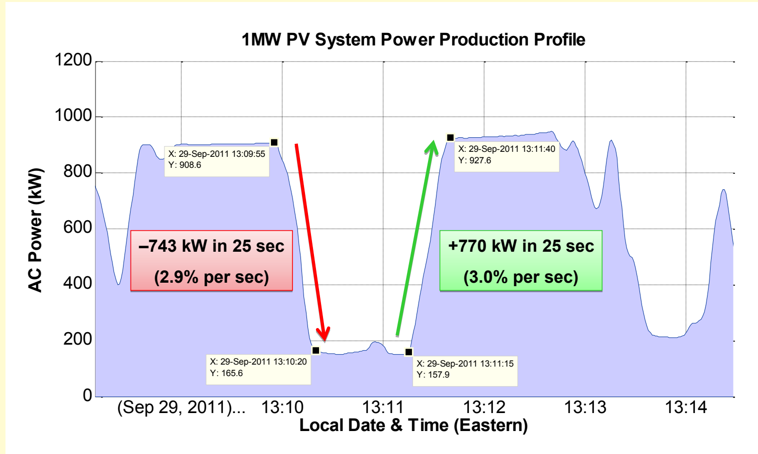


Figure 2 – Clouds may cause rapid, substantial, and recurring ramps, as demonstrated by data from a 1-MW plant in eastern Tennessee, where EPRI has installed a comprehensive measurement network to track the effects of shading and other factors on energy production and grid integration. (Credit: EPRI)

Shading caused by cloud passage over distributed PV installations may produce substantial output fluctuations within just a few seconds. This may lead to localized power quality problems, depending on where and how many systems connect to individual distribution feeders. Clouds passing over central-station PV plants—nominally at least 10 megawatts (MW) in capacity and getting bigger all the time—may shade different areas sequentially, over seconds to minutes. The resultant output variability—including fast ramps that exceed 50% of rated capacity, occasionally occurring repeatedly—may cause regulation and load-following issues. For both dispersed and centralized PV installations, grid instabilities attributable to or distinct from cloud-induced variability may trip inverters, producing immediate and large losses of solar generation.

Managing variability is critical for accommodating PV technologies at high penetration levels. Historically, much of the research and industry attention to solar resource characterization has focused on improving the siting and design of PV installations. On-the-ground measurement networks, typical meteorologic year (TMY) data sets, and other tools are applied to estimate resource availability and conduct production cost modeling of PV plant output at potential sites over varying time frames. The associated efforts to quantify solar variability and uncertainty are aimed at increasing understanding of the economics of proposed projects in terms of levelized cost of electricity and return on investment.

Once a PV plant is developed, its output variability becomes an integration concern. A range of protection, control, and mitigation options are being explored and applied in countries and U.S. regions with significant installed capacity. In addition, research, development, and demonstration (RD&D) programs are under way to improve understanding and advance integration capabilities in anticipation of continued PV deployment. As yet, most attention focuses on addressing variability introduced to the grid, rather than mitigating it through informed project siting and design.

Experience indicates that areal averaging of point irradiance—an effect known as geographic smoothing—occurs as cloud shadows pass over PV systems, moderating output variability. Similarly, smoothing may dampen aggregate variability across a fleet of projects installed along distribution circuits and within transmission control areas, relative to the ramps experienced by individual arrays. RD&D focused on improving understanding of variability, cloud shading, smoothing, and other factors—combined with progress in resource assessment, plant siting and design, module and inverter technology, sensing and forecasting, and grid planning and operations—is expected to lead to effective approaches for integrating growing amounts of dispersed and central-station PV capacity.

Solar Calendar, La Ola Lanai, Hawaii, August 2011

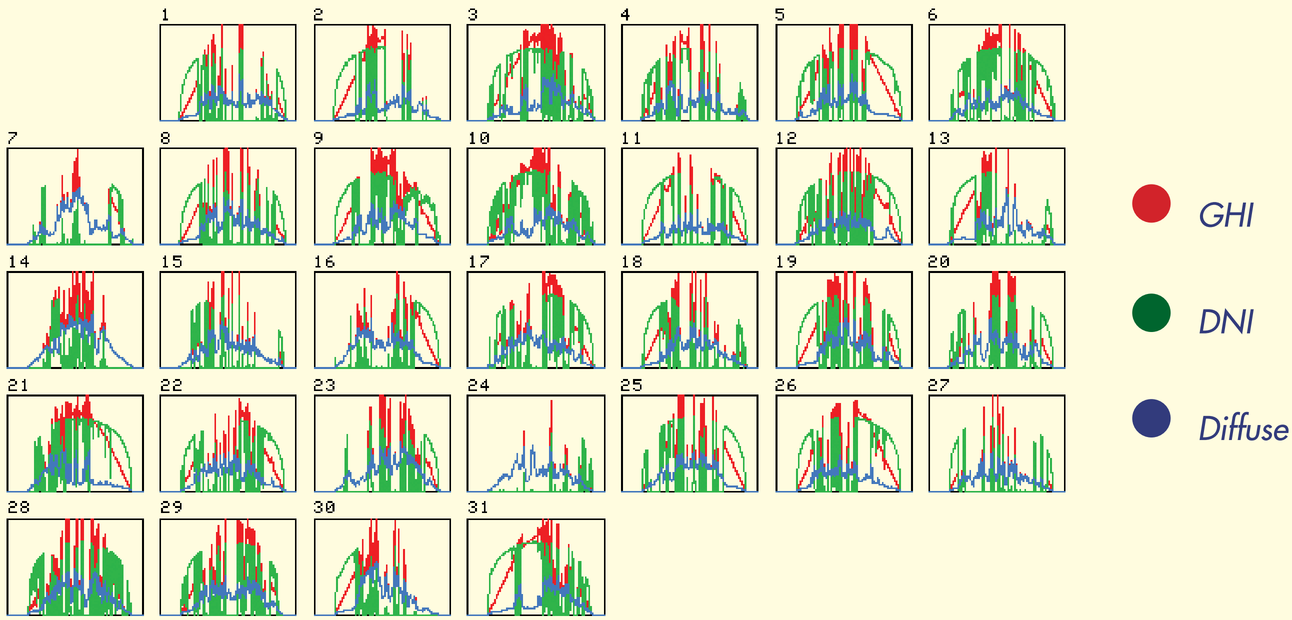


Figure 3 – While the daily and seasonal movement of the Sun across the sky creates deterministic changes in insolation, weather leads to significant and less predictable fluctuations in the direct, diffuse, and total sunlight available for energy production. (Credit: NREL)

Solar Variability & Integration

Grid operators manage the interconnected network of generation and delivery infrastructure to serve load while maintaining affordability and reliability. Load follows a predictable daily trend, increasing rapidly during early- to mid-morning hours, rising steadily to a peak in late afternoon or early evening, and then falling off through the night. Embedded within this trend are significant variability and uncertainty. The availability and performance of power plants and delivery systems also are not givens. In the absence of energy storage, balancing consumption and production in real time requires continuous forecasting, simulation, monitoring, and control of generation and load, as well as voltages, frequencies, and power flows throughout the grid.

Traditional generators serve as dispatchable sources of energy, and they provide functions and services to support reliable, low-cost grid operation. Generation is managed over three time scales: (1) fast regulation to maintain frequency and voltage, (2) intra-hour load following and energy balancing, and (3) hours- and days-ahead scheduling. PV systems are required to deliver standardized, utility-grade AC power at their interface to the grid, but changing weather and moving clouds make PV plant output more variable and uncertain than other forms of generation (Figure 3). Further, PV systems cannot provide the ancillary services afforded by traditional fossil and nuclear capacity and by biomass, geothermal, and concentrating solar thermal power (CSP) plants that employ chemical or thermal energy and turbine-generator trains with controllable output and mechanical inertia. Often, PV is treated as a negative load, and production is balanced through the use of reserves.

PV output variability attributable to daily and seasonal solar cycles is predictable and generally consistent with load shape. On clear days, solar irradiance and energy production change in a predictable manner as the Sun moves across the sky. After sunrise, significant but relatively smooth up-ramps in production occur. As the day proceeds, output increases more slowly, levels off before and after reaching a peak level, begins to decline, and then falls rapidly toward sunset. Seasonal changes in output influenced by hours of daylight as well as position of the Sun relative to the horizon are similarly deterministic. These aspects of solar variability are managed by grid operators in more or less the same way that they plan for load variations—through production modeling, scheduling of

PV Technology & the Multiplier Effect of Cloud Shading

Flat-plate PV technologies are based on cells that are fabricated from semiconductor materials, electrically interconnected by parallel and series contacts, and incorporated within modules. Modules are deployed on roof-mounted racks or ground-mounted platforms, and they are generally connected together in series to minimize wiring requirements. Small arrays often have a single string of modules connected to a grid-interactive inverter with integrated transformer. Larger installations may include multiple strings connected in parallel to a combiner box feeding a grid-tied inverter, or even several inverter blocks serving a grid-connected transformer.

This structure—with cells forming modules, modules connected in strings, strings feeding inverters, and inverter blocks serving transformers—may be maintained up to the central-station scale (Figure 4). Cloud-induced shading has significant effects on solar energy production because of the way PV modules are conventionally fabricated and deployed. When exposed to light, each PV cell produces a certain voltage and amperage, and series connections between individual cells result in an additive voltage and shared current across a module. Shading reduces light exposure and thus increases resistance on a localized basis. Thicker cloud formations have greater impacts.

By degrading the performance of even an individual cell, shading lowers the amperage across the entire module to just above that cell's level, reducing overall output. Similarly, because current is shared along a string of series-connected modules, cloud-induced performance degradation of a single module cuts the output of the entire string. Because large PV systems may include strings containing hundreds of kilowatts, partial shading can cause significant generation losses.

In practice, PV module manufacturers mitigate the multiplier effect of shading by incorporating bypass diodes that route the flow of electricity around cells with increased resistance, and analogous inverter technology allows low-performing modules within a string to be bypassed. These approaches automatically come into play when system-level losses exceed those incurred from bypassing the cells and modules operating at partial output. They reduce but do not eliminate cloud-induced impacts on solar energy production, creating the need for continued progress in cell, module, and system design.

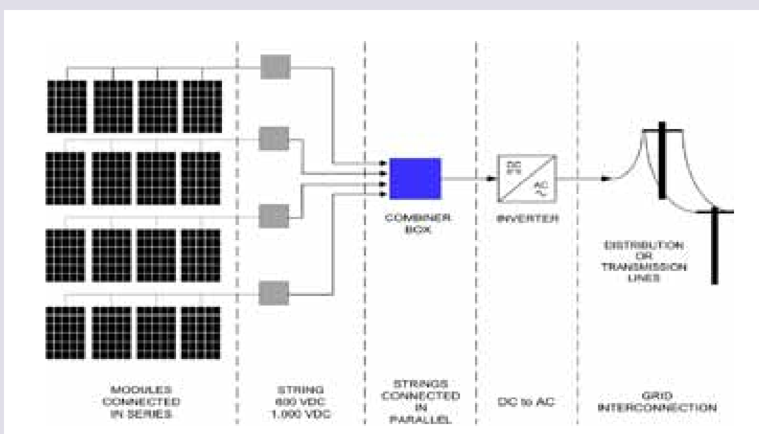


Figure 4 – The typical PV plant configuration includes series-connected strings of modules feeding a centralized inverter. As current is maintained across a string, cloud shading of even a single module degrades performance across an entire string. Alternative plant layouts, wiring configurations, and inverter technologies are being explored for reducing cloud-induced string losses and the associated output variability. (Credit: EPRI)

Supply Mix in Germany, May 2-8, 2011

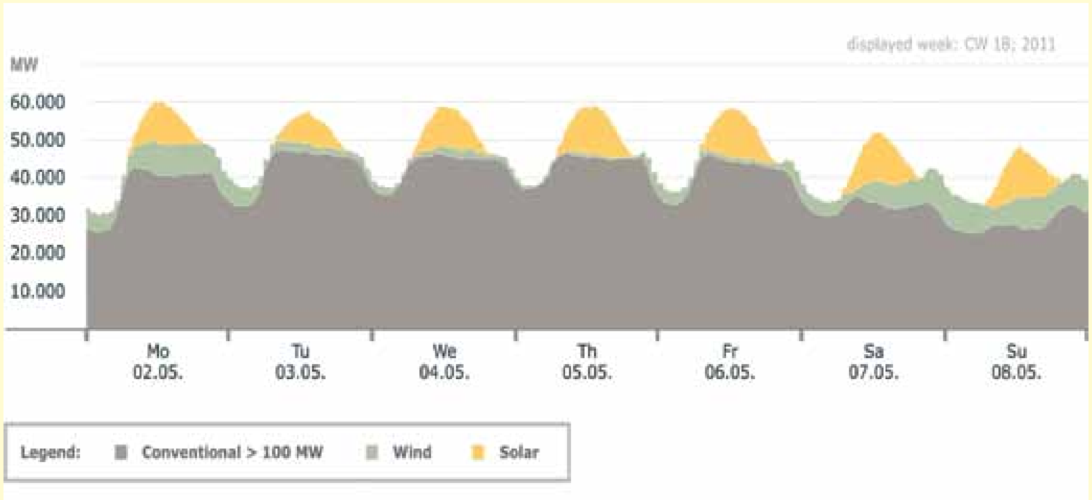


Figure 5 – In Germany, where the grid accommodates high levels of PV penetration in some areas, solar energy helps meet peak demand on a more consistent basis than wind power. (Source: Burger, 2011)

units, and balancing. Though not dispatchable, PV plants offer grid support value by lessening the need to schedule conventional generation during daylight hours and by producing power at times when land-based wind energy may not be available (Figure 5).

Clear skies are most favorable for solar energy production, but PV systems generate power during partly cloudy, overcast, and foggy conditions because they convert both direct and diffuse light into electricity. Averaged over a day, reductions in output are proportional to reductions in irradiance, ranging from less than 10% on mostly sunny days to perhaps 50% on overcast days and greater than 90% on dark and overcast days. The second-to-second and minute-to-minute drops and spikes in generation attributable to cloud shading are the most significant grid integration concern because they can be both dramatic and unpredictable.

Other sources of solar variability exist. Positive fluctuations in output may be experienced by projects installed in areas where diffuse light from water bodies and other reflective surfaces enhances irradiance, relative to projected clear-sky GHI. As this aspect of solar variability will occur predictably, at certain times of the day, it may be incorporated in production modeling and plant siting. Light reflected from ground covered by snow produces similar insolation exceedances that are less easily accounted for, while snowfall may temporarily halt PV system production, create significant spikes in output as melting snow slides off tilted surfaces, and cause losses until melting is complete.

Dust, pollen, and other debris on the surface of PV modules may degrade production by anywhere from a few percentage points to more than 20%. Noticeable drops in output may occur after weather events, seasonally due to vegetation growth cycles, and gradually as contaminants accumulate over time. Soiling is a particular problem in arid areas and during dry periods where rainfall is inadequate as a passive washing solution, creating a need for more frequent maintenance and cleaning.

Cloud Shading

The overwhelming majority of stochastic variability in PV plant output is attributable to cloud shading. The passage of an individual cloud may cause significant changes in measured irradiance levels within just a few seconds—and may have little to no effects on conditions just a short distance away. Lacking the thermal inertia intrinsic to CSP plants and the mechanical inertia that dampens the effects of rapid changes in wind speed on the output of rotating turbines, PV systems respond directly and rapidly when shading occurs. Impacts on solar energy production depend on the areal extent of the installation and the characteristics of the cloud, as well as other factors.

Figure 6 illustrates cloud-induced variability over a 30-minute period, as captured in EPRI research at a plant instrumented to capture 1-second changes in irradiance and other key parameters (see box, p. 8). For small PV installations where shadows quickly span the entire array, cloud transients may almost immediately represent a substantial fraction of rated capacity. Effects of similar magnitude may occur more gradually—over tens of seconds—as increasing numbers of modules are shaded in larger distributed projects and in areas where multiple systems are located in close proximity and connected to a single distribution feeder. In these circumstances, voltage fluctuations, harmonic distortion, loss of effective voltage regulation, changes in radial power flows, reverse power flows, and unintentional islanding may result. Power quality and regulation problems may be particularly acute when large blocks of PV are installed near the end of a feeder or on a relatively weak distribution circuit.

Central-station PV plants spread out across wide areas, with land requirements ranging from 20 to 50 ha (50 to 120 acres) for a 10-MW installation, depending on cell type and mounting system. (EPRI, 2010b) Accordingly, impacts are gradual as cloud shading expands, and different blocks of capacity may be affected sequentially. Some areas may go unaffected. That said, individual plants may experience ramps of ±50% within 30 to 90 seconds and ±70% over 5- to 10-minute time frames. Cloud transients like these may occur multiple times in a single day, occasionally in rapid succession. Fast solar ramps, which are generally more severe than those for wind projects over 5 to 15 minutes, create the potential for regulation and load-following issues. Over the time scales longer than 15 minutes that are relevant for load following and balancing, solar and wind plants are expected to offer comparable levels of overall variability. (Mills *et al.*, 2009; Mills & Wiser, 2010)

Cloud shading typically reduces PV system output. However, light reflected from nearby clouds may result in localized increases in irradiance—beyond projected clear-sky GHI—that temporarily boost production (see box, p. 8). Depending on the relative orientations of the array and the Sun, modest, short-lived gains in production may occur as clouds approach or when they pass nearby but do not cast shadows. When a system is partially shaded, this phenomenon,

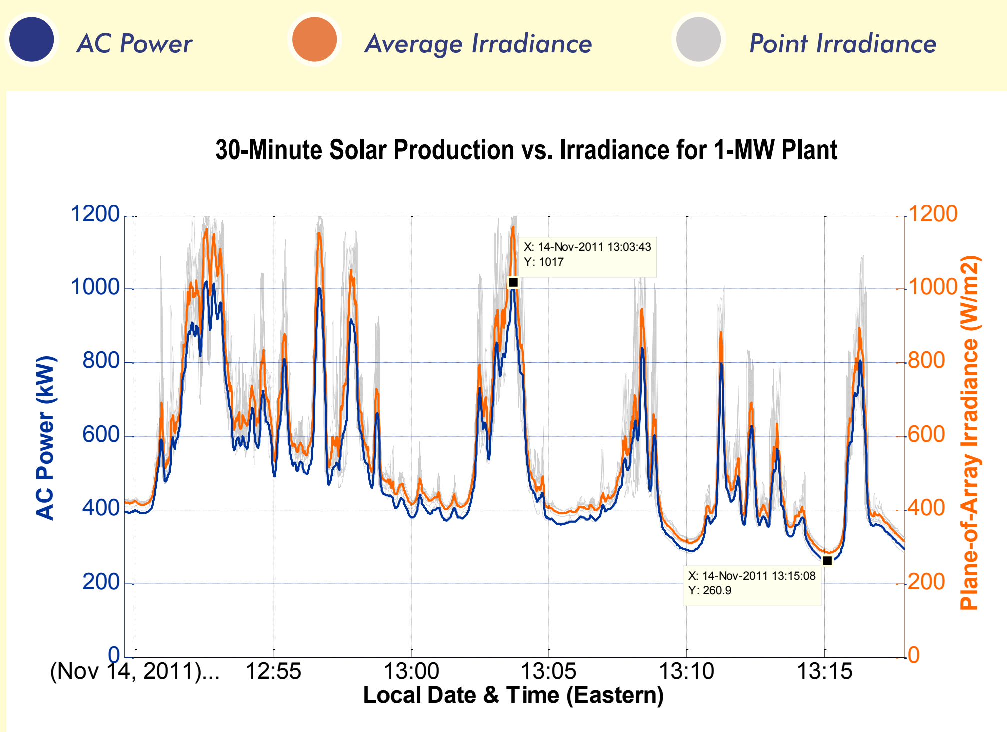


Figure 6 – Cloud transients, as recorded at 1-second intervals by point irradiance and AC output sensors, may occur repeatedly. This figure, from a 1-MW array in eastern Tennessee, illustrates repeated ramps over 30-minute periods. It also shows geographic smoothing within the project: Individual irradiance sensors exhibit the greatest variability, while ramps in output are less dramatic than changes in average irradiance. (Credit: EPRI)

A Case Study in Cloud Shading, Ramping & Smoothing in Eastern Tennessee

EPRI is conducting a comprehensive field study of solar variability at a privately owned 1-MW PV plant served by four 260-kW string inverters and connected to a distribution feeder. Eight pyranometers provide 1-second plane-of-array irradiance data across the field. Inverter AC output is measured and assessed for power quality, and DC monitoring is performed on a selected PV module and a combiner box serving eight strings. A single-module, pole-mounted system, first deployed in EPRI's distributed PV feeder analysis project (see box, p. 22), delivers idealized microinverter-based output for comparison with actual output to and through inverters for the entire plant.

On partly cloudy days, ramps of as much as 75% of total plant capacity have been observed on periods shorter than 30 seconds. As shown in Figure 7, irradiance levels may exceed 1000 W/m² by amounts approaching 20%, then rapidly drop to under 400 W/m². Insolation exceedances are caused by sharp-edged clouds that reflect significant quantities of light backward as their shadow clears the field. Inverter saturation caps fast ramps and results in the spillage of solar energy. As this only occurs on days with clear conditions between thick, fast-moving clouds, production losses are likely to occur for only small fractions of the year.

Continued research addresses cloud passage, output variability, and balance-of-system efficiency for the single-module unit and entire plant. Findings, along with complementary high-penetration modeling studies, are expected to lead to guidance on central-station project siting and design, module and inverter selection, layout and wiring configuration, and other key factors to assist solar energy developers in maximizing production and balance-of-system efficiency, minimizing string losses due to cloud shading, and delivering grid support value.

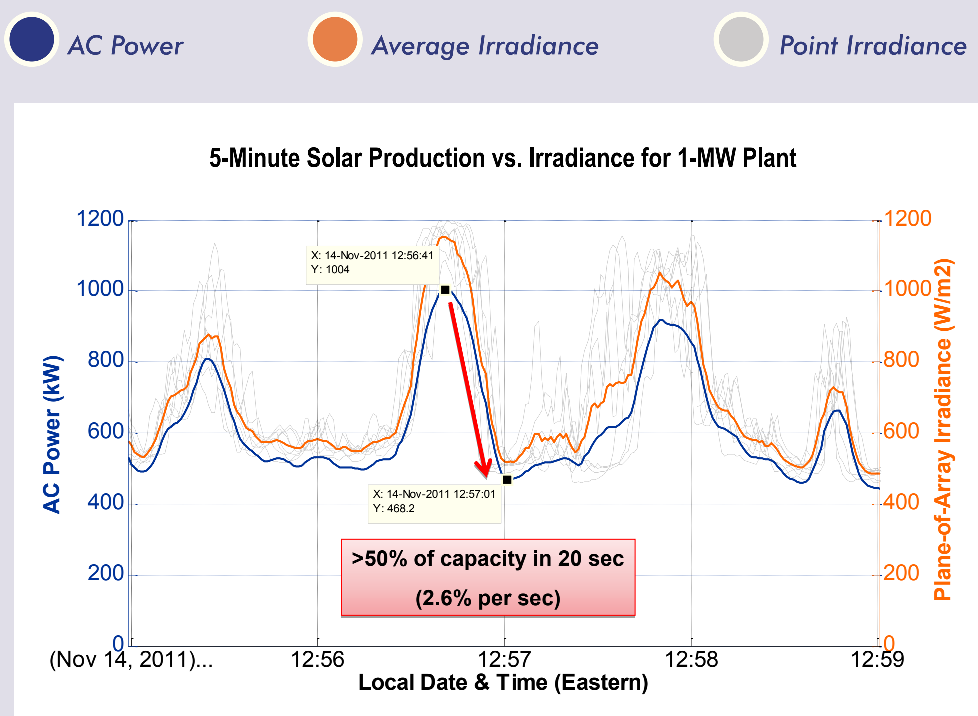


Figure 7 – This figure provides a 5-minute snapshot of the data shown in Figure 6. For the two largest up- and down-ramps created when one cloud's shadow leaves the solar field and another enters it, significant insolation exceedances, driven by cloud enhancement, are evident. Point variability is smoothed across the array, and the ramp exceeding 50% of capacity is curtailed by inverter saturation. (Credit: EPRI)

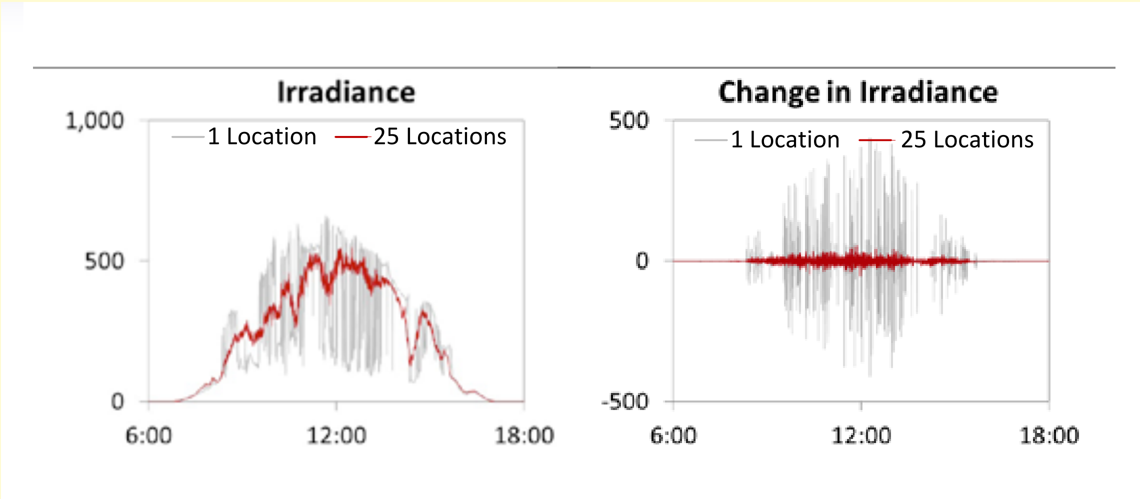


Figure 8 – Field experience and modeling studies demonstrate that geographic diversity moderates cloud-induced changes in solar resource availability. Irradiance measurements taken at a single point are extremely variable. When multiple point measurements taken across a given geographic area are aggregated, resource variability is smoothed, helping reduce ramping and uncertainty in PV plant output. (Source: Hoff, 2011)

known as cloud enhancement, may temper down-ramps. Once cloud shadows have cleared an array, insolation exceedances may lead to steeper up-ramps.

Important cloud characteristics include type and size, density and opacity, and direction and speed of motion. Cloud shading's effects on instantaneous irradiance and the output of individual plants are shaped by atmospheric phenomena—real-time weather, near-future conditions, larger atmospheric flows, and prevailing winds and storm patterns—as well as site-specific geographic conditions. Across a larger fleet, key parameters include the Sun's motion, the insolation and weather conditions within the fleet footprint, and the physical characteristics of the fleet, including its areal extent, the number of and spacing between plants, and each plant's capacity, orientation, and generating profile.

Geographic Smoothing

The magnitude of cloud-induced variability observed at the distribution level and for individual central-station installations suggests that the need for additional power quality, regulation, and balancing resources could represent a limiting factor to significant PV penetration. However, as has proven the case for wind integration, geographic smoothing helps moderate rather than exacerbate cloud-induced variability across all scales. Fluctuations in insolation and production for individual modules, blocks, and projects may be aggregated through their electrical connections and then smoothed to some extent by geographic diversity (Figure 8).

Germany, the world's leader in grid-connected PV capacity, relies on solar power to serve a large fraction of its daily load, particularly at peak periods. During May 2011, for example, 13.2 gigawatts (GW) of grid-connected PV capacity generated 2.6 terawatt-hours of power and accounted for almost 6% of the overall monthly load. Further, predicted and planned daily output were in close alignment, and solar energy was delivered more consistently than wind energy (Figure 5). According to an analysis by the Fraunhofer Institute for Solar Energy Systems, Germany's power grid successfully accommodates PV capacity shares of more than 15% nationally and much higher regionally due primarily to "…the large spatial distribution of the solar plants, where local weather conditions, such as moving clouds, are averaged out completely." (Burger, 2011)

As a passing cloud sequentially shades and exposes modules within an array, systems along a feeder, or individual blocks of capacity in a distributed multi-MW installation, the localized drops and gains in output may largely offset each other. Cloud-induced ramps in irradiance are thus more severe than ramps in output, and net effects on power flow through the distribution system are reduced. Similarly, when two or more central-station PV plants are sited within a grid control area, rapid but uncorrelated changes in the output of individual projects may largely cancel each other out over short time scales. Because operators need only match load with total net generation, this moderates the increase in balancing reserves required to hold reliability (Figure 9).

Geographic smoothing of stochastic variability has been observed for installed PV capacity and simulated in recent studies. The degree of smoothing among generating units is inversely proportional to the correlation between simultaneous changes in their output, which depends on both the time scale being considered and their physical separation: Smoothing generally is more effective over shorter periods, across longer distances, and for slower-moving clouds. It is evident within individual arrays and among two or more projects. (Hoff & Perez, 2010; Mills *et al.*, 2009; Mills & Wiser, 2010) In theory, as penetration levels increase, PV capacity could be deployed to intentionally achieve the geographic diversity required to reduce the impacts of cloud-induced variability across a fleet of projects.

For systems as small as 20 to 30 kW in capacity, 1- and 10-second ramps in point irradiance due to cloud shading are slightly greater than the associated ramps in production, while 1-minute ramps are nearly identical. For larger distributed installations and central-station plants, more significant smoothing may be evident in response to large cloud-induced changes in irradiance (Figure 10). Output ramps may be as much as 60% less dramatic than recorded irradiance transients over 1 second, 40% less over 10 seconds, 30% less over 1 minute, and 10% less across 10 minutes. (Mills *et al.*, 2009; Mills & Wiser, 2010) Larger plants offer greater smoothing because partial shading is more likely and the correlation coefficients associated with simultaneous changes in output are lower for inverter blocks that are farther apart.

For separate MW-scale and larger plants located from kilometers to tens of kilometers apart, smoothing of solar resource variability occurs and extends to longer time scales. Experience indicates that aggregating production across two or more geographically distinct plants significantly reduces ramps, as a percentage of capacity, over periods of up to 10 minutes relative to those experienced at individual sites. To a lesser extent, cloud-induced 30- and 60-minute ramps also may be smoothed through aggregation of projects installed within a control area. (Mills *et al.*, 2009; Mills & Wiser, 2010)

Solar resource data collected in some locations demonstrate that irradiance ramps attributable to cloud passage are uncorrelated at sites separated by about 2 km over time scales of 1 minute, 10 km over 5 minutes, 20 km over 15 minutes, 50 km over 30 minutes, and 150 km over 1 hour. (Mills *et al.*, 2009; Mills & Wiser, 2010) To analyze, predict, and manage cloud shading effects for individual arrays and fleets of projects deployed across the landscape, key influencing factors must be accounted for over time scales of relevance.

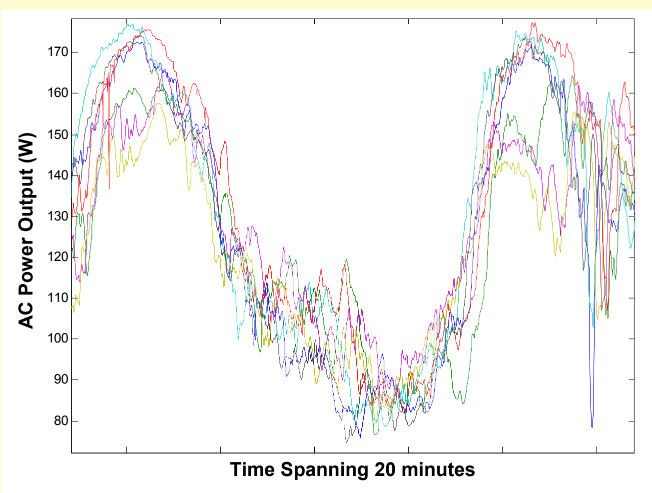


Figure 9 – The 1-second output data generated by single-module systems deployed by EPRI and Georgia Power along a distribution feeder illustrate the geographic smoothing experienced by the grid: Aggregate fleet variability is reduced relative to individual output variations. (Credit: EPRI)

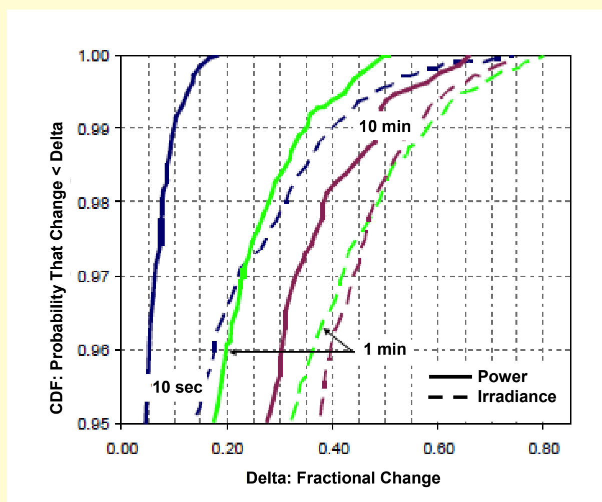


Figure 10 – This irradiance and power distribution for a 13.2-MW plant demonstrates that ramps are more severe for the former than the latter, with geographic smoothing—shown here as the gap between irradiance and output—more evident on shorter time frames. (Source: Mills et al., 2011)

Characterizing, Modeling & Forecasting Variability

Measurement and forecasting of irradiance and weather conditions are critical for characterizing solar resource availability and cloud-induced variability on annual, monthly, daily, hourly, sub-hourly, and shorter time scales and for conducting production modeling and grid planning studies over longer periods. From an integration perspective, a near-term priority is to improve understanding of stochastic variability over intervals of a few seconds to a few minutes, when reserves may be dispatched to provide frequency and voltage regulation services and balance supply with load. Improved forecasting abilities over the 10-minute to 1-hour time frame are needed to increase operational and economic efficiency in load following and balancing. Ultimately, fleets containing tens of gigawatts of central-station capacity and hundreds of thousands of small systems may need to be accommodated within individual control areas, placing a premium on innovative approaches for resource characterization and predictive modeling. (Hoff & Perez, 2011)

Long-term modeling and accurate seconds-to-minutes-ahead forecasting of project output and cloud-induced variability are contingent upon translating irradiance, weather, and other data into energy production profiles. Conventionally, PV performance and production modeling has been based on ground measurements of irradiance and weather conditions, TMY data, and numerical weather modeling. Recently, satellite-based irradiance measurements have begun to be applied for validating and supplementing ground-based resource characterization and informing project siting and development. In the United States, for example, the SolarAnywhere network uses satellite imagery from U.S. National Oceanic and Atmospheric Administration to deliver web-based irradiance data averaged at 1-hour resolution over a 10 km x 10 km grid. Currently, SolarAnywhere is being enhanced to deliver 30-minute data on a 1 km x 1 km grid, first in California and then across the country.

In grid planning and operations applications, higher-resolution satellite data may reduce forecasting uncertainty for PV projects but not enough to address cloud transients, which are controlled by phenomena that occur at much finer scales and are not well-represented in weather models. Significant research is under way to develop practical predictive tools based on knowledge that the primary influences on short-term variability are the Sun's position, sky (clearness/cloudiness) conditions, and the physical characteristics of individual systems and entire fleets.

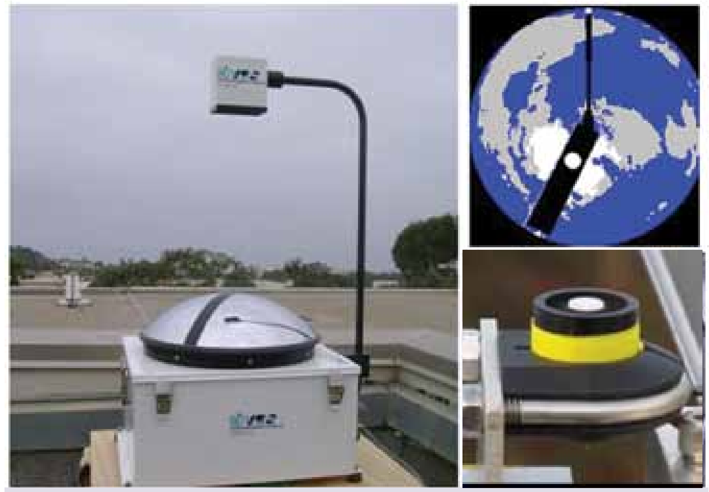


Figure 11 – Dense networks of pyranometers (bottom right) deliver 1-second irradiance data at fine spatial scale, while sky-imaging cameras (left) promise to translate cloud tracking (top right) into a real-time forecasting tool. (Credits: left and top right, UCSD; bottom right, EPRI)

Irradiance at a site or array is typically measured using pyranometers. PV projects incorporate ground- or roof-mounted sensors—usually individual instruments or sparse networks—capable of continuously capturing and reporting on-site solar resource, weather, and production data, while inverters quantify power flows at the sub-second level. Around the world, ongoing RD&D projects are deploying higher-density monitoring networks and novel sensors in resource-rich areas, at central-station plants, and along distribution feeders to provide data-driven insights into solar resource variability and cloud transients and to develop models capable of predicting dynamic output behavior based on shading patterns over array footprints (Figure 11). These efforts, funded by utilities, industry research organizations, U.S. Department of Energy (DOE), California Public Utilities Commission (CPUC), and others, are expected to inform both project development and grid integration.

Advanced measurement networks apply pyranometer grids within and on the perimeter of arrays to collect 1-second GHI and plane-of-array (POA) irradiance data. Ground-based sky-imaging systems use novel "fish-eye" cameras to capture real-time, 360° images of the sky above and around PV installations. Ambient and module temperature, wind direction and speed, solar energy production, voltage and current, and power quality are among other key parameters being tracked. Ongoing EPRI projects focus on characterizing the effects of cloud passage on irradiance and output variability for a fully instrumented 1-MW project in eastern Tennessee and small pole-mounted arrays installed along distribution circuits in a

number of utility service territories (see boxes, p. 8 and 22). Several major U.S.-based measurement and modeling programs are highlighted below.

Near Honolulu International Airport in Hawaii, a network of 17 GPS-linked measurement stations is delivering time-synchronized irradiance data at 1-second resolution to track exactly what happens as clouds approach and pass over PV installations. The data, collected by National Renewable Energy Laboratory (NREL) in collaboration with Hawaiian Electric Company and other partners, are being applied to support modeling and mitigation of cloud transients for projects up to 30 MW in capacity. Brookhaven National Laboratory hosts a new 32-MW installation, currently the largest in the northeast United States. A cloud-imaging system—only the second of its kind in the world—has been installed to complement a comprehensive 1-second irradiance and weather sensor network and a modeling framework focused on linking irradiance and cloud shading with output.

An advanced irradiance sensing system is generating 1-second data from in and around the 1.2-MW La Ola Solar Farm on the island of Lanai, Hawaii. The Lanai Irradiance Network Experiment (LINE), supported in part by Sandia National Laboratories, incorporates 24 fast-response pyranometers, including plane-of-array (POA) sensors located on individual tracker segments and fixed GHI sensors on the project perimeter. As shown in Figure 12, data indicate that project output on time scales as short as 1 second is almost linearly proportional to spatially averaged irradiance across the plant site on both clear and partly cloudy days. In addition, animations of the irradiance field have been created to track cloud shadows crossing the array. At times, individual shadows may be clearly delineated. At others, more chaotic irradiance patterns emerge. Continuing work focuses on developing correlations between irradiance fluctuations, ramps, and the shape, size, and velocity of cloud shadows and incorporating them in predictive models. (Kuszamaul *et al.*, 2010)

Based in part on the relationship between project output and spatially averaged irradiance described above, researchers at Sandia are applying point measurements, fine-resolution weather data, and coarser-resolution satellite data to create 1-minute, 1-hour, and day-ahead irradiance and output profiles for hypothetical PV installations in southern Nevada. This work, conducted in support of a solar integration study by NV Energy, is generating profiles for individual systems based on varying PV technologies, module and tracking configurations, sizes, and weather and cloud conditions. Initial validation tests indicate these profiles are consistent with field irradiance observations and may prove suitable for use in accounting for cloud-induced variability aggregated across a fleet of plants. (Stein, 2011) Complementary research focuses on the use of satellite- and ground-based imaging and measurement systems to develop techniques for tracking clouds and linking their characteristics to ramps. (Reno *et al.*, 2010)

Analysts with Clean Power Research and University of Albany are applying enhanced SolarAnywhere data, a satellite-based cloud motion forecasting method, and advanced modeling tools to characterize output variability and geographic smoothing across fleets. For an idealized fleet containing a given number N of identical plants laid out on a grid and having uncorrelated output, fleet variability has been determined to be $1/\sqrt{N}$ of single-site variability due to

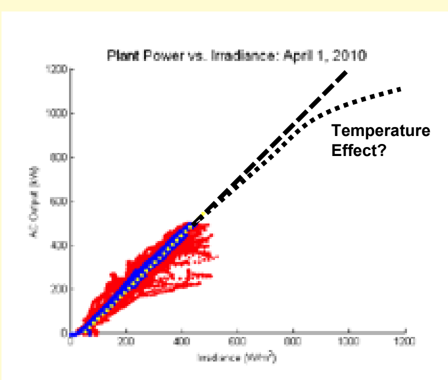


Figure 12 – Correlating PV plant output with spatially averaged irradiance across the solar field on all time scales provides a foundation for accurate predictive modeling and mitigation of cloud shading impacts. (Source: Kuszamaul et al., 2010)

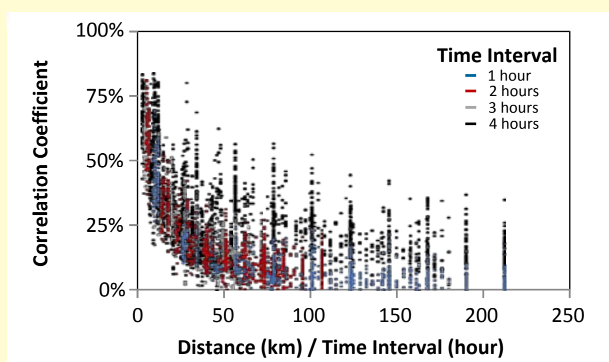


Figure 13 – As the correlation between cloud-induced variability at individual plant sites decreases, the degree of geographic smoothing increases. As shown here, smoothing is more apparent over shorter periods and when plants are farther apart. (Source: Hoff & Perez, 2011)

geographic smoothing. (Hoff & Perez, 2010) In the real world, the degree of correlation in output between installations—as influenced by their location and the direction and speed of passing clouds—also must be considered in order to quantify the true degree of smoothing.

Follow-on work has uncovered a consistent mathematical relationship between the physical characteristics of a fleet and the degree of correlation in changes in the clear-sky index of individual sites, which is the ratio between measured and clear-sky GHI (Figure 13). Generally, the correlation decreases—and thus the degree of smoothing increases—when shorter time frames are considered, sites are separated by greater distances, or shading is caused by slower-moving clouds. (Hoff & Perez, 2011) Continuing research aims to develop and validate a model for predicting output variability for any PV deployment configuration on any geographical and time scale, without using ground-based measurements.

At University of California, San Diego (UCSD), satellite images of cloud formations and a Total Sky Imager are being used to enhance representation of key phenomena in numerical weather models and to develop quantitative relations between cloud characteristics, irradiance measurements, and PV production. Advanced image processing and analysis software has been developed to identify the type, speed, direction, and other characteristics of approaching clouds and translate this information into anticipated irradiance levels as cloud passage occurs. Generally, ramps at individual sites depend on cloud thickness (also know as optical depth) and speed—thicker, faster-moving clouds cause more severe transients. Across fleets, ramps depend primarily on geographic footprint relative to cloud size. For clouds or cloud systems larger than the footprint, the correlation between sites is higher, multiple sites are shaded at the same time, and greater changes in aggregate output occur. Conversely, when the footprint is larger than the cloud shadow, geographic smoothing is stronger. (Kleissl *et al.*, 2011)

Cloud variability is influenced by geographic factors such as surface terrain and proximity to the coastline. Figure 14 shows irradiance under different cloud conditions—expressed as clear sky index, with lower values corresponding to thicker clouds—at two sensors located on the UCSD campus roughly 1 km (0.6 miles) apart. For cirrus clouds, which are large but high in the sky, irradiance is more steady, and the strong correlation in variability indicates limited geographic smoothing. By contrast, both cumulus and altocumulus clouds are smaller than the distance between the two sensors, resulting in less

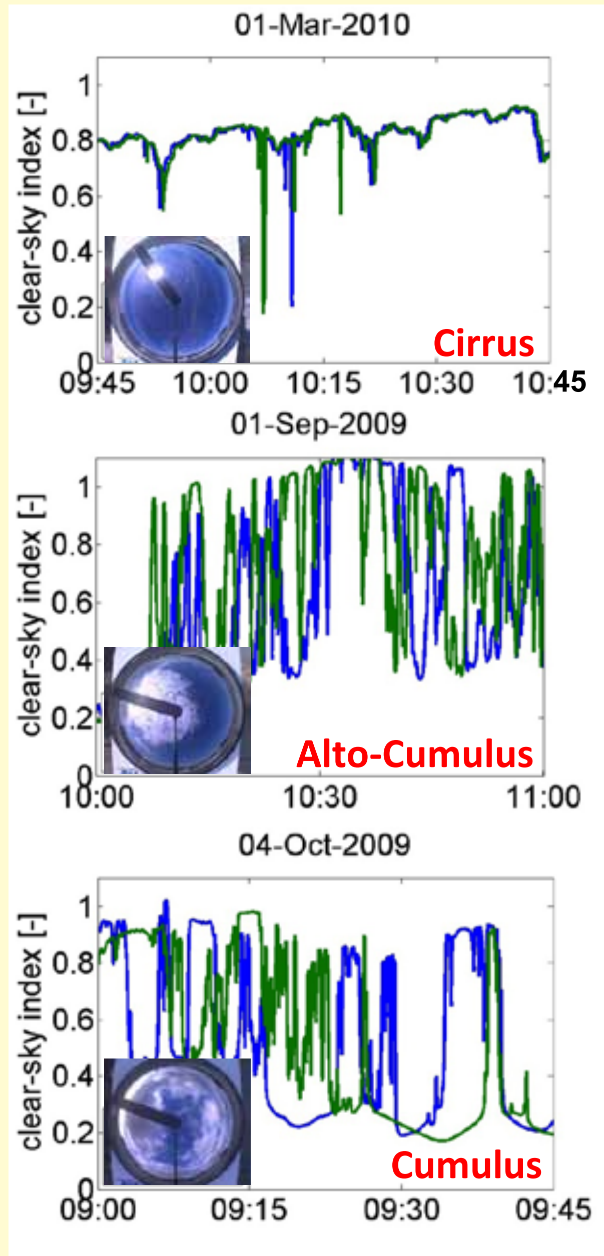


Figure 14 – Sky imaging of different types of cloud formations (insets) is allowing researchers to elucidate the effects of cloud thickness, speed, and direction on irradiance levels at different sites, as indicated by the blue and green lines on the charts. Uncorrelated clear-sky index values indicate stronger smoothing of PV plant output at the two sites under altocumulus and cumulus conditions. (Credit: Jan Kleissl, UCSD)

correlation and strong geographic smoothing as clouds pass over one site and then the second. Based on results to date, deterministic forecasts of cloud-induced transients are expected to prove useful over intervals from 30 seconds to 15 minutes ahead. Probabilistic sky-cover forecasts spanning the 15- to 30-minute window also are anticipated. (Kleissl *et al.*, 2011)

Sacramento Municipal Utility District, Pacific Gas & Electric, Southern California Edison, and Hawaiian Electric Company—all experiencing high penetration on some circuits—are among the U.S. utilities that are actively developing tools to inform PV deployment and grid reinforcement based on the anticipated locational value or adverse impacts of additional variable-output generation. In ongoing EPRI research, a high-fidelity distributed PV model is being created to provide feeder-specific guidance on capacity that may be installed without impacting service quality and on protection and control strategies for allowing additional deployment (see box, p. 22).

Addressing Variability in Project Planning & Design

Much of the ongoing RD&D is aimed at addressing cloud-induced variability through grid planning, support, and reinforcement based on new knowledge and predictive capabilities, as well as advances in power electronics, energy storage, and other technologies. Project development, generation technology, module layout, mounting configuration, inverter, and other balance-of-system options also have a strong influence—and may potentially be applied to manage—solar energy production and the deterministic and stochastic variability attributable to the solar cycle and cloud shading, respectively.

Project Siting & Sizing. Two key physical criteria influencing the development of PV projects include the quality of the solar resource and the ability of the power delivery system to handle additional generation capacity. As penetration levels increase, accounting for these factors alone is unlikely to deliver locational value for addressing cloud-induced variability over the sub-hourly time scales relevant for regulation and balancing purposes.

Detailed solar resource assessment is fundamental to the effective siting of large PV projects. Relying on annual average GHI values is inadequate, as diffuse sunlight, which is important on partly cloudy days and predominates under overcast conditions, makes significant contributions in many regions of the world. Based on weather patterns and other factors, observed GHI in a given year may vary by up to plus or minus 10%—and more in some areas—from the annual average. A number of commercial suppliers offer site assessment services based on field measurement of irradiance and weather conditions for periods from three months to a year or longer. Applying time-series data to characterize production and variability for longer durations, over much finer spatial and temporal scales, provides a more statistically robust assessment of a site's solar resource. Advances in predictive modeling are critical for improving the accuracy of projected production profiles for specific sites and deployment scenarios and thereby reducing project financing risks associated with output variability.

Typically, developers of central-station PV plants like the one shown in Figure 15 evaluate transmission capacity early on in the site selection process and may then be required to support interconnection studies addressing the larger spectrum of site-specific grid integration issues. A more proactive approach to addressing solar variability during siting may prove beneficial in regions that face increasing penetration levels and in markets where the grid support services offered by PV capacity, generation, and advanced inverters are valued. For example, developers and utilities may be able to identify sites with suitable solar resources that also offer interconnection capacity and locational value from a grid support perspective.

Taking this one step further, geographic smoothing currently represents a passive means of addressing integration concerns, but the potential exists for applying emerging knowledge to inform the planning and layout of PV capacity and perhaps even to manage

Figure 15 – As PV penetration levels increase, accounting for variability considerations during central-station plant siting and design may increase the productivity and locational value of new capacity. (Credit: SunPower)

resource variability across distribution circuits or within and between transmission control areas. At present, an approach for quantifying cloud-induced output variability has been validated using selected irradiance data and hypothetical PV installations. (Hoff & Perez, 2011) In addition, a simplified approach has been demonstrated for generating output profiles at 1-minute resolution for individual utility-scale plants based on irradiance and weather data. (Stein, 2011) Additional RD&D is needed to validate these advances across all geographic and temporal scales, demonstrate them on actual installations, and incorporate them in practical decision-support tools.

Ultimately, such tools could help reinforce the grid by identifying sites within a network of existing PV installations where adding capacity would optimize smoothing over specified time frames. In areas where large amounts of PV are to be laid out across the landscape, they could inform siting, design, and layout of plants and fleets. As penetration levels increase in some regions and as projects extend into new areas, they could help mitigate or avoid integration problems by only identifying sites where changes in output attributable to cloud shading would be uncorrelated. (Mills & Wiser, 2010)

PV Technology Selection. Flat-plate PV modules incorporating commercially mature mono- and polycrystalline silicon (c-Si) cells represent the most widely deployed technology to date. They offer higher conversion efficiencies and increased production per unit area at standard test conditions (irradiance of 1,000 W/m^2 and PV cell temperature of 25°C) than flat-plate modules based on thin-film amorphous silicon (a-Si), cadmium telluride (CdTe), and copper indium gallium diselenide (CIGS) cells. However, commercial thin-film technologies deliver lower costs per unit area due to reduced materials requirements and to manufacturing techniques better suited for mass production. The end result is that the various flat-plate options offer comparable costs per unit of output, and thin films have begun to erode the market share of c-Si materials, particularly in larger-scale applications. (EPRI, 2010b) CPV technologies remain in the early stages of commercialization (see box, p. 15).

Individual flat-plate PV options not only offer different energy conversion efficiencies at standard conditions, but also they respond in different ways to changes in temperature, insolation, and the spectral quality of the light received. For example, de-rating of module capacity due to thermal resistance ranges from about 2 to 5% per 10°C increase from standard conditions depending on cell type, module design, mounting system, and other factors. Conversely,

Concentrating PV & Cloud Shading

CPV technologies employ mirrors or lenses to direct large amounts of solar energy along a line of cells or on a single point and individual cell. Though field experience is limited, they eventually are anticipated to be cost-competitive at sites with high-quality solar resources. (EPRI, 2010a) By nature, they are extremely intolerant to cloud shading and thus are unlikely to be economical in the near term in areas with frequent cloudiness.

Generally, line- and point-focus CPV technologies incorporate multijunction cells constructed of several layers of thin-film material, each targeting a different portion of the solar spectrum. These cells offer much higher conversion efficiencies than c-Si and thin-film cells. This attribute, combined with concentrating optics that multiply insolation by at least 100-fold over ambient levels, results in the need for much smaller amounts of expensive semiconductor material per unit of output.

CPV systems are only able to effectively reflect or focus DNI and thus perform best in sunny, arid areas such as California, Nevada, Arizona, New Mexico, Texas, and Colorado in the southwest United States; Spain, Italy, Greece, and other areas of southern Europe; and areas such as Australia, North Africa, and the Middle East. They require tracking to maintain an optimal DNI acceptance angle. Line-focus technologies employ one-axis tracking, while point-focus modules use sophisticated two-axis tracking to precisely follow both daily east-west and seasonal north-south variations in the Sun's position.

Because field experience with CPV technologies is limited, real-world output variability is not well understood. Generation losses and up- and down-ramps due to cloud shading are more dramatic than those from flat-plate PV technologies because these atmospheric phenomena suppress DNI more than GHI. Accordingly, CPV systems may shut down under cloudy conditions. Module siting and tracker design and control represent approaches for smoothing output.

An EPRI project, "CPV Collaborative Testing at SolarTAC," is expected to help illuminate the effects of cloud shading on this emerging generation option. (EPRI, 2011b)

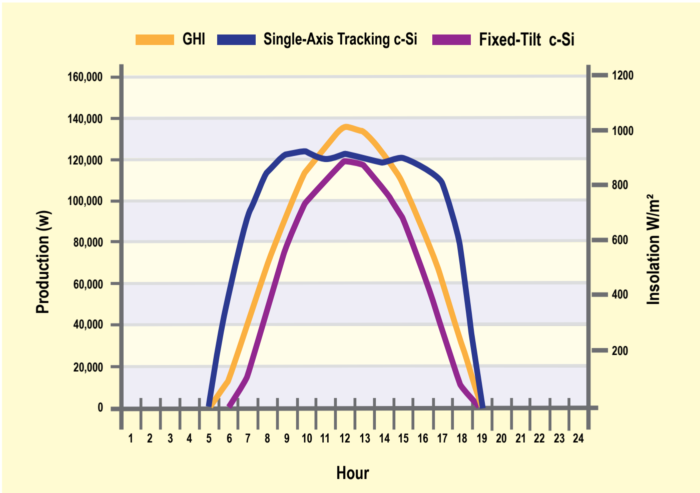


Figure 16 – Single-axis trackers achieve peak production faster and maintain it for longer than fixed-tilt systems, creating opportunities to increase both output and the time value of solar generation. (Credit: EPRI)

at lower temperatures, PV systems may produce more than rated capacity. Thermally induced variability is relatively minor across the day and from one day to the next and may be accounted for in modeling, scheduling, and balancing based on weather forecasts.

Side-by-side evaluations of the real-world performance of modules based on different semiconductor platforms have been conducted in various environments under controlled testing conditions. Consistent with bandgap and other characteristics, certain PV technologies, relative to others, experience lower thermal resistance losses at higher temperatures, offer greater efficiency gains at lower temperatures, or deliver better performance when diffuse light predominates, such as under overcast or cloudy conditions or when the Sun is lower in the sky. (Jardin *et al.*, 2001; Nordmann & Clavadetscher, 2003) Thin films in particular absorb diffuse light better than c-Si.

Additional field testing is required to quantify how the output of existing and emerging PV options varies in response to site-specific latitude, climate, elevation, weather, and other conditions, as well as cloud transients. A variety of work is under way or planned around the world, including EPRI's collaborative flat-plate PV testing project at the Solar Technology Acceleration Center in Aurora, Colorado. (EPRI, 2011a) Of particular long-term interest for grid integration is whether the energy absorption profiles of individual technologies may make them better suited for moderating the ramps attributable to cloud shading at high penetration levels.

Module Layout & Mounting Configuration. PV module orientations and mounting configurations by nature are designed to account for solar variability (Figure 16 and 17). Generally, systems are oriented to maximize southern exposure in the Northern Hemisphere and northern exposure in the Southern Hemisphere, and they are laid out on rooftops or across the landscape to maximize capacity per unit area. Unless deployed flush to a roof, fixed arrays typically employ a tilt angle approximately equal to a site's latitude, with production estimated based on the global latitude-tilt insolation rate or POA irradiance. Lower tilt angles tend to increase production in summer months, and higher ones boost output in winter. Modules usually are arranged in rows running east to west and spaced to reduce or prevent shading when the Sun is lower on the horizon.

Relative to systems installed parallel to a plane at the Earth's surface, fixed-tilt arrays generate about 15% more energy by both boosting peak production and extending the daily high-output period. (EPRI, 2010b) They also offer faster and larger morning and evening ramps. Deploying equal numbers of fixed-tilt modules at different north-south orientations—also known as azimuth angles—provides a means of moderating these ramps and extending high-output periods, albeit at lower peak production than systems

Figure 17 – Tracking arrays boost production and manage variability by following the Sun across the sky, but they also increase upfront, operations, and maintenance costs and require more land per unit of capacity.

with all modules at the same orientation. Orienting a majority of modules in a more westerly direction represents a strategy for shifting additional production to later in the day and better matching load. This approach increases the time value of solar output, but it also reduces overall generation and results in larger evening down-ramps.

The economic and operational impacts of using alternative fixed-tilt angles and module orientations vary depending on site-specific conditions and may change as penetration levels increase. Because the passage of clouds over individual installations is affected by the direction of large atmospheric flows, prevailing winds, and real-time weather, adjusting project layout and module orientation may represent an option for reducing cloud ramps and maximizing geographic smoothing.

Modules mounted on tracking systems follow the Sun's movement either daily or both daily and seasonally. One-axis tracking arrays are deployed in north-to-south rows. They rotate from facing east to facing west during daytime hours to realize more than a 20% increase in production relative to fixed horizontal configurations. (EPRI, 2010b) This gain comes at a cost, in terms of additional capital investment, more land to reduce self-shading, and larger morning and evening ramps.

Single-axis tracking may occur around a horizontal or tilted axis, with the latter case offering both higher capital costs and greater annual production. Even more costly and land-intensive two-axis trackers have the capacity to increase daily output by more than 30% relative to fixed horizontal arrays by also following north-south variations in the Sun's position as the seasons change. (EPRI, 201b) Backtracking control algorithms may be employed to prevent shading among adjacent modules during periods after sunrise and before sunset when the Sun is low on the horizon. They eliminate self-shading losses for horizontal single-axis trackers and greatly reduce them for other tracking arrays.

Generally, module orientations and mounting configurations that manage deterministic variability to increase effective insolation rates over certain time frames also augment the potential for cloud transients—but more in terms of expanding the period during which they may occur, rather than their magnitude. For tracking systems, adaptive control algorithms represent a possibility for optimizing the capture of diffuse light when clouds are present. This approach may increase production on overcast days but is unlikely to afford the fast response and precision required to mitigate cloud ramps.

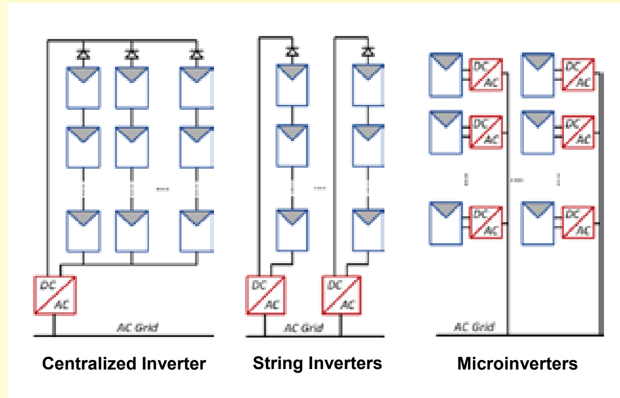


Figure 18 – Emerging alternatives to centralized and string inverter configurations could increase PV project output by reducing string losses attributable to cloud shading. (Credit: EPRI)

Inverter Selection & Sizing. Inverters provide solid-state power conversion and control capabilities that influence PV system production and output variability and have potential to provide some of the functionalities needed to improve grid integration. Generally, they incorporate grid protection functions, while advanced centralized inverters and module- and string-level power electronics are emerging to offer expanded capabilities (Figure 18). Inverters typically are specified to ensure that their maximum AC output rating is approximately equal to the DC capacity of their interconnected modules or strings at standard test conditions. (Luoma *et al.*, 2011) The objective is to optimize the sizing ratio—defined as rated maximum inverter output divided by rated solar field output—and choose an inverter and wiring configuration to maximize the amount of solar energy delivered at lowest cost. This represents a multifaceted decision.

One consideration is to avoid or minimize periods when array output power exceeds inverter rated power in order to decrease the potential for inverter saturation and rejection of excess production (see Figure 8). Another is to maintain proper array voltage, which varies with temperature. Inverter oversizing increases costs per unit of output but avoids solar spillage. Undersizing the inverter—or oversizing the solar field—results in deliberate spillage but also provides an approach for damping instantaneous cloud variability. Field oversizing is commonly employed in CSP systems, where the added cost and lost generation of additional reflector or lens capacity is offset by the benefit of operating the turbine-generator train at its design point. The CSP plant owner gains from this design decision, whereas field oversizing's value proposition for PV developers is less certain because (1) the benefits of reducing cloud-induced variability are not monetized and (2) the investment required to substantially dampen transients likely would prove prohibitive.

The variable efficiency of the DC-to-AC conversion process, which depends on loading level but also is influenced by inverter design, also comes in to play in inverter sizing. For most commercial systems, efficiency is highest at about 80% of rated inverter capacity, drops slightly at full load, and decreases to a minimum at low load. (EPRI, 2010b) Optimal site-specific inverter sizing ratios for large PV plants may vary quite a bit depending on both the available size of commercial inverters and the factors to be optimized at each particular location. For distributed systems, inverter sizing ratios substantially higher or lower than 1 may be employed based on site-specific circumstances—including the average GHI and temperature conditions and the likelihood and magnitude of temperature extremes and insolation exceedances. (Luoma *et al.*, 2011)

Conventional centralized inverters continuously optimize PV system production as insolation changes over time by varying the overall ratio between voltage and current delivered to provide maximum power point tracking (MPPT) among all interconnected modules. During the day, they can sense when one or more modules within a string—or one string among several—are underperforming due

Figure 19 – Microinverters provide maximum power point tracking for each module, isolating adverse impacts due to shading (top) to reduce production only from affected panels (bottom). Initial uses of microinverters on megawatt-scale systems will provide data on their abilities to manage cloud-induced variability at larger plants. (Credit: Gary Reysa)

to cloud shading or other factors, automatically triggering bypass diodes to prevent all interconnected capacity from operating at reduced output (see box, p. 5). At nighttime, they are capable of regulating voltage to reduce parasitic losses associated with maintaining an energized transformer.

Maintaining centralized MPPT is necessarily a compromise, as some modules and strings within an array will inevitably have higher maximum power points than the aggregated level. MPPT mismatch results when the irradiance distribution is uneven or partial cloud shading is occurring. Some commercial inverters include string-level MPPT to address this issue. Alternatives to conventional string inverters are emerging. Distributed MPPT devices and DC optimizers manage DC output at a much finer scale, enabling more effective capture of available energy than inverters serving a larger number of series- and parallel-connected modules (Figure 19). Microinverters bring MPPT and DC-to-AC conversion functionalities down to the module level. These technologies increase overall production, as well as tolerance to shading, by allowing each module to operate at its own optimal power point in response to real-time irradiance conditions, including cloud transients.

Distributed power electronics currently are costlier than centralized inverters because economies of scale remain greater than economies of mass production. As a result, applications to date have been limited to smaller PV installations where increasing output and avoiding the adverse impacts of shading due to trees or structures may justify the added capital expenditure. That said, module-level electronics are seeing rapid deployment, and microinverter-based controls are entering the market for plants with capacity exceeding 1 MW.

Modeling, field-testing, and demonstration projects are needed to assess the abilities of microinverters for increasing productivity, reducing cloud transients, and delivering long-term reliability under various environmental conditions and across large projects. A number of utilities are exploring the capabilities of microinverters and other advanced electronics for enabling PV deployment on distribution systems. In EPRI research, the pros and cons of central and module-level devices are being evaluated and examined in laboratory tests. Over time, distributed power electronics are expected to improve with further integration of components and functions, such as combining the inverter and junction box functions into one factory-mounted device.

At present, the size of the inverter blocks incorporated in utility-scale PV plants, the length of the strings of series-connected modules, and the characteristics of the specified inverters are chosen to balance capital costs—both for equipment and wiring—against production. At higher PV penetration levels, the need to reduce cloud-induced variability may bring new dimensions to the design decision-making process. Smaller blocks, shorter strings, different string orientations, and advanced power electronics may prove advantageous depending on site-specific circumstances.

Balance of System (BOS). Typically, inverter output is equivalent to about 75 to 85% of idealized PV module output based on measured irradiance. In addition to DC-to-AC conversion efficiency, BOS losses depend on array design (including DC bus voltage, cable run, and string configuration), inverter performance (including MPPT algorithms and precision), and panel mismatch (attributable to shading, aging, dust, or debris). As noted above, several of these factors may influence—or be influenced by—solar variability. Commercial plant developers and vendors offer BOS designs and technologies backed by claims of higher efficiencies, but assessing performance is extremely difficult, if not impossible, because it is affected by PV plant architecture, geographical setting, insolation and weather conditions, and other variables.

EPRI is demonstrating a simplified approach for analyzing BOS efficiency by comparing AC output from a 1-MW plant in eastern Tennessee to that from an independent, pole-mounted, microinverter-controlled reference module also installed at the plant site. This simplified field evaluation method assumes that the reference system delivers idealized per-module output over a given time frame, and that multiplying its output by the total number of modules in the plant provides a measure of the larger array's idealized output. The ratio between the plant's actual and idealized output is an indicator of BOS efficiency. Ongoing research is focused on determining how cloud shading and other variables influence losses and whether operating conditions may be adjusted to increase efficiency.

Similar performance monitoring programs at other installations are expected to provide generalizable insights on the connections between BOS design, technology, and site-specific productivity. As even small differences in efficiency translate to significant amounts of instantaneous and lifetime output for large PV installations, controlled testing of design elements and technologies is required under identical conditions—and with the ability to isolate individual elements—to support comprehensive tradeoff analyses and accurate predictive modeling by power producers and plant designers.

Addressing Variability in Grid Integration

In addition to the advances in characterization, modeling, and forecasting described earlier in this paper, other approaches and technologies are available or being pursued to address PV output variability through grid planning and operations. Several are briefly introduced below:

- **Interconnection standards** around the world require PV system inverters to provide anti-islanding protection by automatically disconnecting from the grid during outages. In Germany, all grid-connected inverters must deliver low-voltage ride-through (LVRT) capabilities, while the same holds true in Spain for systems of 2 MW and larger. Plants 10 MW and larger in Spain generally are required to incorporate inverters that provide reactive power control.
- **Advanced inverters** respond automatically when grid voltage falls below a setpoint due to a fault, load change, or other disturbance—including cloud-induced variability. They temporarily disconnect from the grid or inject leading or lagging volt-amps-reactive (VARs) on a fractional-second time scale to compensate for the inductive characteristics of certain loads, minimize reactive power consumption, and bring voltage back to the specified range. Eventually, smart inverters are expected to serve as active control devices capable of providing grid support services rather than independent systems.

Figure 20 – PV plants generate on-peak energy, while installations that incorporate advanced inverters offer additional grid support.

- **Energy storage** offers the greatest promise for PV integration over all time frames. Depending on application requirements, individual technologies are being developed and applied for meeting reactive power needs and moderating ramp rates, matching generation with load, and even scheduling power flows to exploit long-distance and inter-area transmission availabilities and deliver solar power from remote projects to load centers. NREL recently completed an analysis showing how CSP with thermal energy storage capability could potentially enable higher penetrations of PV by optimizing the timing of CSP output to the grid. (Denholm & Mehos, 2011)
- **Wide-area measurement, analysis, and visualization** are required for direct, real-time monitoring and management of the status, real power output, and grid support functions of solar plants and even individual inverters—just as is routinely done today for conventional generation. Eventually, intuitive geographical displays will show real-time irradiance and production, near-future status based on cloud conditions, and effects on grid voltage and frequency, enabling operators to apply data and expert knowledge in making decisions. Visualization tools already are being developed to support analysis and planning for transmission and distribution circuits with high levels of PV penetration.

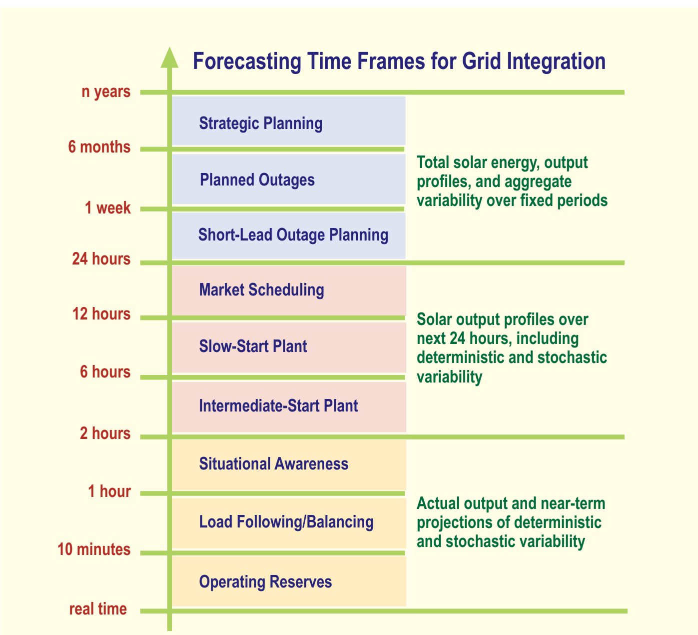


Figure 21 – Advanced PV modeling and forecasting capabilities are critical for increasing the value of solar generation across all time frames and addressing integration challenges at high penetration levels.

- **Stochastic planning**—driven by better understanding of cloud-induced variability as well as enhanced computational capabilities—shows promise for reducing the deviation between predicted and actual time-varying solar output and yielding dynamic unit commitment decisions that represent effective solutions under a range of weather, solar production, and cloud-shading scenarios.
- **Adaptive control strategies** based on the use of time-dependent optimal power flow techniques and other methodologies are needed to account for deterministic and probabilistic variability, adjust power flows on the fly in response to changing cloud conditions, and support finer-grained generation and transmission scheduling.
- **Large-area control** offers the potential to enable higher penetration levels at reduced cost to the grid by expanding grid support functionalities and improving the value of solar generation. Broad geographic smoothing of output variability promises to moderate ramps across the regulation and load-following time horizons. More accurate, less uncertain hour- and day-ahead forecasts will optimize scheduling and unit commitment.
- **Ancillary service markets and real-time pricing** will reward solar power producers for delivering grid support functions and firming on-peak output based on new knowledge, enhanced forecasting capabilities, and advanced technologies.

Conclusions & Implications

PV projects are capable of generating significant quantities of power, helping meet on-peak demand, and providing other grid support services. Output variability attributable to the Sun's daily and seasonal cycles is predictable and relatively easy to plan for and manage. Cloud-induced variability represents a more significant concern as deployment grows and penetration levels increase. Individual central-station plants may experience ramps totaling in the tens of megawatts within less than a minute and larger transients over 5 to 10 minutes.

Experience to date indicates that geographic smoothing of irradiance ramps caused by cloud shading tends to levelize PV plant production as a function of time, both within individual arrays and among two or more projects. The degree of smoothing among generating units is inversely proportional to the correlation between simultaneous changes in their output, which depends on both the time scale being considered and their physical separation: Smoothing generally is more effective over shorter periods, across longer distances, and for slower-moving clouds.

Figure 22 – Ambitious PV deployment targets imply penetration levels of 50% and higher and a concomittant need to account for solar variability in all aspects of project development, implementation, and integration.

Geographic diversity helps reduce but does not eliminate the stochastic variability that must be managed over regulation, load-following, and longer time scales. PV integration impacts for individual projects and entire fleets will differ from site to site and circuit to circuit and be realized in the form of the additional protective measures and regulation and balancing resources required to hold reliability and meet load. Advanced inverters, accurate predictive models, fine-resolution forecasts, and storage innovations represent key building blocks for reducing integration costs and enabling high penetration.

Technologies and strategies for characterizing, planning for, and managing cloud transients are being tested and applied in countries and regions with significant installed PV capacity and growing levels of deployment. In the United States and abroad, RD&D is under way to improve understanding and enhance grid integration capabilities in anticipation of continued expansion. However, much of the ongoing work addresses distributed PV applications rather than central-station plants. Further, ongoing work focuses on handling variability through advances in measurement, forecasting, and control, rather on exploring the plant siting and design factors that might mitigate transients and promote geographic smoothing.

Typical project design and development challenges are to site and size the array, choose the PV technology and mounting configuration, orient and space the modules, and wire and interconnect the entire system in ways that maximize production per unit area, as well as balance capital costs against levelized costs of electricity. Plant siting and design factors with impacts on deterministic and stochastic output variability include the following:

- **Plant size**, in terms of capacity and land area
- **Solar resource**, in terms of DNI, GHI, and irradiance levels at 1-second resolution
- **Location**, in terms of elevation, climate, and wind/storm patterns
- **Relative location**, in terms of physical separation from other PV installations and degree of correlation between on-site irradiance and instantaneous resource availability at other project sites
- **PV technology**, in terms of efficiency, thermal sensitivity, spectral absorption, and other key characteristics
- **Mounting configuration**, in terms of tilt angle and one- or two-axis tracking
- **Power electronics**, in terms of inverter size, sizing ratio, and grid support capabilities
- **Layout**, in terms of the size, distribution, azimuth orientation, and wiring of blocks and strings
- **Balance of system,** in terms of overall efficiency

The large number of factors influencing variability and the costs imposed on the grid make it challenging to develop rules of thumb for plant and fleet siting, design, and development. Each factor may play a role, but quantitative recommendations do not yet exist. The ideal PV deployment scenario is unique to each site, region, and specific grid configuration. This ideal may change over time as market conditions vary, grid integration capabilities advance, and PV penetration levels increase. While grid planning, protection, control, and operations are likely the keys to effective integration, a combination of smart plant design and external mitigation approaches is likely to yield the best outcome in optimizing energy production, reducing costs, and minimizing variability at the site-specific and fleet-wide levels.

For solar power producers and investors, measures taken to avoid or mitigate PV impacts on the grid may in the near term increase project development costs and reduce productivity. On the other hand, they may create both immediate and long-term opportunities by making on-peak generation more predictable, increasing capacity credits, providing grid support functions valued as ancillary services, and improving abilities to bid solar energy into day-ahead and other power markets. For solar power purchasers, variability mitigation may facilitate the firming of PV capacity within asset portfolios and reduce the need to purchase additional resources to deliver full-requirements energy. For distribution companies and independent system operators, advanced integration capabilities will allow more capacity to be accommodated at lower costs.

Over the long term, accounting for variability during project development and integration is critical for preventing bottlenecks to high penetration levels and for growing PV's role in satisfying renewable energy mandates, generating carbon-free power, and meeting the world's electricity needs. At SolarTAC and sites around the world, EPRI plans continued RD&D to advance knowledge of cloud-induced variability and to quantify the benefits of mitigation based on plant design and other factors. This will support the larger body of collaborative work geared toward improving the performance of PV cell, power electronics, modeling, and forecasting technologies and delivering state-of-the-art assessment, deployment, and integration guidance.

EPRI's Solar Power Research Programs

The Renewable Generation (84) Program supports cost-performance assessment of flat-plate PV, CPV, and CSP technologies and technical and business analysis of issues shaping solar energy deployment and grid integration. Controlled field evaluation of CPV technologies begins in early 2012, and a similar supplemental project addressing emerging PV options is scheduled to start later in this year (EPRI, 2011a,b). Ongoing research at the 1-MW plant in eastern Tennessee (see box, p. 8) is supported through the Integration of Distributed Renewables (174) and Bulk Power System Integration of Variable Generation (173) programs.

EPRI's Distributed PV (DPV) Monitoring project is delivering insights on individual and fleet variability from standardized, single-module systems installed across the United States. Among the more than 150 installations are 50 pole-mounted, microinverter-controlled PV monitoring units embedded on seven of Georgia Power's distribution feeders to help guide grid planning and reinforcement and to quantify how temperature and humidity levels may affect PV's ability to serve on-peak load and meet peak-day requirements.

The complementary DPV modeling study draws on diverse databases to evaluate how array sizing, location on the feeder, circuit topology, cloud-induced variability, and additional factors influence grid operations at increasing levels of PV penetration (Figure 23). Modeling is under way for 15 circuits owned by four utilities, with the goal of providing feeder-specific guidance on boundary conditions, safe penetration levels, and management strategies for allowing deployment of additional PV capacity.

Generalizable insights and planning tools developed through EPRI research are expected to enabling smart siting of solar arrays based on interactions with existing infrastructure. EPRI is considering a modeling study to optimize the siting and design of central-station plants by simulating insolation and weather conditions—including cloud passage in different directions and at different rates—and examining how different field layouts, module orientations, tracking systems, inverter technologies, and other factors influence capital cost, energy production, grid integration, and overall project economics.

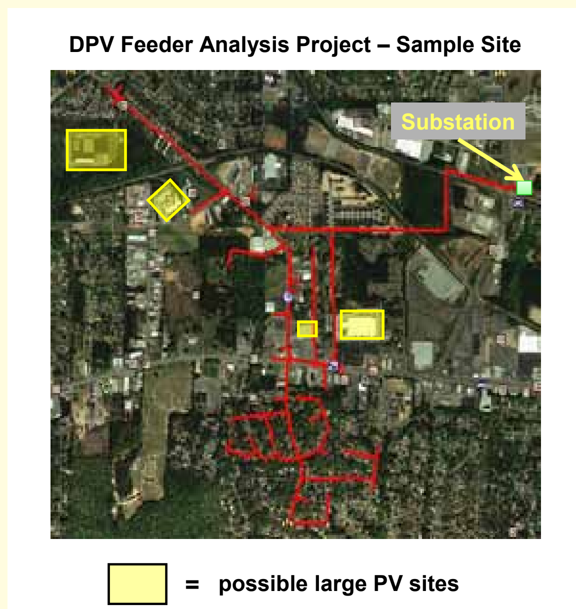


Figure 23 – Real-world feeder modeling studies are providing guidance on how much PV capacity individual circuits can accommodate based on a variety of factors. (Credit: EPRI)

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Additional RD&D Resources

- High-Penetration Solar Portal, U.S. Department of Energy: https://solarhighpen.energy.gov/
- PV Power System Programme, International Energy Agency: http://iea-pvps.org/

The Electric Power Research Institute, Inc. (EPRI, www.epri.com) conducts research and development relating to the generation, delivery and use of electricity for the benefit of the public. An independent, nonprofit organization, EPRI brings together its scientists and engineers as well as experts from academia and industry to help address challenges in electricity, including reliability, efficiency, health, safety and the environment. EPRI also provides technology, policy and economic analyses to drive long-range research and development planning, and supports research in emerging technologies. EPRI's members represent more than 90 percent of the electricity generated and delivered in the United States, and international participation extends to 40 countries. EPRI's principal offices and laboratories are located in Palo Alto, Calif.; Charlotte, N.C.; Knoxville, Tenn.; and Lenox, Mass.

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1023090 December 2011

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