Grid Modeling for the SunShot Vision Study

G. Brinkman, P. Denholm, E. Drury, E. Ela,
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Technical Report
NREL/TP-6A20-53310
February 2012

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NREL
NATIONAL RENEWABLE ENERGY LABORATORY

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Executive Summary

This document describes the use of production cost modeling in the SunShot Vision study, including methods used to create the SunShot Vision scenarios, their implementation in the Gridview model, and assumptions regarding transmission system and operation of each generator type. It also describes challenges and limitations of modeling solar generation technologies in production cost models, and suggests methods for improving their representation in current models.

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1 Introduction

The SunShot Initiative was launched by the U.S. Department of Energy (DOE) in 2011 and aims to reduce the installed price of solar energy systems by about 75% between 2010 and 2020.[1] Achieving this target will likely make the unsubsidized cost of solar energy competitive with the cost of other currently operating energy sources, paving the way for rapid, large-scale adoption of solar electricity across the United States.

To assess the potential benefits and impacts of achieving the SunShot Initiative targets, DOE's Solar Energy Technologies Program (SETP) produced the *SunShot Vision Study* (DOE 2012). This study assumes that the SunShot price targets are achieved by 2020 and models the resulting penetration of solar technologies in the United States. Solar growth based on non-cost factors (e.g., greenhouse-gas reduction and energy security benefits) is not considered in this analysis, but could result in additional solar market penetration. The results suggest that solar energy could satisfy roughly 14% of U.S. electricity demand by 2030 and 27% by 2050.[2] The modeling scenarios are not predictions of the future; rather, they represent internally consistent model results based on a specific set of assumptions. The model scenarios are used to explore and quantify the costs, challenges, and benefits of reaching high levels of solar penetration. The analysis provides insights that could assist research, development, and deployment (RD&D) portfolio managers and policy makers in designing programs aimed at achieving the SunShot targets and increasing opportunities for the United States to reap economic benefits from photovoltaic (PV) and concentrated solar power (CSP) technology advancement.

Several modeling tools were used to develop and evaluate the SunShot and reference scenarios. The Regional Energy Deployment System (ReEDS) capacity-expansion model, developed at the National Renewable Energy Laboratory (NREL), simulated the least-cost deployment and operation of utility-scale electricity-generating resources in the reference and SunShot scenarios (Short et al. 2011). The Solar Deployment System (SolarDS) model (Denholm et al. 2009), also developed at NREL, simulated the evolution of the residential and commercial rooftop PV markets. These models evaluated the trade-offs between solar resource quality, cost of electricity, transmission requirements, and other factors to determine a least-cost geographical deployment of the various solar technologies and configurations. Similarly, the remaining mix of electricity generating technologies (conventional and other renewable) were determined on a least-cost basis with considerations including the impacts of variability, reserve requirements, and projected fuel prices. Because the geographic scope of both models is the contiguous United States, the SunShot study did not address Alaska or Hawaii.

A major challenge of large-scale solar deployment 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, solar generators (and PV in particular) have limited dispatchability. While the ReEDS model uses a reduced-form dispatch simulation to capture many aspects of renewable integration, it is not a chronological

[1] For additional discussion of the SunShot initiative see various websites at www1.eere.energy.gov/solar/sunshot/

[2] All results in this report refer to the contiguous United States (excluding Alaska and Hawaii) unless otherwise noted, e.g., solar technologies are projected to satisfy roughly 14% of *contiguous* U.S. electricity demand by 2030 and 27% by 2050.

dispatch model, and cannot fully capture the challenges of operating a power system with large penetration of variable renewable generation sources. To help validate the ReEDS scenarios and to better verify the basic operational feasibility of the U.S. power grid for two scenarios in 2050, the SunShot study used the GridView model from ABB Inc. This model is a utility production simulation tool which includes chronological dispatch, detailed generator characteristics and hourly transmission power flow simulations. While the SunShot study is not a fully detailed renewable energy integration study, and does not include a complete assessment of power system reliability (addressing such issues as stability, contingencies, and AC power flows), it does consider a number of electric system integration challenges, including solar resource variability, operational constraints of conventional generators, and new transmission requirements. The limited treatment of electric system reliability in this study is addressed in section 3 and in Text Box 2.

This document describes the use of production cost modeling in the SunShot Vision study, including methods used to create the SunShot Vision scenarios, their implementation in the Gridview model, and assumptions regarding transmission system and operation of each generator type.

2 Scenario Development

2.1 Scenario Modeling Tools

While the focus of this report is on the operational modeling, the scenarios actually modeled depend on the solar and other generation technologies projected in the SunShot Vision scenario. These scenarios were developed using two models: ReEDS, which determined the overall national mix, and SolarDS, which determined the distribution of rooftop PV.

ReEDS is the analytical backbone of the SunShot Vision Study.[3] ReEDS is a linear-optimization, generation and transmission capacity expansion model of the electricity system of the contiguous United States. It simulates the least-cost deployment and dispatch of generation resources and is unique among nationwide and long-term capacity expansion models for its highly discretized regional structure and statistical treatment of the impact of variability of wind and solar resources on capacity planning and dispatch.

ReEDS was used to explore the evolution of the U.S. electric sector assuming the SunShot cost reduction targets for PV and CSP are met, and to calculate the additional transmission capacity and reserve capacity required to meet customer demand and maintain grid reliability. ReEDS determines the geographical deployment of PV, CSP, and other generation technologies based on a number of factors: regional solar resource quality, future technology and fuel price projections, future U.S. electricity demand projections, impacts of variability in renewable generation, transmission requirements, and reserve requirements. The ReEDS model does not take into account potential distribution side impacts and issues.

The ReEDS optimization routine chooses from a broad portfolio of conventional generation, renewable generation, storage, and demand-side technologies listed in Text Box 1. Additionally, because of its detailed regional and temporal representation, ReEDS can estimate the costs of transmission expansion. The capacity expansion and dispatch decision-making of ReEDS considers the net present value cost of adding new generation capacity and operating it over an assumed financial lifetime (20 years for this study). This cost minimization routine is applied for each two-year investment period from 2010 until 2050.[4]

[3] Differences exist between the ReEDS model version used for the SunShot Vision Study and the version presented in Short et al. (2011), including retirement assumptions for coal and natural gas powered plants, technology costs, and fuel price assumptions. For the analysis presented in this report, the model assumptions described here supersede the model description in Short et al. (2011).
[4] ReEDS includes power plants and transmission lines that existed in 2010. All expansion from that point is drive by the cost optimization; proposed generators and transmission are not included.

Text Box 1. Generation, Storage, and Demand Technologies Considered in SunShot Vision Modeling for New Builds[a]

Conventional Generation

- Pulverized coal
- Natural gas combined cycle
- Natural gas combustion turbine
- Nuclear

Renewable Generators

- Onshore wind
- Offshore wind (fixed bottom)
- Concentrating solar thermal power (CSP) with and without thermal storage
- Utility-scale photovoltaics[b]
- Distributed rooftop photovoltaics[c]
- Dedicated biomass
- Cofired biomass with coal
- Geothermal (hydrothermal) (only air-cooled)
- Hydropower

Storage

- Pumped-storage hydropower
- Compressed air energy storage (CAES)
- Batteries

Demand-Side Technologies

- Thermal energy storage in buildings
- Interruptible load

[a] ReEDS also represents existing municipal solid waste, landfill gas, and oil steam turbine plants, though "new builds" of these plant types were excluded in the model.
[b] The utility-scale PV category in ReEDS encompasses all non-rooftop systems, including smaller (up to tens of MW) systems that are within the distribution network and larger systems. Short et al. 2011 describes the different model treatments for these systems.
[c] As discussed later, rooftop PV deployment was estimated using the SolarDS model and was exogenously input into ReEDS

There are a large number of additional constraints and requirements in ReEDS, including planning reserves, capacity credit calculation for solar and wind resources, operating reserves and overall supply/demand balance constraints. Details of each of these are provided in Short et al (2011).

The regional resolution of the ReEDS model allows it to perform limited estimates of new transmission expansion options[5] and their associated investment requirements. For wind and CSP technologies, additional interconnection supply curves are applied to account for the strong

[5] As used in this study, ReEDS represents transmission using a transportation or pipeline model where electrical power is only limited by the carrying capacity of the lines and not by actual power flow limitations. The GridView model simulates transmission transfers using DC power flow modeling.

location-dependence of those resources. A detailed description of these supply curves and of the transmission treatment in ReEDS can be found in Short et al. (2011).

In generating the SunShot Vision scenarios, there are important caveats which strongly influence capacity builds. One of the notable issues is that while ReEDS does allow storage to provide some operating reserve services, its reliance on coarse time slices prevents ReEDS from accurately evaluating all of the short-term (e.g., sub-hourly) services that can be provided by some storage and flexible technologies. Also, no attempt was made to model the competitiveness of short-term storage devices such as flywheels. In addition, explicit modeling of the distribution system is not included in this study, therefore the analysis is unable to identify the potential value and opportunities of storage sited in the distribution system. As a result of these factors, ReEDS will undervalue many opportunities for storage and thus likely underestimates its adoption in the marketplace.

Because ReEDS is not designed to account for distributed generation, the penetration of distributed (residential and commercial) rooftop PV capacity was based on results from the Solar Deployment System (SolarDS) model (Denholm et al. 2009). This model—also developed at NREL—simulates PV adoption in residential and commercial rooftop PV markets based on regional solar insolation, retail electricity rates, and market diffusion characteristics. SolarDS simulates regional PV economics at high spatial resolution by combining hourly PV generation profiles from hundreds of solar resource regions with state-based retail electricity rate distributions compiled from more than 1,000 utilities. PV economics are used to project PV adoption rates using market adoption and diffusion characteristics. The resulting adoption rates are combined with a residential and commercial building stock database to calculate market size. Utility integration concerns at the distribution level, such as voltage regulation, unintentional islanding, and coordinated protection, are not considered as part of the SolarDS model.

These SunShot scenario results are not a prediction of the future. Rather, they represent a possible growth trajectory for the U.S. electric sector if the envisioned price and performance improvements are achieved. Modeled deployment is highly dependent on several assumptions, including projections of future technology and fuel prices, electricity demand, retirement schedules for existing generation resources, transmission expansion costs, and several others, all characterized within the modeling framework. Key model assumptions are listed in Text Box 2.

Text Box 2: Key Model Assumptions Used in the SunShot and Reference Scenarios

- Electricity demand projections are based on the EIA (2010) reference scenario through 2035 and extrapolated through 2050. Electricity demand increases about 20% by 2030 and 40% by 2050.
- Capital cost projections for all energy technologies other than PV and CSP are based on an engineering analysis by Black & Veatch (forthcoming).
- Capital costs for coal, gas, or nuclear generation technologies are assumed to stay fixed through 2050, but coal and gas achieve 10%–20% performance improvements by 2030.
- Non-solar renewable technologies are assumed to achieve moderate price and performance improvements.
- Geothermal is projected to achieve a 17% price reduction by 2050.
- Onshore wind has fixed prices through 2050 but about a 10% increase in performance by shifting to taller towers.
- Offshore wind is projected to achieve a 20% price reduction by 2050 in addition to a performance improvement similar to onshore wind.
- Biopower is projected to achieve a small price reduction, on the order of a few percent, and performance improvements of about 25% by 2050.
- Future coal and natural gas fuel prices and price elasticities are based on EIA (2010) through 2035 and extrapolated based on electric sector fuel use through 2050. Coal prices stay fixed through 2030 and then increase by about 5% from 2030 to 2050. Natural gas prices increase by about 50% by 2030, and 95% by 2050.
- Retail electricity rate projections (used to model rooftop PV) are based on the EIA (2010) reference scenario and extrapolated through 2050. Residential rates are assumed to increase by 0%–1.5% annually, depending on region. Commercial rates are assumed to increase by 0%–1% annually, depending on region.
- State-level renewable portfolio standards (RPS) enacted by 2010 are represented in the reference and SunShot scenarios.
- Only existing energy and environmental policies are included. No carbon tax or emissions prices are assumed. Proposed regulations which may effect retirements of existing coal plants are not included. However, a 6% investment risk was added to the required rate of return for new coal investments to characterize uncertainty over future carbon policy[b] (Barbose et al. 2008).

[b] The 6% investment risk is higher than the base case assumption used by many electric utilities for capacity expansion planning, but is representative of the middle to lower range of carbon sensitivities used by many utilities to develop capacity expansion plans (Barbose et al. 2008). Carbon prices were used to estimate equivalent investment risk adders based on system financing assumptions as described in the SunShot Vision Study (Section 8).

2.2 Reference and SunShot Scenarios

Table 1 summarizes the results of the SunShot scenario analysis, including the cumulative installed capacity, energy generation, and fraction of electricity demand[6] met by solar generation in 2050. In the SunShot scenario, solar generation meets about 14% of U.S. electricity demand by 2030 (11% PV, 3% CSP) and 27% of demand by 2050 (19% PV, 8% CSP). About two thirds of PV generation is from utility-scale ground-mounted systems,[7] and the remainder is from rooftop PV systems.

Note that all results in this report refer to the contiguous United States (excluding Alaska and Hawaii) unless otherwise noted. For example, solar technologies are projected to meet about 14% of *contiguous* U.S. electricity demand by 2030 and 27% by 2050.

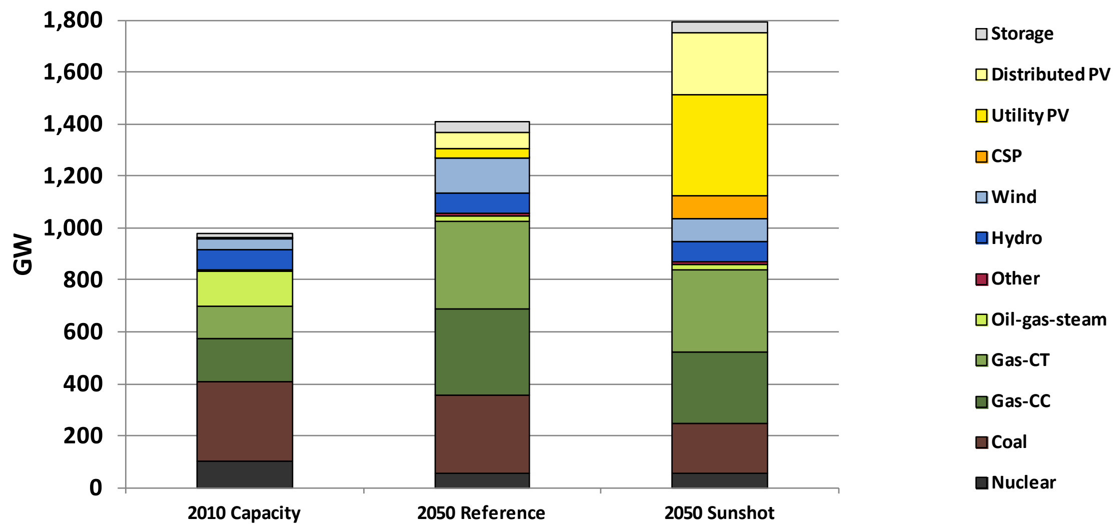

Figure 1. Evolution of electricity-generation capacity in SunShot and reference scenarios ("other" includes biomass and geothermal technologies)

Due in part to model limitations discussed earlier, storage technologies see modest growth in the SunShot scenario, growing from 20 GW in 2010 to 38 GW by 2050. Interruptible load resources used as operating reserves grow more significantly, from 13 GW in 2010 to 48 GW by 2050 in the reference scenario, and 93 GW by 2050 in the SunShot scenario.

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[6] The scenarios represent end-use electricity demand generated by the electric power sector; they do not include on-site industrial generation or on-site co-generation of heat and electricity.

[7] Utility-scale PV systems are represented in ReEDS by both central and distributed systems. See the SunShot Vision Appendix A for descriptions of these types of utility-scale systems. Distributed systems represent ~1-20 MW plants located within distribution networks, while central systems represent ~100 MW plants located outside of distribution networks. Both systems assume single-axis tracking.

Table 1: Installed Solar Capacity in the SunShot Vision Scenario in 2050

	Capacity (GW)	Energy (TWh)[a]	Fraction of Electric-Sector Demand (%)
Total Solar	**714**	**1,448**	**26.9**
Total PV	**632**	**1,036**	**19.3**
Rooftop PV	240	318	5.9
Utility PV[b]	391	718	13.4
Total CSP	**83**	**412**	**7.7**
Electricity Demand [c]	**-**	**5,103**	**-**

Components do not always add up to totals because of rounding.
[a] The capacity-expansion models (ReEDS and SolarDS) place solar technologies in locations where they are most economic, leading to capacity factors of about 15% for rooftop PV, 23% for utility-scale PV (1-axis tracking systems), 60% for CSP (ReEDS primarily builds CSP systems with several hours of storage), and 41% for wind.
[b] Utility PV includes central and distributed utility-scale PV systems.
[c] Electricity demand is based on projections of electricity sales through 2035 from *Annual Energy Outlook* 2010 (EIA 2010) extrapolated through 2050

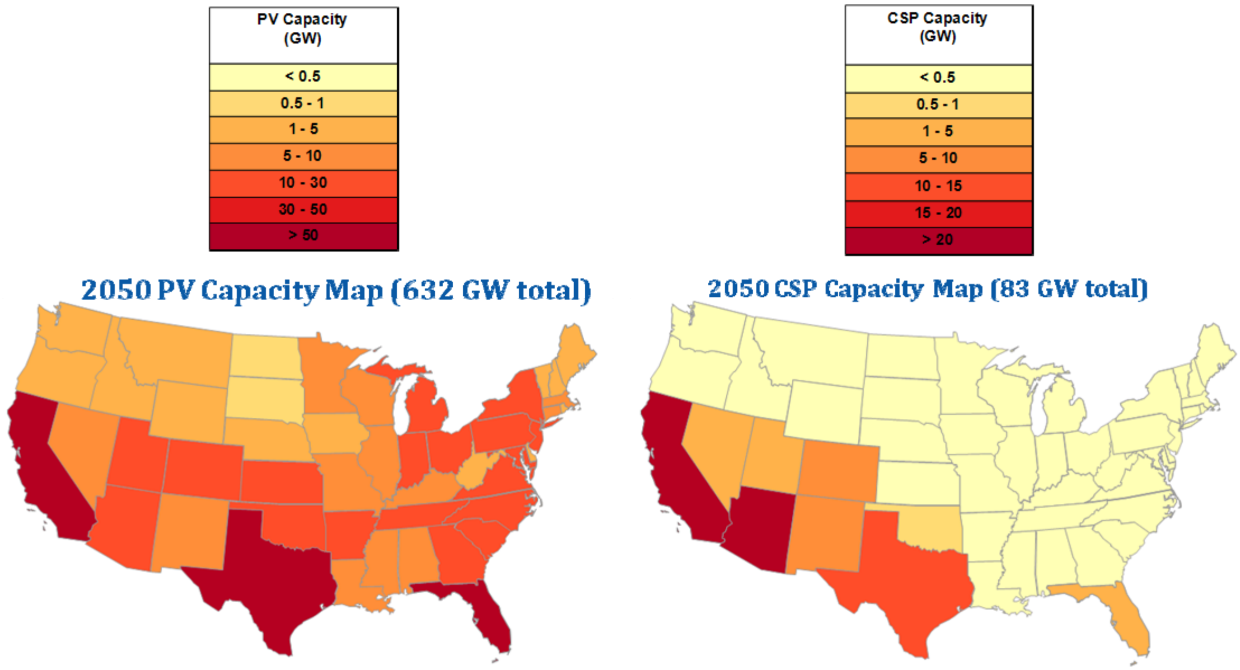

Figure 2. Cumulative installed PV and CSP capacity in the SunShot scenario in 2050

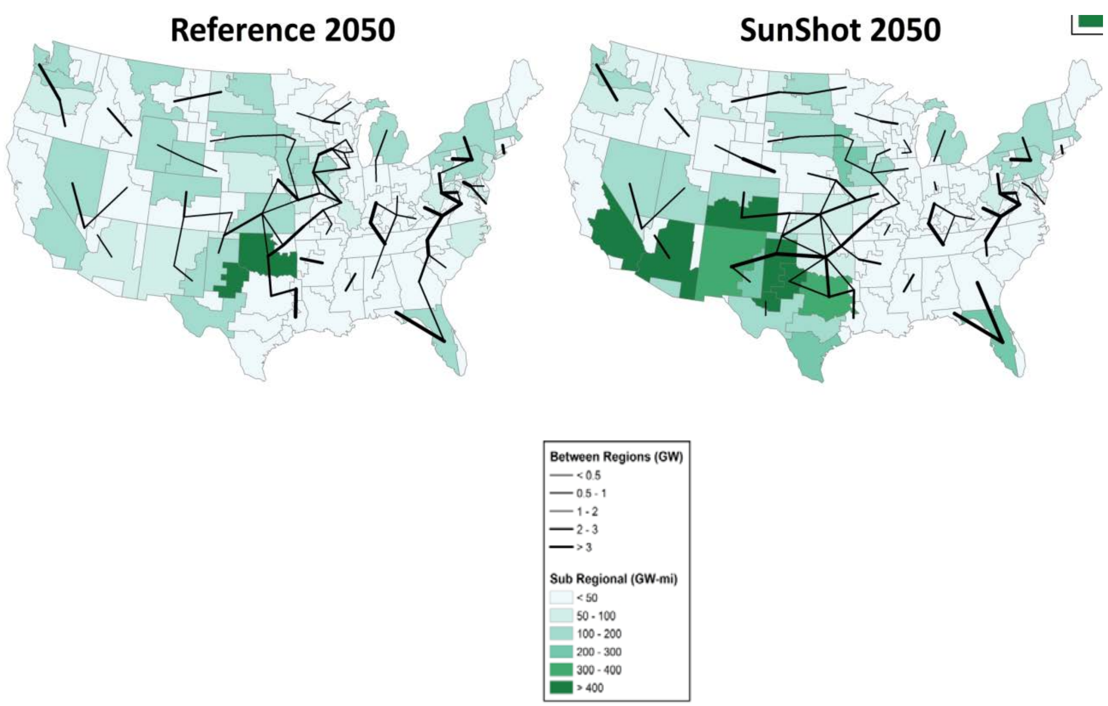

Figure 3. Transmission capacity additions (intraregional capacity expansion shown by color, interregional expansion shown by lines)

3 Scenario Modeling in Gridview

GridView is used to supplement the ReEDS analysis by modeling the detailed operation of the system in 2050 for the SunShot scenario. GridView helps to demonstrate the operational feasibility of a system with high solar and wind penetration by using an hourly time step, a more accurate representation of thermal generation ramp-rate limits, and a more realistic representation of transmission power flows as compared to ReEDS. As a result of these capabilities, GridView can analyze how the system responds to uncertain ramps in the output of variable generation, and provides a more complete understanding of the need for curtailment in times when generation supply exceeds demand.

While the analysis conducted here goes further than previous studies, it is important to note that it does not represent a detailed renewable energy integration study, and thus it does not evaluate many of the potential technical challenges of deploying solar energy at large scale. A discussion of power system reliability analysis and what SunShot Vision does and does not analyze is provided in Text Box 3.

3.1 Production Cost Modeling

While ReEDS considers some elements of grid operation and renewable integration issues, its focus is on capacity expansion. A better understanding of system operation requires more detailed production simulations with finer temporal resolution and with a more accurate representation of transmission flow. [8] This requires a class of models often referred to as production cost models that simulate the optimal dispatch of a power plant fleet to provide reliable electricity at the lowest cost. These models include security constrained unit commitment and economic dispatch, as well as DC optimal power flow models, in order to minimize the production cost of the system as a whole while meeting electricity demand and reliability reserve requirements.

The GridView model from ABB Inc. was used to supplement the ReEDS analysis and to provide further insights into the operational feasibility of the SunShot Vision scenario. Its hourly time resolution facilitates an improved understanding of how variable generation, thermal unit flexibility constraints, and transmission congestion impact the ability of the system to serve load and limit curtailment (ABB 2008 and Feng et al. 2002). GridView models the same generation technologies as in ReEDS, including thermal generators, hydroelectric generators, variable generators such as wind and PV, CSP with thermal storage, and multiple energy storage technologies. GridView also represents the same demand-side technologies as ReEDS, including interruptible load.

For the SunShot Vision study, the 2050 generation and transmission capacity, as projected by ReEDS and SolarDS, is imported into GridView, which is then run to determine the operational feasibility of the capacity expansion scenarios. The integration of the ReEDS and SolarDS results into GridView required modifications of the original GridView code and input databases

[8] ReEDS uses a reduced form dispatch to capture the basic adequacy of the generator and transmission buildout. It divides regional load patterns into time slices but does not use chronological dispatch to estimate impacts of ramp rate limits and other generator constraints. These operational constraints are handled statistically, with these approaches historically validated by the use of detailed production simulations such as those described in this document. A detailed description of the how ReEDS considers grid operations is provided by Short et al. (2011).

so that the model could be run over a larger geographic scope with significant transfer of power between interconnections. New algorithms in GridView were necessary to accurately model the high renewable scenarios central to this report due to the presence of new technologies. These technologies include compressed air energy storage and optimal dispatch of concentrating solar power with thermal storage.

Though the full suite of reliability considerations listed in Text Box 3 were not addressed, the GridView analysis did help validate the basic operational feasibility of the ReEDS results, taking into account a more detailed representation of variable generation, flexibility constraints, and transmission flow. The simulation of grid operations is discussed in detail in GridView references (ABB 2008; Feng et al. 2002). In brief, production cost models consider system operation on multiple time scales as illustrated in Figure 4. Over the unit commitment time scale (spanning hours to days), the software commits (turns on) least-cost generators so they are available for dispatch during real-time operations. This process is based on day-ahead load forecasts and necessary because many large thermal units take many hours to reach operating temperature before generating electricity. A typical schedule is planned hourly for the next 24–48 hours, depending on operating practices.

Unit commitment takes into consideration, among other factors, forecast demand, generation availability, and operating constraints of individual generators such as how long it takes to start up individual generators. In the economic dispatch time frame (typically on the order of tens of minutes to hours), the simulation optimally readjusts the output of online generators in a least-cost order, taking into account short-term forecasts and system constraints.

The time resolution of GridView simulations is one hour, meaning that the software considers to constraint of ramping the generator fleet to meet change in load in one hour intervals. To balance changes in load and generation that occur over a shorter time frame—from seconds to minutes—the simulation ensures adequate operating reserves, including 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). It should be noted that the software does not actually dispatch the reserves in response to real regulation requirements or contingency events, and only "holds" reserves so that these requirements could be met.

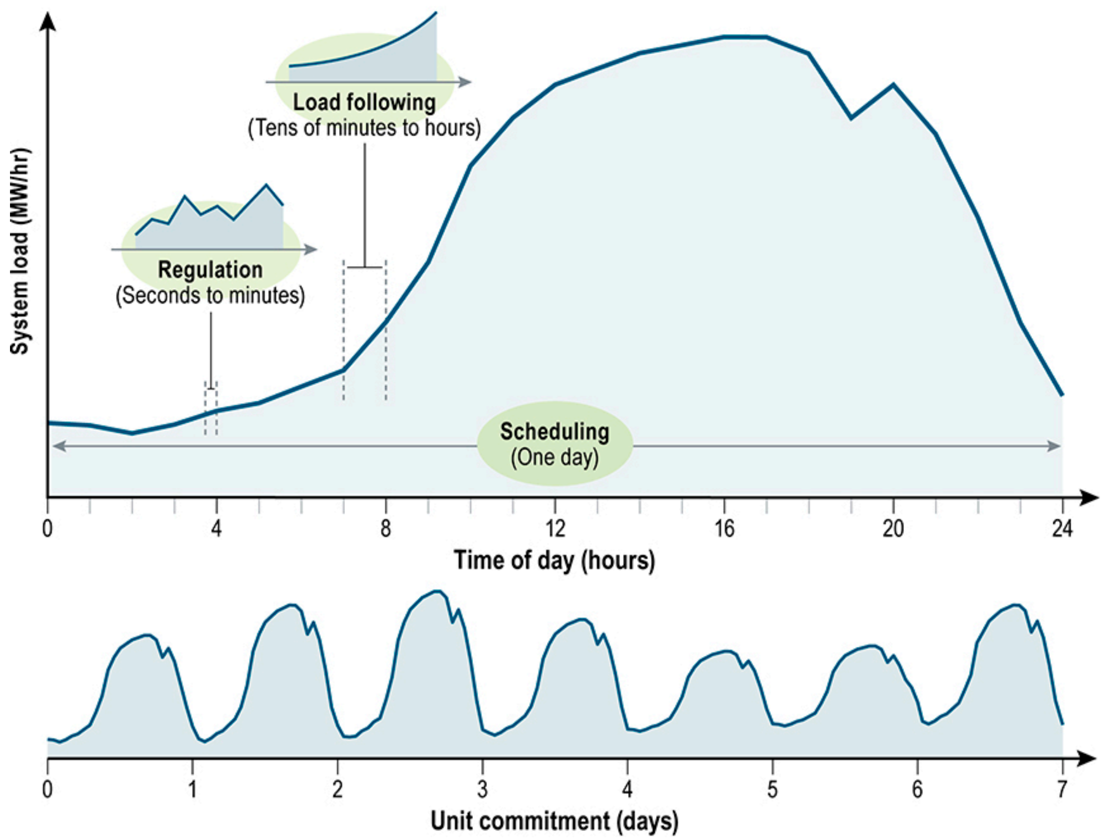

Figure 4. Time scales for power system operation

Text Box 3. Electric System Reliability

The North American Electric Reliability Corporation (NERC) defines a "reliable bulk power system as one that is able to meet the electricity needs of end-use customers even when unexpected equipment failures or other factors reduce the amount of available electricity." NERC divides reliability into two categories: adequacy and security as follows[9]:

- *Adequacy* means "having sufficient resources to provide customers with a continuous supply of electricity at the proper voltage and frequency, virtually all of the time." "Resources" refer to a "combination of electricity generating and transmission facilities, which produce and deliver electricity; and demand-response programs, which reduce customer demand for electricity. Maintaining adequacy requires system operators and planners to take into account scheduled and reasonably expected unscheduled outages of equipment, while maintaining a constant balance between supply and demand.
- *Security* is "the ability of the bulk power system to withstand sudden, unexpected disturbances such as short circuits, or unanticipated loss of system elements due to natural causes, … as well as disturbances caused by man-made physical or cyber attacks. The bulk power system must be planned, designed, built, and operated in a manner that takes into account …these risks to system security."

In assessing high-penetration of variable renewable electricity, the SunShot Vision study addressed some aspects of electric system adequacy. In particular, the ReEDS capacity expansion model handled limited aspects of adequacy and—purely on a statistical basis due to its coarse time resolution—nonetheless sought to ensure that adequate capacity and operating reserves would be available to match supply and demand. GridView evaluated the frequency that load is served (and not served) on an hourly basis and considered a greater number of constraints to the flexibility of conventional generation units, along with a direct current (DC) load flow assessment.

<u>The SunShot Vision study did not conduct a full reliability assessment of the high-solar electricity scenario.</u> Further analyses along these lines are warranted, though a complete analysis of power system reliability impacts and mitigation measures would require extensive additional efforts, including the following:

System Adequacy: To understand overall system adequacy fully, Monte Carlo simulations would be required to measure loss of load probability with the correct probability density functions of various power system variables. Many scenarios would need to be analyzed to understand whether the overall electric system has adequate system capacity to meet load under a variety of operating conditions. With conventional generation units, this type of study typically involves running reliability models using the forced outage rate and mean time to repair of the full suite of conventional units, while also considering possible changes in electricity demand, to estimate the loss of load probability. With high amounts of variable generation, analyses of this type become somewhat more difficult due to the unique behavior of variable generation. As discussed elsewhere, ReEDS addressed system adequacy on a statistical basis, whereas GridView was used to analyze a single scenario at a time to determine whether loss of load was expected under that scenario. Further analysis of system adequacy would require an assessment of a broader array of scenarios, using GridView or alternative tools.

High-Resolution Production Modeling: In most electricity systems today, load changes with somewhat regular patterns from one hour to the next, and within each hour, increasing during the morning period and falling off in the evening. With high penetrations of variable renewable generation, however, 'net load' (load minus variable generation) may vary irregularly and on shorter time frames than is presently the case. Running simulations at sub-hourly levels or even at sub-minute levels may be needed to

[9] North American Electric Reliability Corporation (NERC) definition of reliability: http://www.nerc.com/page.php?cid=1%7C7%7C114

understand fully the impacts of these changes in net load and assess the quantity of reserves needed to manage variability and forecast errors that occur within the hour. Sub-hourly concerns were treated statistically, and were not specifically simulated with advanced modeling tools.

Power System Stability Studies: Stability is a condition of equilibrium between opposing forces.Maintaining power system stability is essential to ensuring a reliable electricity system. Rotor angle stability refers to maintaining synchronism between synchronous machines. Small-disturbance (small-signal) rotor angle stability refers to maintaining synchronism following small disturbances. Large-disturbance (transient) rotor angle stability refers to maintaining synchronism when subject to severe disturbances. A variety of studies are necessary to address these aspects of power system stability, including analyses of synchronism during transmission system faults, as well as other studies that evaluate frequency response during loss-of-supply events. As one example of the issues in question, many variable renewable energy sources cannot currently respond to system-wide frequency deviations with off-the-shelf technology. Analyses are therefore needed to assess (1) future electricity systems where substantial amounts of generation do not have frequency response capabilities, as well as (2) new technologies that might be used to manage those possible deficiencies. Voltage stability, meanwhile, refers to the ability of a power system to maintain steady and acceptable voltages at all buses in the system under both normal conditions and following disturbances; it may be impacted by growing shares of renewable energy generation. Regardless of the specific aspect of system stability under consideration, stability studies require very high time-resolution analysis, usually at the hundredths-of-second time scale but for only the first few seconds following disturbances.

Alternate Current (AC) Analysis: Many power system models use what is called a DC power flow assumption, which approximates how power flows on the system to enable readily solvable optimization programs. In practice, this means the voltage of the system is ignored, reactive power flows on the system are ignored, line losses are approximated, and small angle approximations are used for phase angles. The GridView analysis relied on a DC power flow assumption and, as a result, (1) was unable to evaluate voltage issues that may exist in steady state, and (2) approximated actual power flows as well as the line losses.

Contingency Analysis: Power systems are typically designed for high reliability and therefore need to be secure following severe but credible contingency events. Real power systems are operated with various contingencies in mind, and careful consideration is required to determine which contingencies should be monitored and how the system should operate to maintain a stable system following contingency events. Analysis of such issues usually includes determining those contingencies that are most likely based on historical evidence, as well as those that are most severe based on contingency screening. A system with high levels of variable generation can make these tasks more difficult, and further research is needed to understand fully those implications. Although GridView holds sufficient reserves for contingency events in principle, no actual contingency modeling was performed.

Additional information on these types of analyses can be found in Kundur (1994), Taylor (1994), Wood and Wollenberg (1996), NERC (2010), and Vittal et al. (2009).

3.2 Scenario Implementation

The GridView analysis used the ReEDS SunShot scenario results for 2050 as inputs to the GridView modeling. The database was created by starting with data sets representing the existing transmission and generation infrastructure in the three interconnects and by expanding and retiring the system as projected by ReEDS in the 2050 SunShot scenario.

The database of existing (2006) electric system infrastructure comes from three separate sources, one for each interconnect.[10] Load data was based on 2006 NERC region level data disaggregated to GridView balancing authority regions. Demand in 2050 is assumed to grow at 0.84% per year. Additional details about load assumptions and modeling are provided in the complete SunShot analysis. Meteorological profiles for renewable generators discussed in sections 3.5-3.6 are also consistent with 2006 meteorology. Transmission capacity and generator fleet expansion projections from ReEDS were input into GridView as individual new units and lines discussed in more detail in section 3.3. ReEDS represents the contiguous United States using 356 wind and solar (CSP) resource regions, 134 power control areas (PCAs), and 21 reserve sharing groups. The geographic regions within ReEDS that were used as inputs for GridView are provided in Figure 5, with the PCAs shown as color shaded groups of wind/CSP resource regions.

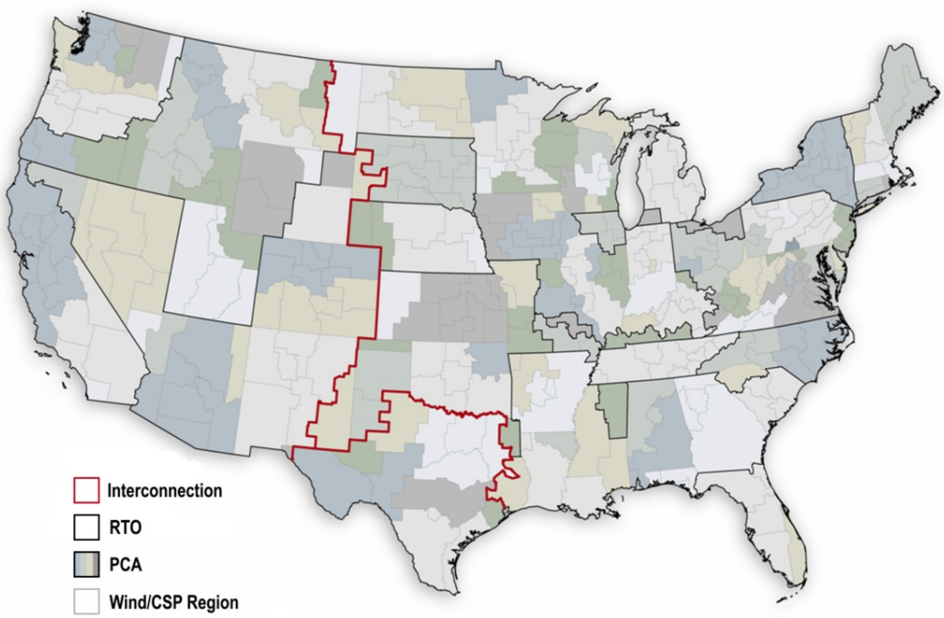

Figure 5. ReEDS geographical regions

The electric power systems represented in these three data sets were merged into a single database[11] and centrally dispatched to minimize production cost on a national basis. Nationwide dispatch is an inherent feature of the modeling framework and can be interpreted as a single

[10] The three sources are (1) the Western Electricity Coordinating Council Transmission Expansion Planning Policy Committee, (2) the Electric Reliability Council of Texas, and (3) the North American Electric Reliability Council Multiregional Modeling Working Group, with proprietary updates from ABB, Inc. Location information is from the Transmission Atlas by Energy Visuals, Inc. (http://www.energyvisuals.com/products/ta.html)

[11] The three interconnections are currently connected with high-voltage, direct current (HVDC) transmission lines and the extent to which these connections are increased are represented by the ReEDS and GridView models.

system operator that manages the entirety of the U.S. electric system or frictionless markets between separate system operators. Nationwide dispatch results in the lowest-cost energy-supply solution for the country as a whole, given the assumptions used. Though economic dispatch was assumed at the national level in both GridView and ReEDS, planning and operating reserves were still assumed to be maintained regionally (at the same 21 reserve-sharing group level as in ReEDS). Additional details on the GridView model (Feng et al. 2002) and previous studies (Liu et al. 2009) are also available.

3.3 Transmission assumptions

The GridView model of the 48 contiguous states has approximately 65,000 buses and 85,000 transmission lines. Although the transmission system in GridView is capable of operating in a detailed nodal format—where every major substation and transmission line is modeled individually—computational constraints and the spatial resolution of the ReEDS output limited the SunShot GridView analysis to an aggregated zonal format—where transmission constraints are modeled only across the interfaces between the 134 assumed PCAs as defined by ReEDS.

The total transmission transfer capacity between ReEDS PCAs was estimated using GridView and the existing GridView transmission databases for each interconnect. These existing transmission limits were used as inputs for the ReEDS modeling. When ReEDS modeled additional transmission capacity between regions, this capacity was then input into the GridView model using the set of assumptions described below.

Where ReEDS modeled additional capacity between regions, new lines were added to the GridView input database. Each line was assigned a voltage level based on the amount of additional capacity modeled by ReEDS and the location. A description of the maximum assumed voltages for new transmission lines by area is provided in Short et al. (2011). The minimum voltage level required to transmit the capacity was used, unless that voltage is higher than the maximum assumed voltage for each PCA. Multiple lines were built if necessary to supply the capacity. The new lines were terminated at both ends with new buses. These new buses were connected to existing buses by new transmission lines (and transformers, if necessary). The number of these new lines depends on the total new capacity connected to the ReEDS PCA and the maximum capacity that can be carried by each of the new lines that connect the new and existing buses. Existing buses are chosen based on the voltage (highest first) and the number of connected transmission lines (most first). The parameters of all new lines and transformers (capacity, resistance, and reactance) were estimated using per-mile parameters by line voltage from the Joint Coordinated System Plan (JCSP) study (JCSP 2009). Reactance for lines greater than 180 miles in length was assumed to be equivalent to a 100-mile line to represent a series capacitor that would be required to prevent voltage problems.

As discussed previously, the study assumes central dispatch, with appropriate new DC connections or HVDC lines connecting the interconnections based on projections from the ReEDS model.

Each scenario was run for two iterations in GridView. The first iteration used the assumptions listed above. After the first iteration was complete, two changes were made. The first involved the distribution of renewable generators onto buses in the transmission network. Due to power-flow constraints, a small number of buses may have significant, negative location marginal prices (LMPs) of less than -$10/MWh during a significant portion of the year (more than 100 hours). If these buses are included in the distribution of renewable generators, the model sees average LMPs much lower than the real average for the PCA and curtails more than it should. These buses were eliminated from the distribution of renewable generators for the second iteration. The second change that was made after the first model iteration involved the transmission capacity between PCAs. Due to the physics of power flow, congestion along one path limits flow along all parallel paths. Because ReEDS is not a power flow model, it builds all capacity between two hypothetical areas by building a line directly between them. This leads to congestion in GridView along some of the smaller paths, limiting flows along paths where ReEDS builds additional transmission. The shadow price of transmission interface constraints is used to determine which lines need additional capacity. If the annual shadow price is higher than the annual cost of transmission capacity, the line is increased in capacity by 1 GW. This small increase in overall transmission capacity expansion represents capacity that ReEDS would have placed on parallel paths if it had power-flow capabilities. Because some of the additional transmission capacity projected by ReEDS is uncongested according to the power flow model in GridView, the additional capacity probably represents a change in the location of ReEDS transmission additions, not an overall increase in usable capacity, which would add to the overall cost.

Transmission losses were estimated using the GridView loss model with a distributed reference bus. Distribution losses were calculated at approximately 2.6% based on the total transmission and distribution losses experienced today minus the transmission losses estimated by GridView for a reference scenario. The distribution losses were added to the end-use demand to make the GridView load input include distribution losses (but transmission losses are still calculated by the model for each specific scenario).

3.4 Conventional Generator Assumptions

Conventional generators in the 2050 scenario are a combination of units that exist today and new units projected to be built by ReEDS. If the ReEDS 2050 projection had lower capacity for a given unit type compared to the existing units in the GridView database, then units were retired (oldest units first) until the correct capacity was reached. If the ReEDS 2050 projection had more capacity than the existing units did, additional units were built in the GridView database. For the new natural gas units, combined cycle units were built up to 200 MW per unit until the projected capacity is reached. Combustion turbines were sized up to 100 MW in capacity, while coal units were up to 500 MW. Existing natural gas units are all assumed to be replaced with new identically sized units, based on the 30-year lifetime assumption. These units have the same properties (except the maximum capacity) as the new units described below.

Each new unit was placed at an existing bus that had a unit that was retired, if available. If no more of these buses were available, the units were placed at the highest-voltage buses in the area. This eliminates the need to carefully site each individual generator. Heat rates, forced outage rates, and planned outage rates were equivalent to the ReEDS assumptions for these values. Startup costs and minimum on and off times were taken from WECC (2009), using the “Coal Recent,” “CT Large,” and “CC Recent” categories. All combustion turbines were assumed to be quick-start, meaning that they could be operated during dispatch even if they were not committed during the unit commitment cycle. Thermal unit maintenance was scheduled using the GridView maintenance-scheduling algorithm.

All nuclear generators were assumed to have a minimum generation level of 98% of the maximum capacity, regardless of the minimum generation level in the original database. Nuclear generators were retired in order of descending age to match the ReEDS capacity by interconnect, leading to retirement of the same generators as the ReEDS assumptions. ReEDS did not project any new nuclear capacity.

Fuel costs were assumed to match the ReEDS fuel price outputs by NERC "subregion" for coal, natural gas, and uranium. Base fuel prices were derived from EIA's 2010 AEO reference case (EIA 2010), and deviations from those base prices were calculated from elasticities derived from comparison of the 2010 AEO reference, high economic growth, and low economic growth cases.[12] These price estimates and elasticities do not account for the fundamental uncertainties that exist in predicting future natural gas and coal prices.

3.5 Solar Technology Assumptions

PV generators were added in each PCA based on ReEDS capacity deployment. Hourly profiles were generated using the Solar Advisor Model[13] using resource data obtained from Clean Power Research[14] for 2006. Utility PV was assumed to produce a profile of a 1-axis tracking system from the best TMY3 (Typical Meteorological Year 3) location within each PCA.[15]

Distributed PV profiles were estimated using the projected parameters (e.g., direction, tilt) of distributed PV capacity from the SolarDS model as inputs to the Solar Advisor Model using the average output from systems at all TMY3 locations in the PCA. The profiles from these types of PV were normalized to the annual generation projected by ReEDS. Forecast data were unavailable for the solar resource, and as a result perfect forecasts were assumed. Previous work has found improving ability of forecasting wind, and possible mitigation of forecast errors using advanced unit commitment strategies like rolling unit commitment windows and stochastic optimization (Meibom et al., 2011). However the impact of PV forecast errors on integration challenges remains an important area of analysis (Lew et al. 2011).

It should be noted that analysis of the impacts of distributed PV on distribution networks and feeders was not evaluated. It is assumed that the distribution system will evolve to accommodate high levels of distributed PV. Significant penetration of PV 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 (Liu and Bebic 2008). Also, it was assumed that this distributed PV is "seen" by the system operator in terms of forecasting net supply. This also means that the operator will have to ability to curtail distributed PV generation when necessary, as discussed in section 4.

CSP capacity was modeled as individual discrete units, with the number of units depending on the capacity in each area. If capacity was less than 200 MW, one CSP unit was placed in the area. If capacity was between 200 MW and 1 GW, 3 units were placed in the area. If capacity

[12] Short et al (2011) describes the methodology use to calculate these fossil fuel elasticities for use in ReEDS.
[13] PV generation profiles were calculated using version 2011.8.30 of the System Advisor Model (SAM) (www.nrel.gov/analysis/sam, accessed September 2011)
[14] https://www.solaranywhere.com/Public/About.aspx
[15] TMY locations are a set of sites for which "typical" weather profiles are generated. TMY sites were used to determine the location of likely solar installations. A list of sites is available from Wilcox and Marion (2008).

was larger than 1 GW, eight units were placed in the area. Although areas with large CSP capacities could end up with large CSP units, there will be eight units in these areas and this will prevent the output from being too discrete. The CSP units were placed at buses with the highest voltage, secondarily sorted by the number of transmission lines attached to the bus.

Hourly resource data for CSP units were obtained from Clean Power Research for 2006. This data was processed using the Solar Advisor Model for a CSP unit without storage, and this input profile was used for CSP units with and without storage. For CSP units with storage, GridView optimized the dispatch of thermal energy to and from the storage tanks to produce electricity, considering losses involved in thermal storage. For CSP units with thermal storage, capacity and annual generation were matched to the ReEDS projections, while other parameters matched Solar Advisor Model defaults.[16] These parameters include:

- Maximum and minimum generation levels equal to the rated capacity of each unit multiplied by 1.1 and 0.15, respectively.
- Storage tank losses and pump losses equal to 0.0097 and 0.02 multiplied by the rated capacity, respectively and storage round-trip efficiency of 95%. Pump losses only occur when energy is going to or from the storage tank.
- Startup losses of the steam turbine equal to 0.2 multiplied by the rated capacity.

3.6 Other Renewable Generators

Geothermal capacity and annual generation were assumed in GridView to be identical to ReEDS projections. Geothermal units were assumed to be distributed equally to all high-voltage (greater than 200 kV) buses in each PCA. Geothermal units were assumed to have constant generation throughout the year, but could be reduced to 90% of maximum power if desired by the system operator

Wind generators were distributed to all high-voltage buses (greater than 200 kV) within each PCA. Hourly resource data for the wind generators were obtained from the Eastern Wind Integration and Transmission Study (EWITS) (EnerNex 2010) and the Western Wind and Solar Integration Study (WWSIS) (GE Energy 2010). Wind sites from these studies were chosen by priority of annual capacity factor until the total capacity reached the capacity projected by ReEDS. The profiles from these chosen sites were summed and then normalized to the annual generation projected by ReEDS. Day-ahead forecasts were used for unit commitment within GridView and actual modeled wind generation was used for the economic dispatch. Several PCAs in Texas and the southeastern United States did not have data from EWITS or WWSIS, so nearby PCA profiles were used.

Existing hydropower units were allowed to be dispatched by GridView to minimize the system production cost, subject to minimum generation constraints to match the ReEDS assumptions. Minimum generation levels at each unit were assumed to be 55% of the average monthly output. New hydropower capacity built by ReEDS was assumed to be run-of-river plants that were not dispatchable. They produced consistent output for every hour of each month. Available monthly

[16] CSP parameters derived from version 2011.8.30 of the System Advisor Model (SAM) (www.nrel.gov/analysis/sam), accessed September 201.1

generation for existing and new hydropower units match the equivalent seasonal generation limits in ReEDS.

The very few additional biomass units added were placed at buses in the system using the same method as for fossil-fuel generators. Biomass plant heat rate, forced outage rates, and minimum generation levels were assumed to be identical to ReEDS assumptions.

3.7 Storage

Energy storage units were dispatched by GridView using an algorithm to minimize overall production cost to the system. Most additions were Compressed Air Energy Storage (CAES) units based on relatively low cost and limits to the ability to model a variety of storage technologies. CAES heat rate, compressor efficiency, and storage capacity matched the ReEDS assumptions for the associated scenarios. New pumped-storage hydropower units were assumed to have eight hours of available storage, and the efficiency and other parameters match the ReEDS assumptions. These units were placed at buses in the system using the same method as for fossil-fuel generators.

3.8 Reserve Requirements

In ReEDS, planning and operating reserves were assumed to be maintained independently in 21 reserve-sharing groups for all years of the study period, representing greater cooperation over larger areas than exist in the current grid. Existing regional transmission organizations (RTOs) and independent system operators (ISOs)[17] were used in the construction of some of the reserve-sharing groups; where there was no existing RTO or ISO, a future reserve-sharing region was assumed. Some of these reserve-sharing groups were larger than those that currently operate under the assumption that additional market integration and transmission expansion over the next 40 years would expand current reserve-sharing regions.

Operating reserve requirements were estimated using the methodology for the Eastern Wind Integration and Transmission Study, described in detail by Ela et al. (2010). This method takes into account the additional frequency regulation that would be required with additional penetration of wind and solar energy (as opposed to the ReEDS treatment where frequency reserves are independent of variable generation penetration), based on the hourly and 10-minute changes in output of the wind and solar input profiles. GridView enforces constraints for two types of operating reserves: spinning and non-spinning reserves. All frequency regulation required for balancing load and 10-minute wind variability contributes to the spinning reserve category, while hourly variability in wind and solar output contribute to both spinning and non-spinning reserves. Contingency reserves are assumed to be 6% of demand to match the ReEDS assumptions, and split equally between spinning and non-spinning.

In addition to deriving operating reserves from generators and storage, interruptible load was also allowed to provide this service. Interruptible load was modeled in GridView as a thermal generator with infinite flexibility and very high cost ($500/MWh). This allows the interruptible load to primarily provide reserves, although, if a generator contingency or forecasting error would cause unserved load or prices above $500/MWh, the interruptible load could be

[17] Examples of existing RTOs include Midwest Independent Transmission System Operator (MISO), Independent System Operator New England (ISO-NE), PJM Interconnection, Southwest Power Pool (SPP), and California Independent System Operator (CAISO).

dispatched. This method does not limit the number of times that interruptible load can be used to provide ancillary services or actual energy per year.

Interruptible load is primarily used (along with storage and thermal units) to provide spinning reserves to handle contingencies and short-term forecast errors. In the case of day-ahead forecast errors, interruptible load can also be used to shed load to ensure that the balance of energy supply and demand is kept in equilibrium. This means that interruptible load is primarily called upon by GridView to curtail load for brief periods of time during contingencies while the system operator brings other units online. The model projects usage of interruptible load to respond to an hourly generation shortfall 14 different times in the simulated year (in response to forecast errors or generator contingencies); however, the majority of calls would be to respond to shorter term events and contingencies. Because GridView is an hourly model it cannot analyze these events. More detailed analysis of these short-term events (including cost implications) would require sub-hourly analysis.

4 Results

GridView was used to check the basic operability of the SunShot scenario in 2050, including analysis of transmission-flow constraints. In particular, ReEDS and GridView were compared with regard to how they dispatch generation resources, transmit and curtail electricity, and analyze electric-sector fuel use and emissions. In general, the GridView analysis helped confirm that the ReEDS dispatch method produces comparable results to a more detailed dispatch model. Electric-sector operating parameters—primarily fuel use and generation mix—are very similar in ReEDS and GridView (Figure 6). One difference is that GridView projects more usage of combustion turbines (CTs) due to its more detailed modeling of transmission and associated congestion.

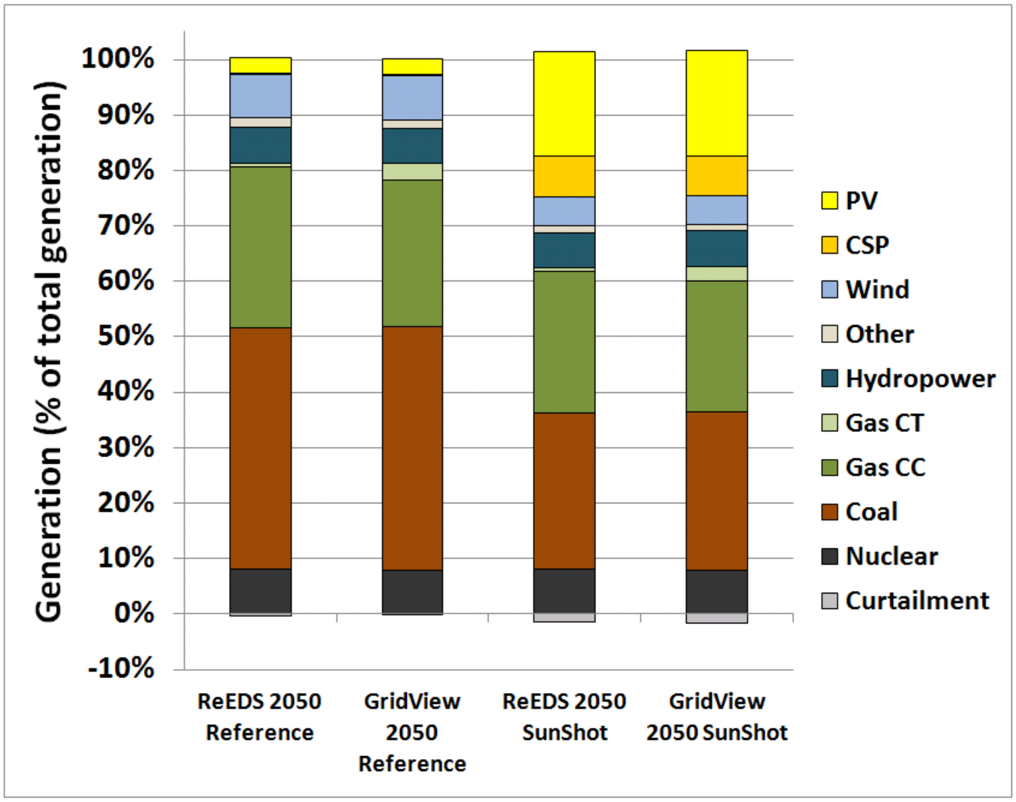

Figure 6. Comparison of the national generation mix simulated in GridView and ReEDS for the reference and SunShot scenarios, 2050

The key observation of the GridView modeling is that simulations of power system operation in 2050 show that electricity supply and demand can be balanced every hour of the year in each region. Although a full reliability assessment was beyond the scope of the analysis, hourly production simulation did consider unit commitment, DC optimal power flow, reserve requirements and thermal generator flexibility limits (e.g., ramp rates and minimum generation levels). The operational simulations did not project any hours of unserved load during the peak load hour, lowest coincident load hour, or any other hour of the year.

GridView uses a number of options to address the increase in net system variability introduced by additional solar. These include:

- Transmission between regions can help reduce ramps in net load because it allows system operators to access a more diverse mix of variable generation with some smoothing of output profiles and demand profiles over larger geographic areas.
- Thermal conventional and renewable generation units can provide varying degrees of ramping capability, from base-load units that provide relatively little flexibility to natural gas combustion turbines that have low minimum generation constraints and are less expensive and faster to start; some of the constraints that limit the flexibility of generating units as evaluated in GridView include minimum generation levels, maximum ramp rates,[18] minimum on and off times, and startup costs.
- Dispatchable, non-combustion renewable generation units, including CSP with storage and hydropower, can be dispatched to accommodate changes in net load.
- Energy storage technologies, including PSH and CAES are available to provide flexibility.
- Interruptible load is also available to provide reserves for the system.
- Curtailment of renewable generation is also an option in GridView.

The relative use and ordering of the aforementioned options is determined in GridView's production cost minimization routine.

Figure 7 shows the hourly dispatch from GridView for the entire United States during a typical four-day summer period in the SunShot scenario in 2050. Electricity load is shown by a black line—the difference between generation and load is due to transmission losses—and curtailment is shown by the grey above the load line. Although most summer days show little or no curtailment, some days, such as July 16 (a Sunday), show significant curtailment during midday because of the combination of higher solar output and lower demand. CSP units with thermal storage generate at more than half capacity during all hours and generate near peak capacity during the evening after PV generation has decreased but load is still high. The peak net load (load minus wind and PV) shifts from approximately 3 or 4 p.m. local time (in an electric power system with insignificant PV penetration) to approximately sunset in the SunShot scenario. This is true during all seasons in most areas in the SunShot scenario. During these evening hours, the remaining thermal generators ramp to provide additional energy. The flexibility of CSP generators allows them to produce electricity at maximum capacity during the evening peak in net load.

[18] Actual ramp rates tend to be non-binding with the hourly resolution of GridView because most units can ramp from minimum generation to maximum capacity within one hour.

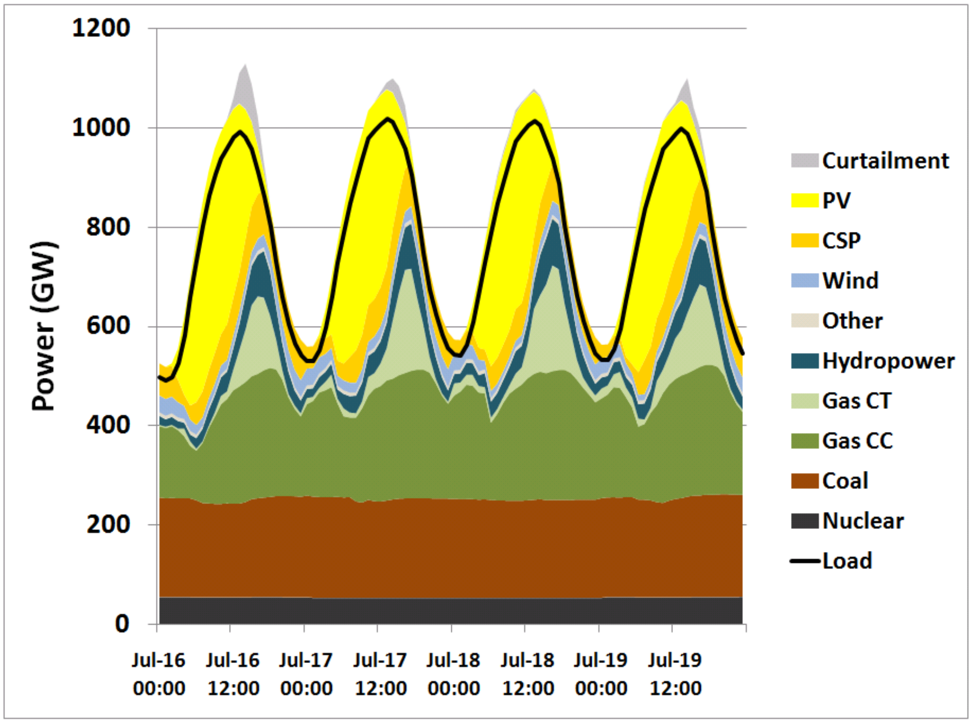

Figure 7. GridView-simulated national mean dispatch stack during four days in summer for the SunShot scenario in 2050

A key element of grid flexibility required in the SunShot scenarios is a rapid ramp rate of units used to meet the net load. Figure 8 shows a ramp duration curve for the ERCOT system. Each of the three curves shows the hourly ramp rate ordered from maximum up ramp rate (how fast generators will need to increase output) to maximum down ramp rate (how fast generators will need to decrease output). The load only curve shows the ramping requirements of the assumed electricity demand in 2050, which peaks at about 10 GW/hour. The reference case (which adds a small amount of solar) shows a small change in the amount of ramping requirements. The SunShot case demonstrates a significant increase in both up and down ramping requirements. As with other challenges, this ramping flexibility is derived from a number of sources including conventional generation, storage, curtailment, and energy exchanges which may require new transmission development.

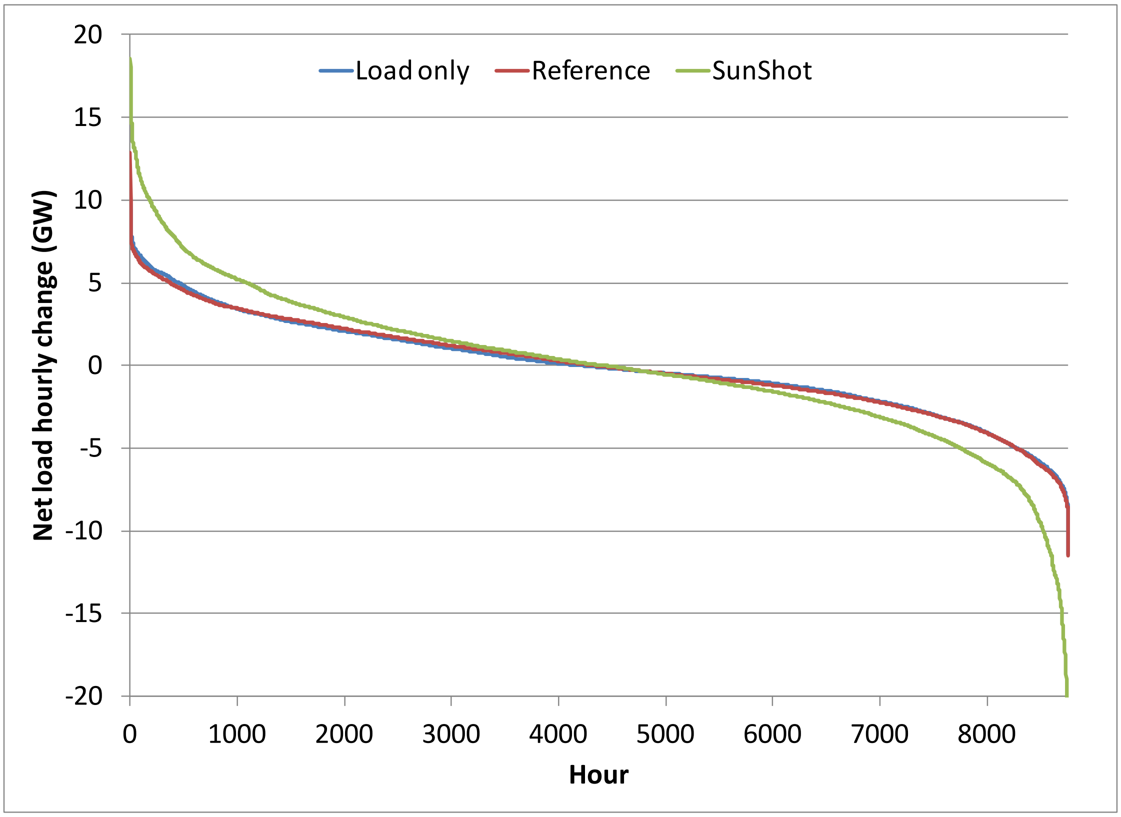

Figure 8. GridView-simulated ramp duration curve for ERCOT in 2050

As discussed, a 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 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 9 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.

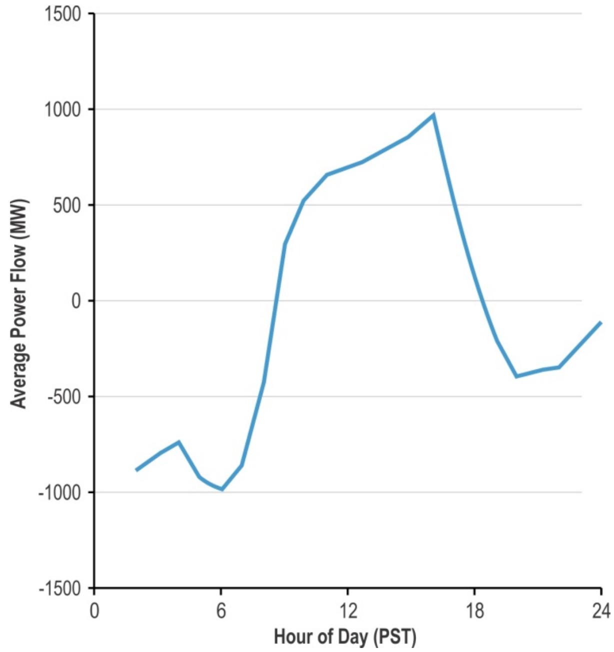

Figure 9. Average annual hourly power flow from Wyoming (western interconnection) to South Dakota (eastern interconnection), SunShot scenario, 2050[19]

The hourly analysis also found that, in contrast to today's fossil-fuel dominated electricity system where the peak time (summer afternoon) is of most concern, operational challenges were most acute during off-peak times (spring evenings) when the abundance of renewable supply relative to demand forces thermal generators to cycle or ramp down to their minimum generation levels and forces curtailment of electricity when these and other flexibility options were not adequate. Figure 10 shows the hourly dispatch for a typical four-day period during May for the SunShot scenario in 2050. During spring, peak electricity demand is up to 40% lower than the summer peak and renewable generation is high.

Most of the resulting curtailment occurs in the Western Interconnection and is primarily attributed to CSP in GridView. The CSP capacities described in the SunShot growth trajectories represent systems with up to 12 hours of storage and an average solar multiple of 2.6.[20] For the SunShot scenario in 2050, the 81 GW of installed CSP capacity with storage represents approximately 210 GW of instantaneous power from the solar field at peak output. The curtailment of more than 100 GW on May 20 (Figure 10) represents times when some of the CSP thermal storage capacity is "full" and excess power from the solar field is curtailed. Although curtailment in the Western Interconnection is significant, the amount of curtailment in the ERCOT and Eastern Interconnections during this period is small.

[19] Negative numbers indicate flow in the reverse direction (e.g., SD to WY).

[20] The solar multiple is the ratio of the peak thermal power generated by the solar field to the power required to operate the thermal generator at peak capacity. A solar multiple that is greater than one represents a system with increased solar collector area. The additional thermal energy can be used to increase system capacity factors by running the generator at peak load for more hours each year. The solar multiples used in this study are determined in the ReEDS optimization.

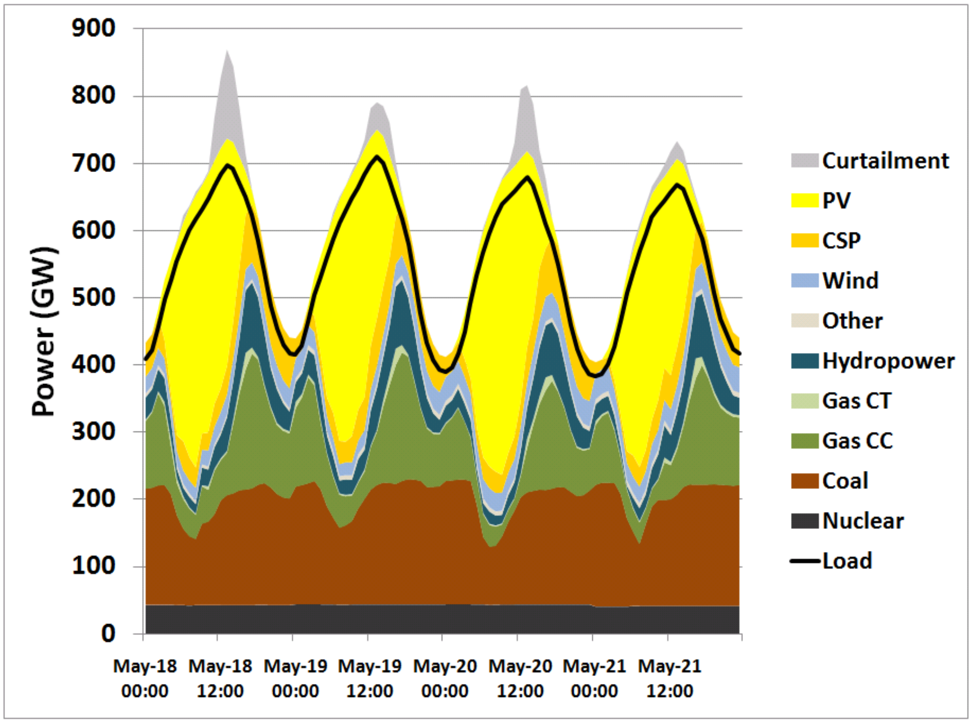

Figure 10. GridView-simulated national mean dispatch stack during four days in spring for the SunShot scenario in 2050

The GridView simulation of the SunShot scenario shows 90 TWh of curtailment in 2050, representing 1.8% of the demand and 5.3% of wind and solar generation. GridView often curtails CSP more than other energy sources because the stored energy is more valuable than variable renewable electricity that cannot be stored. The model chooses to dispatch the variable sources first and keep energy in the CSP tanks when possible. Consider the following example. At midnight, all large thermal units are at minimum generation and the system can use 100 MW of zero marginal cost energy. Wind is available, and CSP tanks are full. The model will dispatch 100 MW of wind energy and little or no CSP because the energy in the CSP tanks could be important later in the night or early in the morning if the wind is no longer available, load increases, or a generator or transmission outage occurs. In the morning, the CSP energy storage tanks will still have energy in them if the aforementioned conditions do not occur. In the spring, the tanks can be nearly full in the morning. These CSP units with thermal storage have oversized thermal fields, so if the solar input is at its maximum, the power block can only convert approximately one-third of the input energy into electricity. The rest must go to storage. Therefore, if the storage tank is full, the unit will curtail up to two-thirds of the input solar energy at peak solar input.

A variety of technical and institutional approaches might be used to reduce curtailment. First, additional transmission capacity in congested corridors would help alleviate congestion and reduce curtailment. This would work best for areas that would see curtailment during many hours of the year. Second, increasing the size of reserve-sharing groups[21] could help reduce the

[21] The size of the reserve-sharing groups assumed (both ReEDS and GridView) is larger than today's reserve-sharing groups for many regions of the United States. Expanding these reserve-sharing groups further would likely reduce curtailments.

aggregate amount of operating thermal capacity needed to provide spinning reserves, thereby reducing the need to curtail renewable generation when the flexibility characteristics of the fossil units are exhausted. Third, the flexibility of the thermal fleet could be improved or market structures could be used to encourage the operation of more flexible generators. Fourth, additional energy storage and controllable loads could be used to improve system flexibility. This would work best for areas where curtailment occurs occasionally (not regularly for many consecutive hours). Finally, new or existing industries could take advantage of the low-cost electricity available during seasons or times where curtailment would have occurred. Additional discussion of addressing resource variability is discussed in the full SunShot report, as well as many of the wind and solar integration studies performed to date, such as the WWSIS (GE Energy 2010) and EWITS (EnerNex Corporation 2010).

This result does not imply that the electric power system would never have outages in the scenarios or that other reliability considerations can be ignored. Examining sub-hourly and local impacts were beyond the scope of the analysis presented here. The GridView results did show that the supply- and demand-mix, planning and operating reserves, and the transmission system predicted by ReEDS under the analyzed scenarios were sufficient to meet load on an hourly basis, and that hourly mismatches between supply and demand on a regional basis were therefore not anticipated.

5 Conclusions

The GridView modeling of the SunShot Vision scenario supplements the ReEDS modeling to provide further insights into the challenges of achieving high penetrations of solar-generated electricity. The GridView analysis suggests that the serving load on an hourly timescale is feasible in the scenario analyzed. System-wide operational challenges were met with a variety of supply- and demand-side technologies—including flexible generators, interruptible load, curtailment, and increased transmission capacity—which enables dispatch decisions to take advantage of the geospatial diversity of wind and solar. Operational challenges were found to be most significant during new “off-peak times” during periods of high solar generation and low demand in spring.

This analysis suggests areas for additional work in understanding the reliability of a grid under high-solar scenarios. This includes a detailed analysis of the impact of solar forecast errors on system operation. While short-term variability was considered in terms of additional reserves, the actual sub-hourly dispatch of a system with large amounts of solar also needs to be considered. Additional analysis is needed to examine the impact of a high penetration of PV on distribution systems. Analysis of all these factors will require both new data sets (specifically improved solar data at higher time and spatial resolution) as well as new models to incorporate solar variability and uncertainty. Several ongoing and future studies, such as the second phase of the Western Wind and Solar Integration Study (Lew and Brinkman 2011) will address the impact of solar variability on grid operations in more detail.

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