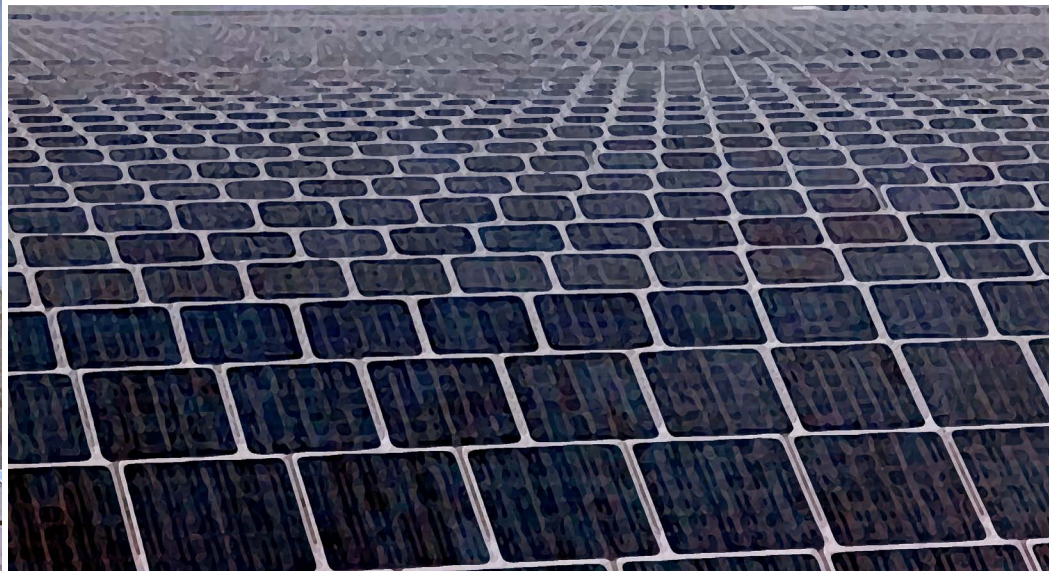
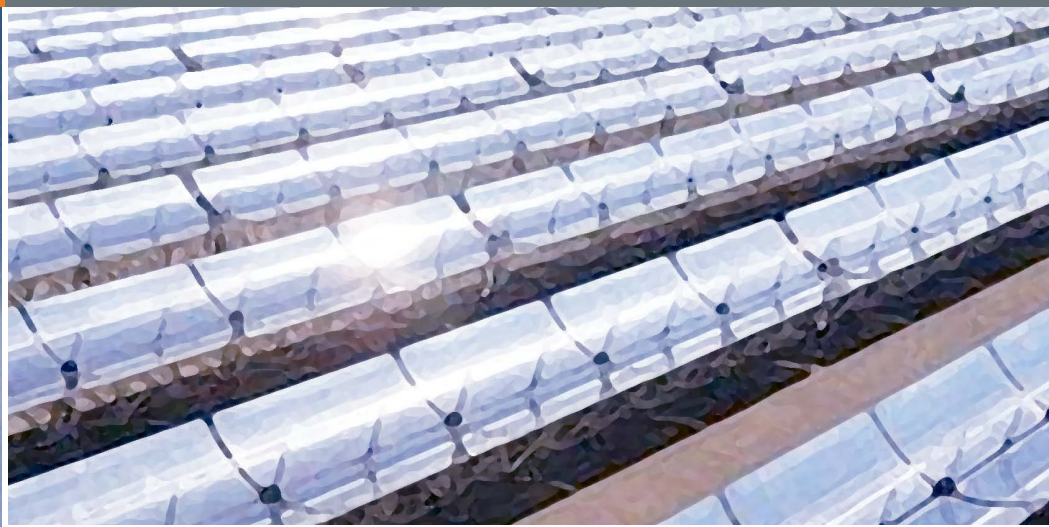


SunShot Vision Study

February 2012



6. Integration of Solar into the U.S. Electric Power System

6.1 INTRODUCTION

The *SunShot Vision Study* lays out a scenario in which solar energy technologies satisfy a significant fraction of U.S. electricity demand. The contribution of solar energy in this scenario is projected to be 14% and 27% of total contiguous U.S. electric demand by 2030 and 2050, respectively, which introduces several integration challenges.

The first challenge is to ensure that the system can operate reliably with increased variability and uncertainty. Unlike the hydropower and thermal generation sources that currently provide most of the nation's electricity, PV generation in particular has limited dispatchability. Another challenge is planning for and building the new transmission facilities that will be required to access high-quality solar resources. A third major challenge involves evaluating and addressing the impacts of distributed solar generation on electricity distribution systems, most of which were not designed to accommodate generation at the point of use. Previous work on solar integration, along with substantial work on wind integration, reveals several potential solutions for these challenges to widespread deployment of solar-powered generation technologies.

This chapter gives an overview of the major integration challenges along with potential solutions needed to achieve the SunShot scenario. Section 6.2 describes the operation of the electric power system and the important role of reliability standards in ensuring adequate balancing of generation and demand. It then discusses the characteristics of the solar resource and generation technologies, including variability, uncertainty, and capacity value. Section 6.2 also addresses the integration of solar into power system operations and planning, including lessons learned in this and other studies (DOE 2008) to maximize the role of solar energy and minimize integration costs. In addition, it discusses the specific role of markets in providing flexibility and incentivizing efficient use of generation and demand resources. Section 6.3 discusses the feasibility of developing the transmission infrastructure required to accommodate increased development of solar power installations and to connect high-quality solar resource regions to load centers. This section highlights the importance of developing models and performance standards to ensure the reliable operation of the transmission system with significant levels of solar energy. Section 6.4 covers the feasibility of integrating significant levels of

solar energy into the existing and future distribution grid, which will include improved monitoring, information exchange, and control at the distribution level.

6.2 PLANNING AND OPERATION OF ELECTRIC POWER SYSTEMS WITH SOLAR ELECTRIC GENERATION

The electric power system has developed historically with thermal power plants as the main source of generation. Nearly 90% of the installed generation capacity in the United States is composed of dispatchable natural gas, coal, and nuclear power resources. Incorporating a large fraction of electricity from photovoltaic (PV) and concentrating solar power (CSP) systems will require changes to many of the practices and policies that are designed for dispatchable thermal plants. The variability and uncertainty associated with solar generation requires new sophistication of real-time operations and planning practices. Maintaining reliability and the most economic dispatch will undoubtedly require new strategies to manage the grid. The need to evolve new grid operating paradigms becomes even more significant considering the likely deployment of both solar and other variable generation sources such as wind.

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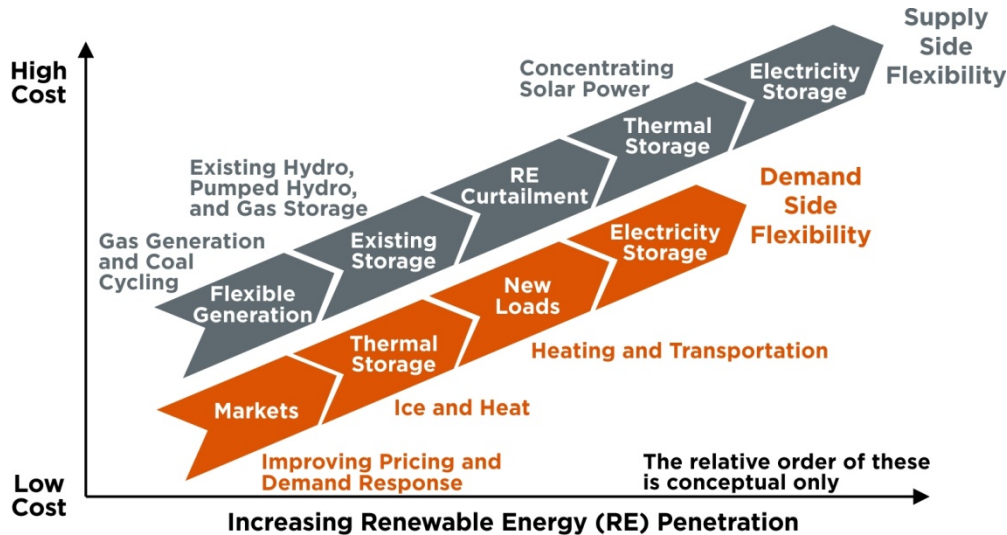
Studies of increased levels of solar and wind generation show that the variability and uncertainty associated with weather-dependent resources can be managed with increased operating reserves, increased access to flexibility in conventional generation plants, demand response and storage, better cooperation among adjacent electrical operating areas, and incorporation of solar and wind generation forecasting into system operations. The set of technologies and mechanisms enabling greater penetration of solar energy can be described in terms of a flexibility supply curve that can provide responsive energy over various timescales. Figure 6-1 provides a conceptual flexibility supply curve that summarizes the options for incorporating variable generation. The optimal mix of these technologies has yet to be determined, but several sources of flexibility will likely be required for the most cost-effective integration of solar at high penetrations.

6.2.1 POWER SYSTEM DESIGN, PLANNING, AND OPERATIONS

Power systems are planned and operated to meet established performance and reliability standards. System operators work with existing system assets—generation, network, and responsive demand—to maintain safe and reliable system operation in real time and in compliance with established standards. As the standards generally do not dictate how they must be met, different system planning and operations practices have evolved to meet system performance and reliability targets while minimizing costs. An effective way to reduce the operating cost of producing electricity and increasing reliability of supply is to aggregate a large number of different generation resources and loads. This type of aggregation relies on a dynamic transmission and distribution network and associated communication and control infrastructure.

Continually balancing generation and load, even with a degree of uncertainty and unpredictability in both load and generation, is among the primary requirements for operating the power system reliably. Balancing Authorities (BAs) accomplish this

Figure 6-1. Options for Increasing Power System Flexibility to Accommodate Renewables



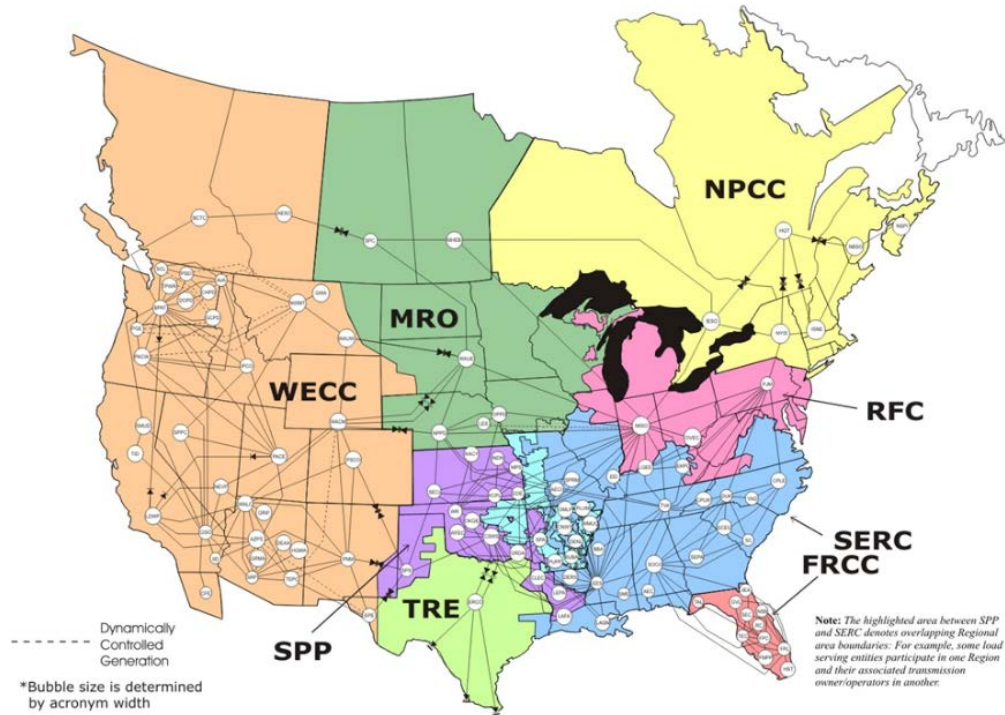
Source: Denholm (2008)

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by scheduling, dispatching, and controlling generation and by facilitating exchange of electricity with other BAs. The map depicted in Figure 6-2 identifies the eight regional entities⁵⁵ and well over 100 BAs that coordinate the supply of electricity within the bulk power system. Each BA is responsible for balancing energy supply with demand and maintaining reliable service in an assigned BA area (NERC 2008). The interchange of power among BA areas must be scheduled and managed to avoid exceeding the capacity of transmission interties. Because load forecasts are imperfect and generation cannot respond instantaneously, it is neither possible nor required to match perfectly at all times the actual interchange to the desired or scheduled interchange across BA area boundaries. To balance changes in load and generation that occur over a short time frame—from seconds to minutes—automated systems continually adjust the output of generators that are able to ramp up and down relatively quickly. This class of operating reserves is required to address regulation (the ability to respond to small, random fluctuations around normal load), load-forecasting errors (the ability to respond to a greater or less than predicted change in demand), and contingencies (the ability to respond to a major contingency such as an unscheduled power plant or transmission line outage) (NERC 2008). Over periods on the order of tens of minutes to hours, operators optimally readjust the output of online generators in a least-cost order, taking into account short-term forecasts and system constraints. Over longer periods, spanning hours to days, operators commit least-cost generators so they are available for dispatch during real-time operations. Unit commitment takes into consideration, among other

⁵⁵ The North American Electric Reliability Corporation (NERC) works with eight regional entities to improve the reliability of the bulk power system, accounting for most of the electricity supplied in the United States, Canada, and a portion of Mexico. The entities responsible for regions in the Eastern Interconnection include: Florida Reliability Coordinating Council (FRCC); Midwest Reliability Organization (MRO); Northeast Power Coordinating Council (NPCC); Reliability First Corporation (RFC); SERC Reliability Corporation (SERC); and Southwest Power Pool, RE (SPP). The Electric Reliability Council of Texas (ERCOT) Interconnection is covered by the Texas Reliability Entity (TRE) and the Western Interconnection by the Western Electricity Coordinating Council (WECC).

Figure 6-2. Regions and Balancing Authorities in North America



Source: NERC (2011)

factors, forecast demand, generation availability, and operating constraints of individual generators.

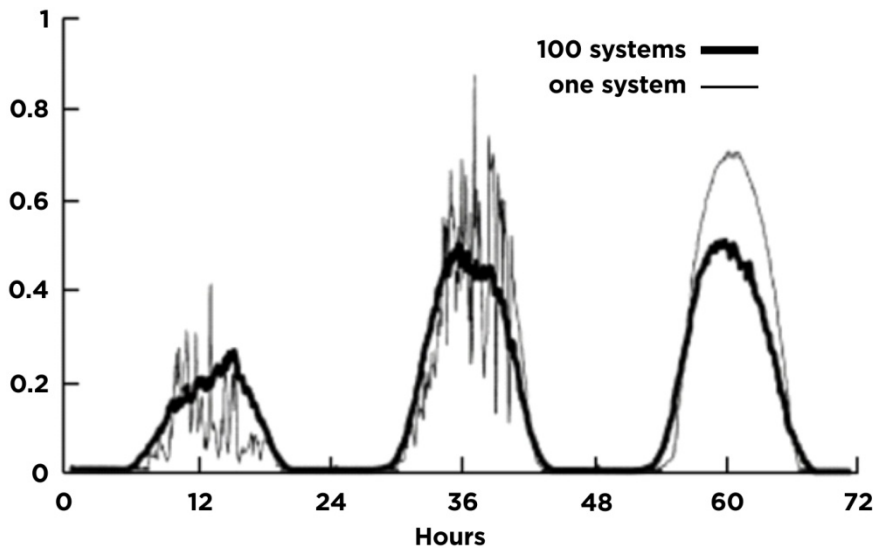
System planners are responsible for ensuring that the assets are adequate for the reliable operation of the system. Complex models and operational experience are used to evaluate the adequacy of the transmission and generation infrastructure. One measure of adequacy is the ability of the system to serve load with a certain level of reliability (measured by the effective load-carrying capability of the generation fleet). Power systems must also be able to operate reliably under abnormal conditions; that is, they should be sufficiently robust to recover from significant contingencies, such as the unplanned loss of a large generator or a large transmission line. System planners design upgrades and operating procedures to ensure that minimum margins of transmission and generation capacity can be maintained at all times.

6.2.2 SOLAR RESOURCE AND TECHNOLOGY CHARACTERISTICS RELEVANT TO GRID INTEGRATION

Solar electricity has unique attributes relative to conventional generation that need to be accounted for to reach high penetrations in the electric power system. The primary characteristics of solar generation relevant to system operation and planning are variability (and associated uncertainty) and capacity value. Although significant measurement data are not available for analysis of variability, some general characteristics of the solar resource are known.

With respect to power-system operations, the most relevant characteristics of solar generation are the output variability and rate of change—ramping—over different time periods, and the predictability of these ramping events. Figure 6-3 illustrates the high degree of variability and high ramp rates that can occur in a single PV plant over a short time frame—from seconds to minutes—resulting from passing clouds. Figure 6-3 also shows that the aggregate of multiple solar plants over a wide geographical area, but within a single BA area, has far less variability and smaller short-term ramp rates relative to the amount of PV deployed. This demonstrates the value of geographic diversity in mitigating short-term variability (Mills and Wiser 2010).

Figure 6-3. Solar Variability: 100 Small PV Systems Throughout Germany, June 1995



Source: Wiemken et al. (2001)

The variability and predictability of the aggregated solar electric generation in a system depends on the degree of correlation of cloud-induced variability between solar plants. The correlation between solar plants, in turn, depends on the locations of solar plants and the regional characteristics of cloud patterns. Generally, the variability of solar plants that are farther apart are less correlated, and variability over shorter time periods—minutes—is less correlated than variability over longer time periods, such as multiple hours (Murata et al. 2009). The decrease in correlation with distance leads to much less relative variability, i.e., a smoothing effect. Consequently, forecast accuracy improves as the number of solar plants aggregated over larger areas increases.

Unlike PV systems, most CSP plant designs have inherent thermal inertia that greatly reduces or eliminates short-term variability. Parabolic trough plants using oil as the heat-transfer fluid and modern direct-steam systems with integrated steam storage vessels can typically operate in a predictable manner with no solar input for a period of about one-half hour (Steinmann and Eck 2006). Dish/engine CSP plants have less thermal inertia than the other CSP technologies, and thus the output of these plants can vary much more with passing clouds.

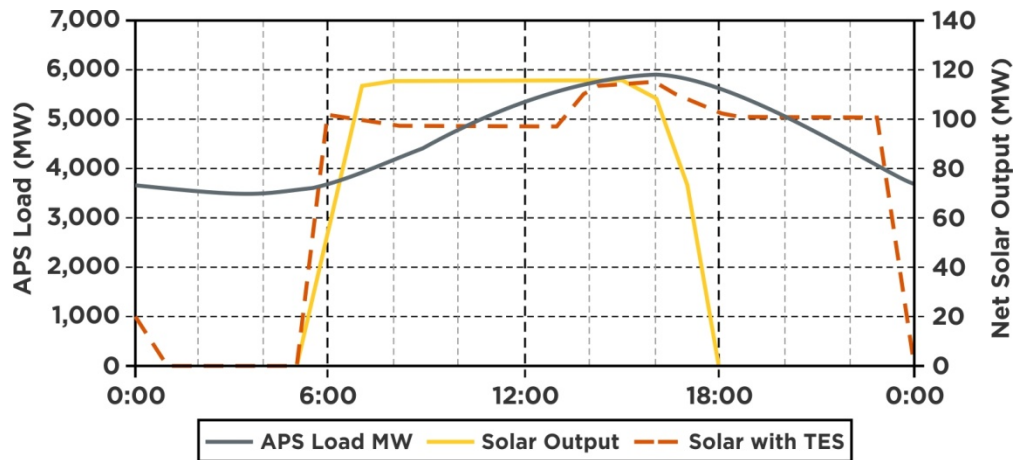
Some CSP plants are designed with several hours of thermal energy storage (TES), allowing them to generate electricity even during periods with low or zero solar input. This provides operating flexibility and the ability to shift solar generation into the evening hours or other periods to better match the load profile and provide more value to the grid. The additional capital costs for multi-hour thermal storage must be justified by the reduced levelized cost and/or increased value of energy delivered by the plant (Sioshansi and Denholm 2010). A number of cost projections indicate that the addition of thermal storage will reduce the levelized cost of solar energy for parabolic trough plants (DOE and EPRI 1997, Sargent & Lundy 2003, Stoddard et al. 2006). Thermal storage with molten-salt power tower plants is projected to produce even more pronounced reductions in the levelized cost of energy (LCOE) relative to power towers without storage.

With the exception of dish/engine plants, existing CSP plant designs can also be augmented readily with fossil-fueled generation, providing either short- or long-term dispatchable output in the absence of solar input. The Solar Energy Generating Systems (SEGS) plants in southern California, for example, include natural gas fuel augmentation. The reverse is also true; in some cases, fossil steam-cycle generation plants have been augmented with CSP, e.g., the Florida Power & Light Company (FPL) Martin Next Generation Solar facility (FPL 2010). This approach could result in lower CSP cost by using generation components already in place.

With respect to system planning, the most relevant characteristic of solar is the correlation of solar power with periods of high electricity demand and, therefore, high system risk. The correlation between solar resources and high demand affects the capacity value that can be assigned to solar generation for the purposes of generation resource planning. The capacity value assigned to the generation resource indicates the fraction of its nameplate capacity that contributes to the overall capability of the system to reliably meet demand. The capacity value of new solar plants is expected to be greatest where electricity load and solar production are strongly correlated. Electricity demand in most of the United States, and particularly in the Southwest, is the greatest during summer afternoons when solar insolation is also generally high. Figure 6-4 illustrates the coincidence of electricity load and modeled solar output for a CSP plant with no storage or with 6 hours of thermal storage. In Figure 6-5, PV acts to reduce the peak demand during the summer, reducing not only the fuel used, but also potentially the need to construct new generation capacity. PV plants would be slightly less correlated with load because their output tapers off in the evening when demand is highest.

As suggested in Figure 6-4, the incorporation of on-site energy storage and the amount of such storage greatly increases the probability that solar generation will be available when the system is most in need of that generation. A detailed probability analysis of the capacity value for CSP with 6 hours of thermal storage in the western states found capacity values of 90%–95% (GE Energy 2010), which is similar to conventional power plants, at a 3.5% energy penetration level. At higher penetrations, the larger amount of storage deployed (up to 14 hours) should maintain very high capacity values. A more detailed discussion of the capacity value of CSP plants with thermal energy storage is provided by Madaeni et al. (2011).

Figure 6-4. Southwestern Utility Load and CSP Generation Profile Illustrating That Thermal Energy Storage Can Increase the Coincidence of High Load Periods and Solar Plant Output



APS: Arizona Public Service
 Source: Price et al. (2007)

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For solar generation without storage or fossil-fuel augmentation, either PV or CSP, the capacity value depends much more heavily on the correlation between system peak load and solar insolation. A variety of methods and technologies has been used to estimate the capacity value of PV, and they result in a wide range of estimates. The *Western Wind and Solar Integration Study*, which used a traditional loss of load probability technique, found a 27%–38% capacity value for PV—based on the direct current (DC) rating—in the U.S. Southwest for penetration levels up to 1.5% by energy (GE Energy 2010). Xcel Energy’s Public Service of Colorado used a similar technique at a penetration level of 1.4% by capacity and found a 53%–70% capacity value for PV and 66%–83% for CSP without storage (Xcel Energy 2009). Other studies have estimated the effective capacity of PV plants in the Southwest greater than 60% and sometimes greater than 80% of the nameplate capacity of the solar plant (Hoff et al. 2008, Perez et al. 2006). In other parts of the United States, these studies have found capacity values greater than 50% for many regions, but lower value in others such as 30% for parts of the Pacific Northwest, where peak electricity demand occurs during winter evenings.

It is misleading to compare capacity value results directly because of the differences in methodologies, technologies, orientation, load shapes, and penetration levels. For example, the Xcel study compared PV to a natural gas plant, and the *Western Wind and Solar Integration Study* compared PV to a perfect plant (Xcel Energy 2009, GE Energy 2010). The high capacity values (60%–80%) from the Perez et al. (2006) study are for two-axis tracking PV systems. It is also important to note that most of these high capacity values occur at relatively low penetration, below 5%, and the capacity value drops significantly as penetration of PV increases. Hoff et al. (2008) show an example of a Southwest utility where the capacity value of PV decreases from about 80% to about 60% as the nameplate capacity of PV increases from 1% of the peak load to 20% of the peak load. The reason for this decline in reliability

contribution is that, as solar output increases, the times of peak net electricity demand will increasingly occur when solar output is low.

6.2.3 SYSTEM OPERATIONS WITH SOLAR AND LESSONS LEARNED

Utility operators are already accustomed to dealing with variability in the load. Accommodating the variability in the net load—load minus solar (and wind) generation—is possible with approaches similar to those used currently. Because wind generation has characteristics that are similar to solar generation, the large body of experience with wind integration can provide valuable insights regarding costs of solar integration, as well as the changes to operations and markets needed to facilitate large-scale integration of solar generation. This includes significant international experience in locations such as Germany and Spain where penetration of wind energy exceeds that in the United States.

The wind-integration studies find modest cost impacts (Gross et al. 2007, Smith et al. 2007), and a summary of wind-integration costs in the United States shows the expected range to be between \$5 and \$10/megawatt-hour (MWh) for penetrations up to 30% on a capacity basis, i.e., about 20% on a generation basis (Wiser and Bolinger 2009). The modest cost impacts of wind integration have been based on exploitation of low-cost options for flexibility to balance the system. For example, full utilization of the existing flexibility in the utility's dispatchable fleet or existing storage systems can help accommodate the increased variability and uncertainty. At higher penetrations, when these low-cost options have been fully tapped, integration costs are expected to rise.

A few studies have quantified specific aspects of solar-integration costs. EnerNex Corp. (2009) evaluated the costs of managing day-ahead forecast errors for up to 800 megawatts (MW) of solar in the Public Service of Colorado system. The cost of the day-ahead forecast error with 200 MW of PV, 200 MW of CSP with 4 hours of thermal storage, and 400 MW of CSP without thermal storage was between \$4 and \$7/MWh, depending on assumptions about natural gas prices. More detailed studies are needed to develop integration cost estimates for solar generation scenarios.

The existing power system evolved over a long history with dispatchable generation with controllable and largely predictable output. Operational strategies and tools, market structures, and system planning were developed for a dispatchable generation paradigm. Significant institutional and physical steps need to be undertaken to transform the existing power system to one that is planned with and integrates high levels of variable and uncertain resources. A “one size fits all” solution does not exist for solar electric integration, but in general, more flexible markets and operational practices can significantly reduce the cost of solar integration and can allow for cost-effective deployment of higher penetration levels. Based on U.S. and international experience (DeCesaro et al. 2009, Ackermann et al. 2009, Milligan et al. 2009a, EnerNex Corp. 2010, GE Energy 2010, Smith et al. 2007), several key conclusions have emerged, which are listed here and described in greater detail below:

- Managing the net load economically and reliably will require flexibility in conventional generation.

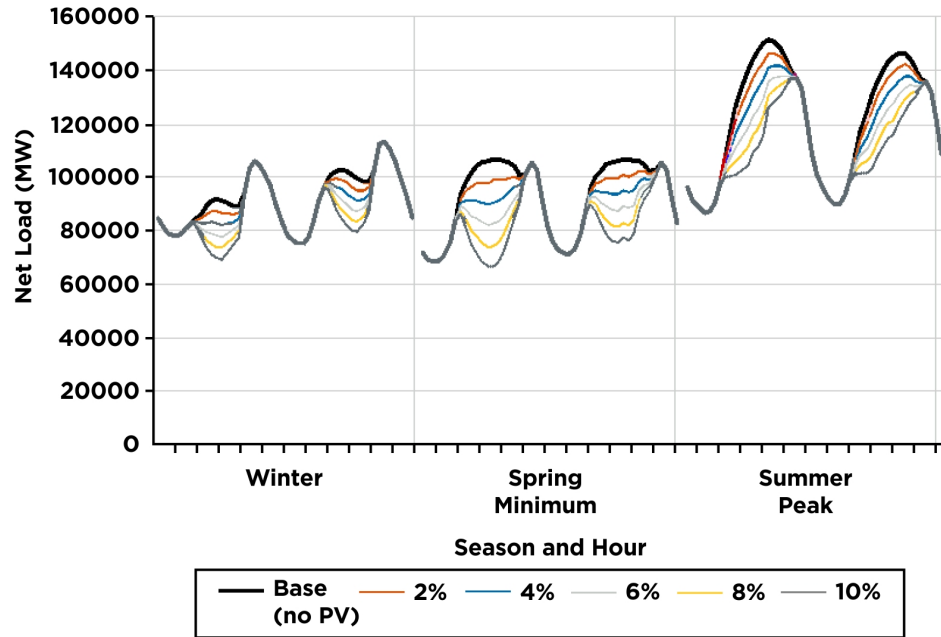
- Aggregation over greater load and generation sources provides opportunities to handle the additional variability and uncertainty of solar generation more efficiently.
- Power system operations must be focused on managing the net variability of aggregated load *and* generation, not the variability of individual plants.
- Increased reserves may be required to manage the additional net variability and uncertainty.
- Better integration of solar forecasting into scheduling and dispatch helps reduce integration costs.
- Shorter-term scheduling can decrease reserve requirements and integration costs.
- Full participation of load as a controllable resource is a cost-effective way to increase system flexibility.
- New mechanisms are needed to incorporate distributed energy resource (DER) assets efficiently.
- Different generation mixes and sources of flexibility will provide the lowest overall cost of energy.

Managing the net load economically and reliably will require flexibility in conventional generation. Increased flexibility of the conventional generation fleet will be required to accommodate large penetrations of solar energy. Even at lower penetration levels, increased penetration of solar without storage can lead to a net load shape that requires thermal generation units to ramp more than they would without the solar. Additional start-ups and shut-downs, part-load operation, and ramping will be required from the conventional units to maintain the supply/demand balance (Goransson and Johnsson 2009).

This additional flexibility comes with some cost and may increase plant operation and maintenance costs (Troy et al. 2010). Figure 6-5 shows the new load shapes with several penetrations of PV in the Western Interconnection territory. Following the net load will require more flexible generation units and may increase generation costs. This may also require increased use of natural gas storage to increase the use of flexible gas turbines and decrease contractual penalties for forecast errors in natural gas use (Zavadil 2006). At higher penetration, energy prices may fall toward zero when minimum generation limits on thermal plants are reached. In an inflexible system, this would lead to curtailment of solar and an increase in the relative cost of energy from PV (Denholm and Margolis 2007). Proper market incentives, as discussed in the next section, can ensure that the ability of a generator to provide flexibility is made available to the system operator.

Aggregation over greater load and generation sources provides opportunities to handle the additional variability and uncertainty of solar generation more efficiently. Aggregation can be in the form of larger BA Areas or through cooperation among BAs, allowing for greater ability to share supply and demand resources. This simultaneously gives access to more responsive resources and reduces net variability, providing several benefits. First, aggregation of dispersed solar resources and load mitigates the net load variability because short-term variability is largely uncorrelated for solar systems at multiple locations. The larger

Figure 6-5. Seasonal Average Load Net PV Generation Shape for Several PV Penetration Scenarios in the Western Interconnection



Source: Denholm et al. (2008)

the region over which the solar plants and load are aggregated, the lower the variability will be. Second, increased BA Area size allows operators to access a larger pool of reserves, reducing the proportional cost of managing the variability. Aggregation of resources and load can be accomplished by physically increasing the size of BA Areas. In several regions with restructured electricity markets, such as PJM Interconnection LLC (PJM) and the Midwest Independent Transmission System Operator (Midwest ISO or MISO), BA Area consolidation has taken place in recent years (see Figure 6-2). In locations without structured wholesale markets—such as the Southwest, Northwest, and Southeast—effective cooperation among BAs can still provide substantial opportunities for resource sharing and lower integration costs for variable generation. Dynamic scheduling of variable generation and sharing of contingency reserves, as well as regulating reserves, are examples of effective collaboration among BA Areas that increase flexibility and reduce cost of integrating variable generation, without physical consolidation of BA Areas.

Power system operations must be focused on managing the net variability of aggregated load and generation, not the variability of individual plants. It is neither efficient nor necessary to manage PV plant variability on a project-by-project basis by trying to create firm power from PV output. There will be times when PV moves in the same direction as load, or when down-ramps in one plant are offset by up-ramps in other plants in the same BA Area. Firming up PV output on a project-by-project basis would unnecessarily increase cost and result in suboptimal use of power system assets. Any local impacts on the transmission or sub-transmission system of variability from PV plants potentially could be mitigated through systems-level changes rather than addressed on a project-by-project basis.

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Increased reserves may be required to manage the additional net variability and uncertainty. Greater solar penetration will increase the ramping rate of the net load due to the morning and afternoon PV ramping, as well as short-term fluctuations due to clouds. This may require an increased need for fast response generation and reserves. The actual amount of increased ramping and regulation reserves has yet to be extensively studied and quantified, especially considering the effects of widely distributed PV and the lack of spatially diverse sub-hourly solar radiation data. However, based on operational studies with wind, it is anticipated that solar-generation variability aggregated over a wide geographical region will reduce the impact of variability and reduce the relative increase in operating reserves requirements (EnerNex Corp 2010, GE Energy 2010). Detailed analysis, however, is required to determine specific requirements on factors such as location, penetration level, and balance of generation. Forecasts of weather events that may result in large changes in solar generation locally—if it is a large plant—or over a large region would be valuable. With advance warning, operators can temporarily increase ramping reserves, and thus reduce the cost of solar variability and uncertainty without compromising overall system reliability. Finally, a forecast that alerts operators to potentially faster fluctuations caused by fast-moving clouds could be useful so that sufficient regulating reserves can be available or variable generation plants can be controlled to given set points. Similar actions are already taken by system operators for forecasted lightning storms, which increase the risk of transmission line outages (Alvarado and Oren 2002, NERC 2009). Some aspects of solar integration may be easier than wind integration because the clear-sky output is predictable, and reserves will likely need to be held only in proportion to the clear-sky output.

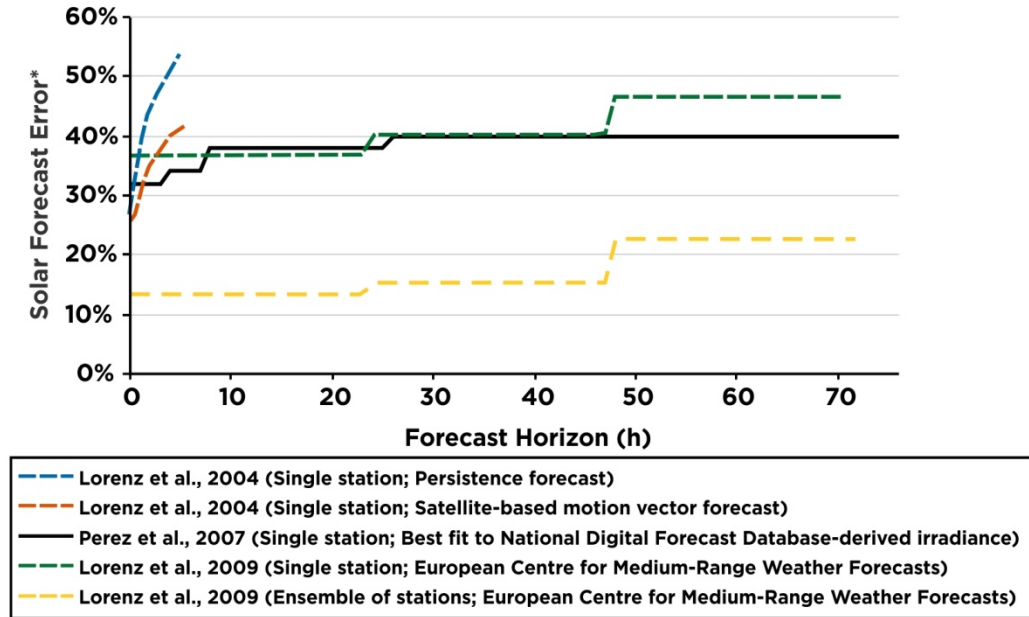
Better integration of solar forecasting into scheduling and dispatch helps reduce integration costs. Integration of solar forecasting into operations on a day-ahead, hour-ahead, and real-time basis improves operational efficiency and reduces integration costs. When good day-ahead and short-term forecasts are available and are fully used, operators can optimize dispatch strategies. Forecasts for both energy production and variability—ramping events and higher frequency fluctuations—should be taken into account during system operations. Inclusion of state-of-the-art wind forecasts has been shown to dramatically reduce scheduling costs relative to not taking such forecasts into account (Smith et al. 2007, GE Energy 2010). Similarly, operational decisions based on an understanding that forecasts are imperfect allow for more conservative and overall lower-cost scheduling decisions (Tuohy et al. 2009). Full integration of solar forecasts into dispatch and scheduling decisions may require operator training and new decision-support tools. Additional research and development is needed in this area.

Shorter-term scheduling can decrease reserve requirements and integration costs. Reserve requirements can be reduced by making unit-commitment decisions closer to the real time. Currently, many utilities make their unit-commitment decisions the morning before the day being planned, pursuant to long-standing regional guidelines. Forecasted information that feeds into this process is based on meteorological data that is 24–48 hours ahead of the hour being planned, and thus is likely to have a higher forecast error than forecasts made closer to real time (Lorenz et al. 2004, Perez et al. 2007, Lorenz et al. 2009, GE Energy 2010). Rolling unit-commitment approaches or moving unit-commitment decisions closer to real time should result in decreased forecast error between load and generation and reduced

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requirements for expensive short-term reserve capacity. Figure 6-6 illustrates the magnitude of solar forecasting errors for forecast horizons up to 76 hours using different forecasting methods. All methods are more accurate over shorter forecast horizons. In addition, the bottom line in Figure 6-6 shows that forecasting the aggregate output of multiple sites is much more accurate than forecasting the output of an individual site.

Figure 6-6. Solar Forecast Error for Different Forecast Horizons and Different Prediction Methods



*Relative Root Sq. Mean Error of Global Solar Insolation Forecast

Likewise, sub-hourly system dispatch can also reduce integration costs. This includes sub-hourly scheduling of all balancing resources such as generators and voluntary responsive loads and sub-hourly scheduling of interchanges between BAs. Without sub-hourly scheduling, expensive regulating generators must account for all the sub-hourly variability of the solar instead of the less-expensive load following generators.

Full participation of load as a controllable resource is a cost-effective way to increase system flexibility. It may be less costly for load to respond to system needs by shifting or curtailing consumption than to increase reserve requirements or procure additional flexible generation. ERCOT’s Loads acting as a Resource (LaaR) program is a good example of load participation to increase flexibility. The LaaR program is able to curtail load during those specific hours when additional reserves would be necessary, achieving the same objective as deploying operating reserves for 8,760 hours of the year (Ela and Kirby 2008). Expanding this type of load-participation arrangement could decrease the costs of solar integration.

New mechanisms are needed to incorporate DER assets efficiently. Because of their small size, customer-owned PV installations are typically not incorporated into system operations and markets. As future “smart grid” concepts and technologies are implemented on the distribution system, it will become increasingly feasible to

integrate DERs into grid planning and operations. Better visibility of DERs from the utility control room, coupled with inverter technology that can be responsive to system needs via operator commands and price signals, would enable DERs to participate in energy and capacity markets and help support system reliability. To accommodate high penetration at the distribution level, technical changes to the distribution circuit devices may be needed to make them more responsive to the impacts of variable resources (for additional discussion of this topic see Section 6.4).

Different generation mixes and sources of flexibility will provide the lowest overall cost of energy. Adding a large amount of solar generation to the power system can have a significant impact on generation planning assumptions. Adding solar to the existing mix of generation will displace energy from plants with higher operating costs (Denholm et al. 2008). As the penetration of solar expands, however, solar will increasingly displace lower cost generation, and the value of additional solar to the generation mix will start to decline. In the long run, however, the generation mix with significant solar will begin to look different than the current generation mix. Adding solar will, in the long run, influence the “balance of system” mix, likely toward less baseload capacity and more flexible generation capacity than a similar system without solar (Lamont 2008). The set of technologies and mechanisms enabling greater penetration of solar energy can be described in terms of a flexibility supply curve that can provide responsive energy over various timescales. Figure 6-1 provides a conceptual flexibility supply curve that summarizes the options for incorporating variable generation. The optimal mix of these technologies has yet to be determined, but many sources of flexibility will be required for the most cost-effective integration of solar at high penetration.

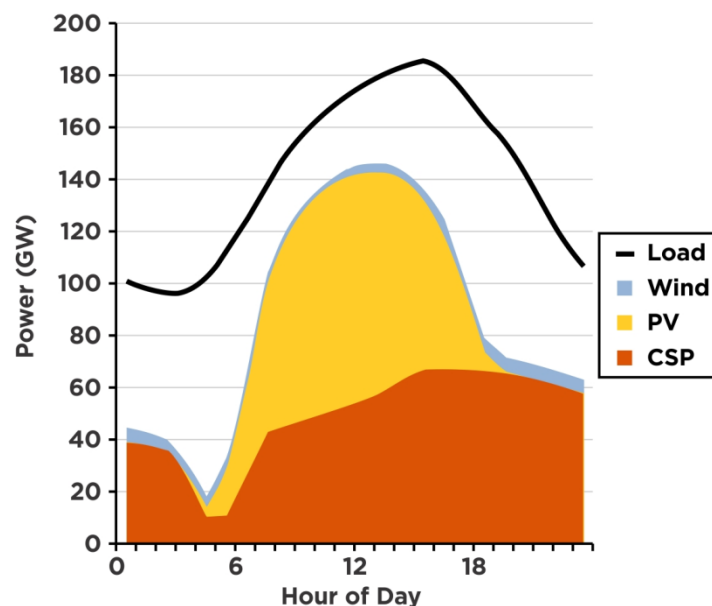
6.2.4 OPERATIONAL FEASIBILITY OF THE SUNSHOT SCENARIO

In the SunShot scenario, the most challenging region of the country in terms of electric system operation would likely be the Western Interconnection. The SunShot scenario envisions meeting 31% of the Western Interconnection’s demand with solar (and 6% from wind) in 2030. This increases to 56% of demand from solar by 2050. The operational feasibility of the SunShot scenario was modeled using GridView, in particular, to investigate the flexibility required to balance hourly supply and demand for the system as envisioned in 2050. GridView simulations indicate that hourly load could be met at all locations throughout the year. Flexibility in these simulations was provided by CSP with thermal storage, hydropower and pumped hydro storage, transmission capacity and power exchanges between the Western Interconnection and the other interconnections, curtailment, demand response, and the fleet of existing and new fossil-fueled generators. While this type of modeling validates the ability to operate the electric system on an hourly basis, in order to evaluate the complete operational feasibility of the SunShot scenario, additional modeling of sub-hourly balancing, system stability, and voltage stability would be required.

The biggest challenge with the SunShot scenario from a systems operation perspective is integrating variable generation, including PV and wind. By 2050, 29% of the electricity demand in the Western Interconnection is met with wind and PV generation, and 33% is met with CSP. CSP is deployed with up to 12 hours of thermal storage and provides dispatchable energy. As a result, the fraction of demand met by variable sources (29%) is similar to previous studies modeling

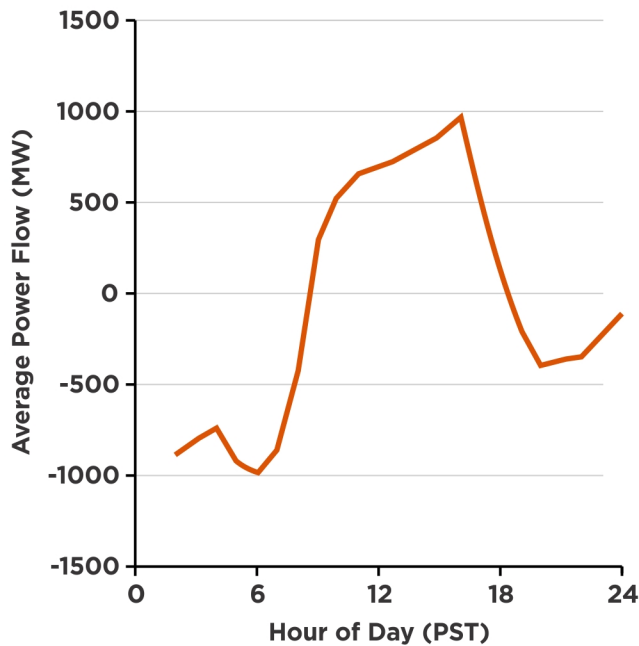
renewable penetration in the western United States, including the *Western Wind and Solar Integration Study* (GE Energy 2010) and the ongoing assessment of the California independent system operator (ISO) 33% renewable portfolio standard (CPUC 2008). Figure 6-7 shows the GridView average diurnal dispatch of CSP generators with thermal storage during July, along with PV output, wind output, and load in the Western Interconnection. During this time of the year, CSP in the Western Interconnection coupled with 12 hours of storage allows most CSP generators to operate 24 hours per day. CSP generators also typically generate at close to 100% of their capacity during the evening hours, i.e., after PV has stopped producing electricity, but the load is still relatively high.

Figure 6-7. Average Hourly Dispatch in the Western Interconnection during July



Another major source of flexibility in the SunShot scenario is the ability to exchange energy with other interconnections. The Western Interconnection currently has very limited transmission capacity to other interconnections [less than 2 gigawatts (GW)]. To accommodate solar penetration levels in the West, the SunShot scenario develops a total of 18 GW of transfer capacity on DC connections between the Western Interconnection and the Eastern Interconnection. Although the Western Interconnection does export more than it imports, the transfer capacity is not used simply to export excess solar electricity. The interties are used to import and export electricity to optimize the total system production cost, which adds additional flexibility to the system. Figure 6-8 is an example of the average annual diurnal profile of the AC-DC-AC interconnection between Wyoming (in the Western Interconnection) and South Dakota (in the Eastern Interconnection) modeled in the SunShot scenario in 2050. Power exchange along this line is usually near the capacity of the line, yet the direction of power flow changes twice per day on most days.

Figure 6-8. Annual Hourly Power Flow from Wyoming (Western Interconnection) to South Dakota (Eastern Interconnection), SunShot Scenario, 2050



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There are several other major sources of flexibility that could facilitate penetration levels discussed here. Hydro generators, including pumped hydro storage, are flexible and have inherent storage capabilities. Existing and new fossil-fuel generators can also provide flexibility. Although coal and natural gas combined cycle (gas-CC) units are relatively expensive to start, they can be ramped and operated at part-load to allow for changes in generation. This may, however, have implications for nitrogen oxide (NO_x) and sulfur dioxide (SO₂) emissions (Mills et al. 2009) and long-term maintenance costs (Agan et al. 2008). Natural gas combustion turbines (gas-CT) are more flexible and can be cycled regularly to help provide generation for relatively short periods. Interruptible loads can also be a cost-effective solution for providing operating reserves. Finally, curtailment of wind and solar generation can provide flexibility to the system.

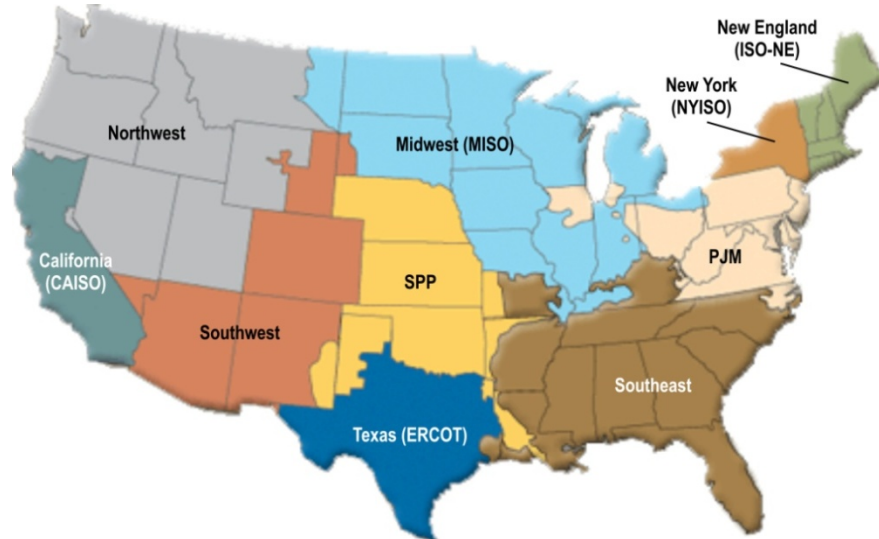
The ability to curtail generation can be used by the system operator to reduce system ramp rates or avoid transmission congestion or minimum generation problems. A generator that is curtailing energy may also be able to use that capacity to provide operating reserves (Miller et al. 2010). The GridView simulations indicate that by using a combination of CSP with thermal storage, other generation technologies, transmission, and curtailment, the SunShot scenario can feasibly balance supply and demand on seasonal and hourly time scales.

6.2.5 THE ROLE OF ENERGY MARKETS

Market structures have an important role in the integration of solar generation, and nearly all the factors discussed in Section 6.2.3 are affected by the design and implementation of markets. Markets provide a mechanism for buying and selling electric power to meet the system load and maintain an acceptable level of

reliability. In the United States, electricity market structures vary widely by region (Figure 6-9). Some markets, such as the MISO, PJM, New York Independent System Operator (NYISO), Independent System Operator-New England (ISO-NE), ERCOT, California Independent System Operator (CAISO), and increasingly the SPP, are integrated, flexible, and efficient. Some of them offer a wide variety of energy as well as capacity and ancillary services products that can be accessed day-ahead, hour-ahead, or in some cases, on a sub-hourly basis. In other areas such as the Southwest, Southeast, and Northwest, however, electricity markets are less flexible and require BAs to rely more heavily on bilateral transactions to access electricity and capacity resources that are not under their direct control. However, it is possible that areas without electricity markets could develop cooperative agreements that would provide some of the benefits of markets (Milligan et al. 2009b).

Figure 6-9. Electricity Markets in the United States



Source: FERC (2010)

Market characteristics, including size, sub-hourly interval, and product options and rules, can significantly affect how effectively and economically system operations are able to use the flexibility that is physically available to deal with increasing levels of solar generation. Whether operating in a large liquid market or in a regulated utility with limited resource access, the market features listed here and described following the list can help enable more efficient integration of solar generation:

- Markets that are more flexible, larger, and more diverse provide opportunities for the integration of solar generation at a lower cost.
- Market flexibility, such as shorter transaction closure intervals, can significantly lower the cost of solar integration.
- Market-based incentives can produce optimal solutions to uncertainty and variability and maximize system flexibility.

Markets that are more flexible, larger, and more diverse provide opportunities for the integration of solar generation at a lower cost. Larger, more flexible markets

tend to be more adaptable to changes in system requirements, such as the need for additional generation flexibility to handle increased levels of variability. Such markets provide a mechanism to access the flexibility that is physically available from all generators in the area and all responsive loads. The larger the market is, the larger the pool of generators and responsive load and the smaller the relative variability of aggregated load. Larger markets also have the advantage of more geographic diversity of solar resources, as discussed earlier. The results of numerous wind-integration studies and actual experience have shown that, for the same level of penetration, integration cost is significantly lower in markets such as the MISO compared to a smaller BA Area without the ability to exchange resources across a larger area (Milligan et al. 2009b). This conclusion will almost certainly hold for solar generation as well.

Market flexibility, such as shorter transaction closure intervals, can significantly lower the cost of solar integration. A key measure of flexibility is how often system operators can interact with the market to optimize operating cost. For example, markets that allow for faster transactions—scheduling power exchanges every 5 or 10 minutes as opposed to 1 hour—reduce requirements for regulation, which is the most expensive ancillary service.

Market-based incentives can produce optimal solutions to uncertainty and variability and maximize system flexibility. Efficient market structures can incentivize the most cost-effective technical alternatives to deal with variability at the system level. This includes flexible generation, storage, better forecasting, and full participation of load as a resource. Some electricity markets do not include capacity or ancillary services options. Real-time prices for ancillary services should provide sufficient incentive for the right amount and type of generation capacity and responsive load needed to maintain system reliability. Studies have shown that the existing generating fleet is capable of providing a large amount of flexibility; however, much of that capability is not tapped due to a lack of appropriate market incentives or prices for flexibility services (Kirby and Milligan 2005). Markets can also be designed to deal with transmission congestion through mechanisms such as location marginal pricing (LMP). Flexible generation that has shorter commitment times—the time required to start and begin delivering energy—and lower cycling costs will be more valuable in an environment with high solar and/or wind penetration. Markets can be structured to motivate new capacity entrants to be more flexible, for example, by providing the amount of expected variable generation to help inform conventional generation owners/investors of future opportunities for flexible generation response.

6.3 FEASIBILITY OF THE NEW TRANSMISSION INFRASTRUCTURE REQUIRED FOR THE SUNSHOT SCENARIO

Both the SunShot and reference scenarios require significant transmission expansion. In the reference scenario, transmission is expanded primarily to enable new conventional and wind resources to meet growing electricity demand. In the SunShot scenario, transmission is expanded at a similar level, but in different locations in order to develop solar as well as wind and conventional resources. In the

SunShot scenario, concentration of large-scale CSP and central utility-scale PV would occur in some areas such as the Southwest where solar electricity can be generated at a significantly lower cost based on the higher-quality solar resources in the region. Additional transmission capacity will be needed to deliver solar-generated electricity from these areas to load centers—for more information, see Chapter 3. Transmission development represents a major challenge based on cost, cost allocation, permitting, and the long time frames involved. Major transmission lines typically take 7–10 years to plan, permit, and construct. Therefore, it is important that large-scale deployment of renewable generation be considered proactively as part of the regional transmission planning process. Furthermore, because only 1–2 years of transmission-project time lines are devoted to construction, there could be opportunities to reduce transmission development timescales. In particular, new frameworks to address transmission siting and cost allocation could facilitate the transmission development needed for solar.

Several challenges are associated with integrating solar energy into the United States transmission system. There is a clear need to develop or improve planning models and methodologies to represent solar generation properly in grid-planning and interconnection studies. Another challenge is the need to develop, improve, or adapt performance and interconnection standards to ensure that solar generation can be integrated reliably and cost effectively into the transmission system. Perhaps the most difficult challenges will be the permitting and financing of the new transmission infrastructure required to move large amounts of solar generation, as discussed in Chapters 7 and 8, respectively. This section discusses the technical issues and solutions associated with the integration of SunShot-level solar generation onto the grid.

6.3.1 METHODOLOGIES FOR TRANSMISSION PLANNING

Transmission planning is a complex process whereby system planners identify system-expansion requirements to meet future needs. The process is driven by predictions of load growth and generation patterns that are informed by decades of accumulated experience. There is a growing trend toward regional transmission planning to capture the benefits of obtaining least-cost renewable energy, increasing reliability through diversification of the resource areas employed, and decreasing the need for ramping/ancillary services when balancing occurs over larger areas. As the penetration level of solar and other variable sources of generation increases, the analysis techniques and study approaches employed in transmission planning must become more sophisticated. Below are some examples.

- Regional planning studies are conducted on a limited set of scenarios that represent peak and off-peak conditions during different seasons of the year. For the most part, the generation pattern assumed for each load scenario can be inferred based on the use of dispatchable generators. The accelerated introduction of large amounts of solar as well as other sources of variable generation, primarily wind, will give rise to a wider range of operating conditions that need to be considered in the transmission planning process.
- Large and potentially frequent changes in generation are possible with PV and CSP without storage. As the amount of solar generation increases relative to the strength of the local transmission system, additional reactive power support may be needed to maintain voltage levels and system

stability. However, variability scenarios are not typically considered as part of transmission-planning and interconnection studies.

- The existing grid relies, in part, on the mechanical inertia of large generators. The inherent inertia of the collective synchronous generators in an interconnected system provides frequency stability that helps the system withstand severe disturbances. Certain solar-generation technologies, such as PV and dish/engine CSP systems, have no effective inertia and provide relatively low short-circuit currents during faults. Inverter-based wind generation exhibits similar behavior unless specifically designed to provide an inertial response. Technically, displacing a significant amount of conventional generation with solar generation that has no mechanical inertia has the potential to affect the dynamic performance of the interconnection negatively. This characteristic must be taken into account in the design of control and protection systems. That said, tower and trough CSP plants use synchronous generators that provide inertia in the same manner as conventional generators, thus minimizing the potential for additional challenges.

None of the issues discussed above constitute insurmountable challenges to achieving significant penetration levels of solar energy. However, new approaches are needed to integrate solar into the grid. Three issues have been identified as requirements for improving the integration of solar into the U.S. transmission system. These issues are listed here and described in greater detail below.

- New and improved models of solar-generation technologies will be needed.
- Interconnection procedures and requirements will need to evolve.
- Solar systems will need to be integrated into utility operations via supervisory control and data acquisition (SCADA) systems.

New and improved models of solar-generation technologies will be needed.

Adequate solar-generation electrical models for transmission-planning and interconnection studies are indispensable to achieving high solar penetration levels. Transmission-planning and interconnection studies consist mainly of power flow, dynamics, and short-circuit simulations that take into account the effect of a large number of system components. Because trough and tower CSP technologies employ conventional generators, well-established electrical models can be used to represent these types of systems. However, PV and dish/engine technologies require different types of dynamic and short-circuit models that still need to be developed or improved. PV systems are inverter-based generators, which are fundamentally different from conventional generators. Inverters exhibit a very quick electrical response, which results from fast switching capability and lack of mechanical inertia. Unlike conventional generators, inverters are able to quickly control current with little or no oscillatory behavior following system disturbances. Dish/engine systems are induction generators driven by low-inertia reciprocating engines. Models that represent this behavior and these characteristics need to be developed or improved. Models also need to be validated and supported by the various industry-standard simulation software platforms and be readily shared among multiple system planning entities and consultants. For example, the Western Electricity Coordinating Council (WECC) initiated an effort to develop models for solar generation, following a similar effort for wind generation that started in 2006.

Interconnection procedures and requirements will need to evolve. In addition to the new models needed, interconnection requirements for solar and other variable-generation resources, both distribution-connected and transmission-connected, must continue to evolve to adequately cover solar-generation technologies. At the transmission level, existing interconnection procedures can be applied to solar-generation technologies that use conventional generators, such as CSP troughs and towers, but are not adequate to address PV and dish/engine systems.

The North American Electric Reliability Corporation (NERC) has already identified several gaps in the standards related to transmission planning and operations with high levels of solar and wind generation (NERC 2009). One of them is the need to reconcile key aspects of the standards that apply to distribution-connected generation. Distribution-level connected solar systems typically are required to follow the Institute of Electrical and Electronics Engineers (IEEE) 1547 interconnection standard. The existing IEEE 1547 requirements carry the implicit risk that a large amount of distribution-connected PV generation may trip as a result of transmission system disturbances if voltage and frequency levels fall outside narrow windows. A recent study performed by General Electric (GE) as part of the U.S. Department of Energy's (DOE) Renewable Systems Integration (RSI) study effort shows that, in high-penetration scenarios, PV inverter tripping caused by transmission disturbances can exacerbate voltage instability in load centers (Achilles et al. 2008). As solar penetration increases, voltage tolerance or low voltage ride-through (LVRT) will start to be required, as it is required for wind generation today. In high-penetration scenarios, solar plants should also provide reactive support of a character similar to conventional power plants. In Europe, several jurisdictions have adopted new voltage and frequency standards that add LVRT and reactive support for PV generation connected to the high- and medium-voltage networks (Troester 2009).

Future standards for solar generation should also address power control and frequency support. All solar-generation technologies could be designed to limit power output, control ramps to some extent, and even contribute to frequency support. This capability would essentially mimic the behavior found in rotating machines. For PV and dish/engine systems, power control and frequency support functionality could be achieved by curtailing some amount of solar power, although the costs of this approach would need to be compared to the value of curtailed energy.

Because PV systems are inverter based, evolutionary changes in capabilities could take place relatively quickly. Wind turbines, which use the same type of inverter technology as PV systems, have rapidly evolved over the last 5 years to meet rather stringent voltage ride-through requirements and are able to support advanced active and reactive power-management options. It is expected that PV inverters will be able to adapt rapidly to expected changes in performance standards or grid codes.

Solar systems will need to be integrated into utility operations via SCADA systems. For full integration into utility operations, centralized solar plants, and, increasingly, distribution-connected PV plants, should be integrated into a utility's SCADA systems. This integration not only provides visibility to system operators, but also allows solar systems to participate in energy and ancillary services markets. During periods of system stress or reliability risk, SCADA integration would allow system

operators to request dynamic voltage support, frequency support, and power management from solar plants, assuming the plants have the capability to do so. Integration of distributed solar installations into SCADA is significantly more challenging than integrating centralized solar installations, because the distributed plants could be deployed in extremely large numbers. Aggregation of these distributed systems is a promising approach to integrating with utilities' SCADA systems.

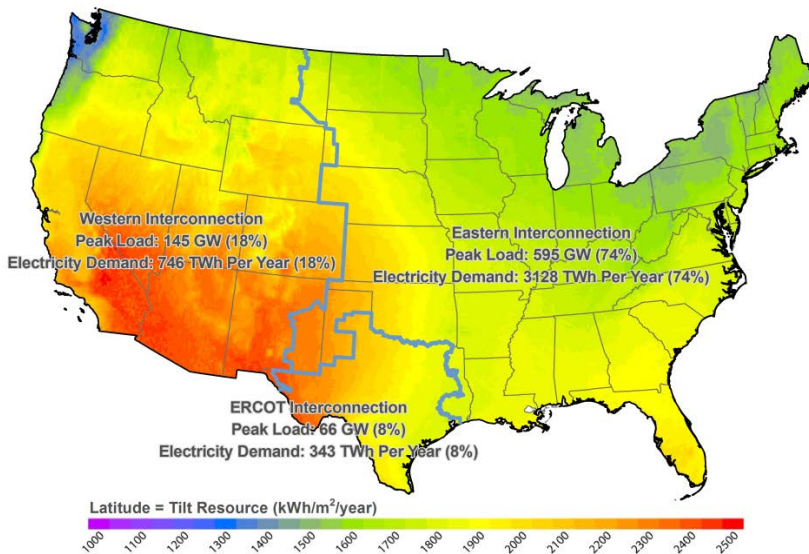
6.3.2 TRANSMISSION CAPACITY NEEDS TO FACILITATE SOLAR GROWTH SCENARIO

The need for new transmission for a high solar-penetration scenario will be driven primarily by the location of new solar plants and the availability of existing transmission capacity. The economics of exploiting high-quality solar resources may be favorable, even if long transmission lines are required to deliver the power, because the lower cost of electricity from these remote sources could offset the capital cost of additional infrastructure to deliver the power to demand centers. In other cases, however, it may be preferable to place new facilities closer to areas of high population density. These tradeoffs will be a central concern when considering the balance between centralized and distributed solar electricity deployment.



It is expected that a large fraction of the infrastructure additions to carry power from high-quality solar resources to nearby load centers are, in the near term, likely to be built in the Southwest. This is especially true for transmission to access CSP capacity. Figure 6-10 shows the solar insolation for a south-facing latitude-tilt array along with electricity capacity and demand statistics for the three large power system interconnections in the United States. As shown in the figure, the locations

Figure 6-10. Global Horizontal Solar Resource (South Facing, Tilted at Latitude) with Electricity Use Statistics by Interconnection



Source: NREL

with the highest insolation are concentrated in southwestern states such as Arizona, New Mexico, California, and Nevada. The concentration of resources in the southwestern states is even more pronounced for direct-normal irradiance (DNI) with two-axis tracking, such as, for CSP and concentrating photovoltaic (CPV) technologies.

Although CSP and central utility-scale PV deployment in the SunShot scenario is concentrated in the Southwest, there are notable exceptions where they are deployed in areas with lower insolation, like Florida, to access greater load-density regions.

PV deployment in the SunShot scenario is highly concentrated in the Western Interconnection in the early years of the analysis. Later deployment, benefiting from continued technology cost reductions, has a broader geographic scope; however, it is clear that the western United States faces the more significant integration challenge in these scenarios (see Chapter 3). This deployment trajectory for CSP and PV, coupled with the fact that the Western Interconnection accounts for less than one-fifth of the national electrical load, results in very high solar penetrations in the Western Interconnection. By 2050 in the SunShot scenario, the solar penetration in the Western Interconnection is 56% on an energy basis. While this is a very high level of solar penetration, as discussed in Section 6.2.4, GridView simulations indicate that through a combination of CSP with thermal storage, other generation technologies, transmission, and curtailment, it would be feasible to balance supply and demand on seasonal and hourly timescales.

Significant transfer capacity between the interconnections, in addition to long-distance transmission lines, is required to accommodate the large solar deployment in the western United States. Increased transfer capability between the three electrical interconnections (Eastern, Western, and ERCOT) could facilitate integration of larger quantities of solar. The SunShot scenario shows this type of transfer capacity increasing substantially (with a total of 18 GW between the Eastern and Western Interconnections and 5 GW between the Eastern and ERCOT Interconnections by 2050). The SunShot scenario also requires substantial transmission system additions within the interconnections.

The low capacity factors for solar electric systems raise asset utilization concerns for transmission systems. Several methods can be employed to enhance line-load factors or otherwise address these issues. In particular, where night-peaking wind is prevalent, such resources can provide a suitable complement to the day-peak output characteristics of solar electricity. Fast-ramping, dispatchable generating capacity, such as from gas-CT or energy storage, can also provide balancing capacity for solar (NERC 2009). Other tools to maximize the use of new and existing lines for variable energy resources include dynamic line rating and conditional firm service agreements (WIRES 2008). However, in the case of solar, the applicability of these tools will be limited because peak solar output will occur during the hottest times of the day when line ratings are at their minimum, system load is highest, and available transfer capacity (ATC) is most scarce.

Based on the vast size of high-quality solar resource areas and economies of scale for transmission, the optimal scale of transmission to access a given resource is often much larger than is required for any individual facility. The mismatch of individual project size and scale of transmission creates complications for system planning and

transmission cost allocation. Lines built for each individual plant in a resource area would be much more expensive than bundling multiple projects together on a single transmission line. Furthermore, the time required to develop new transmission (about 7–10 years) is often much longer than the 1–3 years that are typically needed to develop individual solar projects. It will be increasingly important to meet these challenges with multi-regional system planning to exploit the economies of scale and reduced land use—right-of-way width per unit of capacity—that higher-voltage lines offer. If long-distance power transfer (greater than 500 miles) becomes necessary, high-voltage direct current (HVDC) lines offer lower losses and further reduced rights-of-way widths (Bahrman and Johnson 2007).

Integrating large quantities of solar electricity into the power system will require substantial additional transmission infrastructure to deliver the power from the point of generation to where it is needed. The concentration of the highest-quality solar resources poses significant integration challenges in the West. Targeted transmission development, however, can help address these issues and, in many cases, BA Area transfer capacity will be most critical. Finally, as PV system costs continue to come down, the viability of solar will be less dependent on solar resource strength, potentially broadening the geographic distribution of PV development.

6

6.4 FEASIBILITY OF THE NEW DISTRIBUTION INFRASTRUCTURE REQUIRED FOR THE SUNSHOT SCENARIO

In the SunShot scenario, 121 GW and 240 GW of rooftop PV will be installed by 2030 and 2050, respectively. In addition, a significant fraction of utility-scale PV is expected to be connected to the distribution system. The main difference between transmission and distribution system planning is that generation, except for emergency backup power, rarely has been connected at the distribution level, and even more rarely has been part of dispatch and control for load balancing. Distribution feeders are typically designed to manage one-way power flows from the transmission system to the customer.

The benefits of siting generation near loads include reducing line losses, increasing reliability due to fuel diversity, increasing access to an emergency backup supply for consumers, and potentially deferring equipment upgrades. However, adding significant quantities of generation to the distribution system presents several challenges. At high levels of PV penetration on distribution lines, the distribution system will be required to manage two-way power flow. Significant penetration of PV or any other form of DER sited on distribution lines will require modifications to standards, practices, and equipment to manage two-way power flow safely and cost effectively while maintaining the same level of power quality for customers. In particular, equipment upgrades and advanced communication and monitoring equipment may be required to accommodate high levels of power exported from the distribution system to other parts of the grid and avoid interference with the operation of local-protection-system and voltage-control devices.

6.4.1 INTEGRATING SOLAR WITH THE DISTRIBUTION SYSTEM

Interconnection of PV with the distribution system requires the involvement of the utility, which must approve interconnection of the electricity source, as well as building inspectors who are responsible for the safety of the installation. Processing the paperwork required by the utility or building departments is typically handled by the solar installer and can be time consuming. As the number of distributed PV installations increases, it will be important for utilities and building departments to be able to handle the high number of applications. With greater penetration of PV, improvements in inverter technologies, and increasing comfort with the technology on the part of developers, utilities, and building departments, interconnection processes are being streamlined in many states to allow expedited treatment for PV systems smaller than 25 kilowatts (kW) that are connected to the distribution system. Currently, most utilities will allow up to 15% capacity penetration (rated output divided by peak load) per circuit of the DER to be connected to the grid using a simplified interconnection process. Once that threshold has been reached, a detailed, costly interconnection requirements study is usually mandatory before interconnecting. The 15% penetration level at which a detailed interconnection study is required may be a barrier for large deployments on the distribution system. As more real-world experience is gained, it is possible the level at which in-depth interconnection studies are required could rise above 15% penetration, and/or gradations could occur where studies at lower penetrations are not as in-depth as studies for higher penetration levels. The impact of high penetrations of PV on distribution circuits and the conditions under which issues occur is an important area of research.

There are several technical concerns for integrating solar on distribution systems. In most cases, the magnitude of the influence of DERs on the distribution system depends on the size, nature, and operation of the generation system as well the characteristics of the distribution system. At low penetration levels, the existing standards are adequate to address the technical concerns. For example, the industry standard IEEE 1547 “IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems,” applies to any distributed energy resource up to 10 megavolt amperes, or MVA (roughly equivalent to megawatts), in nameplate capacity connected through to a single point of common coupling (PCC), and includes requirements for connecting PV systems deployed on the distribution system. Most PV inverters are designed and tested to this standard, which prevents PV and other distributed generation from controlling voltage and requires them to disconnect from the utility when voltage or frequency fall outside a narrow operating range.

An important limitation of IEEE 1547 is that it provides neither the guidance nor technical specifications for protection requirements that might be needed for aggregated DERs along a supply feeder or in a network, but is only applicable to the single PCC between the DER and the utility. This limitation should be kept in mind when considering potential impacts of high penetration of PV on the distribution system—for some cases, the high-penetration scenarios will need to be studied further. Prior studies have shown virtually no impacts at low (5%) penetration levels on a capacity basis, and possible system instability at higher (20%) penetrations on a capacity basis, when the DER follows the requirements of IEEE 1547 (Achilles et al. 2008, Liu and Bebic 2008). As penetration levels of distributed PV increase,

interconnection standards will need to be updated to ensure the safety and reliability of distribution systems.

As the penetration levels of DERs increase and their role in grid operations and the grid’s dependence on DER capacity and energy increases, it may be useful to define different rules for different levels of PV involvement in the operation of an electric distribution system. As shown in Table 6-1, three different levels are used to illustrate this point. The actual penetration values that constitute low, medium, and high penetration will vary depending on distribution circuit and PV system characteristics. The main point is that different penetration levels will, by practical necessity, lead to different roles and operating requirements.

Table 6-1. Grid-Penetration Scenarios and Impacts

Penetration Level	Impacts on Power System and Standards Defining Role and Operating Rules for Distributed PV
Low	<ul style="list-style-type: none"> • No impact on normal feeder or grid operation. • Current interconnection standards are sufficient.
Medium	<ul style="list-style-type: none"> • Distributed PV affects feeder voltage, may need to widen voltage trip limit, adjust circuit voltage regulation, and adapt circuit-protection settings. • Under-frequency tripping needs to be widened to coordinate with load-shedding schemes. • Evolve interconnection standards to consider feeder-level interactions.
High	<ul style="list-style-type: none"> • PV systems affect utility feeder and grid balancing (transmission system) and will need to be integrated with both planning and operations. • Ramp rates may be controlled at the PV system level. • Update interconnection standards to integrate PV for voltage and energy support, allowing voltage regulation, low-voltage ride-through, and enhanced anti-islanding schemes.

Source: Key et al. (2003)

It is clear that at the higher penetration levels, standards may need to be changed or requirements expanded to address changing requirements for interaction with PV systems. Issues of concern include steady-state voltage regulation, voltage flicker, harmonics, unintentional islanding, and protection design and coordination. These are discussed in detail below.

Steady-state voltage regulation. Steady-state voltage is the voltage of the power system over a sustained period, usually defined as anywhere from about 1–3 minutes or longer in duration. Utilities require generation on the distribution system to be operated in a manner that does not cause the voltage regulation to go outside the applicable limits. In addition, operation of the DER may not cause interference with the normal operation of the utility’s voltage regulation equipment. Because DERs raise voltage levels when they inject power into the grid, they may cause high-voltage conditions at high penetration levels. A solution to increased voltage levels at high penetrations would be to allow the PV inverters to have the ability to regulate voltage at the local level. Because voltage regulation has historically been done by the utility, proper coordination with existing voltage-regulation schemes would be necessary. If the operation of the voltage regulation on the distribution circuits is not



coordinated, there may be additional costs associated with wear and tear on transformer tap changers and power-factor management devices.

Voltage flicker. Voltage flicker is a sudden change in voltage that occurs in seconds or fractions of a second that can cause objectionable changes in the visible output of lighting systems. The PV inverter standards and designs can evolve to help mitigate any potential voltage-flicker issues that might emerge as penetration increases.

Harmonics. Harmonics are distortions in the regular 60-hertz (Hz) sine wave in North American power systems. Too much harmonic distortion can cause adverse operation of customer and utility equipment. Improvements over the last 10 years in the quality of inverter output have drastically reduced issues with PV system harmonics. The existing standards including requirements for the amount of harmonics that inverters can produce are likely adequate for high penetration of distribution-system-connected PV. Inverters could be designed to cancel harmonics at local loads and provide a benefit to the utility.

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Unintentional islanding. Utilities are regularly required to isolate a section of the power system by disconnecting the section with network protectors or switches. Unintentional islands can be established when a section of the grid is isolated from the substation supply while the load continues to be maintained by an energy source within the isolated section. Unintentional islands pose a threat to proper utility system operation for a number of reasons:

- The upstream utility system might attempt to reclose into the island unsynchronized with voltage, frequency, and/or power factor, which can damage switchgear, power-generation equipment, and customer equipment.
- An unintentional island can increase public exposure to unsafe, energized downed conductors.
- Line crews working on power restoration following storms or other events may encounter unintentional energized islands, making their job more hazardous and slowing down the power-restoration process.
- Unintentional islands do not usually have their generators set up with the proper controls to maintain voltage and frequency conditions adequate to the customer loads.
- Unintentional islands can increase the likelihood of dangerous spikes or surges in the system.

Because of the possibility of unintentional islands, the IEEE 1547 standard and utility interconnection guidelines require DER systems connecting to the network to disconnect from the utility grid in the event that the network voltage or frequency goes outside of predefined limits. Certified inverters do this by employing an active anti-islanding scheme. As a result, unintentional islands are not currently considered a significant concern at low-penetration levels. Under high-penetration levels, however, current anti-islanding techniques may not adequately detect island formation and cease to energize the utility within a suitable amount of time. Furthermore, current anti-islanding techniques require DER systems to drop offline rather than ride through temporary faults, contributing to voltage drop or frequency problems. Large amounts of DERs could be prone to tripping during severe transmission-system disturbances that typically affect a wide geographical area. A

recent study shows that, in high-penetration scenarios, PV inverter tripping caused by transmission disturbances can exacerbate voltage instability in load centers (Achilles et al. 2008).

Protection design and coordination. Utility protection systems are designed to reduce the impact of faults that can be caused by lightning or other problems on the utility system. All power-generation equipment should meet the applicable surge-voltage withstand and insulation ratings found in current standards. PV systems also need to coordinate with the protection systems employed on distribution circuits. Typically, a distribution system will employ a protection scheme that consists of fuses, circuit breakers, reclosers, and sectionalizers that are coordinated to operate with a protective relay scheme. Adding additional sources of power to the distribution circuit will affect the coordination of these devices. PV inverters contribute relatively small levels of short-circuit current. This can have potential benefits, or cause issues, depending on distribution circuit characteristics (Keller and Kroposki 2010).

6.4.2 INTEGRATING DISTRIBUTED RESOURCES AT THE SYSTEM LEVEL

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Incorporating distributed energy resources requires ensuring their safe and reliable operation on the distribution network. However, as discussed in Section 6.2, maximizing their usefulness to the grid as a whole will require new methods to communicate with and control resources at the grid system level. A variety of strategies can be employed to incorporate high-penetration PV as a safe and reliable energy resource for the grid and reduce concerns of distribution system integration.

Managing energy supply from the distribution system, rather than the transmission system, requires a new strategy for system design, planning, and operations. New models of the PV systems will be needed to evaluate the potential impacts of DERs and ensure proper system protection. These models will need to be able to simulate the full range of steady-state and dynamic conditions encountered in the operation of the power system. As the penetration of DERs increases and the necessary technology is developed, it is anticipated that the distribution system will evolve to accommodate two-way power flows and will take full advantage of the benefits of DERs.

Integrating large numbers of DERs into utility SCADA systems from a systems-operation perspective is needed. Based on their larger size, distributed utility-scale PV plants can be integrated into utility SCADA systems more easily than customer-owned PV and other DERs. As smart grid concepts are implemented on the distribution system, it will become increasingly feasible to integrate distributed PV into grid operations. Managing large amounts of data from multiple DER and demand side management (DSM) sites will add complexity, along with cyber security concerns. All of these data will also need to be time synchronized for proposer coordination. Better visibility of distributed PV system output from the control room, coupled with PV inverter technology that can be responsive to system needs via operator commands and price signals, would enable distributed PV to participate in energy and capacity markets and help support system reliability.

Emerging communication and control technologies make it feasible for DERs to be aggregated into “virtual power plants.” Combining solar with demand response

creates a compelling reliability product, but this concept is in its infancy. All of these changes will add complexity to the operations of the distribution system. Rules and performance standards for such a product need to be established, and system operators need to be assured that the resource will be available before they can plan to it and operate with it. Markets and systems operations should evolve guided by the expectation that DERs will play a part. Changes to the regulatory environment may be needed to allow DERs to participate fully in markets and ancillary services.

Updating interconnection standards is also an important aspect to handling increasing DER penetrations. One example is changes to existing interconnection standards, such as IEEE 1547, to permit active voltage regulation, and possibly new anti-islanding techniques that can be used. Communication capability could be added to the PV inverter to allow the distribution system to signal the inverter to dispatch power and loads to optimize power flow to the utility. Such communication could be in the form of time-of-use rates and demand charges or could be real-time pricing via smart-metering technology. Communications between the PV inverter and distribution-system protection equipment, utility control room, and customer or utility storage systems are expected to help overcome variability and power-export concerns.

Benefits of such interactivity would include allowing PV systems to stay connected and ride through during temporary faults as needed. Utilities could command an inverter to ride through voltage sag, rather than having a large number of inverters go offline while leaving the loads online. Interactive control would also enable the distribution system to direct the inverter to go offline when there is a fault, rather than relying on multiple inverters, each supplying power to the grid, to detect a fault or islanding condition independently.

Combining energy storage with solar energy systems can also address some of the issues associated with solar energy integration. A relatively small amount of energy storage can be used to minimize the rate of change of system output to the grid to avoid demand charges. Storage on a distribution feeder could also be used to avoid reverse power flows at the substation. Much more storage would be required to provide significant capability for energy shifting or off-grid operation.

A variety of research and development activities can help with integrating high penetrations of DERs at the distribution level. These include the development of advanced inverter and control technologies, advanced distribution voltage and reactive power management, aggregation of distributed resources systems, and integration of PV systems with local load control and energy management.

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