CSP ALLIANCE REPORT

The Economic and Reliability Benefits of CSP with Thermal Energy Storage: Literature Review and Research Needs

TECHNICAL REPORT

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CSPA
Concentrating Solar Power Alliance

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The CSP Alliance

The CSP Alliance is a public policy advocacy organization dedicated to bringing increased awareness and visibility to this sustainable, dispatchable technology.

Our membership includes many of the world's largest CSP corporations and their supply-chain partners. Our objectives include advancing the industry's value proposition, addressing issues of job creation and environmental sustainability, and setting the foundation for future uses of the technology.

The first version of this report was released in December 2012. This next version includes expanded discussion of methodology and new study results available over the course of 2013-14.

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Contents

Acronyms

AC	Alternating Current
AGC	Automatic Generation Control (to provide Regulation)
AS	Ancillary Services
BSE	BrightSource Energy
CAISO	California Independent System Operator
CCGT	Combined Cycle Gas Turbine
CPUC	California Public Utilities Commission
CSP	Concentrating Solar Power
DC	Direct Current
DG	Distributed Generation
DOE	Department of Energy
DR	Demand Response
ELCC	Equivalent Load Carrying Capacity
ERCOT	Electric Reliability Council of Texas
FERC	Federal Energy Regulatory Commission
GE	General Electric
GHG	Greenhouse Gases
GW	Gigawatt
GWh	Gigawatt-Hours
HTF	Heat Transfer Fluid
IEA	International Energy Agency
IEEE	Institute of Electronic and Electrical Engineers
IOU	Investor Owned Utility
IRENA	International Renewable Energy Agency
ISO	Independent System Operator
kW	Kilowatt
kWh	Kilowatt-Hour
LBNL	Lawrence Berkeley National Laboratory
LCOE	Levelized Cost of Energy
LFD	Load-Following Down
LFU	Load-Following Up
LTPP	Long Term Procurement Plan (of the CPUC)
MW	Megawatt

MWh	Megawatt-Hours
NERC	North American Electric Reliability Corporation
NOAA	National Oceanic & Atmospheric Administration
NREL	National Renewable Energy Laboratory
OOS	Out-of-State
PJM	PJM Interconnection, LLC
PMU	Phasor Measurement Unit
PV	Photovoltaics
RD	Regulation Down
RE	Renewable Energy
RPS	Renewable Portfolio Standard
RU	Regulation Up
SAM	System Advisor Model (NREL)
SM	Solar Multiple
SP	Spinning Reserve
SSI	Sub Synchronous Interaction
SSR	Sub Synchronous Resonance
STATCOM	Static Synchronous Compensator
SVC	Static VAR Compensator
TMY	Typical meteorological year
VAR	Volt-Ampere Reactive
WECC	Western Electricity Coordinating Council
WWSIS	Western Wind and Solar Integration Study (NREL/GE)

1. Introduction

Concentrating Solar Power (CSP) plants with thermal energy storage are renewable resources that provide not only clean electric power, but also a range of operational capabilities that support the continued operational flexibility and reliability of electric power systems. Thermal energy storage allows CSP to store some of the solar energy captured during the daylight hours and shift energy production overnight or to the next day, as desired. CSP, with or without storage, utilizes a conventional synchronous generator, which in addition to energy, provides voltage support and inertial response capability. When equipped with a thermal storage system, CSP plants can follow economic dispatch and provide a range of other ancillary services, including frequency responsive reserves, frequency regulating reserves, spinning reserves, and ramping reserves. CSP with thermal storage combines this operational flexibility with high capacity value, and hence is well-suited to provide the "flexible capacity" requirements being established in many power systems.

CSP technology is now relatively mature. The first commercial CSP plants incorporating significant thermal energy storage capacity, both parabolic troughs and power towers, began operations in Spain in 2008. As listed in Table 1-1, almost 20 such plants are now operating (along with many other CSP plants that do not include storage), and new designs will enter service in 2014. The CSP industry continues to seek cost reductions in the next generation plants and to work with researchers, regulators and utilities to identify and quantify the economic and reliability benefits of different configurations of thermal storage systems.

This report provides a survey of research into the economic and reliability benefits of CSP with thermal energy storage and other solar technologies, as well as results from other studies of renewable integration. The economic benefits are defined as the avoided fixed and variable costs of electric power from conventional fossil-fueled generation resulting from the operations of CSP with thermal storage, and other solar technologies. Some operational attributes identified as needed for future power system operations have, to date, been less amenable to economic analysis. For example, few studies estimate the value of inertial and frequency response services with increased reliance on variable wind and solar resources, although the need for replacement of such services currently provided by conventional thermal generation is likely to occur in the next few years in the United States (FERC 2014). Hence, the report describes these capabilities as additional operational and reliability benefits whose economic value will require further analysis.

Although this report is intended to support improved cost-benefit analysis of CSP with thermal energy storage, it does not examine the trends in the levelized cost of energy[1] of alternative solar technologies. The report does discuss alternative operational solutions to renewable integration, but it does not attempt to quantify their value. Surveys of estimated CSP costs are available[2] and potential utility buyers know competing bid costs for their particular projects. The economic case for continued investment in CSP with thermal storage rests not only on calculations of comparative economic benefits, but also on plant costs being reduced sufficiently to remain competitive with the net costs of other renewable energy and integration solutions. These include other types of storage now being promoted through policies in some regions, such as Germany and California.[3]

[1] The levelized cost of energy (LCOE) is a detailed calculation of the capital and operating costs of a project divided by its forecast energy production.
[2] For recent surveys of CSP (and PV) costs, see Bollinger and Weaver (2013), IRENA (2012), and IEA (2010). However, CSP companies generally do not publicly release cost estimates, and so these studies may not correspond to bid costs.
[3] To date, CSP with thermal energy storage is eligible to count against the storage procurement targets recently established in California.

1.1 The Design of Clean Power Systems

Until recently, renewable resources represented a small percentage of total power system generating capacity and production, and the effect of renewable energy on power system reliability and operations was considered secondary to the objective of meeting policy goals with the least-cost, lowest-risk, renewable technologies. However, wind and solar resources are no longer marginal contributors to electric power production in some regions.[4] As this penetration increases, other considerations are becoming prominent, such as the impact on the power system of growing supply variability, production forecast errors, and minimal controllability and responsiveness to economic dispatch.

Currently, the power system relies on the control of generator output to provide system balancing in the upwards and downwards directions on various time-scales – seconds, minutes, hours – as well as to provide frequency control in the event of system contingencies. However, power system operators may not have economic dispatch control over large-scale wind and solar plants, and even if they do, it is primarily in the downward direction (curtailment) in the event of system emergencies or otherwise to preserve short-term reliability. The increasing number of small-scale, distributed power plants, are typically not controllable by the system operator and may require further investments to achieve such controls (e.g., CAISO/KEMA 2012). Until such capabilities are wide-spread, other resources must be utilized to balance the increasing quantity of variable generation and ensure long-term resource adequacy.

The operational and reliability solutions for power systems with high penetration of renewable energy are varied, including adjusting incremental procurement of renewable resources to create less variable aggregate production profiles, more flexible utilization of hydro, coal and natural gas generation, more flexible demand response, and various types of energy storage (see, e.g., NREL 2012). As one of these potential solutions, CSP with thermal energy storage meets renewable policy goals, reduces the variability of the aggregate renewable portfolio, and provides the wide range of operational and reliability attributes reviewed in this report. All stored thermal energy is gathered from the solar field and is, therefore, certified as renewable energy. The addition of bulk energy storage allows higher utilization of the CSP plant's power block and other components. Although not the focus of this report, CSP technology can be hybridized with other fuels – either "brown" or "green"[5] – to further improve plant performance and reduce emissions. The quantification of the resulting economic benefits requires detailed analysis of individual plant design and particular power systems, as described next.

1.2 Economic and Reliability Benefits of CSP with Thermal Storage

Competition among alternative renewable technologies has increased substantially over the past few years, due to downward cost trends within each technology that have resulted from policy support

[4] In 2013, Germany had installed almost 35 GW of distributed solar energy capacity, along with 31 GW of wind capacity, providing over 15% of energy generated. In California and Spain, renewable energy already accounts for 15-20% or more of annual retail electricity sales and California policy aims to increase that share to 33% by 2020, with higher targets are being considered for later years. Other countries and regions have deployed wind generation on a large-scale, including Denmark and Ireland. Many of these systems have recorded operating hours, typically during light load conditions, with even higher renewable production, in the range of 40-50%, while some Spanish states record even higher penetrations. Many other U.S. states, some countries and international institutions have ambitious annual national renewable energy targets, some ranging from 20-25% within the next decade or so. Some of these targets are on-track to be achieved despite the current low cost of fossil fuels, in part because of continued reductions in the cost of wind and PV.

[5] The hybridization of thermal power plants with solar and brown fuels, gas or coal, is well researched. In addition, the plants can be hybridized with green fuels, such as biomass. There are a number of hybrid CSP-biomass projects under development in Spain and North Africa.

and financial incentives. For CSP with thermal energy storage, these developments have made appropriate valuation all the more critical, because on a levelized cost of energy basis, CSP, with or without storage, has fallen behind wind and PV. However, comparisons of CSP with thermal storage with competing renewable technologies that focus only on differences in the levelized cost of energy are incomplete. This is because they do not capture the potentially significant differences in economic benefits when comparing renewable resources that have substantially different production characteristics (for a review of this point, see Joskow 2010). CSP with thermal energy storage is shown to be much more competitive when the comprehensive *net costs*[6] of the CSP plant are compared to wind or PV. These net costs include the long-term energy, ancillary service and capacity benefits, and can be reasonably shown to provide an additional $30-60/MWh, or even higher, of benefits when compared to a PV plant with equal annual energy production in high renewable penetration scenarios.

The comparison between the economic benefits of CSP with thermal storage and PV is intended to provide a useful metric for utility planners and procurement analysts when considering alternative solar projects. It is not intended as a criticism of PV. Rather, as explained further in the report, there are synergies between the two solar technologies that could result in higher aggregate solar capacity value and less solar curtailment as PV penetration increases. There are also opportunities for CSP with thermal storage in remote locations to provide operational needs that cannot be cost-effectively provided by other renewable solutions.

The net cost of CSP plants with thermal storage was not considered comprehensively during the initial phases of renewable procurements in Spain and the United States. Historically, CSP plants have been recognized for their capability for both hybridization with other fuels and addition of thermal storage. Many existing parabolic trough plants have included auxiliary gas capability, which has improved their capacity value.[7] The utility-scale CSP plants with thermal energy storage operating in Spain and the United States have demonstrated the capability to scale up to very high storage capacities (Table 1-1). However, until recently, the Spanish plants were operated under feed-in-tariff contracts that did not provide economic incentives to participate in power markets or system operations. Instead they provided a steady production of power across the hours of operations (e.g., Usaola 2012). While recently there have been some examples of these plants operating to follow energy market prices due to changes in the Spanish tariff structures (Dinter 2013), as yet there is no commercial example of a dispatchable CSP plant consistently operating to maximize energy and ancillary service benefits.

However, the perception of the economic benefits of CSP with thermal storage is changing due both to the detailed technical studies reviewed here, and because additional data is anticipated over the next few years on the operations of new projects. In the United States, where the first new utility-scale CSP plants have come on-line in 2013-14, policymakers and utilities have shown increasing interest in technologies that can provide operational flexibility and ensure long-term reliability without increasing emissions. Utility solar valuation methods are also evolving in corresponding ways, although there is some lag in fully capturing the value of solar thermal storage (and other types of storage) due to the lack of data, modeling requirements and other factors (Mills and Wiser, 2012a).

Comparisons of CSP with thermal storage with competing renewable technologies that focus only on differences in the levelized cost of energy are incomplete because they do not capture differences in economic benefits with different production characteristics.

[6] Net cost is essentially the cost minus the benefits of a renewable project, where the benefits include any market products and operational attributes that can be quantitatively or qualitatively evaluated. Section 4 provides further definition.

[7] The first commercial parabolic trough plants in Southern California – the Solar Energy Generating System (SEGS) plants – had significant auxiliary gas capability (one included thermal storage), which has allowed them to consistently demonstrate a very high capacity value over their 21-26 years of operation. More recently, many of the plants in Spain have also utilized auxiliary gas capability.

Policymakers and utilities have shown increasing interest in technologies that can provide operational flexibility and ensure long-term reliability without increasing emissions.

1.3 Report Objectives and Overview

This report summarizes the key findings of studies that evaluate the economic and reliability benefits of CSP with thermal storage. The report is structured to provide readers with backgrounds in CSP engineering and project development with enough information to understand how the economic benefits are determined, while also giving readers with backgrounds in electric power market and system operations sufficient information on how CSP plants with storage might be operated. The structure of the report is also intended to allow for updates and further content development. Basic concepts of electric power systems and markets, along with the new operational and reliability requirements created by variable energy resources are introduced first, followed by a detailed discussion of the technical analyses and their results.

Most of the studies cited were conducted by the U.S. national laboratories, particularly the National Renewable Energy Laboratory (NREL) and the Lawrence Berkeley National Lab (LBNL). These labs not only did the foundational work of building publicly available models of CSP plants, but have recently conducted some of the first detailed regional simulation studies to characterize both the operational needs of power systems with high renewable penetration and the potential economic benefits of CSP with thermal storage.[8] In addition, selected other studies of California, other U.S. states, and other countries are reviewed that provide further insight into potential benefits of CSP with thermal energy storage under different renewable penetration scenarios. Since most of these studies are technical and do not provide basic definitions or literature review, this report also attempts to serve those functions. Lastly, the report suggests regulatory and policy reforms that could better reflect the benefits of CSP with storage in utility procurement, and recommends additional research required to support comprehensive economic valuation of these technologies.

Report Organization

The report is organized as follows. In Part I, Sections 2-6 provide background on CSP technology, valuation methods, institutional structures in the electric power sector, and some of the challenges in simulating high penetration renewable scenarios. In Part II, Sections 7-11 summarize the results of recent studies on valuation of economic and reliability benefits. Section 12 concludes the report with recommendations. Appendix A surveys capacity valuation methodologies relevant to CSP with thermal storage. Appendix B summarizes some methods for calculating integration costs. The report and appendices include lists of references.

For ease of reading, the report minimizes the use of acronyms, and does not include the common acronym of "TES" to represent thermal energy storage. All acronyms used are included in the Acronym section, above.

Note to Readers

Many of the study results discussed in the report compare CSP with thermal storage to both PV and CSP without storage. For convenience, we refer to the latter two technologies as "variable solar technologies," or as "solar technologies without storage," although both technologies can include operational capabilities that reduce variability and CSP in particular has capabilities delivered by a synchronous generator. The more general term "variable energy resources" refers to wind, PV and CSP without storage.

[8] See, e.g., Madaeni, Sioshansi, and Denholm (2012a,b), Denholm and Mehos (2011), Denholm and Hummon (2012), Mills and Wiser (2012a,b), Denholm et al., (2012), Denholm et al., (2013), Jorgenson et al., (2013, 2014), and NREL (2012).

Table 1-1: CSP with thermal energy storage projects in operations, under construction and in development (as of April 2014)

Project Name	MW	Hours Storage	Technology	Developer	Status	Country	Year Completed	Expected Completion
Planta Solar 1 (PS10)	11	0.5	Tower	Abengoa	O	Spain	2007	
Andasol 1	50	7.5	Parabolic Trough	ANTIN / Cobra / RREEF Infra.	O	Spain	2008	
Andasol 2	50	7.5	Parabolic Trough	Cobra	O	Spain	2009	
Planta Solar 2 (PS20)	20	0.5	Tower	Abengoa	O	Spain	2009	
Puerto Errado 1	1.4	1	Fresnel	EKZ / Elektra Baselland / EWB / EWZ / IWB / Novatec Solar	O	Spain	2009	
Extresol 1	50	7.5	Parabolic Trough	Cobra	O	Spain	2010	
Extresol 2	50	7.5	Parabolic Trough	Cobra	O	Spain	2010	
Extresol 3	50	7.5	Parabolic Trough	Cobra	O	Spain	2010	
La Dehesa	50	7.5	Parabolic Trough	Renovables SAMCA	O	Spain	2010	
Archimedes	5	7	Parabolic Trough	Enel	O	Italy	2010	
Andasol 3	50	7.5	Parabolic Trough	Marquesado Solar SL	O	Spain	2011	
Astexol-2	50	7.5	Parabolic Trough	Aries / Eiser / Elecnor	O	Spain	2011	
Manchasol 1	50	7.5	Parabolic Trough	Cobra	O	Spain	2011	
Manchasol 2	50	7.5	Parabolic Trough	Cobra	O	Spain	2011	
Valle 1	50	7.5	Parabolic Trough	Masdar / Sener	O	Spain	2011	
Valle 2	50	7.5	Parabolic Trough	Masdar / Sener	O	Spain	2011	
Gemasolar	20	15	Tower	Masdar/Sener/Torresol Energy	O	Spain	2011	
Augustin Fresnel 1	1	0.25	Fresnel	Solar Euromed	O	France	2012	
La Africana	50	7.5	Parabolic Trough	Grupo Magtel/Grupo Ortiz/TSK	O	Spain	2012	
ASTE - 1A	50	8	Parabolic Trough	Aries / Eiser / Elecnor	O	Spain	2012	
ASTE - 1B	50	8	Parabolic Trough	Aries / Eiser / Elecnor	O	Spain	2012	
Puerto Errado 2	30	1	Fresnel	Novatec Solar	O	Spain	2012	
Solana	280	6	Parabolic Trough	Abengoa	O	USA	2013	
Termosol 2	50	7.5	Parabolic Trough	NextEra Energy Resources	C	Spain	2013	
Khi Solar One	50	2	Tower	Abengoa / IDC	C	S. Africa		2014
Gujarat Solar One	28	9	Parabolic Trough	Cargo Power and Infrastructure	C	India		2014
Crescent Dunes	110	10	Tower	SolarReserve	C	USA		2014
Alba Nova 1	12	1	Fresnel	Solar Euromed	D	France		2014
KaXu Solar One	100	3	Parabolic Trough	Abengoa	C	S. Africa		2015
Xina Solar One	100	6	Parabolic Trough	Abengoa	D	S. Africa		2016
Rice SEP	150	8	Tower	SolarReserve	D	USA		2016

Key: O - Operational; C - Under Construction; D - Development. Note that this table does not include a number of planned projects for which there is not sufficient information about technical specifications or commercial on-line dates.

2. Design and Operational Attributes of CSP with Thermal Energy Storage

CSP with thermal energy storage can provide the same operational attributes as a fossil-fueled thermal power plant. When operated from thermal storage, CSP plants are actually more flexible than many existing coal and gas plants, i.e., have greater capability to utilize the full operating range of the turbine coupled with fast ramp rates.

CSP technology uses reflectors to focus sunlight onto solar receivers to heat a working fluid. The heat thus captured can then be converted to mechanical work in a turbine (or other heat engine) that drives a generator to produce electricity. Because heat can be stored more cost-efficiently than electricity, CSP technology also provides the foundation for a thermal energy storage system that can support plant operations according to market and power system needs, rather than depending on the immediate availability of sunlight.

The commercialization of CSP with thermal energy storage is currently focused on three configurations, all using molten salts as the heat storage medium (although research continues into alternative designs and heat transfer media). The parabolic trough design is the most established CSP design, and the first augmented with significant thermal storage. As listed in Table 1-1, several 50 MW plants are in operations in Spain with 7.5 hours of storage, and a plant with 250 MW net capacity and 6 hours of storage is now operational in Arizona. Power towers, initially demonstrated at smaller scales of up to 20 MW, are now in operation at up to 130 MW individual towers and larger units are in development. Power towers come in two varieties. Power towers with molten salt receivers directly heat the salt and are under construction and development at 110-150 MW capacity and up to 17 hours of storage capacity. Power towers with steam boilers with turbine capacity of approximately 130 MW are now operational, and extensions of this approach to include indirect heating of the molten salts are in development. The direct steam design also allows for non-storage operation without any use of a heat exchanger and associated losses.

This section reviews the key design and operational details typically analyzed in economic valuation studies, primarily of these commercialized designs, but also extendable to other CSP plant designs. The section does not review the extensive technical literature on CSP design. The section is organized as follows:

- Section 2.1 provides background on the design and operations of CSP plants with thermal energy storage.
- Section 2.2 discusses key components of CSP plant design and production modeling, including solar resource modeling, determination of the solar multiple and storage capacity, operational attributes of the plant, and the basic production modeling framework.

2.1 Background on CSP Plant Design and Operations

All CSP plants focus sunlight to heat a working fluid, which captures the heat of sunlight and ultimately transfers solar-generated energy to a heat engine that can convert the heat into mechanical energy. In most operating commercial designs, the working fluid is heated by pumping it through a solar receiver, located at the focus of the solar collectors.

Table 2-1 summarizes the four major types of CSP technology (IEA, 2010). In parabolic trough plants, the receiver is a tube that runs along the focus of a parabolic trough of mirrors. Sunlight that hits the trough is focused onto the receiver tube. The trough collector is usually oriented along a north-south axis and tracks the sun from east to west across the sky. Coatings on the receiver

tube maximize absorption of this energy and a glass envelope around the tube insulates the tube reducing the loss of captured heat to the environment. A compact linear Fresnel reflector (CLFR) system is similar to a trough, except that an array of long flat mirrors on individual, single-axis trackers focuses the sunlight onto a fixed receiver tube. In power-tower plants, an array of slightly curved mirrors called heliostats on two-axis tracking mounts reflect sunlight onto a single, centrally-located receiver that is mounted on a tall tower near the center of the mirror field. The fourth CSP system architecture is the dish-engine where a field of parabolic dishes tracks the sun in two axes reflecting their solar images to solar receivers located on each dish.

In a dish system the working fluid can be any gas, including air, and the engine, which is directly coupled to a generator, is typically a Stirling engine.

The design of the receivers for CSP systems varies, but in all cases their purpose is the same: to absorb solar flux and transfer the heat to the working fluid. Temperatures between 400-550/560 °C are common for parabolic troughs (Giostri et al., 2012; Montes et al., 2010), CLFR, and Power Tower systems. Dish-engine systems operate in the range of 700-800 °C.

Once the working fluid is heated, the heat must be converted to mechanical motion to make electricity. If the working fluid is water, it is converted to high-pressure steam and, if operation without storage is desired, the steam is sent directly to a turbine which drives a generator in a conventional Rankine cycle. The use of a conventional Rankine power cycle in CSP plants is a familiar one for power system operators since this is the same power cycle used in coal-fired and combined-cycle gas plants.

Table 2-1: The four CSP technology families

Receiver Type		Focus Type	
		Line Focus	Point Focus
		Collectors track the sun along a single axis and focus irradiance on a linear receiver. This makes tracking the sun simpler.	Collectors track the sun along two axes and focus irradiance on a single point receiver. This allows for higher temperatures.
Fixed	Fixed receivers are stationary devices that remain independent of the plant's focusing device. This eases the transport of the collected heat to the power block.	Linear Fresnel Reflectors	Towers
Mobile	Mobile receivers may move together with the focusing device. In both line focus and point focus designs, mobile receivers collect more energy.	Parabolic Troughs	Parabolic Dishes

Source: IEA (2010), pg. 11.

In other systems, the heat collection fluid is not water, but a high temperature fluid (HTF, a synthetic oil) or molten salt (a mixture of KNO_3 and $NaNO_3$ salts in their molten state).[9] IIn this case, conversion to mechanical energy is accomplished by pumping the primary working fluid through one side of a heat exchanger to heat a secondary working fluid – commonly water – and produce steam for use in the conventional Rankine power cycle. The need for thermal energy transfer between the primary working fluid and a secondary one, enables energy storage, since the heated primary working fluid can be stored for later use rather than used to make steam immediately.

[9] We note that in Stirling Dish technology, air is the working fluid. The solar flux heats one side of the Stirling engine and heat is dissipated to cool air on the other side. The temperature differential is exploited directly by the engine to produce motion.

CSP plants that use water/steam as their primary working fluid can also store energy for later production. They do so by making use of a heat exchanger twice. First, they pass heat from the directly-generated steam to a storage medium, which is then stored. Later, the process is reversed, using the heat exchanger to pass heat from the storage medium back to water, which generates steam to produce power. In this case, energy produced through the storage goes through two heat exchanges rather than one: first, from steam to storage medium, later from storage medium to steam again. Thus, this type of system experiences a heat conversion loss twice when operating from storage. However, when operating in non-storage direct mode, there are no heat exchanges, and thus no associated losses.

CSP plants that use molten salt as their primary working fluid can store heat directly in molten salt. To produce electric power, such plants transfer the heat from the molten salt to water/steam to drive the conventional Rankine cycle power block. Therefore, this design only requires a single heat exchange, but it must use it at all times.

Thermal Energy Storage Systems

The different types of CSP with thermal energy storage systems are each in different phases of technology development and demonstration and each has its own set of costs and benefits with implications for the plant's operational attributes, as described later in this section. It is beyond the scope of this report to examine all the technical and economic tradeoffs associated with these options and the design decisions necessary to assemble an entire working system. However, a brief discussion of storage media options is worthwhile.

In general, a thermal energy storage system includes a collection method, a reservoir, and a storage medium. Depending on CSP plant configuration and design, the storage medium may also be the working fluid of the CSP cycle or it can be a separate loop that communicates with the working fluid through a heat exchanger. This medium is heated (directly or indirectly) by sunlight and held in reserve until a later time when it is used to generate steam to drive a turbine for electricity production.[10] The choice of the medium is important since the mechanical and thermal properties of the medium determine its operational characteristics and the overall cycle efficiencies. The ideal medium is inexpensive, extremely stable through a large temperature range, non-reactive with piping and other materials with which it will come in contact, environmentally benign, has a high specific heat (ability to store heat per unit of mass), has a high heat density (heat per unit of volume), and is easy and safe to handle and pump. Additionally, it is convenient if the material does not experience a phase change over a large temperature range which could complicate handling, although in some advanced storage concepts under examination phase change can be exploited to allow more energy to be stored within a given temperature range and in a much smaller volume.

Steam was an early storage medium and is still used in some plants. For example, the PS10 plant in Seville, Spain has a steam accumulator. While it is difficult to store large quantities of energy with steam cost-efficiently an advantage of steam storage is that it can drive a turbine directly avoiding losses associated with heat exchangers.

[10] The amount of energy that can be transferred by a storage medium that does not change phase can be approximated by these formulas: $Q=m\cdot C_p\cdot\Delta t$; $\Delta t=t^h-t_l$, where Q is energy, m is mass, C_p is specific heat of the storage medium, and Δt is the temperature differential that the storage material goes through between its "cold" state (tl) and its "hot" state (t_h). C_p is a quality of the material itself. Thus, if one wants to store more heat, the amount of storage medium can be increased (m), a storage material with a higher specific heat can be selected, or the temperature delta for storage can be increased. However, there are tradeoffs. For example, it may not be possible to increase t_h because the storage material degrades or begins to become reactive with the plant. Similarly, it may not be possible to reduce t_l because the storage material would turn to solid.

Later designs used special oils or other heat transfer fluids (HTF) as a heat storage and transfer medium. For example, the original SEGS parabolic trough plants built in Southern California and many other trough facilities use Therminol VP or Dowtherm A[11], special oils formulated for this purpose. An advantage of HTF over steam is that, although it does exhibit relatively high vapor pressures at high temperatures, it does not require the high pressures and volumes associated with steam accumulators. However, oil also has temperature limits before it begins to coke and otherwise chemically decompose. This limits the operating temperature range and upper storage temperature that the oil can provide, thus limiting the amount of energy that can be stored per unit of HTF.

Several existing and planned CSP plants use molten salt as both the heat transfer and storage medium. The salts are typically a mixture of nitrate salts designed to be close to eutectic point (lowest melting point). The salts are stable at high temperatures (up to 600 °C), and therefore can support conventional Rankine steam power cycles. A requirement of molten salt is that the temperature must be maintained above about 220 °C to prevent solidification. This requires sufficient insulation on the piping and tanks, and potentially supplemental heating at night.

Experimentation continues with new heat storage media. For example, a material under consideration recently is molten glass, which can operate at even higher temperatures than salts. Other research includes particle receivers, granular solid mixtures of materials (Ho et al., 2009) such as granular carbon and ceramics, and molten salts exhibiting a low solidification temperature (~100 °C).

Experimentation continues with new heat storage media that will allow increased efficiency, storage capacity, and flexibility at lower cost.

2.2 Key Components of CSP Plant Design and Production Modeling

This section describes some of the key variables related to CSP plants modeled in studies of CSP with thermal energy storage. Much of the analytical framework and modeling details have been developed by researchers at NREL, and individual companies have proprietary versions of these types of models. Preliminary analyses are often performed using simple thermodynamic models or publicly available tools such as NREL's System Advisor Model (SAM), which was used to generate inputs to the economic models in the NREL studies reviewed here.[12] At more advanced stages of plant design, engineers will typically use detailed engineering models that reflects their specific CSP design and/or project parameters. Depending on the model, it may be able to predict not only energy output, but also dynamic plant variables such as start-up times, ramp rates, and other state-dependent characteristics. Studies of CSP operations in power systems will typically utilize SAM or related models as a basis for developing simplified models of CSP plants with thermal storage that are then optimally dispatched within a production cost model. These models are discussed further in Section 4.2 and subsequently in the report.

Solar resource modeling

CSP production, even with storage, is limited by the availability of direct normal insolation, and this availability affects economic valuation, depending on plant configurations. The production of electric power with CSP plants is sensitive not only to direct normal insolation but also ambient temperature, wind speed, humidity, and other weather phenomena (Stoffel, et al., 2010). NREL and NOAA provide "typical meteorological year" or TMY data for many sites around the US

[11] A eutectic mixture of biphenyl-diphenyl oxide still used in some plants as a storage medium.
[12] The SAM model is available at https://sam.nrel.gov/. In SAM, detailed models of the physical characteristics of CSP power plants and their sub-components along with detailed weather data are used to produce electricity output profiles for the plant. The performance and cost models in SAM have been reviewed publicly and many have been econometrically fit to the performance of existing CSP plants.

and world.[13] This data does not represent any particular year's observations but is instead synthesized from many years' observations to represent a "typical" year. TMY data is a good starting point, but for robust economic analysis of a specific project, highly local data – ideally obtained over several years from a weather station installed at the site of interest – is desired. Such data is generally not available and by definition requires years to collect. As such, engineers and project developers resort to other methods, such as extrapolating from nearby weather stations, using satellite data, or some combination thereof.

The solar multiple is the ratio of the actual size of a CSP plant's solar field compared to the field size needed to feed the turbine at design capacity when solar irradiance is at its maximum for that location (typically about 1 kW/m^2).

Solar Multiple

The solar multiple is the ratio of the actual size of a CSP plant's solar field compared to the field size needed to feed the turbine at design capacity when solar irradiance is at its maximum for that location (typically about 1 kW/m^2). A plant with a solar multiple of 1.0 would only be able to produce its nominal rated output during peak sunlight hours. Higher multiples allow the plant to maintain full output even when solar input is less than 100%, thus earning a better capacity value and realizing better overall utilization of the power block. Plants without storage have an optimal solar multiple of roughly 1.1 to about 1.5 (up to 2.0 for CLFR), depending primarily on the amount of sunlight the plant receives and its variation through the day. Plants with large storage capacities may have solar multiples of up to 3 to 5 so that they have sufficient energy gathering capability to operate the plant at full output while also fully charging the storage system in a typical solar day. As discussed below, studies of market and operational benefits that use explicit models of CSP plant design, can examine the benefits of alternative solar multiples (e.g., Jorgenson et al., 2013, 2014).

Thermal Storage Capacity

The thermal storage capacity of a plant represents the total amount of energy that can be stored. It is technically expressed in terms of MWh-thermal (MWh-th), or MWh-energy (MWh-e)[14] if adjusted to reflect the efficiency of conversion from thermal to electric energy. Thermal capacity is often presented in terms of time – the amount of time that the plant could operate from storage at its nominal capacity. For example, a 200 MW plant with "two hours" of storage has 400 MWh of storage capability. CSP projects in operation or under construction include storage capacity that is sized from a few hours of storage, intended primarily to serve early evening loads, to the Spanish Gemasolar plant that is essentially "base-loaded" in the summer months, meaning that it operates at rated output up to 24 hours per day.[15]

Several of the studies presented below – including Sioshansi and Denholm, 2010; Mills and Wiser, 2012b; Denholm and Hummon, 2012; and Denholm et al., 2013 – model a parabolic trough plant with 6 hours of thermal storage capacity. The use of 6 hours in these studies is primarily a convention and not necessarily the result of optimal design. In other studies, notably Madaeni et al., (2012b) and Jorgenson et al., (2013, 2014), a range of storage capacity, solar multiple, and other design parameters is modeled. These studies suggest both optimal solar multiples associated with particular storage capacities on types of CSP plants (e.g., troughs vs. towers), but, as discussed further below, also the rate of change in economic benefits as these design parameters are changed.

[13] See http://rredc.nrel.gov/solar/old_data/nsrdb/1991-2005/tmy3/.
[14] This report uses MW and MWh without any subscript to refer to electric power and energy, respectively. When referring to thermal energy, the report will explicitly include the –th designator.
[15] A 110 MW CSP power tower with 17.5 hours of thermal storage has also been announced in Chile.

Table 2-2: Assumptions about CSP plant characteristics in selected studies

Study	Location and Date Modeled	Characteristics of Solar Technologies		
		CSP without storage	CSP with thermal energy storage	PV
Sioshansi and Denholm, 2010	Western U.S., various locations, 2005; ERCOT 2005	Trough, Solar Multiple 1.5	Trough with 6 hours of storage, Solar Multiple 2.0	Not evaluated
Madaeni et al., 2012b	Western U.S., various locations, 2005	Trough, Solar Multiple 1.5	Trough with 1-11 hours of storage, Solar Multiples of 1.5-2.6	Not evaluated
Denholm et al., 2013	California 2020	Trough, Solar Multiple 1.5	Trough with 6 hours of storage, Solar Multiple 2.0	Single axis tracking PV
Denholm and Hummon, 2012	Colorado-Wyoming 2020	Trough, Solar Multiple 1.5	Trough with 6 hours of storage, Solar Multiple 2.0	Single axis tracking PV
Mills and Wiser, 2012b	California 2030	Trough, Solar Multiple 1.5	Trough with 6 hours of storage, Solar Multiple 2.5	Single axis tracking PV
Jorgenson et al., 2013	Colorado 2020	Tower, Solar Multiple 1.3	Tower with 3-12 hours of storage, Solar multiples 1.3-2.7 [Refer to report for particular combinations modeled]	Single axis tracking PV
Jorgenson et al., 2014	California 2022	Tower, Solar Multiple 1.3 (40% RPS scenario)	Tower with 6 hours of storage, Solar Multiple 1.3 (33% RPS scenario); Tower with 0-15 hours of storage, Solar Multiples 1.3, 1.7, 2, 2.3, 2.7 (40% RPS scenario)	Single axis tracking PV

Operational Attributes of Different Configurations

In addition to solar multiple and storage capacity, different CSP plant designs are characterized by a number of other operational attributes and costs that will affect plant operations and economic valuation. Table 2-3 shows a number of key parameters, including the assumptions in a "base-case" scenario used in recent NREL studies (Jorgenson et al., 2013) which can be varied to estimate the effect of these parameters on economic benefits. Note that the base-case assumptions in the table refer to a scenario, and do not reflect an assessment that these operational values are preferred. As a general matter, CSP companies do not share operational parameters of actual projects with independent researchers for reasons of confidentiality. To achieve better understanding of how these parameters could influence the economic benefits, independent researchers can conduct parameter sensitivities, whereas the actual firms can utilize the study methodologies to evaluate project design options using their own data.

Table 2-3: Key Operational Parameters for CSP plants

Parameter	Unit of Measurement	NREL "base-case" assumption for dry-cooled troughs and towers (Jorgenson et al., 2013)
Minimum Up-Time	Hours	1 hour
Minimum Down-Time	Hours	1 hour
Number of Starts per Day	Integers	Unconstrained
Ramp Rate	MW/min	10% of capacity per minute
Minimum Generation Point	MW or % of capacity	15% of capacity
Maximum Generation Point	MW (maybe a function of temperature)	Varies by plant modeled
Ancillary Service certification	Certification requirements will vary by utility or region	Yes
Heat Rate Curve	Ratio of Relative Heat Input plotted against Fraction of Full Load. May be modeled as a function of ambient temperature.	See Jorgenson et al., (2013), pg. 11
Regulation Range	MW or % of rated capacity	60% - 100% of rated capacity
Cost of Providing Regulation Reserves	$/MW-hr	$4/MW-hr
Start-up Energy	Energy for period of start-up	20% of rated output for 1 hour
Start-up Cost	$ per start	$10/MW/start
Variable O&M	$/MWh	$1.1/MWh
Average Storage Loss Rate	% of energy sent to storage	2% (direct molten salt tower), 7% (indirect trough)
Maintenance Rate	%	0%
Forced Outage Rate	% of capacity/year	4%

3. Utility or Market Services Offered by CSP with Thermal Energy Storage – and Comparison with PV

CSP with thermal energy storage can provide the full range of utility and/or market services in energy, ancillary services and capacity. Each of these capabilities needs to be defined and appropriately valued in solar procurement processes.

With the operational attributes listed in Section 2, CSP plants with thermal energy storage can, in principle, offer essentially all the electric power products and services provided by conventional, flexible thermal power plants. This section provides additional detail on how these operational attributes map into particular electric power products and services on different operational, scheduling and planning time-frames. This section, and the remainder of the report, primarily uses the U.S. terminology for these products, but there are relatively direct analogues with products in different countries. Table 3-1 provides a comparison of different terminology in the European and North American reliability organizations.[16] Table 3-2 provides brief definitions and summary descriptions of the key products and services.

The section is organized as follows:

- Section 3.1 reviews definitions and characteristics of capacity resources.
- Section 3.2 reviews definitions and characteristics of energy and ramping services.
- Section 3.3 reviews ancillary services categorized as operating reserves.
- Section 3.4 reviews other ancillary services, including those used for primary frequency control and voltage support.
- Section 3.5 discusses the potential advantages of larger solar plants for operator visibility and control.

For each of these utility or market services, this section provides a basic comparison between CSP with thermal storage and PV. Improvements in inverter technology will allow PV systems to provide static and dynamic voltage support, synthetic inertial response, regulation, and active power management. CSP will provide these capabilities from a synchronous generator, which can in some cases provide qualitative differences in contribution to system reliability.

An important difference between CSP and PV is that the CSP plant operating from storage will provide ancillary services, whether requiring upward or downward response, without appreciable loss of stored renewable energy. In contrast, provision of ancillary services will require a solar plant without storage – CSP or PV – to curtail some energy production. Hence, especially for operating reserves, these plants are not likely to be major suppliers until either costs are reduced significantly or the cost of alternative supply increases (or both).

[16] See Ela et al., (2011) for further terminology comparisons.

Table 3-1: Comparison of European and North American terminology for reserves

European Union for Coordination of Transmission of Electricity (UCTE)	North American Electric Reliability Corporation (NERC)
Primary control reserves	Frequency responsive reserve
Secondary control reserves	Regulation Spinning Reserve Non-spinning Reserve
Tertiary control reserves	Supplemental Reserves

Source: Ela et al., (2011).

The CSP plant operating from storage will provide ancillary services, whether requiring upward or downward response, without appreciable loss of stored renewable energy.

3.1 Capacity

Capacity, conventionally denominated as a % of nameplate capacity (MW), is the expected output of a generator for the purpose of meeting a reliability criterion or standard, such as a loss-of-load expectation, under specified system conditions. The methods for assigning capacity credits or ratings for different classes of generation, with a focus on solar technologies, are discussed further in subsequent sections of the report.[17] Generally, capacity resources are differentiated on the basis of the following characteristics:

1. *Location*. Many regions differentiate capacity resources on the basis of location on the transmission network. Congestion on transmission facilities serving load centers can limit the capacity rating of more remote resources.

2. *Energy and operational limitations*. Certain classes of generators, such as hydro units with seasonal storage or other operational constraints, conventional generators subject to environmental emissions constraints, or demand response that can only be called for a fixed number of hours per year, must be modeled with consideration given to their availability during periods of high risk of loss-of-load.

3. *Variable energy production*. Wind and solar generation (without storage) are assigned capacity credits based on their forecast or actual hourly production, under the assumption that their energy is produced as available, with no capability to store production. The methods for doing so are reviewed in Appendix A.

4. *Operational flexibility*. The characteristics listed above affect the resource capacity rating in terms of generic MW. In some regions, the capacity product is being further differentiated to reflect its operational attributes, such as start-up times, ramp rates, and ability to sustain ramps.

CSP plants with thermal energy storage can provide both generic capacity (MW) and "flexible capacity" attributes, such as fast ramp rates and the ability to sustain ramps for multiple hours. As discussed below, the sizing of the thermal energy storage system will have a significant effect on the capacity credits allocated to particular plants, as well as their ability to offer operational flexibility for sufficient hours.

[17] These include Section 4 (modeling methods), Section 6 (discussing drivers of capacity credits in high solar penetration scenarios), Section 8 (results from studies), and Appendix A (additional methodological details on capacity credits).

In contrast, both CSP and PV without storage are typically modeled as variable energy resources and assigned capacity credits on the basis of expected (forecast) production (both plant-level and aggregate variable solar generation) during hours of highest risk (see Section 8). On the other hand, in terms of locational attributes, PV can be located closer to load and hence be eligible as local capacity, whereas CSP plants are typically, but not necessarily, remote from load.

3.2 Energy and Ramping

For system operational purposes, energy delivery is defined as the injection of real energy (MWh) into the grid at a time and location, matched by the utility or system operator with a corresponding withdrawal at another location, with consideration of transmission congestion and losses. The energy product, at least in organized wholesale markets, is further defined by additional bid or cost components for start-up and minimum load on the generating units. More recently, there is additional emphasis on the operational characteristics of the units, such as ramp rates (MW/min), and new market products such as ramping reserves.

A further differentiating characteristic is whether resources are able to follow economic dispatch instructions, whether from a utility or through a bid-based wholesale auction market. The scheduling procedures to establish a "least-cost" unit commitment economic dispatch are typically conducted on day-ahead and real-time time-frames. In these time-frames, energy is either (a) scheduled inflexibly (self-scheduled) by the plant operator or utility owner, based on a known production schedule or a forecast, or (b) offered as dispatchable, which allows the plant's production to be optimized to minimize system costs. In the day-ahead markets, accepted energy schedules or offers obtain an hourly schedule for the next operating day and are financially settled at day-ahead prices. In the real-time markets, the supplier may either operate according to the day-ahead schedule or buy-back some or all of the day-ahead position. Dispatchable energy offered into the real-time market generally has more explicit performance requirements and can be optimized on a five-minute basis by the market or system operator. The deviations from prior schedules being followed in real-time is sometimes called load-following, or "net" load following, when it also reflects deviations from variable energy resources.

Solar resources without storage are generally scheduled on a day-ahead and hour-ahead basis using production forecasts in those time-frames, and do not currently submit bids to alter their production. Due to its operational flexibility, CSP with thermal energy storage has the capability both to schedule energy in forward time-frames with significantly lower forecast error than other solar plants, as well as participate in real-time economic dispatch on a 5- to 15-minute basis. As surveyed below, most of the studies to date have modeled CSP with thermal storage on an hourly basis, although some have modeled capacity reserved on the plant to follow 5-minute dispatch.

Some system operators are preparing for increasing supply variability and forecast errors in real-time operations by procuring additional ramping reserves to augment load-following capabilities.[18] There are also initiatives to procure "flexible capacity" in forward time-frames from resources that are capable of meeting inter-hourly ramping requirements, as discussed below. In real-time operations, a ramping reserve requires procuring additional capacity that can support real-time energy ramps. CSP with thermal energy storage could be operated to serve this function without significant loss of production. For solar resources without storage, bids to decrement production could also provide system ramping support, but would require loss of production.

Due to its operational flexibility, CSP with thermal energy storage has the capability both to schedule energy in forward time-frames with significantly lower forecast error than other solar plants, as well as participate in real-time economic dispatch on a 5- to 15-minute basis.

[18] See, for example, the discussions about the California ISO's "flexi-ramp" product, available here: http://www.caiso.com/informed/Pages/StakeholderProcesses/FlexibleRampingProduct.aspx.

3.3 Ancillary Services – Operating Reserves

One major category of ancillary services is the operating reserves, also grouped as secondary and tertiary reserves. These reserves have generally been fairly straightforward to organize wholesale markets around, because they can be provided by a wide range of supply and demand resources and are procured on a system or zonal basis. In practice, conventional thermal generators have provided the majority of these reserves to date, with other types of resources increasingly penetrating the markets.

Regulation

Frequency regulating reserves are carried by the system operator to balance the system on intervals of seconds in between the system operator's or utility's dispatch instructions. Frequency regulation – often simply called Regulation – requires generation or non-generation resources to be synchronized to the grid and responsive to automatic control signals (e.g., automatic generation control, or AGC) within a pre-determined regulating range that depends on the unit's regulating ramp rate. The quantity procured is usually a function of measured or forecast deviations in particular time intervals by demand and supply, as well as by the need to meet applicable reliability standards for frequency control. In some U.S. markets, regulation is procured as a regulating range; in others, Regulation Up is procured separately from Regulation Down.

CSP with thermal storage can be certified to provide Regulation using the governor controls on the turbine, although there is no publicly available engineering analysis of the regulating ranges and durations that particular thermal energy storage designs could support. In most of the studies surveyed here that model CSP with storage providing Regulation (e.g., Denholm et al., 2013; Mills and Wiser, 2012b), there are simplifying assumptions about the operations of the plant, the capacity reserved for regulation, and the energy used in the process of providing Regulation. In particular, the studies to date assume that in each hour that the plants provide Regulation, the upward Regulation is provided in equal quantities to the downward Regulation, meaning that the plant would not draw additional energy from thermal storage for Regulation.[19] Table 2-3 shows the regulating ranges tested in recent studies (Jorgenson et al., 2013).

For solar resources without storage, provision of Regulation would require some loss of energy production. CSP without storage can still provide Regulation using governor controls on the turbine, although with loss of production. PV can also provide Regulation through the design of DC-AC inverter controls with AGC-like functions, but similarly with curtailment of some energy production.

Contingency Reserves

Spinning and non-spinning reserves are ancillary services provided by generation or non-generation resources to meet system contingencies. System operators typically carry sufficient spinning reserves (i.e., from units synchronized to the grid) to cover the loss of the single largest generator or transmission facility on the grid, and sometimes an additional margin. In the United States, a unit's eligible spinning reserve capacity is generally defined as the resource's ramp rate

[19] For example, if a 100 MW plant is operated at a dispatch set point of 80 MW, and provides a regulating range of 20 MW up and 20 MW down for a particular hour, then the net energy neutral assumption is that for half of the hour the plant is providing upwards Regulation and operating up to 100 MW, while the other half of the hour the plant is providing downwards Regulation and is operating down to 60 MW. The upwards and downwards control signals are assumed to cancel out over the time period. Hence, on average, the plant is producing at 80 MW. In actual operations, such symmetry may not be the case, although most system operators will operate regulating resources around a set point (as determined in each hour).

(MW/min) × 10 minutes, with the capability to provide energy for 1 hour in the event of a call on energy from spinning reserves. Non-spinning reserves have similar requirements, but are provided from units not synchronized to the grid. A unit's eligible non-spinning reserve capacity is generally defined as the resource's maximum energy production within 10 minutes of start-up and with the capability to sustain energy production for 1-2 hours in the event of a contingency. In current markets, non-spinning reserves are typically provided by quick-start generators, such as combustion turbines, but can also be provided by grid-synchronized generators that have surplus reserve capacity after the spinning reserve requirements been met.

CSP generators can provide spinning reserves from thermal energy storage by operating the plant below its maximum operating level with the potential to ramp the turbine to full output in response to the system operator's instruction. The duration of the supply of spinning reserves is a function of the state of charge on the thermal energy storage system, since the stored thermal energy is being drawn down and, at least overnight, not being replenished. With respect to non-spinning reserves, most CSP generators cannot achieve a cold-start in 10 minutes from thermal energy storage but they could remain available for warm starts or possibly remain synchronized to cover a system's non-spinning reserve requirement.

For solar technologies without storage, provision of contingency reserves will require holding back production, and hence losing energy.

Due to fast ramp rates, CSP generators can provide a wide range of spinning reserves, similarly to a flexible fossil fuel plant but without causing emissions due to keeping the plant on-line.

Supplemental Reserves

Power system operators may carry additional, supplemental reserves on time-frames greater than 10 minutes, typically requiring full operations between 20-60 minutes. CSP with thermal energy storage would be eligible to provide such supplemental reserves.

3.4 Other Ancillary Services and Operational Requirements

In addition to the operating reserves, there are a number of other ancillary services and operating requirements for which CSP generators may provide valued capabilities, especially as penetration of variable energy resources increases. Some of these ancillary services are procured on a bilateral basis (rather than through centralized markets), or required under interconnection rules. These include frequency response, inertial response, and voltage support.

Frequency Response

Utility system frequency, the frequency of oscillations of alternating current (AC), is controlled second-by-second and is determined by the balance between system demand and total generation available on the grid. When the amount of electric power produced by the generators exceeds demand, the frequency of the electricity rises. Conversely, when electricity demand exceeds available generation output, the frequency drops, which can lead to grid instability and outages.

Generally speaking, grid operators are required to maintain frequency within specified limits for which they use controls available on primary, secondary and tertiary time-frames (see, e.g., Table 3-1). Primary frequency control, or frequency response, is provided by generators with inertia and responsive governors as well as by quick response storage and potentially demand response. Several European countries, including Spain, already carry frequency responsive reserve requirements. In the United States, FERC has recently approved the NERC BAL-003 standard (FERC 2014), which requires each Balancing Authority to meet a minimum Frequency Response Obligation (for a study of the California ISO system, see GE/CAISO 2011).

Through inertia and the use of responsive governors, CSP with thermal energy storage has inherent capabilities to support frequency response and can be operated to provide frequency response reserves. For solar plants without storage, provision of frequency responsive reserves through governors (CSP) or inverter controls (PV) will require holding back some production, and hence losing some energy production.

Most PV systems have not been designed to provide reactive power.

Inertia Response

Inertia on the grid is created by the energy stored in the rotating mass of conventional power plants, or by synthetic inertia in inverter-based systems. It acts as a buffer for the initial seconds of a disturbance that helps suppress frequency deviations due to unplanned changes in the power system. Currently, inertia response is provided by synchronous generators because they and their attached turbines provide rotating mass. CSP plants without storage provide some inertia due to the characteristics of the power block, with the capability depending on their design. When thermal storage systems are added, they extend the number of hours that this capability is offered across the operating day.

Inverter based systems, whether wind or PV, have no rotating parts, hence do not have intrinsic inertia. These systems instead require changes to the software and electronics controlling the inverter to provide a synthetic inertia response, which has been demonstrated in wind plants, but is not yet commonly deployed.

Reactive Power and Voltage Support

In addition to real power (MW), power grids require reactive power (MVAR) from generators, synchronous condensers or capacitors. Reactive power is necessary to support and maintain operating voltage levels under normal and emergency conditions. Reactive voltage support is required to maintain power quality and to prevent voltage collapse, which can result in wide spread blackouts. Reactive power must be supplied locally, i.e., cannot be transmitted over long distances. In general, injecting reactive power into a transmission system will increase the voltage level near the point of injection and withdrawing it will decrease the voltage level. Because system operating conditions are constantly changing, the need for reactive power is also be constantly changing, requiring automatic adjustments to the reactive power supply at specific locations. Under some emergency conditions, i.e, when the system voltage begins to collapse, automatic increases in reactive power output are required to raise the voltage and prevent it from collapsing to the point of causing a blackout.[20] Although market pricing of reactive power has been considered for several years in the U.S. (e.g., FERC 2005), this service remains an administrative requirement in U.S. regions. However, power generators are compensated when they are dispatched to particular operating points to provide reactive power. CSP plants with or without thermal storage will provide automatically adjustable reactive power to the system. Most PV systems are currently not designed to provide reactive power but could be configured to do so.

Static Voltage Control

Static voltage control is the ability to adjust reactive power to maintain a specified voltage profile, possibly in response to operator instructions, which can be dynamic depending on the loading conditions on transmission facilities in the grid. The term “static” represents a relatively slow time frame in power system operations which could span up to several minutes.

[20] For example, one of the important lessons learned in the blackouts in the U.S. Western Electricity Coordinating Council (WECC) in July and August of 1996 was that operation of generation in a constant reactive power mode increased the risk of voltage collapse and, therefore, should be limited.

Synchronous generators on CSP plants provide static voltage control through the exciter/automatic voltage regulator control. When coupled with thermal storage systems, these plants can provide voltage control for longer periods of the operating day. For inverter-based systems, either the DC-AC inverter control of the PV generator must be designed to provide static voltage control or reactive devices such as capacitors/reactors can be installed on the grid to increase reactive power capability in the area. The costs of these investments for PV in $/MWh of solar energy are likely to be small relative to the total cost of renewable energy but worth considering in portfolio development.

Dynamic Voltage Control

During and after sudden changes in grid conditions, such as during a fault or following the outage of transmission facilities, fast and automatic reactive power support is crucial to reliable operation of the power system. Typically, this type of response (seconds or less) is provided by the exciter controls of synchronous generators.

For PV generators, this type of response can also be provided through the design and implementation of DC-AC inverter controls. Unlike static voltage control, less costly and simple additional reactive devices such as capacitors/reactors cannot be used to satisfy this need. Instead, more expensive and complicated devices for voltage control such as static VAR compensators (SVC) or static synchronous compensators (STATCOMs) are required. Moreover, even with such devices, control is still not as robust as that offered by a synchronous generator. For example, if a low-voltage situation is already established, such devices cannot output their rated reactive power, while a synchronous generator can meet the need (NERC 2009; FERC 2005). This low-voltage scenario is precisely when reactive power is most needed and this represents a shortcoming when adding voltage control devices to PV plants.

3.5 Visibility and Control

Visibility and control over system resources are operational needs that can affect ancillary service procurement and system operations. The trend in power systems towards large numbers of small, distributed renewable resources will eventually require additional investments in control systems and capabilities to visualize the effect of these resources on system operations (CAISO/KEMA, 2012). Large-scale CSP plants with thermal storage are fully visible to the system operator and can be engineered to provide a high degree of operational flexibility. Hence, such plants could provide the operators with a substitute for displaced large conventional power plants.

The trend in power systems towards many small distributed renewable resources will eventually necessitate investment in monitoring and control systems to reliably track and manage these resources.

Table 3-2: Description of Power Sector Energy Imbalance and Ancillary Services

SERVICE DESCRIPTION					
Service	Response Speed	Duration	Cycle Time	Market Cycle	Wholesale Market Product?
Normal System Conditions					
Regulating Reserve		On-line resources, on automatic generation control (AGC) that can respond rapidly to AGC requests for up and down movements; used to track the minute-to-minute fluctuations in system net load and to correct for unintended fluctuations in generator output to comply with relevant reliability standards, such as NERC's Control Performance Standards (CPS) Reliability Standard.			
	~1 min	Minutes	Minutes	Hourly	Yes
Load Following or Imbalance Energy Markets		Typically 5- to 10-minute energy dispatch, but can be conducted on other time-frames. Bridges between the regulation service and the hourly energy markets.			
	~5-10 minutes	5 min to hours	5 min to hours	Hourly/Subhourly	Yes
Ramping Reserve		Additional ramping capacity reserved if needed for load-following within the operating hour.			
	~5-10 minutes	5 min to hours	5 min to hours	Hourly/Subhourly	Yes
Contingency Conditions					
Spinning Reserve		On-line generation, synchronized to the grid, that can begin to increase output immediately in response to a major generator or transmission outage and can reach full output within ten minutes to comply with NERC's Disturbance Control Standard (F).			
	Seconds to <10 min	10 to 120 min	Hours to Days	Hourly	Yes
10-Minute Non-Spinning Reserve		Same as spinning reserve, but need not respond immediately; resources can be off-line but still must be capable of reaching a specified output within the required ten minutes.			
	<10 min	10 to 120 min	Hours to Days	Hourly	Yes
Replacement or Supplemental Reserve		Supplemental reserve is used to restore spinning and non-spinning reserves to their pre-contingency status; it must have a 30-60 minute response time.			
	<30 min	2 hours	Hours to Days	Hourly	Yes
Other Services					
Voltage Control		The injection or absorption of reactive power to maintain transmission-system voltages within required ranges.			
	Seconds	Seconds	Continuous	Year(s)	No, but could be in the future
Black Start		Generation, in the correct location, that is able to start itself without support from the grid and which has sufficient real and reactive capability and control to be useful in energizing pieces of the transmission system and starting additional generators.			
	Minutes	Hours	Months to Years	Year(s)	No

Source: Modified from GE Energy and Exeter Associates (2012)

4. Valuation of Renewable Resources – Definition of Net System Cost and Quantitative Methods

To fully capture the long-term benefits of CSP with thermal storage, stakeholders should adapt and extend existing quantitative methods to comprehensively analyze each renewable resource's "net system cost".

To date, CSP with thermal energy storage has not been valued accurately in renewable energy procurement. This is due to several factors. First, the operational attributes of CSP with thermal storage are not yet sufficiently well-defined and; even in locations where such plants currently operating, there is little experience with dispatching them. The CSP industry anticipates that this will change with the commercial operations of new CSP plants with thermal storage in the western United States that are designed for increased operational flexibility. In tandem, there should be an effort by the U.S. Department of Energy (DOE) and its national laboratories working with industry to collect and analyze data from operating plants to address this issue.

Second, there hasn't been sufficient experience with the integration of solar power on a large-scale in power systems, and as such, utility procurement has not yet fully incorporated the findings of the solar valuation studies and other integration analyses discussed in this report. The issues are complex and decision-makers often need guidance when interpreting the methodologies and results of valuation studies. The U.S. DOE and its national laboratories have provided much of the preliminary research on the benefits of different configurations of CSP, and their sustained engagement is needed as power system conditions continue to change.

Finally, as the power system continues to evolve, many utilities and regional power systems have not yet determined the mix of infrastructure that the future grid will require. Most notably, this includes the quantity and characteristics of flexible, dispatchable generation, storage or demand response to support integration of variable energy resources at higher penetration. The attributes of CSP with thermal energy storage can meet many of the operating requirements forecast to be needed, providing support for even higher levels of integration of variable wind and solar resources (e.g., Denholm and Mehos, 2011; NREL 2012). Recent studies have attempted to demonstrate these capabilities with models similar to those used in utility procurement decisions (e.g., Denholm et al., 2013), and these types of modeling applications are also needed in portfolio planning methods (Mills and Wiser, 2012b).

To assist this comparison of valuation methodologies, this section of the report provides definitions and background on renewable energy valuation with the focus on issues arising in the valuation of CSP with thermal energy storage. The section is organized as follows:

- Section 4.1 reviews utility valuation and the components of "net system cost".
- Section 4.2 summarizes the modeling tools and methods typically used to calculate components of net system cost, with reference to the studies surveyed in this report.
- Section 4.3 explains further how utilities and regulators will use the information from cost-benefit analysis in procurement and planning.
- Section 4.4 reviews some methods for constructing portfolios and measuring the model results, again with reference to the studies surveyed.

This report does not attempt to describe in detail the different types of policy, planning and procurement processes and valuation methods used in the CSP markets around the world. For interested readers, Mills and Wiser (2012a) provide a useful survey of solar valuation methods used in utility procurement in the western U.S. markets. Readers familiar with these topics can move to the next sections.

4.1 Utility Valuation and Net System Cost

As part of the planning and procurement processes arising from renewable policies, utilities or other decision-makers use variants on cost-benefit analyses, along with other assessments, to evaluate the types and locations of renewable resources. The calculation of "net cost" or "net system cost" is a central element in such analysis for purposes of ranking alternative projects. The basic equation is as follows:

Net Cost = Levelized Cost of Energy (or bid cost) + Transmission Cost + Integration Cost – Energy Benefits – Ancillary Service Benefits – Capacity Benefits

For renewable technology projects, the levelized cost of energy (LCOE) or a project bid cost is used on the cost side of the equation, along with any other infrastructure and integration costs.[21] For variable wind and solar resources, the major elements on the benefits side of the equation are the energy and capacity costs avoided by the project. As CSP with thermal storage enters the renewable markets, the calculation has to be expanded to capture the additional operational attributes offered by the plant, such as the capability to optimize provision of energy and ancillary services, as well as the costs created by other renewable resources that may not be incurred with a CSP plant, such as integration and curtailment costs.

As the studies reviewed in this report have shown, for any particular power system, these costs and benefits are functions of renewable penetration levels and the composition of renewable resource portfolios. The net system costs of incremental project additions to existing resource portfolios, or to future portfolios, are significantly more complicated calculations. These require the detailed simulations of power systems surveyed in this report.

CSP with thermal storage is one of a range of operational solutions to address the supply variability introduced by rapidly expanding wind and PV production.

While the report does not evaluate trends in the LCOE of alternative solar technologies, curtailment of production from variable solar resources under high solar penetration scenarios will obviously affect project costs as well as benefits, by reducing the denominator (MWh) in the equation. Hence, it could further affect comparative net system costs of alternative solar projects.

CSP with storage is one solution to the operational and reliability requirements of future power systems. There are a range of other operational solutions to the supply variability introduced by rapidly expanding wind and solar production (e.g., NREL 2012). These include the following:

- More flexible existing (through retrofits) and planned conventional generation, including quick start-up times, lower minimum operating levels, and fast ramp capabilities.
- Institutional and regulatory changes to expand markets for energy balancing and operating reserves (e.g., through the development of a regional market for imbalance energy in the western U.S.).

[21] As a generic measurement, the LCOE does not consider when during the operating day the energy is delivered, the capacity value of the plant, nor whether the renewable plant can offer any other operational attributes such as ramping reserves or ancillary services. Hence, the LCOE is widely recognized to be of limited value for long-term renewable planning and procurement purposes, particularly at higher penetrations of renewable energy (Mills and Wiser, 2012b; Joskow 2010).

- Modifications of future renewable resource additions to minimize the net load variability and other system impacts, such as surplus generation that could lead to curtailment.
- Increased participation by renewable generation in providing ancillary services and ramping reserves.
- Additional non-generation resources, including distributed and utility-scale storage capacity and demand response.

While this report does not review all of these alternatives, thermal energy storage additions to CSP plants are potentially among the lowest-cost energy storage solutions (Turchi et al., 2010). They have the further advantage that they are charged with solar energy and hence all production is fully eligible for renewable energy credits.

Thermal energy storage additions to CSP plants are potentially among the lowest-cost energy storage solutions.

4.2 Quantitative Methods for Economic Valuation

Modeling the economic and reliability benefits of CSP with thermal energy storage has required the development of new analytical methods linking together inputs from models on operational, market, capacity and planning time-frames. This section briefly reviews the types of models and particular extensions needed for modeling CSP with storage. Power system models represent the supply, demand, storage and the transmission network at different levels of spatial and temporal aggregation. They are reviewed below roughly in order of the time-steps modeled, ranging from seconds (primary frequency control), to minutes and hours (system and market operations), to months and years (capacity), to multiple years (planning). Table 4-1 then surveys which methods are used in the studies referenced in this survey.

Power system models represent the supply, demand, storage and the transmission network at different levels of spatial and temporal aggregation.

Power system sub-hourly operational models

Variable wind and solar production affects system operations on time-steps of seconds and minutes, requiring new statistical models that measure the interaction of production variability and forecast errors on system requirements for primary and secondary frequency control (e.g., CAISO 2010; Ibanez et al., 2012). These requirements can be aggregated into hourly reserve capacities as inputs to the power system dispatch models described next, which allow economic analysis over periods of months, years or multiple years (e.g., Denholm et al., 2013). Alternatively, models have been implemented that can simulate resource operations on time-frames of seconds and minutes to maintain system frequency, but which are usually used to evaluate particular hours or days (e.g., KEMA 2010). Both types of models have been extended to include CSP with thermal energy storage.

Power system dispatch models

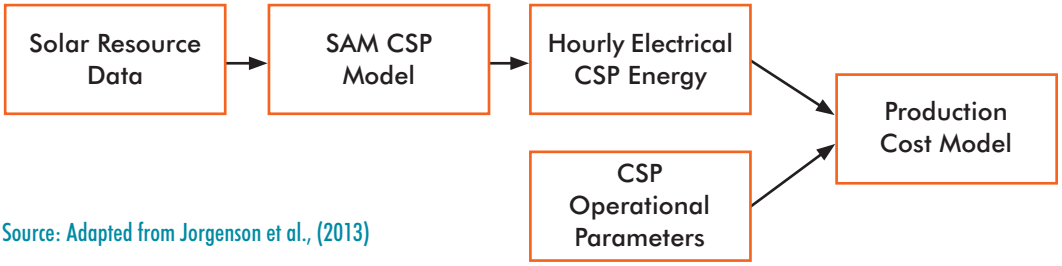
Power system unit commitment and dispatch models simulate the commitment (start or stop) and dispatch of generation and non-generation resources on time-frames of minutes to hours, although hourly models currently predominate. There are many variants on such models, including those utilizing commercial software (such as Plexos and Gridview) that has been used in several of the studies reviewed here, as well as models developed for research (e.g., the models in Mills and Wiser, 2012b). In addition, there are the actual, highly detailed models used by utilities and system operators for market and system operations, which incorporate significant additional detail on resource and transmission constraints.

Dispatch models are used to evaluate operational changes on the power system due to renewable penetration, and calculate the resulting changes in production costs or simulated market prices. For studies that model production costs, the typical measurement in the studies reviewed here (e.g., Denholm et al., 2013) is to calculate the change in production costs between different scenarios with either different portfolios or different technologies added incrementally to the same

portfolio. In the "equal energy" portfolios, this means that the total energy being modeled is the same in each scenario. Historically, when used for planning or operational assessment, these models primarily use time intervals of one hour and are called production cost or production simulation models. Recent extensions of these models include greater detail in sub-hourly simulation, such as 5-minute or 15-minute dispatch.

Figure 4-1 shows the process flow for simulating CSP in a production cost model, as developed over several recent studies by NREL researchers (e.g., Denholm and Hummon, 2012; Denholm et al., 2013; Jorgenson et al., 2013).

Figure 4-1: Process of simulating CSP in a production cost model developed by NREL



Source: Adapted from Jorgenson et al., (2013)

Plant-level simulation with exogenous prices

A plant-level model incorporates a detailed representation of CSP plant operations, including the solar field, thermal energy storage system, and the power block, structured as a linear or non-linear optimization problem. They can be used directly for economic valuation or to generate quantity inputs into power system models (e.g., as in Figure 3-1). The earlier literature on the economic valuation of CSP with thermal energy storage was primarily plant-level, hourly models, utilizing the data in the NREL SAM (see, e.g., Sioshansi and Denholm, 2010; Madaeni et al., 2012b). When individual plants are modeled, it is possible to represent performance/operational characteristics in greater detail than in power system models, but the market prices or utility costs are generally fixed and external ("exogenous") to the model. When historical market prices or utility costs are used, these models provide a good estimate of what the plant could have earned from the different products for which external prices are available. However, unless the plant is truly marginal to the power system – that is, has no significant effect on market prices – this approach has the limitation that it does not consider the effect of the plant's energy and ancillary service operations on market prices. Moreover, this method is not suited to evaluating the effects of other future changes to the power system on economic benefits, unless it uses prices generated by a larger system model.

Option pricing models

Some utilities use option pricing models for valuation in long-term procurement of dispatchable resources; however, there has not yet been any option pricing modeling of CSP with thermal energy storage configurations in the research literature. To the extent that such plants have sufficient storage capacity to be highly dispatchable, the modeling approach would be similar to that for conventional dispatchable generation.

Statistical and operational models for measuring capacity credits

At the intersection of planning and reliability are models used to evaluate the resource mix that will minimize loss-of-load events, generally to achieve a reliability standard such as 1 loss-of-load event

in 10 years. Historically, these models have used statistical simulations to measure the probabilities of loss-of-load under different resource mixes and expected loads. Capacity ratings for variable wind and solar resources are typically conducted using a modified measurement called equivalent load-carrying capability (ELCC). To evaluate the capacity credits of CSP with thermal storage, these models have to be coupled with variants on dispatch models that measure the availability of energy from these plants in the highest risk hours of the year (e.g., Sioshansi and Denholm, 2010; Madaeni et al., 2012b; Denholm et al., 2013). They can also be incorporated into variants on capacity expansion models (e.g., Mills and Wiser, 2012b). Appendix A in this report reviews the methods used in these models.

Portfolio planning/capacity expansion models

Portfolio planning models are used to evaluate large numbers of resource options on the supply and demand side, and include consideration of uncertainty about key variables, such as renewable energy production, hydro availability, and future prices for fuels and emissions. Portfolios can be developed endogenously based on the forecast comparative costs of alternative renewable and conventional generation options (e.g., NREL 2012; Denholm et al., 2012), or exogenously based on both quantitative and qualitative analysis. These models may be coupled with dispatch models to evaluate operations and fuel usage and a few have simulated the integration of renewable resources and the operations of CSP with thermal storage (NREL, 2012; Mills and Wiser, 2012a).

4.3 Applications in long-term planning and procurement methods

In regions where CSP plants are being constructed to fulfill utility renewable energy requirements (e.g., under RPS), their costs and benefits are evaluated within long-term planning and procurement by utilities or regulatory agencies. These processes have historically utilized several of the modeling tools discussed above. Mills and Wiser (2012a) provide an overview and evaluation of the planning study and procurement methods followed by western U.S. utilities for solar valuation. They identify the general steps followed by the utilities or regulatory authorities with purview over planning and procurement as follows:

1. Assessment of future needs and resources
2. Creation of feasible candidate portfolio that satisfy needs
3. Evaluation of candidate portfolio costs and impacts
4. Selection of preferred portfolio
5. Procurement of resources identified in preferred portfolio

Each of these steps requires the intensive use of modeling and in each case current modeling limitations in commercial software can inhibit the accurate modeling of CSP with thermal storage (Mills and Wiser, 2012a) – as well as other storage technologies. Particularly within the steps that utilize portfolio planning/capacity expansion models, notably Step 2, most existing commercial software used by utilities are not yet configured to evaluate storage technologies, including CSP with thermal storage (Mills and Wiser, 2012a; Sioshansi et al., 2012). Within Step 3, utilities currently use different models to estimate the present value of the revenue requirement of candidate portfolios (PVRR). The PVRR is predicted using statistical models to evaluate the effect of uncertain factors, such as fuel prices, future loads, and emissions permit costs, and production simulation models to evaluate changes in variable costs. As discussed above, the production simulation models are in the early stages of evaluating renewable integration and incorporating

Comprehensive quantitative evaluation of CSP with thermal storage requires modifications and extensions to a range of existing models used for portfolio planning, long-term reliability, operational feasibility and market price forecasting.

CSP with thermal energy storage (Denholm et al., 2013). Any deficiencies in modeling particular technologies could affect the subsequent evaluations that take place in steps 4 and 5.

When the utilities are operating in restructured electric power markets, such as California, these steps take place through a sequence of regulatory and wholesale market proceedings and internal utility decision-making processes. In California, much of the quantitative analysis to identify resource portfolios and associated operational requirements has taken place in California Public Utility Commission (CPUC) proceedings intended to cover Steps 1-4. Step 5 is disaggregated based on the different classes of resources (e.g., procurement of renewable resources under RPS, capacity under the Resource Adequacy program, storage resources under a separate mandate, energy and operational flexibility from all resources under long-term procurement planning). In utility procurement, the quantitative methods used are largely proprietary to the utilities, although the CPUC provides oversight and the general approaches are known to sellers. There have been some improvements in valuation relevant to CSP with thermal storage. These include the expansion of the net system cost equation required by the CPUC for RPS market valuation to include ancillary services, and the incorporation of detailed production cost models of system operations into long-term procurement decisions that recently have been extended to consider CSP with thermal storage (e.g., see CAISO 2011; Denholm et al, 2013; Jorgenson et al., 2014). However, as of this writing, there remain several further steps in California to appropriately value CSP with thermal storage, including the consideration of avoided integration costs and comparative capacity credits of alternative solar technologies, as calculated in some of the studies surveyed here.

Table 4-1: Studies of CSP with thermal storage by type of model

Type of model	Electric power products valued	Studies of CSP with thermal storage
Plant-level simulation with exogenous fixed prices	Energy, ancillary services	Madaeni, Sioshansi, and Denholm (2012b); Sioshansi and Denholm (2010)
Power system unit commitment and dispatch models (with endogenous system production cost or market price formation)	Energy, ancillary services, integration requirements and costs	Jorgenson et al., (2014); Jorgenson et al., (2013); Denholm et al., (2013); Mills and Wiser, (2012b); Denholm and Hummon (2012)
Long-term resource planning/ expansion models	Energy, ancillary services, capacity	Survey in Mills and Wiser (2012a); Mills and Wiser (2012b); NREL (2012)
Capacity valuation models	Capacity	Jorgenson et al., (2014); Jorgenson et al., (2013); Denholm et al., (2013); Madaeni, et al., (2012b); Mills and Wiser (2012b); Sioshansi and Denholm (2010)

4.4 Scenario Development and Baseline Measurements

In addition to using different quantitative methods and modeling tools, the studies reviewed in this report also use different approaches to scenario development and to the baseline or comparative measurements of economic benefits, i.e., the reference value to which the value of incremental CSP with thermal energy storage is compared. When comparing studies, the reader needs to understand how these methods affect the results. This section of the report provides a brief review of these methods, with further discussion in subsequent sections.

Construction of solar portfolios

As noted above, there are two basic methods for constructing renewable portfolios to meet future policy goals or hypothetical penetration levels: those developed endogenously using a portfolio planning model, in which the costs of alternative resources drive the penetration of those resources in the portfolio, and those developed exogenously by modifying a baseline portfolio.

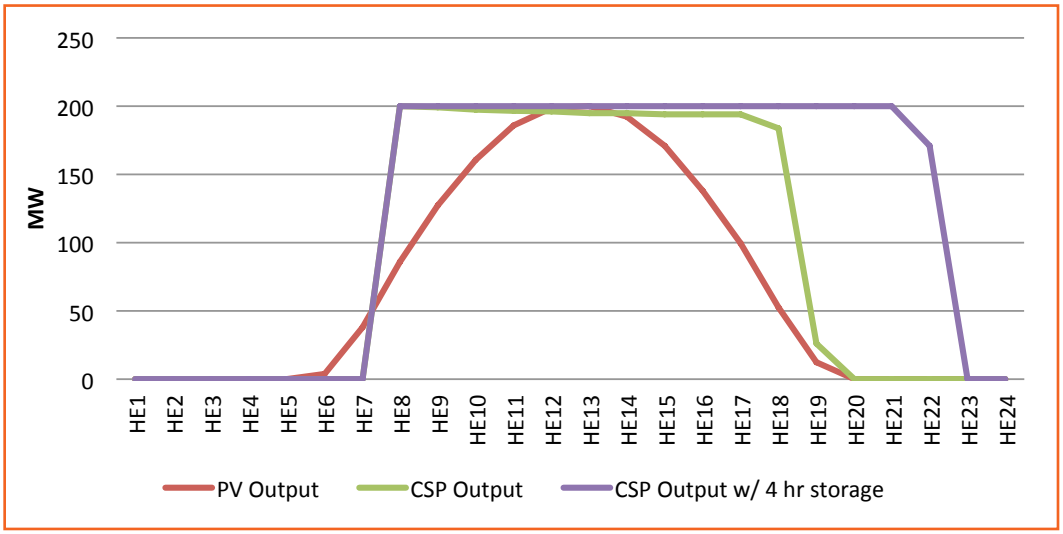
With regard to the latter types of methods, the baseline for calculating the economic benefits of CSP with thermal storage is typically by comparison to a scenario in which CSP without storage and/or PV plants (or wind generation) are added to the power system. Different comparative results can be expected if the solar technologies being evaluated are modeled as incremental additions of energy by the CSP plant with storage, an *ad-hoc* re-allocation of a fixed solar energy portfolio resulting in reductions of other solar production, or as equivalent additions of energy by the different solar technologies. Each of these methods has been used in the studies surveyed, and they need to be differentiated when interpreting the results.

Additions of storage capacity (and other design parameters) on a CSP plant with a fixed power block

In a number of studies, CSP plants with a fixed size (MW) of power block have been modeled with an incremental increase in solar multiple and thermal storage capacity to examine potential plant cost-benefit ratios. Madaeni et al., (2012a,b) provide examples of this type of analysis using exogenous fixed price models. The operational result is an increase in the capacity factor of the plant, potentially yielding additional energy and ancillary service revenues as well as higher capacity value. Results are shown in Sections 6 and 11. These plants can also be compared to PV plants within the same modeling framework.

To illustrate the shape of the resulting production profiles under this approach, Figure 4-2 shows three "clear day" profiles for a solar plant rated at 200 MW of maximum output: a fixed-tilt PV plant, a CSP plant without storage, and a CSP plant with 4 hours of storage. A tracking PV plant would attain a profile closer in shape to a CSP plant without storage. In this example, the thermal storage is represented as operating at maximum output for 4 additional hours after sunset, but could in principle be dispatched to any hours.[22]

Figure 4-2: Energy production profiles for three 200 MW solar plants: fixed tilt PV plant, CSP plant without storage, and CSP plant with 4 hours of storage



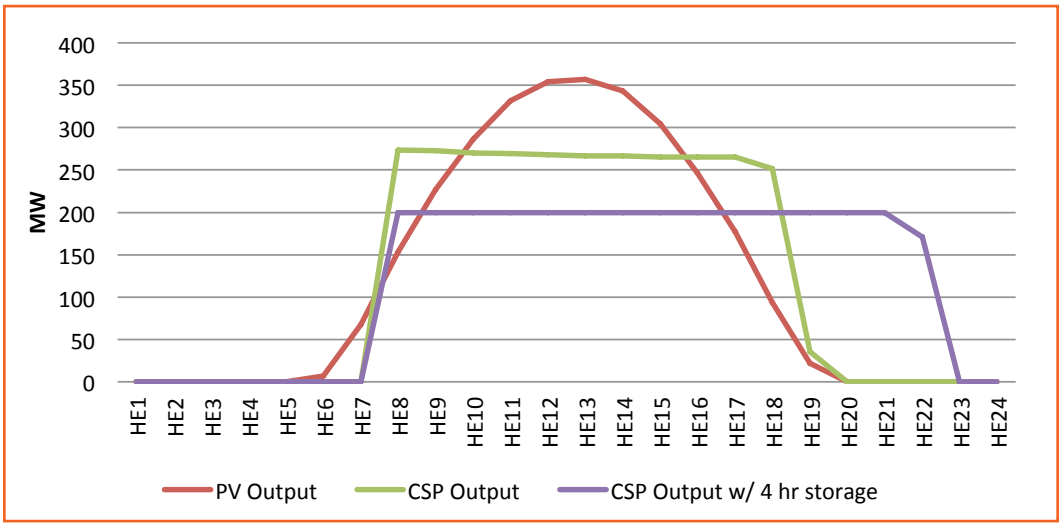
[22] The profiles for the PV and CSP without storage were constructed from generic data provided by the California ISO. The CSP daily generation profile is based on parabolic trough plants, but is indicative, for summer days, to other CSP technologies as well.

"Equal energy" solar scenarios

From the perspective of utility procurement to meet a policy, such as an RPS, the objective is typically to procure a fixed quantity of renewable energy by a particular year. Within that requirement, the mix of renewable resources may change but the quantity of energy remains the same. Hence, many simulation studies that include CSP with thermal energy storage, particularly those that model the power system, adjust the capacities of alternative plants, such as PV or CSP without thermal storage, so that they will all equivalently meet the renewable energy requirement. In some of these studies, researchers model specific RPS scenarios developed by regulators (e.g., Denholm et al., 2013), while in others they model illustrative cases (e.g., Jorgenson, et al., 2014; Jorgenson et al., 2013; Denholm and Hummon, 2012; Mills and Wiser, 2012b).

Figure 4-3 illustrates the types of production profiles that are being compared in these equal energy comparisons; the figure shows the same three technologies as in Figure 3-2, but with maximum operating levels adjusted to provide equivalent energy. The energy output is arbitrarily fixed to be 2970 MWh on a summer clear day, roughly the daily quantity of energy provided by a 200 MW CSP plant with 4 hours of energy storage. The figure shows that to maintain equivalent energy production, the maximum operating levels (or installed capacity) of both the fixed-tilt PV plants and the CSP plant without storage are adjusted upwards to produce more energy. These adjustments would obviously affect both the cost of three such projects with equal energy, and also the economic benefits. In some of the studies discussed here, the aggregate production profiles of the different PV and CSP with thermal storage scenarios being modeled as providing equal energy are dramatically different, especially at higher solar penetrations (e.g., Mills and Wiser, 2012b).

Figure 4-3: Equivalent energy production profiles on a clear day for a 200 MW CSP plant with 4 hours of storage, an approx. 275 MW CSP plant without storage, and an approx. 360 MW fixed-tilt PV plant



Incremental versus Aggregate Additions of CSP with Storage

A further modeling decision is the quantity of CSP with thermal energy storage to model in a scenario, whether an incremental project or a portfolio of multiple projects. For example, Denholm et al., (2013) model an "incremental" addition of CSP with thermal storage, as well as other solar technologies, in a California 33% RPS scenario, while Mills and Wiser (2012b) model aggregations of CSP with thermal storage sized to meet increasing targets for annual renewable energy (but measure economic benefits as marginal additions to the aggregate portfolios). Yet other studies have modeled

somewhat arbitrary portfolios intended to demonstrate operational effects at higher penetrations. For example, Denholm and Mehos (2011) construct two high-penetration solar scenarios for California designed to show the potential for dispatchable CSP to support integration of an aggregate solar portfolio (in which PV is being increasingly curtailed due to over-generation conditions).

Other Benchmarks

Flat block. A further comparative measurement conducted in several studies is the use of a "flat block" of (hypothetical) non-dispatchable, zero-cost "renewable" energy, as an alternative to the incremental wind and/or solar project. The flat block is intended as a proxy for a baseload energy resource with no fuel costs – such as a nuclear plant, a geothermal plant or a CSP plant with sufficient storage capacity such that it could operate 24 hours – and which would not create integration requirements associated with variable energy production (Milligan et al., 2011).[23] Mills and Wiser (2012b), Denholm and Hummon (2012) and Denholm et al., (2013) all include the modeling of a substitute flat block when valuing CSP with thermal energy storage, as well as the other solar and wind technologies which they evaluate. Although the results are not reviewed in this report, the valuation of the flat block could be of interest when considering CSP with high levels of storage capacity (i.e., operated as baseload).

"No renewables" scenario. Because the flat block does not provide any operational capabilities itself and reduces production costs due to its zero fuel costs, another baseline measurement is a scenario in which future load is served by the lowest cost, dispatchable, *non-renewable* resources. For example, CAISO (2011) includes a scenario for an "all gas" case in 2020 that includes only existing renewable resources on the California grid in 2011 and fills all future requirements with additional gas plants (a mix of combined cycle and combustion turbines). This scenario provides a more accurate baseline for measuring total changes in production costs and operational requirements than does a flat block. Similarly, Mills and Wiser (2012b) model a 2030 California scenario with no penetration of the renewable resources for the California grid with the exception of an incremental wind and solar plant of each type. The Mills and Wiser approach is somewhat artificial given the presence of existing renewables on the California grid. However, it is useful for showing how changes in the penetration of renewables on the grid progressively affect each component of economic benefits.

4.5 Low versus High Penetration Scenarios

For purposes of this survey, there are certain inflection points in the economic benefits and integration costs that take place as a function of renewable penetration, and some specific to solar penetration. For that purpose, the discussion of results is organized in some sections by the penetration level being modeled. "Low renewables" scenarios are defined as cases where renewables account for less than 15% of annual energy production. "High renewables" scenarios are cases where renewables account for greater than 15% of annual energy production. This is a somewhat arbitrary dividing line for discussion purposes, and is not intended to imply that key changes in benefits necessarily take place around that point. Section 6 provides more details on the composition and characteristics of high penetration scenarios.

[23] However, as Milligan et al., (2011) note, and as shown in the studies reviewed here, the flat block also has significantly different hourly energy (and capacity) value than wind and non-dispatchable solar, and hence will distort the valuation of the integration component when total net system costs are being compared. They observe that there are some partial corrective measures that could be taken, such as "shaping" the flat block on a daily basis, including to reflect peak and off-peak periods with ramps, but consider these "not entirely satisfactory." If the primary objective of the flat block is to isolate the incremental integration cost component for the variable energy resources, there are other methods discussed in Section 8 below that are more accurate.

Low and High Renewables Scenarios

	Low Renewables Scenarios	High Renewables Scenarios
Exogenous Fixed Price Models	Sioshansi and Denholm (2010); Madaeni, Sioshani and Denholm (2012)	None publically available[24]
System Dispatch Models	Denholm and Hummon (2012); Mills and Wiser (2012b)	Jorgenson et al., (2014); Jorgenson et al., (2013); Denholm et al. (2013); Denholm and Hummon (2012); Mills and Wiser (2012b); NREL (2012)

[24] Note that simulation studies of other storage technologies have been conducted in which either market prices have been estimated for future years using a regression model, or a system model is used to calculate market prices in future high renewables scenarios before the addition of new storage, and then the storage technology is dispatched separately against those simulated prices. Some CSP companies have privately conducted such studies of economic benefits from thermal energy storage, but public studies have not been released.

5. Valuation of Renewable Resources – Implication of Regulatory and Market Regimes

CSP with thermal energy storage has potential applications in many countries and regions of the world that have different market structures and regulatory regimes. Along with conventional project development assessments, these institutional differences must be considered when valuing CSP with thermal energy storage in particular regions. This section is organized as follows:

- Section 5.1 discusses the alternative institutional structures for the power sector which may affect valuation methods.
- Section 5.2 reviews valuation in U.S. markets.
- Section 5.3 reviews valuation outside the United States.

Tables 5-1 to 5-3 at the end of this section briefly summarize institutional structures for the power sector, trends in electric power demand and supply, renewable energy policies, and other CSP-specific market drivers (measurements of direct normal insolation, availability of transmission to those locations) for the primary CSP markets around the world. There is also a list of references for the tables in the References section at the end of the report.

Regulatory and market regimes affect the valuation of resources. In countries with transparent wholesale markets, it is easier to value a plant's attributes, but historical prices do not necessarily help in forecasting future system conditions. In regions without such markets, resource planning methods used by utilities can similarly use simulations to estimate the net system cost of alternative renewable resources.

5.1 Institutional structures for the power sector

There are two basic institutional structures for the power sector globally: competitive wholesale power markets and vertically-integrated, state- or privately-owned utilities. In countries or regions with competitive power markets,[25] the incumbent electric utilities have typically divested most or all of their generation capacity. There may also be competition for retail load. The generation investments are privately owned and the transmission network is operated to provide "open access" by an independent system operator or a regulated transmission company that owns no generation assets.[26] The wholesale markets usually include day-ahead and real-time auctions for energy and ancillary services with transparent market clearing prices, including the products described in Section 2. They may also include capacity markets that settle financially on different time-frames (months, annual, or multi-year). Generation, storage and demand-side resources bid into these markets competitively and set the market clearing prices. Historical market prices along with forecasts of fuel prices and new market products that may be needed (such as a ramping reserve) form the basis for expectations about market value in the future. These forecasts are used in part to estimate the long-term economic benefits of alternative renewable energy plants ad other resources.

In contrast, in a vertically integrated utility, whether privately or government-owned, the utility owns the generation and the transmission assets and serves the retail load. These utilities operate their own power systems to self-provide power and ancillary services or buy these services from a neighboring utility or wholesale seller. In some cases, independent power producers are allowed

[25] Countries and regions with competitive power markets include about 75% of the United States, England and Wales, Scandinavia, Spain, Australia, New Zealand, Chile, and Brazil, while many others have introduced elements of market competition.
[26] An independent system operator owns no assets other than its control room, operating systems and human resources. It is intended to be a true "third party" operator of the power system. A regulated transmission company, sometimes called a "Transco", does own transmission assets but operates the system impartially among generators.

into the market, but have to contract bilaterally with the utility (or sell into a competitive market elsewhere on the grid). Vertically integrated utilities typically serve as their own planning entities with responsibility for meeting future load growth. A vertically integrated utility's capacity investment decisions are generally subject to oversight by a subnational[27] or national regulator or other authority. For such utilities, the decision on how to maximize the benefits of CSP with thermal storage will be based on avoided fuel costs or energy market costs, and estimates of avoided future capacity needs.

5.2 Valuation in U.S. Markets

In the United States, both of these market/utility structures – and "hybrids" of them which allow regulated utilities and IPPs to compete for new investment – exist due to a high degree of regional autonomy in implementing aspects of wholesale market competition.

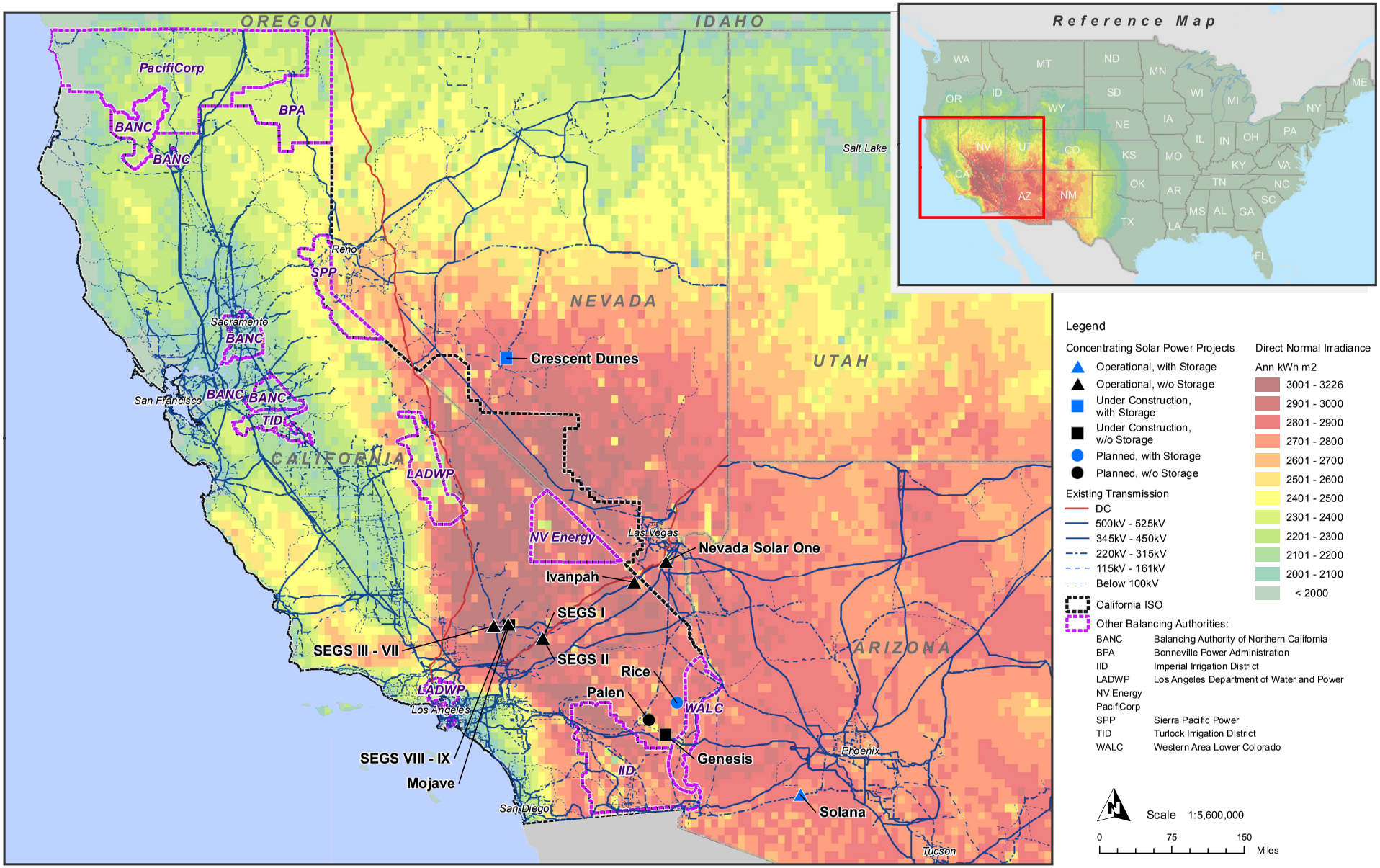
Figure 5-1 shows the locations of the existing CSP plants and much of the CSP development potential in the western U.S., as well as the state boundaries, high voltage transmission, intensity of direct normal insolation, and boundaries of the California Independent System Operator (CAISO) and other balancing areas in California. This region is where most further U.S. CSP development is likely to take place, although there is project development in Colorado and Texas.

Table 5-1 briefly summarizes the regulatory and market structures in the western U.S, as well as certain policies and conditions relevant to CSP development. California has been the largest market for CSP in the United States to date, with over 1 GW of such plants in commercial operation or close to such operations. With regard to electric power market structure in California, the large investor-owned utilities[28] have divested most of their generation assets, but own most of the transmission in their territories, and are all located within the CAISO footprint. The CAISO operates day-ahead and real-time wholesale auction markets for energy and ancillary services (see also Section 3 for further discussion) limited to its footprint, but plants in neighboring regions can sell services into the CAISO markets depending on whether there is transmission transfer capacity and if they are qualified to follow CAISO dispatch instructions. The other utilities in the western U.S. are either owned by municipalities, the federal government, or private utilities that remain vertically integrated; these utilities are required to offer non-discriminatory transmission access under the federal transmission open access rules. These utilities also buy/sell power with other regional entities – utilities or independent power producers – based on bilateral contracts.

To date, the different states and utilities with sufficient direct normal insolation have a mixed record with respect to valuation of CSP with thermal energy storage, and generally have only recently begun to develop and implement the types of long-term simulation models described in this report (Mills and Wiser, 2012a). In California, the California Public Utilities Commission (CPUC) determines the rules and provides oversight of investor-owned utility procurement to meet policy goals, including greenhouse gas emissions reductions, the RPS and the storage mandate, by the investor-owned utilities. Some of the current CPUC-defined methods for the valuation of CSP with thermal energy storage were described briefly in Section 3.3, and there are several proceedings in process to develop new analytical methods which could improve the comparative net cost valuation of more flexible solar plants.[29] With respect to wholesale market valuations of the services provided by CSP with thermal storage, the CAISO markets provide hourly and subhourly locational marginal

[27] That is, states, provinces, municipalities or other subnational bodies.
[28] Pacific Gas & Electric, Southern California Edison, and San Diego Gas & Electric.
[29] These include refinements to capacity valuation to calculate the changes in solar capacity credits using an ELCC model due to increased solar penetration, as discussed in Section 8, and consideration of renewable integration costs, as discussed in Section 9.

Figure 5.1 - Operational and planned CSP plants in the Southwestern United States, 2014



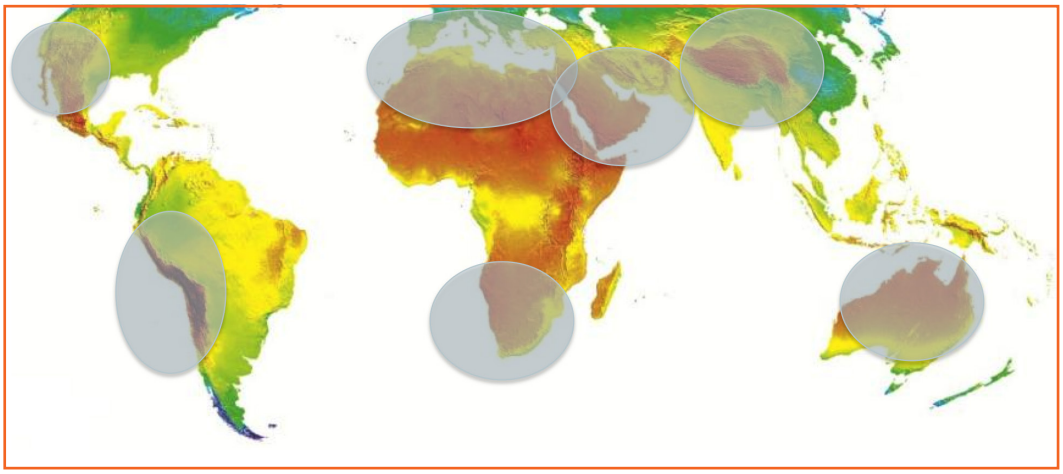
prices for day-ahead and real-time energy, and zonal prices for frequency regulation, spinning and non-spinning reserves. In addition, over the next 1-2 years, the CAISO will add services to value additional operational flexibility needed for renewable resource integration, such as payments for ramping reserves, and frequency response services. In sum, these regulatory and market changes could improve the comparative valuation of economic benefits from CSP with thermal storage when compared to other solar technologies.

Elsewhere in the region, valuation of solar projects by vertically integrated utilities is conducted using conventional long-term planning and procurement methods (Mills and Wiser, 2012a). In California, the municipal utilities outside the CAISO market have evaluated CSP projects in their procurement processes, but have not yet advanced a project. In Arizona and Nevada, two CSP plants with thermal storage have been procured, primarily to help meet utility evening peak loads.

While solar valuation methods vary, to properly value CSP with thermal storage over the long-term, utilities must develop a long-term forecast of fuel prices along with an economic dispatch solution for the CSP plant under various scenarios of increasing renewable penetration.

While solar valuation methods vary among these utilities, there are similarities in the analytical approaches used for long-term valuation of CSP with thermal storage, since in all cases – whether in a restructured market or a vertically integrated utility – the basic method requires a long-term forecast of fuel prices along with an economic dispatch solution under scenarios with increasing renewable penetration (Mills and Wiser, 2012a; Jorgenson et al., 2013, 2014).

Figure 5.2 - Global markets for CSP in high DNI regions



5.3 Valuation outside the U. S.

Outside of the United States, there are many variations along the spectrum between wholesale deregulated markets, regulated privately owned utilities, and nationally- or regionally-owned utilities. Figure 5-2 shows the general locations of regions with high potential for CSP development around the world. The brief summaries of policies, regulatory and market structures in Tables 5-1 to 5-3 provide context for how those factors might affect CSP development and valuation, but obviously each country and region requires in-depth evaluation. The CSP Alliance may provide additional review of solar valuation in these international markets in subsequent reports.

Despite the differences in market and regulatory structures between countries, most of the valuation methods for CSP with thermal energy storage discussed in this report should be applicable with some modification. First, these methods are usually generic, and several of the power system modeling methods and tools discussed herein are used across the world. Modeling methods developed in one location can be utilized to study the systems in others (e.g., Brand et al., 2012). However, in developing countries, while CSP with thermal energy storage has been evaluated in several integrated resource planning processes, the consideration of "value-based" criteria has

apparently been limited in procurement processes and PPA negotiations (Kulichenko and Wirth, 2011).

Second, power systems of similar size, resource mix, and electric power market design, such as in California and Spain, can learn from each other's experiences in system and market operations as renewable resource penetration increases.

Third, while not all regions have transparent competitive wholesale markets, the results of studies from regions with markets provide benchmarks for the benefits of different services provided by the CSP plants with thermal energy storage, especially over time. These can be of interest to non-market regions as well (see, e.g., Madaeni et al., 2012b). In addition, the market regions may provide additional market-based incentives for technology innovation, such as providing greater operating ranges on CSP plants with storage, that are also relevant to operations in non-market regions.

Ultimately, specific regional studies are needed for accurate valuation of the benefits of CSP with thermal storage. The literature survey that follows includes only a few publicly available analyses of the economic and reliability benefits of CSP outside the United States with some exceptions. Brand et al., (2012) model parabolic trough plants with and without storage on the power systems in Morocco and Algeria, with results discussed in Section 7. In regions with competitive power markets, which include Australia, Spain and Chile, there are also few public studies. Although they do not calculate operational benefits, Rutovitz et al. (2013) calculate the value of CSP with thermal storage in providing capacity and avoiding transmission investments in Australia at a number of different locations on the grid. Usaolo (2012) examines the potential market benefits of CSP with thermal storage in Spain, although most plants in that region were at the time under fixed tariff-based payments.

To improve understanding of economic benefits in these countries, government agencies, utilities and the CSP industry should undertake additional studies of CSP with thermal energy storage in different power systems and provide the results publicly to expand understanding of the resource. International associations that support analysis of CSP technology and policy, such as SolarPACES,[30] should expand their research scope to include implementation and comparison of valuation studies in different countries.

To improve understanding of economic benefits in countries without transparent markets, government agencies, utilities and the CSP industry should perform and and publish additional simulation studies of CSP with thermal energy storage in different power systems and under different conditions.

[30] Details on SolarPACES can be found at http://www.solarpaces.org/.

Table 5-1: CSP-TES markets for electric power in the Americas

Structure and Regulation of Electric Power Sector	Current Resource Mix and Energy Demand Forecast	Renewable Energy and Greenhouse Gas Policies	CSP-specific policies/Status of CSP projects	Solar Resource, Land Use and / or Transmission Availability
UNITED STATES				
Arizona				
Electric power sector is composed of vertically integrated utilities, notably Arizona Public Service (APS), Tucson Electric Power (TEP) and Salt River Project. The Arizona Corporation Commission (ACC) established and oversees the RPS.	While load growth has slowed, the major utilities still anticipate growth of between 1-2% per year over the next 10 years. The current fuel mix for electricity generation consists of nuclear and coal (66%), natural gas (25%), hydroelectric (6-8%) and other renewable resources, including wind and solar. About 25% of electric power is exported, primarily to California.	The RPS target, which includes hydroelectric, is 15% by 2025, increasing 1% annually. 30% of the annual requirement must come from distributed resources. Arizona currently has the second highest solar capacity installed in the United States. By 2014, about 2 GW of solar capacity has been installed.	CSP is eligible under the RPS, but there is no specific CSP set-aside. Under contract to APS, Abengoa developed the Solana 250 MW parabolic trough with 6 hours of thermal storage, which began operations in 2013.	Favorable DNI areas in most of the state, particularly in the west and southeast. See Figure 5-1.
California				
The electric power sector has undergone a number of institutional and regulatory changes in recent years. California required divesture of most generation by the three large investor-owned utilities in the mid 1990s – Pacific Gas & Electric, Southern California Edison, and San Diego Gas & Electric. These utilities serve about 80% of California load. They still own nuclear and hydro assets, and are required to procure the bulk of renewable resources under long-term contracts for RPS compliance. Since 1998, the California ISO has operated a competitive wholesale market for energy and ancillary services across these utilities footprint. The remaining approx. 20% of the California power system is self-operated by municipal utilities. The California Public Utilities Commission (CPUC) regulates investor-owned utility long-term procurement planning, resource adequacy, and compliance with state renewable energy policies. The California Air Resources Board (CARB) oversees compliance with greenhouse gas policies.	California Energy Commission (CEC) forecasts ~1% demand growth per year to 2022, reflecting both demand growth and reductions due to energy efficiency policies. These include increased investment in energy efficiency, growth in customer-site distributed energy technologies, and electrification of the transportation sector. Electric power production is currently about 30-40% from in-state natural gas plants, under 10% from the remaining nuclear plant, under 10% from in-state hydro, 20-30% from imports, and about 20% from renewable resources.	33% RPS by 2020, which is expected to be achieved ahead of schedule based on existing contracts. Possibility of 40-50% RPS legislation or new targets focused on GHG reductions by 2030. In 2014, California also enacted a storage mandate, requiring 1.3 GW of new storage (excluding large pumped hydro) to be procured by load-serving entities by 2020. Existing legislation (AB 32) also requires reductions in greenhouse gas emissions to 1990 levels by 2020, with a further goal of 80% reductions from 1990 levels by 2050.	CSP and CSP-TES is eligible under the RPS, and CSP-TES is also eligible under the storage procurement mandate. There are no CSP-specific policies, but RPS procurement conducts calculations of net system costs to compare alternative renewable investments, which is intended to capture the additional benefits of thermal storage (see Section 4). California has the longest history of commercial CSP operations of any region. The SEGS parabolic trough plants without storage (354 MW) in Southern California have been in operation since the mid-1980s. About 500 MW of additional parabolic troughs without storage constructed by Abengoa and NextEra are expected to begin operations in 2014. The BrightSource-developed Ivanpah project (372 MW) power tower without storage began operations in 2014. The Solar Reserve Rice project (150 MW) power tower with 8 hours of thermal storage is due to begin operations in 2016.	Favorable DNI areas in substantial areas of mid-central and southwestern California, particularly in the Mojave desert area. See Figure 5-1. In some cases, areas of the state have either been restricted from further renewable development or face substantial permitting barriers due to environmental regulations. However, certain parts of the desert region are in the process of being designated for renewable energy development. Transmission expansion has been increasing to accommodate 2020 renewable energy goals, particularly in the southern part of the state.
Colorado				
Electric power sector is composed of vertically integrated utilities, with the largest being Xcel Energy, owner of Public Service of Colorado.	Load growth is typically modeled as around 1.5% per year. Coal-fired plants currently provide about two-thirds of net generation; natural gas provides about one-fifth. In 2014, there was about 2400 MW of wind and 331 MW of solar energy installed, providing close to 15% of total electric power.	Renewable Energy Standard (RES) requires investor-owned electric utilities to provide 30% of generation from renewable energy resources by 2020, with 3% from distributed generation.	CSP is eligible under the RES. Solar Reserve has received construction permits for a 200MW power tower with thermal storage in Saguache County, but it has not been able to secure a PPA.	High DNI in Saguache and Alamosa Counties, in the southern part of the state, among others.

Structure and Regulation of Electric Power Sector	Current Resource Mix and Energy Demand Forecast	Renewable Energy and Greenhouse Gas Policies	CSP-specific policies/Status of CSP projects	Solar Resource, Land Use and / or Transmission Availability
Florida				
Electric power sector is composed of vertically integrated utilities, both investor-owned and municipal. The largest utility is Florida Power & Light (FP&L), owned by NextEra Energy, which accounts for almost 50% of retail electricity sales.	Load growth for the next decade is currently forecast to be around 1.2% per year. Electric generation is predominantly from natural gas (over 60%), with coal accounting for about 20% and nuclear power for just under 10%. There is about 1.5 GW of renewable generation installed. Current planning forecasts estimate an additional 1 GW of renewable capacity by 2022.	There is no RPS. However, individual utilities have solar incentive programs.	FP&L Martin hybrid solar thermal (75 MW) with a combined cycle plant has been in operation since 2010.	DNI is not favorable for stand-alone CSP.
Nevada				
Electric power sector is composed of vertically integrated utilities, the largest of which is NV Energy, recently acquired by Mid-American Energy Holdings.	Load growth is forecast to be small over the next few years, before increasing to 1.5% from 2015 onwards. NV Energy recently agreed to retire a significant portion of its coal-fired resources. Upon closure, the resource composition in Nevada will be largely natural gas-fired and renewable resources, such as geothermal (0.5 GW in 2014), solar (0.45 GW), and wind.	The RPS target is 25% by 2025. With the passage of SB 123, NV Energy will be retiring coal plant capacity equal to 800MW and adding 900 MW of gas and renewable energy capacity. SB 252 also will increase renewable energy procurement to the existing RPS by adjusting current rules.	CSP is eligible under the RPS. Also there is a minimum requirement that solar make up 5% of RPS energy until 2015 and 6% from 2016-2025. NV Energy has contracted for the Solar Reserve Crescent Dunes project (110 MW power tower, 10 hours of thermal storage), due to begin operations in 2014.	Favorable DNI areas in most of the state, particularly so in south. See Figure 5-1. The BLM has designated certain lands as Solar Energy Zones.
New Mexico				
Electric power sector is composed of vertically integrated utilities. The two largest utilities are Public Service of New Mexico and Southwestern Public Service.	Load growth is forecast at around 1% per year. Electric power generation is about 70% coal-fired, with 20-30% from natural gas. Renewable energy accounts for almost 10% of generation, of which wind energy is almost 60% and solar only about 5%.	Investor owned utilities have to meet a 20% RPS by 2020 (10% for utility cooperatives). Solar is required to be a minimum of 20% of RPS procurement. New Mexico is also supporting development of transmission to export renewable energy to neighboring states.	CSP is eligible under the RPS. No CSP projects in operation or advanced planning, other than announcement by Tri-State G&T for 36MW CSP hybridization to Escalante coal plant.	Favorable DNI areas in most of the state, particularly in the southwest.
Utah				
Electric power sector is composed of vertically integrated utilities. PacifiCorp is the largest utility, accounting for over 80% of retail sales.	More than 80% of electric power is from coal, with natural gas providing about 10-15%. Over 5% of electric generation is from renewable resources, with hydroelectric power accounting for about one-half of the total. Utah exports electric power to buyers throughout the West.	There is a voluntary goal of 20% renewable energy by 2025 (based on adjusted electricity sales, i.e., net of nuclear and demand side management); no interim requirements prior to 2025.	No utility-scale CSP projects in operation or advanced planning.	Favorable DNI areas in portions of the state, particularly in the west and south.
Texas				
Electric sector is significantly restructured on both the retail and wholesale side. The top 5 load-serving entities are TXU Energy Retail, Reliant Energy Retail, City of San Antonio, Entergy Texas Inc., and Southwestern Public Service. About two-thirds of the generation is owned by independent power producers. A competitive wholesale market for energy and ancillary services is operated by ERCOT. Remainder of the power system is self-operated by municipal utilities. Public Utilities Commission of Texas regulates the electric power sector, including the renewable energy requirements.	More than 65% of electric generation is gas-fired generation, less than 20% from coal generation, 5% nuclear, and more than 10% from renewable resources, primarily wind generation.	RPS targets are 5800 MW of eligible renewable capacity by 2015, 10,000 MW by 2020; the RPS includes 500MW of non-wind resources by 2020. Municipal utilities Austin Energy and CPS Energy have procured the majority of utility scale solar in the state.	No utility-scale CSP projects in operation or advanced planning.	DNI is highest in the far West and far North. The state has developed transmission to access renewable resources in several CREZs (Competitive Renewable Energy Zones), initially primarily for wind development.

Structure and Regulation of Electric Power Sector	Current Resource Mix and Energy Demand Forecast	Renewable Energy and Greenhouse Gas Policies	CSP-specific policies/Status of CSP projects	Solar Resource, Land Use and / or Transmission Availability
Oregon				
Electric power sector is composed of vertically integrated utilities. The largest utility is Portland Gas & Electric, followed by Pacific Power, and smaller municipal utilities.	About 45% of electric generation is from conventional hydroelectric plants, 35% coal and 12-16% natural gas. Wind energy provides about 5-6%. Portland Gas & Electric has agreed to terminate coal-firing at its 500MW Boardman facility by 2020.	Large utilities – defined as those with 3% or more of the state's load – must meet 25% RPS by 2025 (20% by 2020, 15% by 2015).	CSP is eligible for the RPS. No utility-scale CSP projects in operation or advanced planning.	DNI favorable for CSP limited to southeast area of the state.
MEXICO				
Federally-owned and regulated electric power sector, with policy reforms underway. Largely controlled by Federal Electricity Commission (CFE), a state-owned utility. The Energy Secretariat (SENER) defines national energy policy. Currently, private companies must sell all the energy produced to CFE under a PPA. Legislation in 2013 will establish an independent grid operator and create an energy trading market. These reforms are intended to lower electricity prices, but could provide opportunities for solar generators.	Demand is expected to grow between 3-4% per year. Electric power generation is close to 80% from natural gas and oil/diesel generation, and 4% from nuclear power. Large hydro dominates the renewable energy sector at 14%, with geothermal at around 3%. About 1.5 GW of wind installed. Mexico will require an estimated 27 GW of additional capacity over the next 15 years to cover growing demand.	Policies to reduce greenhouse gas emissions enacted in 2012 will require 30 % reductions by 2020 and 50 % by 2050. These policies also limit fossil fuel generation to 65 % of demand by 2024, with the residual (35%) filled by non-carbon generation.	There are no CSP-specific policies at this time. Abengoa is constructing the 12 MW Agua Prieta II parabolic trough plant as a hybrid ISCC.	Favorable DNI close to border population centers and the United States, but distant from central and southern demand centers.
BRAZIL				
Deregulated wholesale electricity markets. The market is dominated by government-owned entities, of which Eletrobrás holds about 40% of generation capacity, with smaller state-companies accounting for another 20%. Privately-owned companies account for the remaining 40% of generation capacity. The Ministry of Energy and Mines (MME) makes policy for the electric power sector. The National Agency for Electricity (ANEEL) regulates generation, transmission and distribution.	Installed capacity (114 GW in 2010) primarily hydro, which currently accounts for about 70% of electric power capacity, with the remainder gas-fired. New hydro resources are difficult to exploit. The National Energy Plan for 2010-2019 targets 63 GW of new capacity, primarily non-hydro. The wind sector is growing quickly and will drive renewables build due to low cost and strong resources. Electricity demand is expected to grow steadily over the decade, despite the current economic slowdown.	The national government holds non-technology specific energy auctions. No solar projects have been selected thus far. The state of Pernambuco hosted the country's first solar-only auction in January 2013. States have also been setting their own renewable energy targets, such as Sao Paolo, which laid out plans to generate 70% of electricity from renewables by 2020.	No CSP currently in operation. There are no CSP-specific policies at this time, and apparently little development.	DNI in north-east shows the highest potential for CSP development.
CHILE				
Electricity sector reforms beginning in the 1980s lead to full privatization of generation, transmission and distribution, and increased competition in generation investment and market services. The four largest generation owners are ENDESA, AES Gener, Colbún S.A., and Suez Energy Andino, and there are over 20 other firms. The Ministry of Energy has authority over energy policy. The Comisión Nacional de Energía (CNE) regulates the electric power sector. The Superintendencia de Electricidad y Combustibles (SEC) is a market monitor with authority to impose penalties.	Electric demand expected to grow at rates of 6-7% annually to 2020. Hydro remains a dominant resource (currently around 33%), with a growing share forecast from gas-fired generation. Oil and coal currently account for around 30% of capacity.	Tenders for non-hydro renewable energy will be expanded. 8% of new installed capacity from 2008 and 10% after 2024 to come from renewables. In total, 20% of energy from clean energy resources by 2025.	No CSP currently in operation. In 2014, Abengoa was selected to receive a grant toward constructing a 110 MW tower project with up to 17.5 hours of thermal storage. When built, this will be the first CSP project for electric power production in Latin America.	Favorable DNI in the north, co-located with mining load centers. Transmission between the northern grid and the southern grid is expected to be expanded.

Table 5-2: CSP-TES markets for electric power in Southern Europe, Middle East and Northern Africa

Structure and Regulation of Electric Power Sector	Current Resource Mix and Energy Demand Forecast	Renewable Energy and Greenhouse Gas Policies	CSP-specific policies/Status of CSP projects	Solar Resource, Land Use and / or Transmission Availability
SOUTHERN EUROPE				
Greece				
The Greek electricity market includes a wholesale spot market for energy and ancillary services and a capacity market. The Regulatory Authority for Energy (RAE) regulates the electric sector. The Hellenic Transmission System Operator operates the transmission grid. The state-controlled Public Power Corp. (PPC) and subsidiaries are still dominant in the sector, owning over 70% of generation capacity and the transmission and distribution systems. However, independent power producers have built the majority of new gas-fired capacity.	Coal has historically been the primary fuel for electric generation, but most new generation has utilized natural gas. Renewable energy exceeded 15% in 2010. An average annual growth rate in electric demand of 3% was reduced since 2007 due to the economic recession.	Renewable energy is targeted to provide 40% of electricity by 2020. Expectation is that wind will be the primary source of growth, expected to increase from 1.6 GW in 2011 to 7.5 GW in 2020.	Under the Feed-in Tariff rate structure of 2010, solar thermal energy was offered 264.85 €/MWh and solar thermal with storage system 284.85 €/MWh. There are two CSP projects in development.	Highest DNI is in the southern parts of the country, with the islands of Crete and Rhodes having the best solar resource for CSP. The transmission system consists of the inter-connected mainland system and islands that are not inter-connected. Potential to export solar energy to other European countries.
Italy				
After unbundling, the grid is now operated by Terna S.p.A. - Rete Elettrica Nazionale (Terna), the transmission system operator, Ente Nazionale per l'energia Elettrica (Enel), which still owns about 25% of generating capacity, and GRTN, the independent grid system operator. GME (Gestore dei Mercati Energetici), and the Italian Power Exchange Market (IPEX), operate the Italian energy market. Regulatory bodies include the Italian Energy Authority (Autorità per l'energia electtrica e il gas) (AEEG) and Gestore dei Servizi Energetici (GSE) S.p.A. Acquirente Unico (AU, soley owned by GSE) acts as the electric distributor to homes and small businesses.	The majority of electric generation is oil and gas-fired (60%), with smaller contributions from hydro (24%), coal (8%), and renewables. As of 2012, renewable installed capacity is 47 GW consisting of hydro (18.2 GW), wind (7.9 GW), solar (16.4 GW), geothermal (0.8 GW), and biomass (3.8 GW). Italy also imports 16% of its electric power. In By 2020, Terna projects renewable portion of production will increase to 35-38% to 120-130 of 345-360 TWh produced annually.	The Renewable Energy share target is 17% by 2020. The FIT support scheme is regulated by the Ministerial Decree of 11 April 2008, and was amended by the Ministerial Decree of 6 July 2012. Incentives are provided to renewable IPPs by the GSE.	FITs are provided 25 years and depend on year of COD and solar integration fraction. Tariffs remain constant throughout the support period. In the case of hybrids, FITs apply only to the electricity generated from the solar portion. Limitations include TES storage requirements greater than 1.5kWh-th TES capabilities per m2 of mirror surface, a maximum mirror surface of 2,500,000 m2, and specific limitations on types and amounts of public funds allowable for capital expenditure. Italy has 2 operational CSP projects including Archimedes and ASE, and 7 in development (all of which are trough) Archimedes is an operational trough ISCC (5MW solar, 130MW natural gas) located in Priolo Gargallo, Sicily, and is the first commercial ISCC use molten salt as the HTF in the parabolic trough receivers.	Italian solar resource in Southern Italy, Sicily, and Sardinia ranges from 1700-2000 kWh/m2-y. Depending on specific location, regional challenges may include topography / elevation changes and/ or nearby hills and mountains. High voltage and medium voltage transmission is available in most areas under consideration.

Structure and Regulation of Electric Power Sector	Current Resource Mix and Energy Demand Forecast	Renewable Energy and Greenhouse Gas Policies	CSP-specific policies/Status of CSP projects	Solar Resource, Land Use and / or Transmission Availability
Spain				
The electricity market has been deregulated and restructured at both the wholesale and retail levels. The National Energy Commission (CNE) is the electric market and transmission regulator. Red Eléctrica de España (REE) is the transmission system operator, including the day-ahead and intra-day wholesale market for electric power. There are two basic methods for compensation of generators: those conventional thermal units within the "ordinary regime" get compensated based on wholesale market prices along with capacity payments; renewable generation under the "special regime" were paid initially through fixed rates or the market rate plus incentives, and more recently through a 'fixed profitability' incentive.	After the large reduction in demand in 2008-09, demand growth has fluctuated, showing growth from prior years in 2010, but reductions in all other years. At end of 2013, total conventional resource capacity totaled about 63 GW, consisting of combined cycle (25 GW), large hydro (17 GW), coal (11 GW), nuclear (7.8 GW), and fuel/gas (0.5 GW). The renewable energy capacity totaled about 40 GW, consisting of wind (23 GW), PV (4.4 GW), CSP (2.3 GW), non-renewable thermal (7.1 GW), small hydro (2 GW) and renewable thermal (1 GW). In 2013, renewable generation provided about 40% of annual energy (nationally), with wind supplying almost 50% of that total. Large hydro provided an additional 13%. Some regions have achieved even higher percentages of wind and solar penetration.	Spain has achieved some of the highest penetrations of renewable energy, and particularly solar energy, through a feed-in-tariff (FIT) program that was in place from 2007-2012. The FIT payments were partly cumulated in a deficit fund, which grew after the economic downturn beginning in 2008. In 2013-14, the FIT was reduced or eliminated, and payments to many existing plants were instead subject to a 'fixed profitability' incentive, which limits profits to renewable energy producers to 7.5%. On the positive side, integration of the very high penetration of wind and solar has been accomplished without any major reduction in reliability. While further expansion of renewable energy is clearly reduced under the current economic circumstances, earlier planning documents, such as the Spanish renewable energy action plan (2010), forecast 38 GW of wind, 8 GW of PV, and 5 GW of CSP by 2020.	Under the FIT, Spain has developed over 2 GW of CSP projects, most of them 50 MW parabolic troughs (the maximum capacity allowed under the FIT) and many of them with thermal energy storage (see Table 1-1) as well as auxiliary natural gas.	Highest DNI is in the central and southern provinces. Transmission upgrades have continued despite the economic recession.
Turkey				
Liberalization of the electricity market began in the late 1980s and has accelerated in recent years. The government institutions for electric power sector ownership and operations include the Electricity Generation Corporation of Turkey (EÜAŞ), the Electricity Trading Corporation of Turkey (TETAŞ) and the Turkish Electricity Transmission Corporation (TEİAŞ). Generation capacity is about 63% government owned, of which about 50% is controlled by the EÜAŞ, with initiatives to increase the level of private ownership. The remainder of capacity is under independent power producers, build-operate-transfer, and build-own-operate producers. TEİAŞ owns and operates the transmission system, in including the electricity market operator and system operator. Energy Market Regulatory Authority (EMRA) oversees energy markets.	Electric demand is expected to grow annually at 6% over the coming decade. Total installed capacity was 57 GW in 2012, with a target of 100 GW of by 2023. In 2013, installed capacity (MW) consisted of natural gas (~36%), hydroelectric (~35%), coal (23%), fuel oil (2%) and renewable (5%). Nuclear capacity to supply 5% of generation is planned for operation by 2020.	Renewable energy target is 30% by 2023. The Renewable Energy Law (Law No. 5346) promotes private renewable energy investments. In 2010, the law was amended to provide technology-specific FITs, with solar provided $133 /MWh and higher payments if local equipment is used.	While two CSP projects have been in construction, development has been slow otherwise. Solar FIT rates were below levels sufficient to provide incentives for substantial CSP project development.	DNI favorable in many locations, particularly in southern, central and southeastern regions. There is a fairly robust transmission network with a process for expansion. The government has identified particular locations for solar development.

Structure and Regulation of Electric Power Sector	Current Resource Mix and Energy Demand Forecast	Renewable Energy and Greenhouse Gas Policies	CSP-specific policies/Status of CSP projects	Solar Resource, Land Use and / or Transmission Availability
NORTH AFRICA				
Algeria				
The Algerian electricity sector has been partially unbundled, with competition in generation. The Electricity and Gas Regulation Commission (CREG) is the national electricity and gas market regulator. The Societe Algerienne de Gestion du Reseau de Transport de l'Electricite (GRTE) is the state-owned buyer of electric power. Soneglaz is the national public utility company.	Electricity demand has increased by average of 6% from 2000 to 2010. In 2009-2010, demand increased by ~20 percent. The generation mix is over 90% natural gas fired, with small contributions from oil-fired generation and hydro.	Algerian Renewable Energy and Energy Efficiency Development Plan (2011) identifies renewable plants with a total capacity of about 1.2 GW for construction between 2016-2020. The 2021-2030 programme projects installation of an annual capacity of 500 MW until 2023, then 600 MW per year until 2030. The plan targets 40% of electric power from renewable generation by 2030.	Solar energy (both solar PV and solar thermal) is recognized by the Algerian government as a primary renewable technology to be developed. The plan targets 37% of annual energy production from solar by 2030. Soneglaz planning identifies potential for 2,475 MW concentrated solar power (CSP) by 2020.	Excellent DNI across region; adequate land availability. Transmission for existing project sites adequate, but broader EU transmission integration plans unclear.
Morocco				
The Office National de l'Electricite (ONE) is a state-owned entity that currently owns transmission and distribution and is the largest owner of generation in the electric power sector. In the early 1990s, the sector was opened to competition from independent power producers. ONE is expected to own only 40% of generation by 2020, with much of the new renewable generation capacity developed by private companies.	Demand growth is currently 6.5% per year. Coal, oil and gas-fired generation accounts for almost 85% of current electric power production. The remainder is hydro and other renewables.	The National Agency for the Development of Renewable Energies and Energy Efficiency (ADEREE) oversees state policy to increase renewable energy to 42% by 2020, equally distributed among hydroelectric, wind (2 GW) and solar power (2 GW). About 500 MW of wind generation is in operation, with a pipeline of over 1 GW in various stages of development. Solar development is also increasing with both PV and CSP projects.	Establishment of MASEN to run Morocco Solar Plan. Outstanding tenders to develop 510 MW of new CSP. The 150 MW Noor 1 parabolic trough project is under construction by a consortium. The 200 MW Noor 2 parabolic trough and Noor 3 150 MW tower projects are in development.	Sufficient DNI in several parts of the country. Renewable development zones are established by the government. There is increased investment in transmission which can help support solar development.
Tunisia				
Societe Tunisienne d'Electricite et du Gaz (STEG) operates generation, transmission and distribution. Independent power producers account for about 14% of generation capacity.	Electricity generation is over 95% gas-fired.	Renewable targets are 11% of electricity generation by 2016 and 25% by 2030. In MW, the targets are 16% of installed power capacity by 2016 and 40% by 2030.	Policy is to develop 500 MW of CSP by 2030.	Sufficient DNI in many locations. There are plans for transmission interconnection to the European grid by 2016.
MIDDLE EAST				
GCC countries (other than Saudi Arabia)				
GCC countries include Bahrain, Kuwait, Qatar, United Arab Emirates (UAE), and Oman, along with Saudi Arabia, discussed next. None of the countries have deregulated markets, but several allow for competition in generation from IPPs and IWPPs. The Kuwait power sector is under the Ministry of Electricity and Water, with IPPs allowed. In Qatar, the General Electricity and Water Corporation is a state utility that contracts with IPPs and IWPPs as well as the Qatar Electricity and Water Company. In the UAE, the electric power sector remains state-regulated, although Abu Dhabi supports joint ventures with IPPs. The Oman power sector is under the Power and Water Procurement Company (OPWP), with IPPs and IWPPs.	The power sector in these countries is dominated by gas-fired and oil-fired generation. For Bahrain, Oman, Qatar, and UAE, gas-fired generation predominates. For Kuwait, oil-fired generation predominates. Electricity demand growth has been very high over the past decade, ranging between 5 -10% annually.	Specific renewable energy policies are still in early phases, with the focus on tenders for initial projects. Kuwait targets 15% of renewable energy by 2030 (about 2,000 MW). Kuwait has an ongoing tender for 70 MW of renewable projects. Qatar has a target of 20% renewable energy by 2024, with 1800 MW renewable energy capacity by 2020. Qatar will tender for 200 MW of solar power projects. In the UAE, Abu Dhabi targets solar to provide 7% of electric power by 2020; Dubai targets 5% by 2030. There are several specific renewable energy projects, including solar plants integrated into the Abu Dhabi Masdar complex. Oman has 5 renewable projects under construction, including 3 solar projects.	Kuwait is developing the 50 MW Shagaya CSP plant. Oman has 200 MW of CSP announced. Most solar power under development in Qatar is PV. UAE Shams 100 MW parabolic trough without storage began operations in 2013. Otherwise, lack of incentives appear to limit near-term CSP potential.	Favorable DNI throughout the region. The GCC's grid interconnection system supports transmission expansion and increased electricity trade between the member states. Grid expansion is taking place to integrate the UAE. Northern grid (Main Interconnected System) of Oman and the UAE established an interconnection in October 2011. The remainder of the Oman transmission network is divided into several parts that are not interconnected.

Structure and Regulation of Electric Power Sector	Current Resource Mix and Energy Demand Forecast	Renewable Energy and Greenhouse Gas Policies	CSP-specific policies/Status of CSP projects	Solar Resource, Land Use and / or Transmission Availability
Israel				
Regulated electricity market, primarily state owned. The Israel Electric Corporation (IEC) owns most of the electric power infrastructure.	Coal has historically been the primary fuel for electric generation, but most new generation has utilized natural gas. In 2013, ~70% and ~30% of electricity produced using coal and natural gas respectively.	Renewable energy to provide 10% of electricity by 2020. Expectation is that the primary source of growth will be in solar energy.	The Ashalim tender for 250 MW of solar was announced in 2008, and includes two CSP plants. The 121 MW BrightSource-Alstom Megalim plant, one of three projects selected under the Ashalim solar tender, will be located in the Negev Desert. The project is scheduled to come online in 2017	The long-term annual average DNI in Israel is 2200-2440 kWh/m2 (at Ashalim - 2,203 kWh/m2); Low land availability; Transmission for existing project sites is under construction.
Saudi Arabia				
A single vertically integrated utility, the Saudi Electricity Company (SEC), owns all the transmission, virtually all of the distribution network, and is the dominant owner of generation, with almost 40 GW. The SEC is planned to be divided into 4 independent power companies. There are a number of other generators, independent power producers, and independent water and power producers, that produce power and sell to SREC or supply isolated loads. These include some large industrial customers that self-provide electric power. The Electricity & Co-Generation Regulatory Authority (ECRA) promotes private sector participation and investment in generation through IPP or IWPP projects.	Generation capacity is around 55 GW, with policy intended to increase capacity to 120 GW by 2020. Natural gas-fired generation accounts for over 50% of current generation.	Government policy has set targets of 13 GW of wind, biomass and geothermal, and 41 GW of solar by 2032. There is an interim target of about 17.5 GW of solar by 2022.	Government solar targets include 25 GW of CSP by 2032. Most of the initial solar projects have been PV, with one 30 MW parabolic trough under construction.	Transmission requirements for the renewable build-out will be evaluated after the initial rounds of the tender.

Table 5-3: CSP-TES market for electric power in Sub-Sahara Africa

Structure and Regulation of Electric Power Sector	Current Resource Mix and Energy Demand Forecast	Renewable Energy and Greenhouse Gas Policies	CSP-specific policies/Status of CSP projects	Solar Resource, Land Use and / or Transmission Availability
SOUTHERN AFRICA				
South Africa				
Regulated power market with state-owned grid Eskom is the dominant owner of generation, supplying 95% of electric power, but independent power producers are intended to increase their share to 30%. Independent System and Market Operator bill going through Parliament. National Energy Regulator of South Africa (NERSA) provides generation licenses. Department of Energy sets policy and drives the procurement process of IPPs as well as developing the Solar Park concept. Treasury provided guarantees for PPAs signed with IPPs. Reverse auction bidding sets price with maximum prices stipulated per technology.	Currently, electric power is primarily coal-fired (90%), nuclear (5%) and hydro (5%). Significant power shortages with base-load coal and peaker gas and diesel generators being used for regulation. The 2013 Draft Integrated Resource Plan base case shows total capacity by 2030 of 81.35 GW, of which shares are forecast to be coal (38.7 GW), natural gas (11 GW), hydro (6.6 GW), nuclear (6.7 GW) and total renewables (18.2 GW), divided among PV (9.77 GW); CSP (3.3 GW); Wind (4.36 GW).	Energy policy targets 40% of new capacity by 2030 from renewables. Ongoing renewables procurement, Kyoto Protocols commitments, and carbon tax starting January 2015.	400MW of CSP projects under construction or final stages of development. Draft Integrated Resource Plan 2013 offers between scenarios of between 3,300 and 38,000MW of CSP allocated by 2050. 5GW Solar Parks under development. Likely scenario expected to be between 7-10 GW of CSP installed by 2030.	DNI of 2,800 to 3,000 kWh sqm/year is available in the Northern Cape, more than enough land available located near sub stations. Transmission lines being upgraded to connect the high DNI areas to the national grid. The Southern African Power Pool, a group of utilities in the region aims to create a common market for electric power in the region. Potential for future gas pipeline tie-ins. Water availability sufficient, good road network and urban infrastructure nearby.
Namibia				
Hybrid power market with state owned electricity grid and very few independent power producers. The government's existing policy follows privatization and unbundling of the state owned utility NamPower but very little has been achieved. Regulation remains complex. The performance of state-owned utility is incentivized. Private sector investment is allowed but tariff system is complex. The key players are state-owned power utility NamPower, responsible for generation and transmission of electricity, the regional electricity distributors (state-owned legal entities tasked with the supply and distribution of electricity in a dedicated region) and local authorities.	Namibia imports about 65% of its electricity from the Southern African Power Pool (SAPP) particularly South Africa. The rapidly declining surplus capacity within the SAPP has exposed the country to a degree of insecurity in relation to future supply. Namibia has been unable to enter into long-term contracts with its major supplier, the South African utility, Eskom. Current installed capacity is 249 MW-Hydro, 120MW-Coal 24MW-Diesel. Annual Imports usually between 100 to 300 MW. Maximum demand in 2013 was 613 MW and demand is projected to reach 750MW by 2020.	The White Paper on Energy Policy (1998) sets out specific national energy policy goals for the electricity supply industry. Although the promotion of renewable energy technologies (RET) is not mentioned as a special target, the White Paper identifies renewable energy technologies as contributing to meeting several targets like energy security and sustainability. There are no specific targets for renewables in Namibia.	There are no specific policies for CSP in Namibia. A 50MW CSP plant is planned, endorsed by Global Environment Facility and its implementation expected to begin in 2014. The project is funded by United Nations Development Program, Government of Namibia, Ministry of Mines and Energy and Renewable Energy, Energy Efficiency Institute and Development Bank of Southern Africa.	DNI of 2,800 to 3,000 kWh sqm/year in areas such as Ausnek, Kokerboom, Hichland and Gerus, more than enough land available but new substations will have to be built close to generation areas. Transmission lines will also need upgrades to connect high DNI areas to the national grid. Water is readily available. Good road network and urban infrastructure nearby.
Botswana				
The electricity market is dominated by government owned monopoly, Botswana Power Corporation (BPC). BPC is vertically integrated and controls the network of transmission and distribution lines. In 2007, the government amended the Energy Supply Act to facilitate the participation of Independent Power Producers (IPPs) in the electricity sector but not much has happened since then.	Botswana imports about 70% of its electricity from the Southern African Power Pool (SAPP) particularly South Africa. Demand for electricity peaked at 600MW in 2013. Demand is driven by electrification drive which now stands at 50% of the population and expected to reach 80% by 2020, requiring 900MW additional capacity. The generation capacity is provided by 25 year old coal fired power station and a new diesel power station. The rest of its capacity is imported from South Africa. There are plans to increase the capacity of Morupule Power Station and to construct a new coal-to-power plant using supercritical coal technology. Botswana has abundant coal reserves.	The main policies concerning electricity sector in Botswana are Vision 2016, National energy policy, Botswana Energy Master Plan (1996, revised 2003). These policies focus on rural electrification and do not set specific targets for renewable energy. In 2011, The Government of Botswana announced that a renewable FIT for electricity generation will be introduced. All projects above 5MW will be implemented through power purchase agreements with the state-owned Botswana Power Corporation. Not much has been achieved since this announcement.	There are no specific policies for CSP. However, the government is currently assessing the development of 100MW CSP Central Power Plant with 4hrs storage in Jwaneng which is expected to come online in 2018. Bankable Feasibility Study was completed in June 2013. The government is expected to commence the tendering process for this plant in 2014.	DNI of 2,600 to 2,800 kWh sqm/year in the Jwaneng area. Significant amount of land is available for CSP development but new transmission infrastructure will have to be built close to generation areas. Botswana has good water and road infrastructure network and urban infrastructure nearby.

Structure and Regulation of Electric Power Sector	Current Resource Mix and Energy Demand Forecast	Renewable Energy and Greenhouse Gas Policies	CSP-specific policies/Status of CSP projects	Solar Resource, Land Use and / or Transmission Availability
Kenya				
Regulated power market with generation, transmission and distribution split between Kenya Electricity Generating Company (generation), Kenya Power and Lighting Company (distribution), Kenya Electricity Transmission Company Ltd (transmission). Kenya Electricity Generating Company owns over 70% of the effective generating capacity. Currently six independent power producers (IPPs) are operating in the country contributing approximately 30% of the effective generating capacity.	Electricity demand in the country is rising significantly mainly due to the accelerated productive investment and increasing population. Total installed electricity capacity (2010) was 1,429 MW, divided among hydro-electric: (743 MW), conventional thermal (472 MW), geothermal (186 MW), wind, others (41 MW). The peak load is projected to grow to about 2.5 GW by 2015 and 15 GW by 2030. To meet this demand, the projected installed capacity needs to increase gradually to 19 GW by 2030.	The Government is committed to promoting electricity generation from Renewable Energy Sources (RES). Currently, 5.5 GW is targeted for Geothermal, 2 GW for wind, 2 GW for renewable energy imports, and 1 GW for hydro. There are no specific targets for solar energy. A FIT Policy has been formulated to promote investment in renewables, along with other incentives.	There are no specific targets for any solar technologies.	DNI of 2,200 to 2,400 kWh sqm/year in North-Western and South-Western Kenya (Eldoret, Marsabat, Lodwar and Maralal). Significant amount of land is available for CSP development but new transmission infrastructure will have to be built close to generation areas. The government is embarking on an electricity transmission improvement project to extend and upgrade transmission infrastructure. The improvement project is financed by the African Development Bank
Nigeria				
The electricity sector has been liberalized, leading to private sector participation in generation, transmission and distribution. The sector is regulated by the Nigerian Electricity Regulation Commission. The Electric Power Sector Reform Act 2005, adopted a wholesale competition model in which distribution companies can buy power directly from generators, and the transmission company is a pure electricity transport and dispatch company. The 100% government owned Power Holding Company of Nigeria has been unbundled into 6 generation companies, 11 distribution companies and one transmission company. Over 100 generation licenses have been issued since 2010. A Nigerian Bulk Electricity Trading company has been set up to trade bulk electricity from IPPs.	Installed generation capacity is 8.6 GW of which 1. 9 GW is hydro and 6.7 GW is thermal (Natural Gas). Only about half of the installed capacity is available. Maximum demand in 2013 was 13.9 GW. Average GDP growth since 2005 has been 7%. If this growth rate continues, it has been estimated that additional 50 GW will be required by 2030. The government is currently facilitating the importation of 5 GW of electricity from the INGA hydropower project, beginning in 2015.	The National Energy Policy 2003 and the Power Sector Reform Act 2005 provides the framework for renewable energy sector. In 2012 the government set a Multi-year Tariff Order for generation technologies including renewables. The index (2014) price for solar technologies was put at USD 527.44/MWh.	There are no CSP-specific policies. A tariff structure has been put in place for solar technologies and other renewable energy technologies.	DNI of 2,200 to 2,500 kWh sqm/year in the northern part. CSP potential has been estimated at 88GW if only 1% of the eligible land area is used. The transmission network is good but the infrastructure needs upgrading. The distribution and road infrastructure needs overhauling. The country has abundant water.

Table 5-4: CSP-TES markets for electric power in China, India and Australia

Structure and Regulation of Electric Power Sector	Current Resource Mix and Energy Demand Forecast	Renewable Energy and Greenhouse Gas Policies	CSP-specific policies/Status of CSP projects	Solar Resource, Land Use and / or Transmission Availability
CHINA				
China's electricity sector and market is regulated by the state. From the 2002 power sector reform onwards, generation and transmission were split into separate state-owned entities. Transmission and distribution are controlled by two regional monopolies: China Southern Power Grid (which serves the provinces of Guangdong, Guangxi, Guizhou, Hainan and Yunnan) and State Grid Corporation of China (which serves the remaining provinces, municipalities and autonomous regions of east, central, north and west China). Pricing of power is regulated at the central level by the Pricing Bureau of the National Development and Reform Committee (NDRC). End user tariffs are set according to different regions and use type (industrial, commercial, residential) , and midstream power plant tariffs are set by fuel and by region.	Generation is forecast to grow at 3% annually over the next decade to meet demand, a slow-down from prior years but still significant. By the end of 2012 China's total installed capacity was 1140 GW. Generation capacity consisted of coal (66%), hydro (22%), wind (5%), natural gas (3%), with smaller contributions by other fuels. The 12th Five year plan sets a 2015 target of 1540 GW, consisting of thermal (1033 GW), hydro (312 GW), nuclear (41 GW), wind (120 GW), biomass (13 GW), and solar (21 GW). In 2015 power demand is expected to reach 6400 TWh.	The NDRC has released targets for 150GW of wind and 50GW of solar by 2020. In 2020 the goal is for 20% of all power generation to come from renewable energy, including hydro, wind, solar and biomass. Pilot carbon markets are being set up in different regions although a national carbon policy has yet to be enforced. Renewable energy power tariffs are set above other power tariffs for conventional fuels (such as thermal and hydro power). For example coal power tariffs range from 0.3RMB/KWh – 0.5RMB/KWh depending on the region, and wind ranges from 0.5-0.6 RMB/ KWh depending on region. A nationwide small percentage levy is collected from all conventional power stations and pooled into a fund which pays the difference between conventional power and renewable power tariffs. In 2007 China passed a set of national regulations for renewable energy which called for full offtake of grid connected renewable energy, but left offtake subject to the technical ability of the grid to dispatch the power. As a result curtailment during periods of low demand or intermittent production of wind and solar is widespread. To date there is no mechanism for compensation for curtailment other than the subsidized tariff mentioned above.	As part of the 12th five year plan and guidance for 13th five year plan the NDRC has released targets for 1GW and 3GW of CSP to be under construction by 2015 and 2020 respectively. While several demonstration CSP facilities of different technologies (trough, fresnel, tower) ranging from 180KW-10MW have been constructed, progress towards the stated targets has been slow until 2013. To jump start progress towards the 2015 and 2020 targets a national pilot commercial program targeting 3-5 domestic and foreign technology commercial projects ranging from 50-100MW per unit was kicked off in 2013. The government criteria for CSP is that it should be economic with a future trend in cost reduction mirroring that experienced with PV; that there should be sufficient land for large scale development and that a domestic manufacturing industry can be established to maximize local content. If the projects and experience under the pilot commercial program are a success in meeting these criteria it is expected by national level institutes under the NDRC and State Grid, although not yet part of the NDRC plan, that the industry and market will exceed the stated 2015 and 2020 targets.	Land use is governed by the local government authorities with coordination at the provincial and national level to establish priorities and coordinate competing uses. The Tibet Autonomous Region contains multiple areas with greater than 3000 KWh/m2/year DNI, but power demand within the region is not sufficient to develop large scale CSP and grid interconnection to other provinces of China is still underway. As a result, the near term focus is developing sites in the Northwest China provinces and regions of Xinjiang, Gansu & Qinghai. Within these regions there are more than 1000KM2 of sites with 2100-2200 KWh/m2/year available for near term development. The existing and planned transmission infrastructure put in place to bring power from resource rich northwest China to central and east China is in line with the stated CSP targets and anticipated future increases.
INDIA				
Regulated electricity markets with mix of private and state ownership. There are 29 states of widely varying size, 7 union territories, and the national capital region. Private ownership is growing at a faster rate than state ownership. The 5 largest power companies (MW) in decreasing order, are state-owned National Thermal Power Corporation (NTPC) and National Hydroelectric Power Corporation (NHPC), and privately-owned Tata Power, Reliance Power and Adani Power. The 2003 Electricity Act provides the regulatory framework for the electric power sector. The Ministry of Power is the primary central government agency with authority over electric power. The Central Electricity Authority (CEA) provides policy and planning advice to the central government. In addition, the Central Electricity Regulatory Commission provides policy support on generation planning, while the State Electricity Regulatory Commissions develop transmission policies. The Ministry of New and Renewable Energy provides research and policy support for advancement of renewable energy.	Electric generation capacity in 2014 of 238 GW, with a forecast of a need for 389 GW by 2020. Coal and natural gas are the primary fossil fuels (59% and 9%, respectively), with hydro providing 17% and renewable energy, primarily wind, 12%. India faces a significant challenge in expanding rural electrification and improving reliability of the power system.	Promotion of renewable energy is a central goal of energy policy, implemented by both federal and state governments. The 12th Five Year Plan (2012-2017), targeted 18.5 GW of additional renewable energy generation, of which wind is 11 GW. Expansion of wind power has been fairly rapid, with over 20 GW installed by 2014. Solar power has lagged with a little over 2 GW installed.	National Solar Mission targets 20 GW by 2022, of which 50% CSP. Large-scale solar projects are particularly targeted for the states of Gujarat and Rajastan. In preliminary planning, there has been a bias towards parabolic trough technology due to lower upfront costs and longer track-record. Four utility-scale CSP projects are in construction, with several others in planning.	While there is a substantial solar resource, DNI levels are too low for CSP development in most of country. Adequate DNI in very select regions including parts of Gujarat and Rajasthan. Transmission /general infrastructure is a potentially limiting factor for CSP development in these regions.

Structure and Regulation of Electric Power Sector	Current Resource Mix and Energy Demand Forecast	Renewable Energy and Greenhouse Gas Policies	CSP-specific policies/Status of CSP projects	Solar Resource, Land Use and / or Transmission Availability
AUSTRALIA				
The Australian National Electricity Market (NEM) encompasses the provinces of Queensland, New South Wales, South Australia, Tasmania and Victoria. Electricity supply in the states of Victoria, South Australia, New South Wales and Queensland is partially or fully privatized. The Australian Energy Market Commission (AEMC) undertakes rule making and energy market development. The Australian Energy Market Operator (AEMO) conducts a spot market for energy and 8 ancillary services for frequency control across the power system. The Australian Energy Regulator (AER) is the national economic regulator with responsibility for monitoring and enforcement.	Demand in the NEM footprint peaked in 2008–09 (~35 GW peak demand) but has since declined. In 2012-13, the generation mix (MWh) was coal (75%), natural gas (12%), hydro (9%), wind (3.4 %) and PV (1.3%). Wind provided 28% of production in South Australia.	The national policy is 20% renewable energy by 2020. There are both "mandatory" renewable targets and state renewable targets, which may be higher. Feed-in tariffs have also been established in certain states. The Australian Renewable Energy Agency (ARENA) provides policy and technical support, as well as funding. The Solar Flagship program initiated in 2009 offered grant funding to a round of large-scale solar projects, on the condition that they were able to obtain additional financial backing. While CSP projects have been terminated, a number of large PV projects have moved forward.	The first round of Solar Flagship funding of large-scale stand-alone CSP projects experienced some notable failures. Large-scale projects are still being developed. In addition, a number of hybrid CSP projects are being planned or under construction.	Very high DNI levels and available land in several regions. Adequate infrastructure, though not always near load. Transmission build-outs occurring slowly.

6. Looking to the Future: Simulating Power Systems under High Renewable Scenarios

A consistent finding in recent studies is that the *comparative* economic benefits of CSP with thermal energy storage, relative to variable solar resources, increase significantly as variable solar and wind energy production expands. Power systems around the world are already undergoing significant operational changes due to the introduction of large-scale wind and solar generation. With the help of more detailed power system models, a clearer picture is now emerging about the system conditions that could be addressed by CSP with thermal energy storage.

This section examines three primary dimensions to the changes to power system planning and operations created by high-penetration renewable scenarios:

- Section 6.1 examines the composition of alternative high penetration portfolios of renewable energy, with a focus on how different resources are added to the portfolio.
- Section 6.2 shows how long-term supply adequacy, often called resource adequacy or capacity requirements, may change in high-penetration solar scenarios.
- Section 6.3 reviews key system operational features of future high-penetration renewable scenarios.

As several studies show, CSP with thermal energy storage increases in value as the penetration of renewables increases in a power system. High-renewable power systems experience increased variability in the hourly supply of energy, less certainty about long-term supply adequacy, and the need for more operational flexibility. CSP with thermal storage can mitigate all these long-term operational and reliability challenges.

6.1 High Penetration Renewable Resource Scenarios

High penetration of renewable resources on the power grid is occurring in many markets across the world, with some major power systems having already achieved 20-30% renewable energy on an annual basis. The high penetration solar studies reviewed in this report examine scenarios that were constructed in several ways. Some scenarios reflect existing renewable policy goals, such as the California 33% RPS (e.g., CAISO 2011; Denholm et al., 2013) while others are hypothetical scenarios that examine penetration exceeding existing policies, such as 40% or greater renewable energy (e.g., Jorgenson et al., 2014; NREL 2012). Scenario development is typically based on multiple criteria, including:

- Renewable policy goals, including long-term de-carbonization targets, e.g., as embodied in California's greenhouse gas reduction goals for 2050
- Cost projections in target years for alternative renewable technologies as well as technologies potentially needed for integration, such as storage and demand response
- Environmental constraints on renewable resource development
- Transmission constraints on renewable resource development
- Operational constraints affecting renewable integration

The high-penetration studies to date which model CSP with thermal energy storage are summarized in Table 6-1. In California, the work of CAISO (2011) and Denholm et al., (2013) utilize the same 33% RPS scenarios, which are used to guide utility procurement and system planning. The next phase of California planning currently underway includes 40% RPS scenarios, as well as possibly 50% cases. Jorgenson et al., (2014) model a hypothetical 40% RPS scenario, using a CPUC 33% RPS scenario as a starting point. Also in the western U.S., transmission planning studies by the Western Electricity Coordinating Council (WECC 2011) examine alternative scenarios for high penetration of renewables and adjust the proportion of CSP in the portfolio on a cost-benefit basis.

Table 6-1: Selected Studies of High Penetration Renewable Scenarios with CSP and thermal energy storage

Study	Region and Year Studied	Total Renewable Energy as % of Annual Demand/ Scenarios Modeled	CSP with Thermal Storage Component of Scenarios
CAISO (2011); Denholm et al., (2013)	WECC with focus on California (2020)	33% (Environmentally constrained scenario used in these studies has ~11% solar energy)	Varies by scenario composition; CSP without storage is in base portfolio; incremental addition of CSP with thermal storage
Jorgenson et al., (2014)	WECC with focus on California (2022)	33% scenario with ~12% solar energy; 40% scenario with ~16% solar energy	One CSP plant with thermal storage is in base portfolio; incremental addition of CSP with thermal storage
Denholm and Mehos (2011)	Southwestern U.S.	30% (10% wind, 20% solar) 45% (10% wind, 35% solar)	CSP with thermal storage provides 10% in the higher penetration scenario
Denholm and Hummon (2012)	Colorado and Wyoming (2020)	34% (25.5% wind, 8.2% PV)	Incremental addition of CSP with thermal storage to the wind and PV portfolio for purposes of valuation
Mills and Wiser (2012b)	California (2030)	Scenarios from 0-40% penetration	All scenarios are composed of individual renewable technologies, including CSP with thermal storage
NREL Renewable Electricity Futures (2012)	Each interconnection in the United States (2050)	See Table 6-2 below.	See Table 6-2 below. Scenarios result in 0.1% - 14% penetration by CSP with thermal storage by 2050

In terms of resource and transmission planning research over longer time frames, a few studies have demonstrated how to use economic cost-benefit analysis in renewable portfolio development.

In terms of resource and transmission planning research over longer time frames, a few studies have demonstrated how to use economic cost-benefit analysis in renewable portfolio development. Mills and Wiser (2012a) model alternative renewable scenarios, including CSP with thermal storage, in a generation expansion model and calculate total economic benefits (as shown in subsequent sections of this report). Although the first phase of this study did not examine combinations of renewable resources, along with integration solutions, the phase will provide such results.

NREL's Renewable Electricity Futures study (2012) provides a long-term planning and operational analysis for very high renewable penetrations of 50%-90% of U.S. demand, and includes a capacity planning model to determine the composition of alternative resource portfolios. Although some of the assumptions and results require further examination, this is the only comprehensive planning and operational study which examines how the cost projections for CSP with thermal energy storage could affect its inclusion in resource portfolios over a multi-decade time horizon. Table 6-2 summarizes the findings; for further details about scenario assumptions refer to the NREL reports.

Table 6-2: U.S. DOE and NREL Renewable Electricity Futures (REF) Estimates of Potential U.S. CSP Capacity in 2050 under Declining Cost Projections and up to 80% RPS

Scenario	Renewable Energy as % of Annual Demand	2050 CSP-TES Capacity (GW) Built by Capacity Expansion Model		
		West	ERCOT[a]	East[b]
SunShot Vision (78% Renewables)	78% in West	66.9	7.2	8.3
REF-High Demand	80%	61.9	5.4	5.8
RE-ITI	80%	48.7	4.1	3.7
REF-Constrained Transmission	80%	20.4	6.0	6.3
REF-Constrained Flexibility	80%	75.5	8.3	5.5
REF-Constrained Resources	80%	101.7	11.3	7.1
RE-ETI	80%	86.9	19.2	19.7

a. This includes only the area within the Electricity Reliability Council of Texas (ERCOT) and does not include construction in Texas that occurs in both the Western and Eastern Interconnections
b. Development occurs in the small part of New Mexico in the Eastern Interconnection, the Texas panhandle, Florida, and Oklahoma

Source: Modification of Denholm et al., 2012, pg. 15; TES-thermal energy storage; REF-Renewable Electricity Futures; ITI-incremental technology improvement; ETI-evolutionary technology improvement.

6.2 Resource Adequacy

A key component of portfolio planning is long-term resource adequacy. Every utility and regional system operator must plan to meet load reliably over time. This includes control over sufficient installed capacity (MW) and energy[31] to meet annual peak loads and the procurement of additional flexible generation or bulk storage to ensure reliability during unplanned generator or transmission outages (i.e., an operating reserve margin). This is a classic, straightforward utility planning problem, complicated recently by the shift to market-based investment decision making in some regions. In many power systems, regardless of market structure, regulators have established a resource adequacy or capacity requirement that must be fulfilled on a forward basis as insurance for long-term power system reliability.[32]

In many power systems, regardless of market structure, regulators have established a resource adequacy or capacity requirement that must be fulfilled on a forward basis as insurance for long-term power system reliability.

To be eligible as a capacity resource, each generator on the power system must qualify for a capacity credit, measured as a percentage of its rated maximum output or installed capacity (MW). A fossil-fired power plant's capacity credit is based on its expected forced outage rate. In contrast, the credits assigned to variable energy resources are based on their forecast production pattern, with the capacity credit calculated using a statistical or approximation method (see Appendix A).

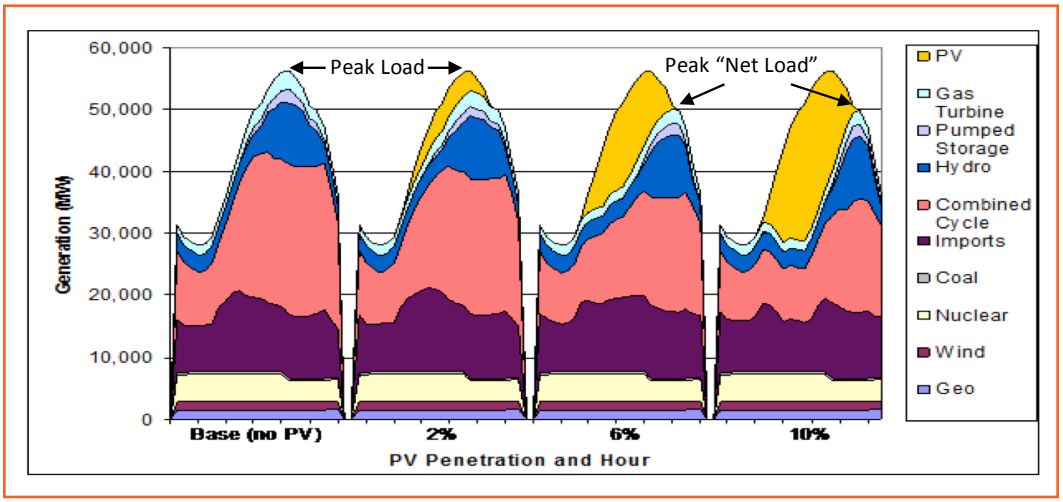
As variable solar resource – PV or CSP without storage – penetration increases, the incremental capacity needs in many regions begin to shift to the early evening hours (Denhom and Mehos, 2011; Mills and Wiser, 2012b). Figure 6-1, excerpted from Denholm and Mehos (2011), shows that as penetration increases, solar energy production (in the yellow band) progressively displaces the need for other types of generation during the summer peak hours in California. The operating point shown in the figure refers to the "net load," which is typically defined as the actual load

[31] Although capacity requirements are denominated in MW, the ratings of energy limited and variable energy resources are adjusted downwards to reflect their expected energy production during hours of high risk of loss-of-load.
[32] In competitive markets, capacity or resource adequacy requirements are in part a vestige of prior reliability rules, but also serve to provide additional payments when energy markets are subject to market power mitigation rules that suppress the price signal for supply scarcity.

minus the production by variable energy resources.[33] As long as the forecast demand growth results in increased capacity requirements during those hours, additional PV and CSP without storage will accrue capacity value in those hours. However, when additional demand growth creates capacity needs outside of the sunlight hours, adding to the "net load" peak shown in the figure, conventional solar production using PV or CSP without storage will face diminishing capacity value. This phenomenon is examined in more detail in Section 8.

Variable wind and solar generation at high penetrations are creating new types of system operational requirements.

Figure 6-1: Simulated Dispatch in California for a Summer Day with PV Penetration from 0-10% Annual Energy – Comparison of Peak Load and Peak "Net Load"



Source: Denholm and Mehos (2011), pg. 3.

6.3 System Operations

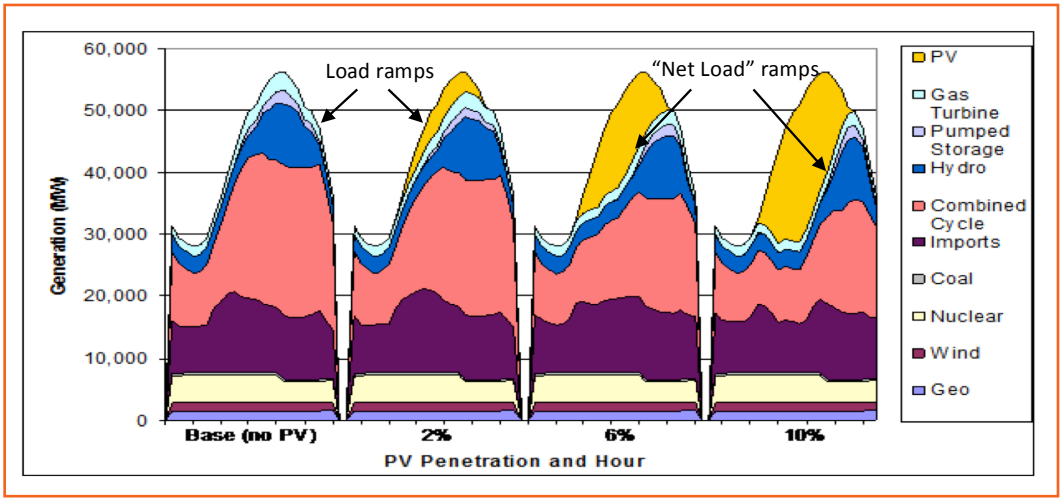
In addition to the prior challenges, variable wind and solar generation at high penetrations are creating new types of system operational requirements. Traditionally, electricity demand (load) has been the primary source of variability in a power system, with dispatchable generators and available bulk storage acting as the resources that respond in the needed time-frames. With the increasing penetration of wind and solar generation, there is now growing variability of supply – minute-to-minute variability, large aggregate fluctuations over the operating day, and seasonal variations. There are also forecast errors in predicting actual daily production from these plants (NERC 2009), which can affect market costs if additional generation units have to be committed to ensure operational feasibility. There may also be increasing changes in the power flows across regions as the penetration of renewable energy becomes concentrated in particular locations. For example, a historically net importing region may now become a net exporting region at certain times, requiring the neighboring power systems to adjust to new operating conditions.

One key indicator for solar power integration requirements is the daily ramp associated with the actual or forecast "net load" curve. The net load ramp is illustrated in Figures 6-2 and 6-3 below, and discussed in more detail in the remainder of the report. Figure 6-2 uses the same NREL figure shown above, but points out how the increased ramp is created by variable solar production.[34]

[33] A more general definition of "net load" is the actual load minus all supply that is not following the economic dispatch instructions of the utility or system operator, which would also include nuclear power plants, some hydro schedules, and any other inflexible generation resource. The "net load" is the residual demand that must be met by dispatchable resources.

[34] The total energy production from CSP without storage and CSP with 6 hours of storage is equalized in the model, which is why the production profile from the plant without storage reaches a higher maximum production than the plant with storage.

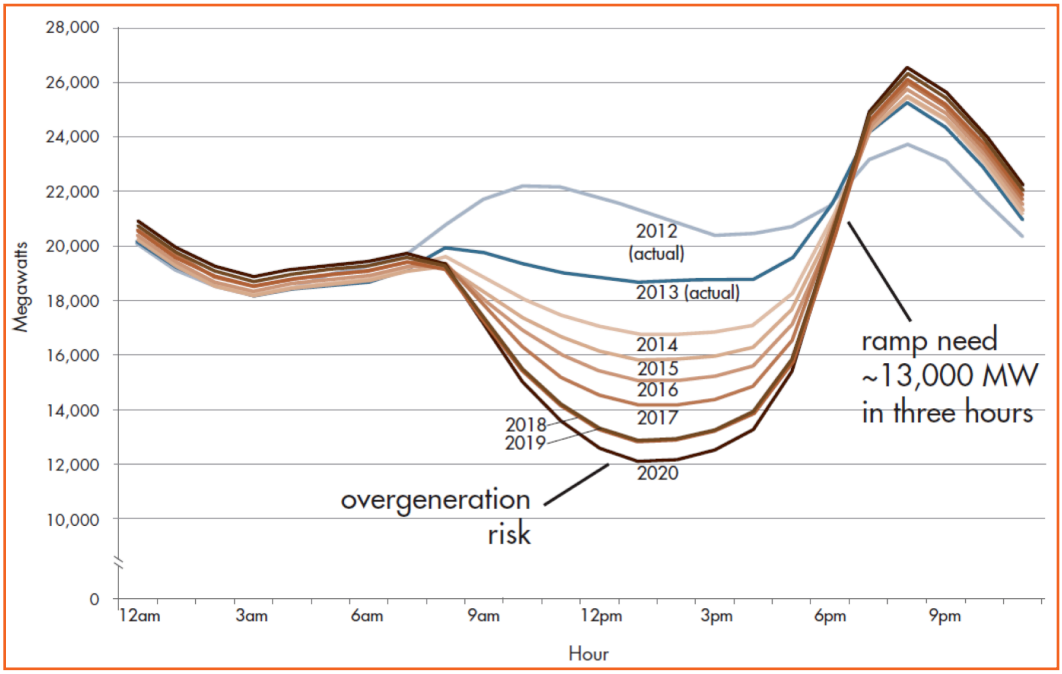
Figure 6-2: Simulated Dispatch in California for a Summer Day with PV Penetration from 0-10% Annual Energy – Comparison of Load and "Net Load" Solar Ramps



Source: Denholm and Mehos (2011), pg. 3.

Figure 6-3 shows a more specific depiction of the year-by-year evolution of the net load ramp curve in the California ISO footprint for a spring day forecast over the remainder of the decade and includes the sum of wind and solar PV generation. This figure was developed on the basis of actual renewable production expected over this time-period. In Section 8, these curves are modified illustratively using CSP with thermal storage. However, we note that simulation studies are still evaluating the operational requirements caused by significant ramps and overgeneration (generation in excess of demand), as indicated in the figure (e.g., Jorgenson et al., 2014).

Figure 6-3: Evolution of Hourly Net Load (Wind + Solar) Ramps in the California ISO for a Spring Day, 2012-2020



Source: CAISO, 2013a.

6.4 Summary

As power systems expand utilization of variable wind and solar resources, a number of new system operational characteristics are becoming apparent. First, the interaction of supply variability and forecast errors create new operational requirements across the operating day. These include the predictable diurnal solar ramps, increased intra-hourly regulation and load-following requirements, and increased potential for surplus, or overgeneration. These evolving conditions have created needs for increased operational flexibility, while also changing the comparative valuation of different renewable resources as renewable portfolios expand.

In response to the scenarios shown in these figures, utilities and regional system operators have to be prepared to start, stop and ramp the available dispatchable resources more frequently and more aggressively, as well as carry additional reserves to ensure flexibility across the operating day. These new requirements are motivating a range of regulatory and institutional changes, including improvements in regional coordination of scheduling and dispatch, additional wholesale market products designed to meet system needs for particular operational characteristics, and the further evaluation of alternative investments to improve operational flexibility, including storage technologies.

CSP with thermal storage has the opportunity to address a number of emerging long-term reliability and operational issues:

- Modification of the aggregate renewable resource portfolio to reduce net load ramps and intra-hour variability;
- The resource adequacy of the power system can be improved with lower investments needed in other types of new resources (or retention of existing conventional generation); and
- Power system operations can be managed utilizing a clean energy resource.

The remainder of this report examines the valuation of CSP with thermal storage under various future, high penetration renewable energy scenarios.

7. Energy and Ancillary Services

CSP plants with thermal energy storage are able to utilize their available stored energy over the operating day to optimally supply energy and ancillary services. These capabilities can provide additional economic benefits credited to the plant, and hence also improve the plant's relative benefits when compared to other solar resources.

This section reviews results from several studies of energy and ancillary service benefits for different solar technologies. A few studies also quantify the additional ancillary service costs estimated for integration of variable solar resources, which are also reviewed in Section 9. The section is organized as follows:

- Section 7.1 surveys results for energy benefits, and energy-only optimization of CSP with thermal storage.
- Section 7.2 discusses value of ancillary services, and reviews results for co-optimized energy and ancillary services are surveyed.
- Section 7.3 summarizes and identifies analytical needs for further research.

CSP plants with thermal energy storage can dispatch energy and ancillary services to the hours of highest economic value. In U.S. power systems with few renewables, this added value is typically calculated as $5-10/MWh. As renewable penetration increases, all energy revenues decrease due to the reduced utilization of fossil generation, but CSP with storage's value increases relative to PV, generally to about $10-20/MWh.

7.1 Energy

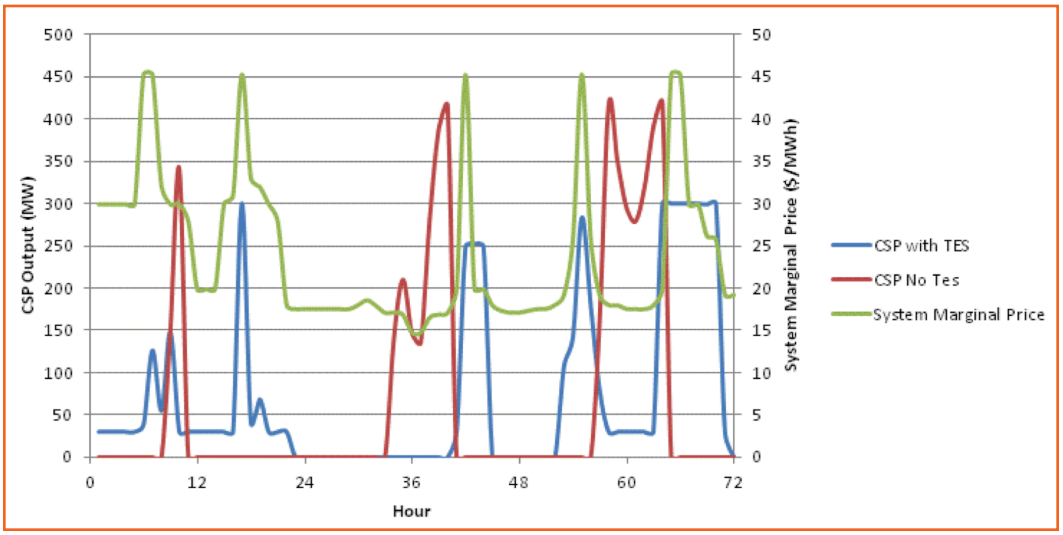
As a practical matter, due to low losses on the thermal energy storage system, CSP with thermal storage is currently the only solar resource that can achieve a high degree of operational flexibility with minimal reduction in overall energy output. The dispatch simulations of CSP with thermal storage discussed in this section have used an hourly time-frame optimized over 24-48 hours, which correlates with utility and organized market day-ahead scheduling practices. In some of the simulations, an additional load-following reserve is also included, to reflect energy dispatch within the operating hour.

Historically, in the competitive power markets, most of the value of energy is determined in the day-ahead market, while real-time energy imbalances, which are currently largely a function of load forecast errors, constitute only a few percent of total energy market financial settlements (e.g., CAISO 2012a). The addition of variable wind and solar production to these markets may increase the quantity of balancing energy transacted in real-time, and possibly the volatility of prices, providing more value to operational flexibility. Some solar integration modeling studies have begun to model sub-hourly intervals, such as 5-minute dispatch (e.g., CAISO 2010); studies that examine sub-hourly dispatch of CSP with thermal storage are underway, with results forthcoming.

Figure 7-1 on the next page (excerpted from Denholm and Hummon, 2012) illustrates the process by which dispatch of energy from thermal storage enhances the average benefits of CSP plants. The figure compares optimized production from CSP plants with and without thermal storage for a 3-day period with cloudy, winter days (note that tracking PV production at the same location would follow a similar pattern to CSP without storage, although the CSP plant's thermal inertia would further smooth out some of its production ramps). The capacity of both CSP resources is adjusted to ensure equal annual energy production (see discussion in Section 3).[35]

[35] The total energy production from CSP without storage and CSP with 6 hours of storage is equalized in the model, which is why the production profile from the plant without storage reaches a higher maximum production than the plant with storage.

Figure 7-1: CSP with thermal energy storage dispatched against simulated January 22-24 energy prices in Colorado



Source: Denholm and Hummon (2012), Figure 10, pg. 19.

The green line represents the system marginal price, i.e., the fuel cost or market price of the fossil generating unit needed to meet demand at that time. The units for system marginal price ($/MWh) are shown on the right y (vertical) axis. The red and blue lines show simulated CSP production with the units (MW/hr) shown on the left y axis. The x (horizontal) axis is the hourly intervals over the 3 simulated January days. The red line is the production from CSP without storage, which produces energy in response to available direct normal irradiance and cannot shift energy.

For the days modeled, production from CSP without storage takes place mostly in the lowest price intervals, as would PV production. In contrast, the blue line shows production from CSP with thermal energy storage, optimized to maximize energy benefits by shifting energy to the highest price intervals. As a result, production coincides more closely with the high energy prices, and the average value of the energy produced by the plant with thermal energy storage is higher. In most power systems studied in the western U.S., those higher price hours that can be accessed by stored energy are either in the evening hours, or in the morning and afternoon system ramps caused by solar production patterns.

Models that use public data on historical market clearing prices or utility marginal costs are easily replicated and can be useful in commercial or regulatory discussions for benchmarking purposes.

Low Renewable Energy Cases or Scenarios

A number of studies have modeled the energy and ancillary service benefits of CSP with thermal storage using historical market prices in power systems that did not yet have high renewable penetration, such as California or Texas in 2005 (Sioshansi and Denholm, 2010; Madaeni et al., 2012b). Others have simulated moderate increases in the penetration of wind and solar generation from a historical baseline (Denholm and Hummon, 2012; Mills and Wiser, 2012b). Such "low renewables" simulations can have several uses. First, models that use public data on historical market clearing prices or utility marginal costs are easily replicated and can be useful in commercial or regulatory discussions for benchmarking purposes. Second, simulations that examine small operational changes to power systems are easier to validate by utilities or regional system operators than long-term, high renewable penetration scenarios.

Sioshansi and Denholm (2010), and Madaeni et al. (2012b) simulated energy benefits using a plant-level model of a parabolic trough system with thermal energy storage dispatched against

2005 hourly prices in the energy markets operated in California by the CAISO and the Texas system operator (ERCOT), as well as utility hourly "system lambdas" elsewhere in the western U.S.[36] At the time, none of these systems had significant renewable penetration. Table 7-1 shows some of Sioshansi and Denholm's (2010) energy dispatch results when modeling a parabolic trough system with 6 hours of thermal storage. When compared to a trough plant without storage, the average added benefit in the wholesale market regions is $9-10/MWh, with lower benefits shown when modeling utility system lambdas.

Table 7-1: Selected results for the difference in energy and ancillary service benefits between CSP with thermal storage and solar technologies without storage

Study	Location and Date	CSP with thermal storage	Methodology/Metric	Baseline Solar	Renewable penetration	Added Economic Benefit
Sioshansi and Denholm, 2010	California ISO, Dagget, CA, 2005 prices	Trough with 6 hours storage, SM 2.0	Plant revenue optimization with exogenous fixed market prices	Trough with no storage, Solar Multiple 1.5	N/A	$9.40/MWh
Sioshansi and Denholm, 2010	ERCOT western zone, 2005	Trough with 6 hours storage, SM 2.0	Plant revenue optimization with exogenous fixed market prices	Trough with no storage, Solar Multiple 1.5	N/A	$9.00/MWh
Denholm and Hummon, 2012	Colorado-Wyoming 2020	Trough with 6 hours of storage, SM 2.0	Production simulation, change in production costs from baseline	Trough with no storage, Solar Multiple 1.3	12.4% wind, 0.8% PV	$6.6/MWh
Mills and Wiser, 2012b	California 2030	Trough with 6 hours of storage, SM 2.5	Equilibrium market prices derived from capacity expansion model with hourly dispatch	Single-axis tracking PV	15% solar (no other renewable energy)	$13/MWh [Energy]; $1/MWh [Ancillary services]
Denholm and Hummon, 2012	Colorado-Wyoming 2020	Trough with 6 hours of storage, SM 2.0	Production simulation, change in production costs from baseline	Trough with no storage, SM 1.3	25.5% wind, 8.2% PV	$13.3/MWh [Energy]
Denholm et al., 2013	California 2020	Trough with 6 hours of storage, SM 2.0	Production simulation, change in production costs from baseline	Single-axis tracking PV	33% RPS; ~11% solar	$15/MWh [Energy-only]; $33.5 /MWh [Energy + Ancillary Services]*
Jorgenson et al., 2014	California 2022	Tower with 0 -15 hours of storage, SM 1.3 – 2.7	Production simulation, change in production costs from baseline	Single-axis tracking PV	33% RPS; ~12% solar	$6.5/MWh [Avoided fuel costs]; $14.7/MWh [Total operational benefits**] (Tower with 6 hours of storage)
					40% RPS; ~16% solar	$8.1/MWh [Avoided fuel costs]; $16.4/MWh [Total operational benefits**] (Tower with 6 hours of storage, SM 1.3)

SM = Solar Multiple; * Sum of difference in fuel costs, variable O&M, and start-up costs.
** Sum of difference in avoided operational costs of variable O&M, startup & shutdown, fuel, and emissions.

[36] The "system lambda" is a publicly reported value ($/MWh) representing the utility's hourly marginal cost of electric power, in U.S. regions under FERC jurisdiction without organized wholesale markets.

In the later extension of this analysis by Madaeni et al., (2012b), a range of solar multiples and thermal storage capacities were modeled, allowing for calculation of market benefits as a function of plant design. Figures 11-1 and 11-2 (in Section 11 of this report) show the total energy revenues plotted against these design parameters; however the paper does not provide the total energy produced for each design option, making it difficult to convert the results to $/MWh. Helman and Sioshansi (2012, unpublished) later used the same model to evaluate benefits using 2010-11 CAISO market prices; the results are shown in Figures 7-4 and 11-2, and discussed in more detail below. As expected, when modeled against the lower CAISO market prices in those years than in 2005, the plant obtained lower energy benefits from storage dispatch.

As noted above, calculating benefits with models that optimize against historical prices has the limitation that they do not account for how new resources affect economic dispatch. A few studies have examined the dispatch of CSP with thermal storage in "low renewable" scenarios using detailed power system models. These analyses can consider the effect of shifting energy dispatch on system production costs. Denholm and Hummon (2012) utilize a production simulation model to examine the dispatch of CSP in a "low renewables" scenario with 13.2% annual energy, composed of 12.4% wind and 0.8% PV production, in the Colorado-Wyoming power system. As shown in Table 7-1, a 300 MW parabolic trough plant with 6 hours of thermal storage accrues almost $7/MWh in additional energy benefits, measured as reduced production costs, when compared to the addition of a PV plant with equal energy production.

Mills and Wiser (2012b) construct a dispatch model of the California power system in 2030 in which they examine the penetration of different renewable technologies from a zero % penetration baseline. As shown in Figure 7-2 on page 59, the difference in energy benefits between PV and CSP with 6 hours of thermal storage ranges from $3-13/MWh as the penetration of each technology reaches 15% of annual energy production. The relatively small difference in energy value at low penetration results in part because the portfolios evaluated in this study are adjusted on equal energy basis, which results in profile shapes in which the maximum output in any hour of the CSP portfolio is less than the PV portfolio (as illustrated in Figure 4-3 on page 29), and increasingly so as the portfolio increases in size.

When renewable energy production is on the margin – that is, when it has displaced all other dispatchable generation – it sets market prices that are zero or possibly negative.

High Renewable Energy Scenarios

While thermal storage can provide additional energy benefits to CSP plants in low renewable penetration cases, the benefits when compared to solar without storage increase as penetration of those plants increases. As additional renewable generation is connected to a power system, it progressively displaces existing generation in order of higher to lower marginal fuel costs (gas and coal). Solar production reduces marginal energy costs during the sunlight hours, and as penetration increases will also create price spikes during the morning and afternoon solar ramps. Wind energy typically results in more uniform reductions in average energy prices but with a diurnal effect in some regions that results in greater energy price reductions in the overnight hours. When renewable energy production is on the margin – that is, when it has displaced all other dispatchable generation – it sets market prices that are zero or possibly negative.[37] This phenomenon is observed in many power markets where wind production has suppressed market prices in the off-peak hours and during other system operating conditions. While currently negative pricing is associated primarily with wind production, solar production could eventually contribute to this effect during the morning and afternoon hours, as the penetration of solar PV increases (Mills and Wiser, 2012b; Denholm and Mehos, 2011).

[37] Negative prices are set by several factors, including negative market bids by generators that prefer to remain on-line in periods of surplus energy or generators that receive production incentives. They thus reflect the "willingness to pay" to remain operating.

As market prices change to reflect these impacts, solar plants that do not have storage will face lower energy market benefits. The net load shapes shown above in Figures 6-1 and 6-2 illustrate how this will take place as solar energy progressively displaces energy from conventional generation. However, CSP with thermal energy storage has the ability to shift energy to the highest price or cost hours of the day, which increasingly will occur during the evening hours and intervals with the highest system ramps. While all solar plants will earn lower average economic benefits at high penetration, the reductions are more pronounced for plants without storage.

There are several studies that demonstrate this finding, summarized in Figure 7-2. Mills and Wiser (2012b) examine progressive increases in solar penetration in a model of California in 2030 and show that as PV and CSP without storage increase their share of energy production, they earn progressively lower energy benefits than CSP with 6 hours of thermal storage.[38] Additions of CSP with storage initially do not earn significantly higher energy benefits ($/MWh) than CSP without storage or PV until penetration levels exceed 5% annual energy. The $1-3/MWh difference in benefits reported at the low penetration levels are lower than those of the California studies discussed above, and could be due to the "equal energy" profiles being modeled as well as the hourly prices being calculated in their model.[39] However, as solar penetration increases, an incremental CSP plant with 6 hours of storage has $9/MWh higher energy benefits at a 10% solar energy penetration, $17/MWh at 15%, $20/MWh at 20% and $36/MWh at 30%.

Figure 7-2: Energy benefits ($/MWh) of solar resources from selected studies of increasing solar penetration

Source: based on a figure in Helman (2014).

[38] In contrast, wind, although not a technology that can be dispatched flexibly, does not experience the same diminishment in energy value in Mills and Wiser's model because its production is spread more evenly on average across the day, due in part to assumptions about geographical distribution, such that energy prices during the sunlight hours aren't suppressed as much (noting again that the wind scenario does not include any solar energy).

[39] Although its hourly price results have not been released, the Mills and Wiser model may not generate the same range of hourly prices that are found in the actual CAISO markets. We have observed that some power system models used to forecast prices yield flatter prices across the day (due to relatively similar heat rates of the marginal units), which then results in little added value for stored thermal energy shifted to those hours.

Denholm and Hummon (2012) find similar results for the transition from low to high penetration renewables scenarios when modeling the Colorado-Wyoming power system. As shown in Table 7-1 and with more detail in Table 7-2 for the low renewable energy case modeled, the addition of 6 hours of thermal storage adds almost $7/MWh in benefit to the CSP plant. In the high renewables case, CSP with 6 hours of thermal energy storage provides almost $17/MWh greater energy benefits than CSP without storage and $13/MWh greater than PV (all specified to provide equal energy production on an annual basis).

Table 7-2: Operational Benefit ($/MWh) of Simulated Solar Generators in Colorado-Wyoming subsystem, low and high renewable penetration cases

	Low RE Case				High RE Case			
	Flat Block	PV	CSP without storage	CSP with 6 hr storage	Flat Block	PV	CSP without storage	CSP with 6 hr storage
Marginal Value ($/MWh)								
Fuel	31.7	35.2	33.9	37.7	22.6	21.2	18.7	31.1
Var. O&M	1.2	1.0	1.0	0.8	2.1	2.0	1.9	1.4
Start	0.4	0.4	0.6	3.5	0.5	-0.9	-1.7	3.1
Total	33.3	36.6	35.5	42.1	25.2	22.3	18.9	35.6

Source: Denholm and Hummon (2012), Table 4, pg. 17.

Denholm et al., (2013) find similar results using a model of 33% RPS in California in 2020. As shown in Table 7-3, they find that the CSP plant earns $15/MWh in higher operational benefits (including energy) than a PV plant of equal energy output annually. Jorgenson et al., (2014) build on this prior study, both re-evaluating the 33% RPS case for California in 2020 with lower forecasts for natural gas prices, and also a hypothetical 40% RPS case. They find that a power tower with 6 hours of thermal storage and a solar multiple of 1.3 provides $6.5/MWh greater fuel cost savings than PV in the 33% RPS case, and $8.1/MWh in the 40% case, and $14.7/MWh and $16.4/MWh in total operational value, respectively.

Table 7-3: Operational Benefit of Simulated Solar Generators in California, 33% RPS in 2020 "Environmental" Scenario (2010 vintage)

33% RPS Environmental Scenario				
	Flat Block	PV	CSP with 6 hr storage Energy-only dispatch	CSP with 6 hr storage Energy + Ancillary Service dispatch
Marginal Value ($/MWh)				
Fuel	33.9	29.1	38.9	54
Var. O&M	4.7	4.4	5.2	6
Start	0.1	-2.3	2.1	4.7
Total	38.7	31.2	46.2	64.7

Source: Denholm et al. (2013), Table 3, pg. 18.

Studies of CSP dispatch in other countries have found similar results. For example, Brand et al., (2012) model parabolic trough plants with and without storage for Morocco and Algeria and simulate an incremental benefit for dispatchability from storage of €39-55/MWh for Morocco and €29-35/MWh for Algeria. The range is associated with the level of CSP penetration modeled by the year 2025: 5% for the low estimate and 30% for the high estimate. The analysis was performed based on simulations of total cost to operate the respective systems (including investment) over a 30 year time period.

Start-up Costs

At higher penetrations, the dispatch of CSP with thermal energy storage could have a further benefit by reducing the start-up costs of conventional generators. Simulations suggest several factors that could affect the frequency of generator start-up. First, as generators with variable fuel costs are backed down to accommodate renewable energy on the grid, the number of generator starts may decrease. At the same time, the need for additional ancillary services, intra-hourly load following and inter-hourly system ramps, may require system operators to start additional generators and operate them below their maximum operating levels for many hours of the day. As noted above, in many competitive wholesale markets, these start-up costs are bid separately by generators, subject to bidding rules, and are compensated through additional "uplift" payments to ensure bid revenue sufficiency. For vertically integrated utilities, these start-up costs are calculated on a cost-basis.

The calculation of changes in system start-up costs requires modeling of generator unit commitment. Recent studies evaluating CSP with thermal energy storage suggest that reductions in generator start-up costs can be significant when compared to solar PV technologies in the same scenarios.[40] For comparison, the net difference in modeled start-up costs is the sum of the reductions in start-up costs due to dispatch of CSP and the increases/decreases in start-up costs due to the operational impacts of PV. As shown in Table 7-2, Denholm and Hummon (2012) find a net benefit (net reductions in start-up costs) of $3.1/MWh for CSP with thermal energy storage when compared to PV in their "low renewables" scenario for Colorado, and $4/MWh for their "high renewables" scenario. As shown in Table 7-3, Denholm et al., (2013) find a difference of $7/MWh in start-up costs between CSP with thermal energy storage and PV in their California 33% RPS model. These benefits are in addition to the energy benefits discussed above. Jorgenson et al., (2014) find slightly lower differences in total start-up costs, of around $3.5/MWh, in their 33% and 40% RPS scenarios in 2022, primarily due to lower projected fuel and carbon emissions costs.

Subhourly Energy Dispatch and Ramping Reserves

The variability of wind and solar (without storage) will require increases in load-following and sustained ramping within the operating hour by dispatchable generators. Estimates of changes in load-following requirements can be found in various studies, such as CAISO (2010, 2011). Moreover, the California ISO will soon procure additional ramping reserves provided by units that hold some ramping capacity in reserve, to follow real-time dispatch when called by the ISO.[41] CSP plants that provide dispatchability could, in principle, participate in these ramping reserve markets. While estimating the potential economic benefit is premature, it appears likely that the value of fast energy ramping capability would increase at high renewable penetration.

While estimating the potential economic benefit is premature, it appears likely that the value of fast energy ramping capability will increase at high renewable penetration.

7.2 Ancillary Services

Ancillary services (defined in Section 2) currently constitute a small segment of utility power system costs but represent a source of potentially significant benefits for CSP plants with thermal energy storage in some regions. Such plants can both provide existing ancillary services, and also help supply the increased ancillary service and related flexibility requirements forecast to grow with high penetration of variable wind and solar power (e.g., CAISO 2010, 2011; see also Section 9). Ancillary services are typically provided from dispatchable resources, currently either gas-fired generation or hydro storage, and more recently in some systems by other storage technologies

[40] Mills and Wiser (2012b) also model start-up costs but do not break out the costs or benefits due to changes in start-up costs separately in their results.
[41] See discussion at http://www.caiso.com/informed/Pages/StakeholderProcesses/FlexibleRampingProduct.aspx.

and demand-side resources. A CSP plant operated from storage can offer both "upward" and "downward" services when there is the capability to increase or decrease energy from a prior set point. These plants are particularly suited to providing spinning reserves and Regulation, but can also provide any other ancillary service offered from a synchronous generator (without significant loss of solar energy production), such as frequency response, inertial response, and voltage control.

For most CSP plants, the ability to provide these services will vary over the operating day, depending on the state of charge of the thermal energy storage system. The operator of the plant will seek to optimize the use of the stored thermal energy for energy production and ancillary services to obtain the highest benefits across these products. Box 7-1 provides a simple example of co-optimization for energy production and spinning reserves; a similar methodology would be used for optimizing the supply of any ancillary service provided by the CSP plant.

Simulations of CSP with thermal energy storage providing ancillary services generally use two methods: optimizing a plant-level model against a set of historical or forecast prices, similarly to the example in Box 1 (e.g., Madaeni et al., 2012b), or calculating the change in total production costs or marginal prices when the plants are added to the resource mix and allowed to provide ancillary services (e.g., Denholm et al, 2013; Mills and Wiser, 2012b).

Turning to the first simulation method, in competitive wholesale markets, historical hourly ancillary service prices are available publicly, allowing for simulation of these benefits using CSP plant models dispatched from thermal storage against published prices (e.g., Madaeni et al., 2012b).[42] For example, in the California ISO average ancillary service prices in 2011, were $10.84/MW for Regulation Up, $9.15/MW for spinning reserve, $6.97/MW for Regulation Down and $1.06/MW for Non-spinning Reserve (CAISO 2012a). As shown in Figure 7-3 on page 64, the hourly prices for ancillary services in the California market vary substantially over the operating day, with higher prices for "upwards" services in the late afternoon and early evening hours. Similar patterns occur in prior years as well as in the simulations of future conditions under the 33% RPS. Based on these historical prices in California, CSP plants charging the thermal storage system during the sunlight hours are well positioned to then obtain the highest value when providing ancillary services during the evening hours.

[42] In wholesale markets, the ancillary service price is denominated in $/MW, representing the capacity (MW) reserved on the resource to provide the service. The market price is typically calculated as the opportunity cost of the marginal unit providing the service, although in some markets, bids are allowed. Any energy provided by the plant is settled at the wholesale price. Recently, the markets for Regulation in the United States have been required also to pay a "mileage" payment, in which the resource is paid according to a measure of how frequently it responds to Regulation dispatch (allowing, all other things equal, for higher payments to faster Regulation resources).

Box 7-1 Simple Example of Co-Optimization of Energy and Ancillary Services

Co-optimization of energy and ancillary services requires finding the dispatch solution to provide the maximum joint revenues from each market product (or the maximum avoided variable costs for a vertically integrated utility). This may create counter-intuitive dispatches in response to market prices. The example below assumes a 100 MW CSP plant with 2 hours of stored thermal energy, a 10 MW/min ramp rate, and a 10 MW minimum operating level. The operator will dispatch the plant from thermal storage for the highest value over Hours 18-21. To provide spinning reserves, the plant must operate at no less than 10 MW of energy (minimum load), but can then sell the remaining capacity on the turbine as spinning reserve. Also, for this simple example, any thermal losses are ignored and the plant does not retain enough energy in storage to respond to a sustained energy dispatch from spin for the hour after Hour 21 (that is, it cannot sell spin in Hour 21). The illustrative market clearing prices for energy and spinning reserves in each hour are shown in Table (a) below. Despite the fact that highest energy prices are in Hours 18 and 19, the joint value of the plant's production is improved if it instead provides spinning reserve in those hours and sells its remaining energy in Hours 20 and 21 at lower prices. This is because over the sum of the hours, the spinning reserve revenues gained in Hours 18-19 and the energy revenues gained in Hours 20-21 are greater than the energy revenues lost in the first two hours. The calculations are illustrated in the following two dispatch cases. In case #1, shown in Table (b), the plant dispatches all its stored energy in Hours 18 and 19, and earns $11,000 over the four hours. In case #2, shown in Table (b), the plant sells as much spinning reserves as it can over Hours 18-19 and releases the remaining energy subsequently in Hours 20-21. It then earns $12,450. Note that there are other optimal solutions which also result in this total revenue, but this solution demonstrates the point and is easy to follow. Denholm et al., (2013: pp. 15-16) provides a more detailed multi-hour example.

Table A	Hour 18	Hour 19	Hour 20	Hour 21	
Energy price	$60	$50	$45	$35	
Spinning reserve price	$25	$20	$5	$2	

Table B		Hour 18		Hour 19		Hour 20		Hour 21		
		price	quantity	price	quantity	price	quantity	price	quantity	
Case #1	Energy	$60	× 100	$50	× 100					
	Spinning reserve									
Total:		$6,000		$5,000						$11,000

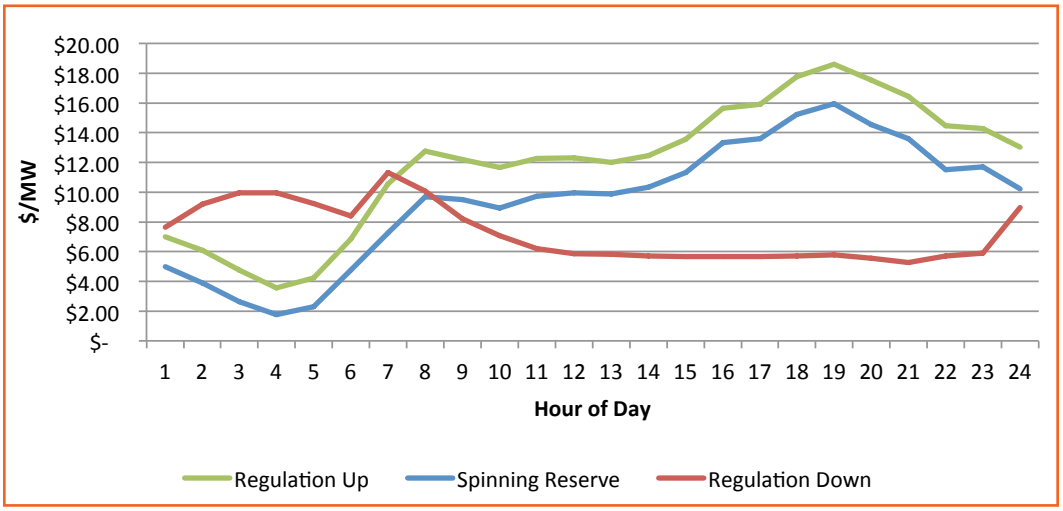
Table C		Hour 18		Hour 19		Hour 20		Hour 21		
		price	quantity	price	quantity	price	quantity	price	quantity	
Case #2	Energy	$60	× 10 [min load]	$50	× 10 [min load]	$45	× 100	$35	× 80	
	Spinning reserve	$25	× 90	$20	× 90					
Total:		$2,850		$2,300		$4,500		$2,800		$12,450

Ancillary service benefits modeled in recent studies

Optimizing production from thermal storage against California ISO prices from 2005, Madaeni et al., (2012b) found that parabolic trough plants with storage could earn up to an additional 17% of their market value from spinning reserve sales, when compared to plants without storage. When running the same model against the CAISO energy and ancillary service prices from 2010 and 2011, as shown in Figure 7-3, which were lower than the market prices in 2005, the CSP plant with storage accrues lower total benefits. However, the *added* benefits from thermal storage are a function not only of absolute prices, but also the difference between energy prices in the daylight and evening hours. For 2010-11, a plant with 6 hours of storage earns an additional $4.50/MWh (2010) to $8.50/MWh (2011) in energy and spinning reserve benefits.[43] Much of the additional benefits come from sales of spinning reserves; the higher benefit in 2011 is due to higher spinning reserve prices than in 2010.

[43] Ramteen Sioshansi, Ohio State University, ran the 2010-11 price simulations, with subsequent data analysis by Udi Helman and David Jacobowitz, BrightSource Energy. The simulations used the weather data for the prior Madaeni et al., (2012) study, and hence the results would be expected to be slightly different if 2011 weather data was used.

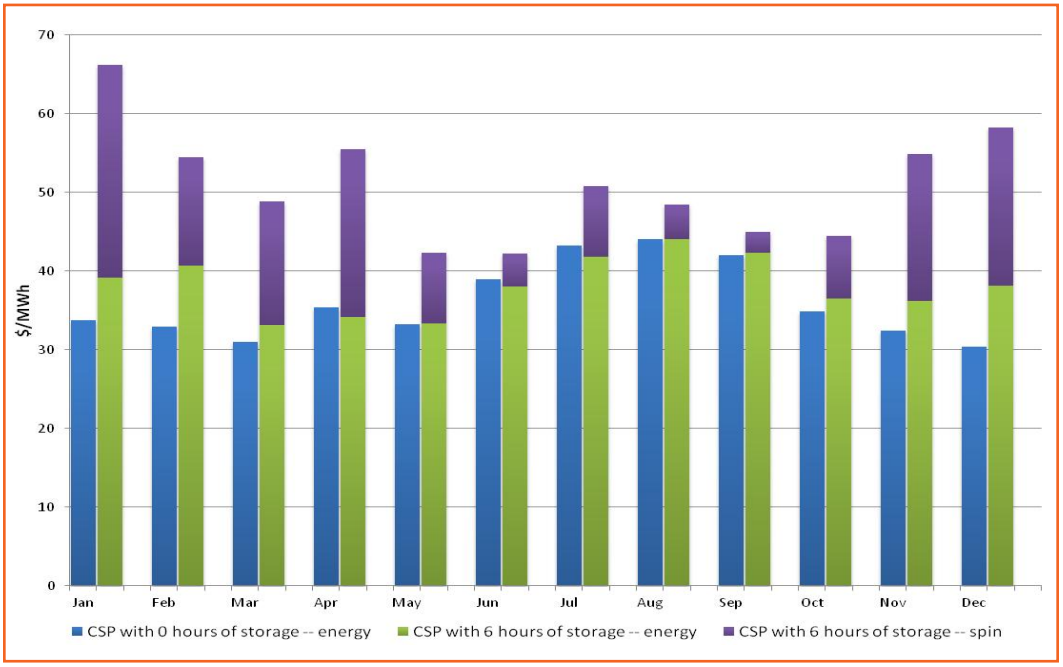
Figure 7-3: CAISO 2011 Average Hourly Prices for Spinning Reserves and Regulation



Source: CAISO SP15 zone, 2011 price data

Notably, average monthly energy and ancillary service benefits are not distributed uniformly across the year. As shown in Figure 7-4 below, the plant earns more from spinning reserves in the winter and early spring months than during summer operations. This is because energy prices are higher in the afternoon and early evening hours during the summer months and there is less benefit obtained by withholding from the energy market to sell spinning reserves.

Figure 7-4: Monthly energy and spinning reserve revenues, optimized against CAISO 2011 prices



Source: Helman and Sioshansi (2012, unpublished); these values are expressed in $/MWh of energy production each month, which slightly skews the calculation of spin $/MWh during months with lower energy production and higher spin revenues.

As noted above, exogenous fixed price models do not model the effect of utilizing thermal storage on power system operations, and hence cannot evaluate the value of ancillary service provision in scenarios with increasing renewable penetration. CSP plants with thermal storage have no fuel cost, low thermal storage losses, and do not require charging of energy from the grid,[44] so they will be lower in the supply stack for reserve units than gas plants or pumped hydro storage. This should allow them to be always utilized at full capability for reserves, and this is validated in the results from the power system unit commitment and dispatch models used by Denholm et al., (2013) and Mills and Wiser (2012b). These system models can also capture other operational benefits provided by CSP plants with storage that the plant-level optimization models cannot, such as the displaced start-up and variable O&M costs of conventional generators providing reserves.

CSP plants with thermal storage have no fuel cost, low thermal storage losses, and do not require charging of energy from the grid, so they will be lower in the supply stack for reserve units than gas plants or pumped hydro storage.

The results of the California system studies to date are not consistent. Using a dispatch model of the California system, Mills and Wiser (2012b) found that CSP with 6 hours of thermal storage provides ancillary services with benefits in the range of $1-$1.4/MWh, even for the marginal CSP plant at 0% penetration.[45] In contrast, Denholm et al., (2013) also model a marginal CSP plant with 6 hours of thermal storage in a California 33% RPS scenario. The plant's production is co-optimized to provide energy, load-following capacity, Regulation, and spinning reserves. When providing these ancillary services, the plant provides $18.5/MWh in additional benefits when compared to a PV plant with equivalent energy production, and $33.5/MWh more for energy and ancillary services. Further analysis is needed to resolve these discrepancies, but at the very least, the models using historical California ISO market prices suggest that ancillary service benefits are higher than Mills and Wiser find, assuming that market prices remain within historical levels. At the same time, the ancillary service requirements are only a small part of power system operational costs. At the higher hypothetical penetrations of CSP with thermal energy storage modeled by Mills and Wiser (e.g., 10-30%), declining value of ancillary services could take place because the CSP can effectively displace all fossil generation from the ancillary service markets, thereby reducing fuel costs to zero, and pumped storage could be operating at low utilization if the modeled energy prices are significantly flattened across the operating day. Hence, the benefits from providing ancillary services could be expected to decline as penetration of CSP with thermal energy storage – or other types of storage – increases in high renewable penetration scenarios.

Other Ancillary Services

Section 3 discussed several other ancillary services that may require technological changes, operational reforms, and market development over the next few years, as penetration of wind and solar technologies increases. These include frequency response, inertial response, and voltage support. In each of these cases, the key difference for evaluation of net cost between CSP with thermal storage and alternative solar without storage stems from (1) the ability to sustain provision of these ancillary services over more hours of the operating day without loss of production, and (2) the avoided cost of other solutions or devices, such as capacitors or electrical storage technologies.

While there are many studies identifying potential solutions,[46] few studies comprehensively compare the costs of meeting these other ancillary services for different renewable technologies. At the same time, there are many potential solutions on the supply and demand side, making the provision of these services potentially competitive.

[44] That is, CSP with thermal storage is not charging the storage system from the electrical grid, at least in current configurations.
[45] Each scenario in the Mills and Wiser study is benchmarked against a scenario where the renewable generator is added incrementally to a scenario with zero penetration by renewable energy.
[46] E.g., studies of frequency response by LBNL (2010), NREL/GE (2010) and GE Consulting (2011).

These include, as listed in various studies:

- Electrical storage devices,
- Provision by inverter-based wind and solar resources,
- Fast acting, flexible demand response,
- Improvements in generator flexibility, and
- Expansion and coordination of balancing areas and regional wholesale markets.

For the CSP sector and utility procurement, these developments need careful monitoring and consideration in plant engineering. CSP with thermal storage presents an opportunity to obtain a very broad range of ancillary service capabilities offered by synchronous generators at no additional plant cost, and requiring essentially no new methods for system operations, other than forecasting to determine the hourly state of charge on the energy storage system.

7.3 Summary and Additional Research Needs

The added energy and ancillary services benefits provided by CSP with thermal energy storage are significant when compared to other solar and wind resources. Studies differ on the added benefits at low solar penetration, where the difference with PV ranges from insignificant (Mills and Wiser, 2012) to estimates between $3-10/MWh in other studies, including those using historical market price data from California. The higher end of the range reflects periods with higher natural gas prices, such as 2005. In low penetration scenarios, some of these differences are also due to the methodology, particularly studies assuming equal energy production between alternative technologies.

At higher levels of solar penetration on the grid, studies consistently identify significant benefits for addition of incremental CSP with thermal storage of up to $33/MWh when compared to incremental PV or CSP without storage (Denholm et al., 2013; Denholm and Hummon, 2012; Mills and Wiser, 2012b). Table 7-1 summarizes some of these results.

To date, these studies focused on modeling hourly blocks of energy and reserves the benefits of the operational flexibility provided by CSP with thermal energy storage could be greater as operational needs increase. Additional research is needed to improve the understanding of the ancillary service ratings of actual CSP plants and to model sub-hourly energy dispatch, Regulation dispatch, and frequency responsive reserves from solar thermal storage. Finally, related to the analysis of energy and ancillary services is assessment of the likelihood and cost of solar energy curtailment during congestion or overgeneration conditions. The additional potential benefits of avoiding these system conditions are discussed in Section 8 under integration analysis, but are also considered in forward energy procurement.

Power system operations at increasing penetration of wind and PV technologies create new operational needs and requirements for interconnection standards that could increase the installed costs of deploying these technologies. In the case of PV, these costs could be incurred through additional inverter controls, addition of transmission equipment such as capacitors, and through loss of production if the plant is actively controlling production. CSP plants with or without storage utilize synchronous generators, providing similar short-term reliability and operational benefits to the system as conventional power plants at no additional cost.

8. Resource Adequacy and Long-term Reliability

Solar energy production from PV or CSP without storage is highly correlated with annual peak demand in many power systems. As discussed in Sections 4 and 6, when coupled with sufficient solar insolation, this results in high capacity credits and long-term capacity value, especially at low penetration of such technologies. However, as solar penetration increases, the capacity value of new variable energy solar projects declines. A key finding is that under such conditions, incremental CSP with thermal storage retains much of its capacity value due to its ability to shift energy to hours of highest reliability risk; it also provides operational flexibility, which will be more highly valued under future "flexible capacity" requirements.

This section reviews several studies which demonstrate these findings for different solar technologies. The section is organized as follows:

- Section 8.1 briefly reviews the methodology for capacity valuation, complemented by the more detailed discussion in Appendix A.
- Section 8.2 surveys results from studies that evaluate low solar penetration scenarios.
- Section 8.3 reviews results from scenarios with higher solar penetration.
- Section 8.4 reviews the recent requirements for flexible capacity and its relationship to the value of alternative solar technologies.
- Section 8.5 summarizes and identifies analytical needs for further research.

In regions with sufficient solar insolation, CSP resources with substantial thermal energy storage capacity have high capacity value, approaching that of conventional gas-fired generators. Non-dispatchable technologies, such as PV and CSP without storage, have rapidly declining capacity value at higher penetrations. The difference in long-term benefit can be as much as $10-30/MWh.

8.1 Methodology for Capacity Valuation

The methods for calculating capacity credits and capacity value of variable energy resources are reviewed in some detail in Appendix A. Table A-1 lists the capacity credit methodology currently used by different utilities and system operators in the United States and Canada. These methods are computationally complex. They are made even more complicated by the need to consider renewable penetration at historically unprecedented levels as well as the associated, and still undefined, requirements for operational flexibility.

The capacity credit or rating (MW) of a generator is its contribution to maintaining a reliability standard, typically based on a risk of loss-of-load. The capacity value of a particular generator ($/MW) is the capacity credit multiplied by the prevailing capacity market price or by the avoided cost of new capacity. The most robust approach to calculating capacity credits is to use statistical methods to determine the contribution of different types of existing and planned resources to achieve a loss of load probability (LOLP) for a particular power system that meets a reliability criterion. This criterion is typically measured in the United States as one (1) loss-of-load event in 10 years, a standard which has been interpreted differently in different locations (Pfeifenberger et al., 2013). As described in Appendix A and Table A-1, these types of models, and approximation methods that simplify the analysis for incremental resource additions, can be used to calculate the effective load carrying capability (ELCC) of incremental variable wind or solar plants under different resource scenarios (ELCC methods measure the additional load that can be added for each MW of variable wind and/or solar while maintaining the same reliability standard). Importantly, valuation of CSP plants with thermal storage typically requires further methodological modifications, because detailed dispatch models are used to calculate how forecast solar energy is stored in the thermal energy storage systems, converted into energy production, and then dispatched to the hours with highest capacity value.

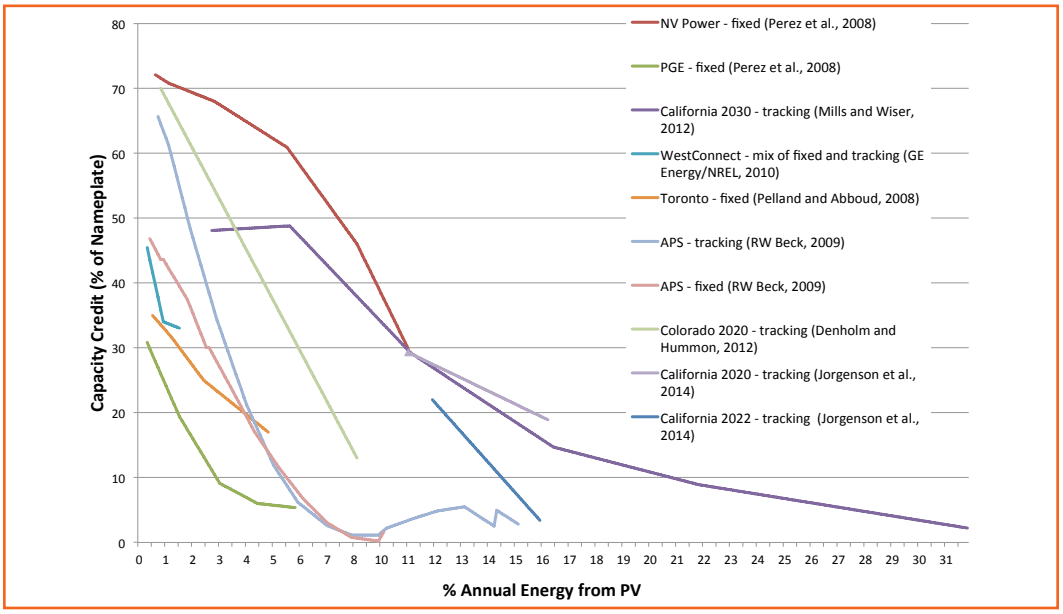
More recently, these traditional capacity valuation methods have been augmented by models that also consider the operational flexibility of capacity resources for purposes of renewable integration. These "flexible capacity" requirements appear likely to further decrease the capacity value of inflexible resources, and hence improve the comparative value of CSP with thermal storage.

The capacity rating (MW) of a generator represents its contribution to maintaining a reliability standard, typically based on the risk of loss-of-load. The capacity value of a particular generator ($) is the capacity credit multiplied by the prevailing capacity market price ($/MW) or avoided cost of new capacity.

8.2 Capacity Value in Low Solar Penetration Scenarios

At low solar penetration, each additional solar project to the renewable portfolio obtains similar capacity credits, as a function of technology type and location. For solar plants without storage, CSP and PV with tracking[47] generally obtain similar capacity credits in study results in the same locations, while fixed tilt PV gets lower credits (for a methodological survey of PV capacity valuation, see Madaeni et al., 2013, and NERC 2011). These results are shown in several figures in this section, some of which encompass results from both low and high penetration studies. We turn first to Figure 8-1, shown below. This figure, adapted from Mills and Wiser (2012a),[48] illustrates the results of several studies of PV capacity credits, with the results to the left side of the *x*-axis illustrating lower solar penetration scenario results. These show that in North America, at low penetration, PV initially obtains a range of capacity ratings, from 30% in areas with higher transient clouds up to 70% in locations with high solar insolation. The remaining results in the figure are discussed in detail in the next subsection. CSP without storage generally gets similar capacity ratings to PV at low penetration, although possibly higher because of the ability to do more sophisticated tracking and also because these plants are only located where there is high direct normal insolation. For example, Madaeni et al. (2012b) find a wide range for CSP without storage by Western U.S. location, from 46% - 95% of nameplate capacity. The reader should also note that Madaeni et al. do not consider hybridization with natural gas, which increases the capacity credits of many of the existing CSP plants.

Figure 8-1: Capacity credits (% of nameplate MW) of marginal PV additions to existing portfolios from selected studies of increasing solar penetration

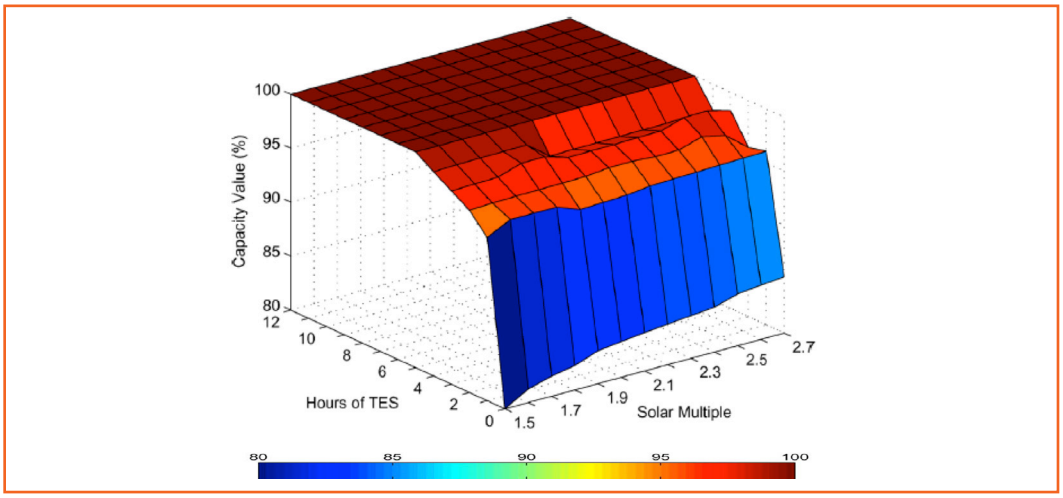


Source: Mills and Wiser (2012); adapted with additional results in Helman (2014).

[47] Double-axis tracking provides a small improvement over single-axis tracking for PV capacity credits (Madaeni et al., 2013).
[48] Refer to Mills and Wiser (2012a), pg. 8, for the references cited in Figure 8-2.

With the addition of thermal energy storage, even at low penetration, a CSP plant increases its capacity credits when compared to CSP plant of equal capacity (MW) without storage. Sioshansi and Denholm (2010) and Madaeni et al., (2012a,b) model changes in capacity value in relation to the solar multiple and number of hours of storage for a parabolic trough plant. As shown in Figure 8-2, they find that in regions with high direct normal insolation, the capacity rating of the plant increases from 80-85% of nameplate MW without storage, depending on the initial size of the solar field, to close to 100% with the addition of 4-5 hours of thermal energy storage. For the technology modeled, increases in storage capacity beyond 4-5 hours provide no incremental capacity value (given that the powerblock is of fixed size), although they may provide improved energy and ancillary service benefits.

Figure 8-2: Calculation of capacity value as a percentage of nameplate capacity of a parabolic trough with and without thermal storage in Southern California (Daggett)



Source: Madaeni et al., (2012b), pg. 343.

At low solar penetrations, the comparative valuation of solar with and without storage is also sensitive to how plant output is modeled. For example, if the solar technologies being compared within a single study – PV, CSP, and CSP with thermal storage – are modeled as producing equal energy, as described in Section 4, then the solar plants without storage – CSP and PV – would have higher maximum output (installed capacity) than the CSP plants with storage. At low penetrations, this may result in a higher or similar capacity value for the resources without storage compared to CSP with thermal storage because the high capacity value hours remain focused in the sunlight hours. However, as discussed next, as solar penetrations increase, the comparative value of CSP with thermal storage greatly increases.

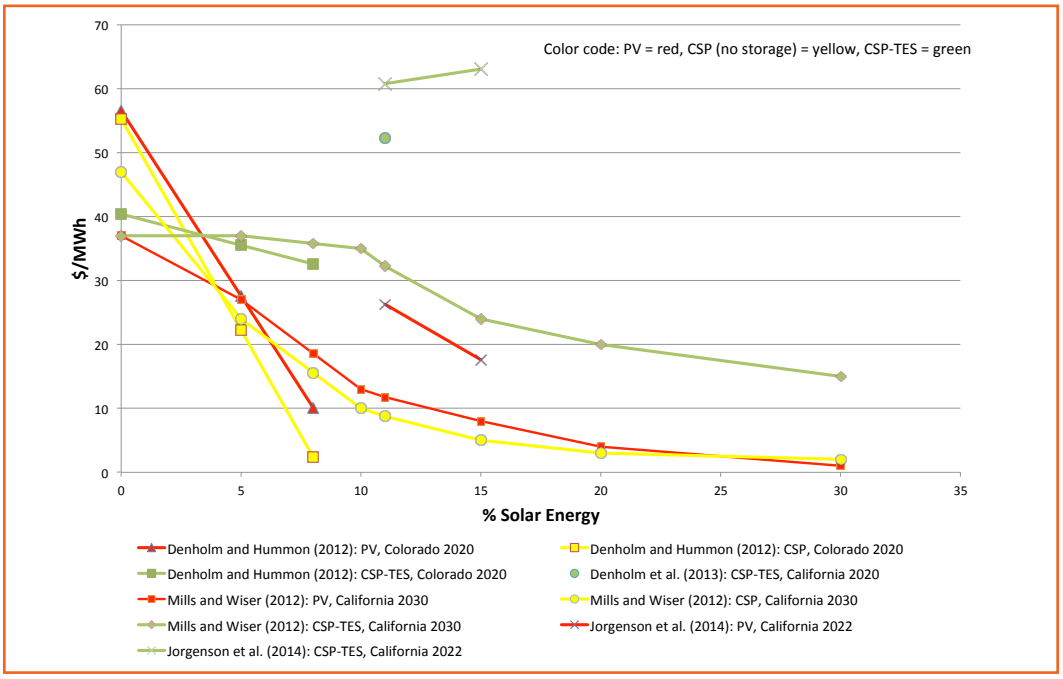
8.3 Capacity Value at Higher Solar Penetrations

As solar penetration increases, the "net load" curve shown in Section 6.2 progressively shifts the net load peak hours into the late afternoon and early evening. As such, incremental additions of PV and CSP plants with production fixed during the sunlight hours will face progressively declining capacity credits and capacity value, unless they include storage that can shift production to the new hours with greatest risk of loss-of-load. As we discuss, this effect is shown graphically in Figures 8-2 and 8-3.

Figure 8-2, introduced above, shows the capacity credits for PV projects calculated in studies conducted of different locations and penetration levels. The reader should note that these studies

also use different methodologies. While most of the studies shown in this figure did not model CSP (without storage), the results would have been similar (in the locations modeled with sufficient direct normal insolation), as can be seen from the studies represented in Figure 8-3. With some exceptions, these studies show significant reductions in PV capacity credits at penetrations above 5% of annual energy. In some cases, the incremental capacity credit is close to zero by 10% annual penetration, while in others, there appears to be incremental credit available until much higher penetrations.

Figure 8-3: Capacity benefits ($/MWh) of solar resources from selected studies of increasing solar penetration



Source: modification of figure in Helman (2014).

Figure 8-3 converts some of the PV capacity credit results in Figure 8-2 into capacity value ($/MWh), and includes the results for CSP with and without thermal storage. As noted, in each case, the studies use different methodologies and assumptions about the cost of displaced new capacity. This makes their results not directly comparable, but shows the general trend.

The studies that include CSP with thermal storage at higher penetrations use a dispatch model to simulate system operations and to shift stored thermal energy to the hours assumed to have highest capacity value. These results are shown in Figure 8-3 and Table 8-2, which also provides data on certain modeling assumptions.

There are commonalities and differences in study results. Denholm and Hummon (2012) model the Colorado-Wyoming power system at different renewable penetrations in 2020. In their high penetration scenario, where solar contributes about 8% annual energy towards a total of 33.7% renewable energy, a marginal parabolic trough plant with 6 hours of thermal storage has a $11.7-$30.5/MWh higher capacity value than PV projects that produce equal energy (the higher capacity value estimates for all solar resources modeled are shown in Figure 8-3). The range in value is created by different net costs for new combustion turbines and combined cycles in that region, based on utility estimates.

In an extension of the Colorado study, Jorgenson et al., (2013, 2014) modeled several different designs of tower CSP, across a range of solar multiples and capacities (MW). Under the equal energy assumption, which requires adjusting the capacity of the plants, they find that capacity value is maximized for towers with solar multiples of 1.3 and 3 hours of thermal storage, due in part to its high installed capacity (MW). Table 8-1 summarizes their results for the Colorado test system (Jorgenson et al., 2013).

Table 8-1: Capacity Value for Design Configurations of a Tower with Thermal Storage, Colorado test system

Solar Multiple	Capacity	Hours of Thermal Storage	Capacity Value, Low/High ($/MWh)
1.3	462	3	30.3/56.6
1.7	353	3	23.5/44.0
2	300	6	19.4/36.3
2.3	261	9	16.7/31.2
2.7	222	12	14.3/26.7

Source: Jorgenson (2013)

California has both potential for further development of CSP with thermal storage and an increasingly rapid penetration of PV resources under its renewable policies, expected to provide more than 10% of annual energy by 2020, if not sooner. As shown in Figure 8-3, several recent studies have calculated the comparative capacity value of different solar resources in California as solar penetration increases, although reaching different conclusions on the rate at which capacity value declines. In addition, the California Public Utilities Commission (CPUC) is revising its methods for calculating ratings of renewable resources over 2014-15, and incorporating some of the methodologies discussed in this chapter. These factors make the California case particularly important for refinement of solar capacity rating methods, including for CSP with thermal storage.

Mills and Wiser (2012b) calculate long-term equilibrium capacity value in California in 2030 for different renewable resources across a range of penetration scenarios, although as noted above, they consider penetration by only one type of resource at a time. Capacity value is measured as the energy and ancillary service revenues of the plant during hours with scarcity pricing, reflecting resource shortage. Figure 8-3 shows their results by solar technology type. At between 10-15% penetration in this model, marginal CSP without storage and PV plants reach a similar capacity value to marginal wind resources, and the capacity value further declines rapidly as penetration increases. Capacity value for parabolic trough plants with 6 hours of thermal storage ranges from $37/MWh at low penetration to $15/MWh at high penetration (30% annual energy). As shown in Figure 8-3 and Table 8-2, the difference between CSP with thermal storage and PV is about $10/MWh in the 5% penetration case, and then rises to $15-20/MWh for the 10% penetration cases and higher.

Denholm et al., (2013) model the grid in the western U.S. with a focus on integration of 33% RPS in California in 2020. Similarly to Mills and Wiser, they model an incremental parabolic trough with 6 hours of thermal storage. Capacity credit for solar resources is measured as the simulated output during hours of the highest net demand multiplied by a capacity value based on market estimates (low estimate) and also on the avoided cost of new generation in the region (high estimate). The difference in capacity value of a marginal CSP plant compared to an "equal energy" PV plant ranges from $3-11/MWh (see Table 8-2 for the avoided capacity costs). This result is shown as points in Figure 8-3, since they only model one scenario.

In a follow-on study, Jorgenson et al., (2014) model power towers with different storage capacities and at different solar multiples in both 33% and 40% RPS scenarios in California in 2020. They find that CSP capacity credits and capacity value increases with the increase in solar penetration between the 33% and 40% scenario, while PV capacity value decreases, resulting in a difference in capacity value with PV of $34.5/MWh and $45.5/MWh, respectively. The increase in capacity value results because of a narrowing of the daily peak hours due to the increased penetration of solar PV.

Additional research is clearly needed to clarify the range of solar capacity valuations in different penetration scenarios of the same regions.

These findings illustrate that as penetration of variable solar resources increases, the capacity value of marginal variable solar plants decreases, sometimes fairly rapidly. In most studies to date, CSP with thermal storage also loses some capacity value as penetration increases, but is able to retain much of its value by shifting energy to the highest capacity value hours as they change. However, Jorgenson et al., (2014) have also found that CSP with thermal storage may experience an increase in capacity value as aggregate solar production increases from around 12% to 16% annual energy. Additional research is clearly needed to clarify the range of solar capacity valuations in different penetration scenarios of the same regions.

8.4 Capacity Resources with Flexible Operational Attributes

With the penetration of wind and solar technologies, in many regions new approaches are being considered for the calculation of capacity requirements to ensure adequate operational attributes of existing, retrofitted or new capacity resources (e.g., Lannoye et al, 2012).[49] Such market rules may result in multiple classes of capacity differentiated by operational characteristics such as sustainable ramp rate over some period of time, and other factors such as start-up times. These developments reflect a concern that the sequence of retirements of existing capacity, and additions of new capacity, may not provide the operational flexibility needed to integrate variable energy resources. In regions with organized power markets, this could be because short-term price signals, sent through energy and ancillary service markets, will be insufficient to provide the incentives for the investment required to support rapid increases in needs for operational flexibility, which some power systems may experience at high renewable penetration. Hence, capacity requirements (or forward reserve markets, which serve similar purposes) could be modified to establish these requirements through forward procurement on a 1-3 year basis.

CSP with thermal energy storage can contribute to utilities' evolving flexible capacity requirements.

CSP with thermal energy storage can contribute to utilities' evolving flexible capacity requirements. As noted above, once synchronized with the grid, these plants offer fast ramp rates, the capability to support a ramp for several hours (as a function of storage capacity), and provide other desirable operational attributes. Based on industry discussions, start-up times are not especially fast from "cold" (i.e., full shutdown) conditions when utilizing thermal energy storage systems but can be reasonably fast from warm or hot conditions. Further analysis is also needed to determine the storage capacity needed to qualify CSP as flexible capacity, because ramping may be required for system operations at times other than the top seasonal peak load or net load hours.

Flexible capacity requirements may further reduce the capacity value of incremental generation resources that do not provide flexibility. This will increase the difference in capacity value of alternative solar technologies as renewable penetration increases, in addition to the difference already noted above.

[49] For progress towards flexible capacity requirements in California, see papers at http://www.cpuc.ca.gov/PUC/energy/Procurement/RA/ra_history.htm.

8.5 Summary and Additional Research Needs

Solar resources bring high capacity value to regions with sufficient solar insolation, but the value of marginal solar additions without storage appears to decline as penetration increases. This finding is quite consistent across the regions studied. Also consistent is that CSP with storage obtains the highest capacity rating of any variable renewable resource, and can also provide flexible capacity.

While these findings appear fairly general, there are notable differences in results between studies of the same system, such as California. These differences suggest a need for further research to clarify the changes in the value of marginal solar additions and the range of operational and resource solutions that may be forthcoming. In California, some of these assessments may take place in 2014 as a result of revisions in the methodology for calculating capacity value and continuing analysis of operational requirements.

Flexible capacity requirements may further reduce the capacity value of incremental generation resources that do not provide flexibility.

Table 8-2: Additional study details and results from selected studies of CSP with thermal storage in scenarios with increasing solar penetration

Study	Location and Date Modeled	Methodology/Metric	Cost of Replacement Capacity - Low	Cost of Replacement Capacity - High	Renewable penetration scenario	Difference in capacity value between CSP with thermal storage and PV
Jorgenson et al., 2014	California 2022		$150/kW-year	$190/kW-year	33% RPS, ~12% solar energy	$32.7- 34.5/MWh (optimal configuration)
					40% RPS, ~16% solar energy	$45.5-47.4/MWh (optimal configuration)
Jorgenson et al., 2013	Colorado 2020	For CSP, assumption of 100% capacity credit due to thermal storage	$77/kW-year	$147/kW-year	2.3% PV, 13.4% wind	Not calculated
Denholm and Hummon, 2012	Colorado-Wyoming 2020	For PV, capacity factor during peak net load hours; for CSP with storage, assumption of ~100% capacity credit due to 6 hours of thermal storage	$77/kW-year	$147/kW-year	25.5% wind, 8.2% PV	$11.7 - 30.5/MWh
Mills and Wiser, 2012b	California 2030	Capacity assumed to be in equilibrium based on scarcity pricing to elicit new generation; solar production during highest value energy and ancillary service hours multiplied by the simulated market prices.		$170-180/kW-year	5% solar (no other renewable energy)	$10/MWh
					10% solar (no other renewable energy)	$22/MWh
					15% solar (no other renewable energy)	$16/MWh

9. Integration and Curtailment Costs

Due to its operating flexibility, CSP with thermal storage can both avoid some or all integration and curtailment costs, and simultaneously also provide several of the services needed to integrate other variable energy resources.

Variable wind and solar resources may increase certain types of power system operational requirements, due to the combination of variability and forecast error which characterizes their production (e.g., NERC 2009). Moreover, as penetration of these resources increases, renewable production can potentially encounter physical operating constraints on the power system, such as ramping constraints and increased frequency of surplus or over-generation. Resolving these constraints could require curtailment of some renewable production and/or new or upgraded infrastructure to support further integration. These integration requirements have not proven to be a long-term impediment to high penetration of renewables in most regions to date, but they do affect decisions about the portfolio of renewable resources in each phase of procurement. Due to its operating flexibility, CSP with thermal storage can both avoid some or all integration and curtailment costs, and simultaneously also provide several of the services needed to integrate other variable energy resources.

Because there are few studies that explicitly calculate solar integration and curtailment costs, this section surveys the available qualitative and quantitative results. It also includes some illustrative examples. The section is organized as follows:

- Section 9.1 describes some basic methodological issues.
- Section 9.2 reviews both quantitative and qualitative estimates of solar integration costs.
- Section 9.3 uses data from California 33% RPS scenarios to illustrate three examples of how CSP with thermal storage can mitigate "net load" system ramps.
- Section 9.4 summarizes and identifies analytical needs for further research.

9.1 Renewable integration requirements

Integration analysis is generally divided into two questions:

- System requirements. What are the additional system operational constraints and needs under different renewable penetration scenarios?
- System capabilities. What are the capabilities of existing generation and non-generation resources across an interconnected region to meet those requirements? When are new capabilities needed to support the integration of renewable resources and what is the optimal mix of system resources needed over time to meet energy and environmental policy goals while ensuring reliability?

With respect to system requirements for integrating variable wind and solar generation, these include most notably the following:

- Increased multi-hour system ramps. As renewable penetration increases, both predictable and more variable multi-hour system ramps will increase in magnitude and duration.
- Increased intra-hourly load-following. Because of the combination of forecast error and actual, real-time variability, system operators must commit sufficient flexible generation to follow wind and solar production on a 5- to 10-minute basis. Due to forecast error, this may require ramping reserves.

- **Increased frequency regulation.** In between dispatch of generation, system operators will require additional automated response to solar and wind variability on time-frames of seconds.
- **Frequency response and inertial response reserves.** Many regions are implementing additional reserves for primary frequency control.

There is a growing body of research literature on these topics.[50] This paper limits itself to studies and surveys of solar integration costs, and particularly those that model CSP with thermal storage. Section 9.3 below also provides some illustrative simulations of the effect of CSP with thermal storage on system ramps. The provision of these services generally may require retrofit of existing conventional generation and hydro plants to provide greater operating flexibility. As described in Section 3, inverter-based renewable technologies will also be adapted to provide these services, although typically with some loss of production. Finally, new flexible conventional generation and non-generation resources, such as electrical storage, may also be needed over time.

New flexible conventional generation and non-generation resources, such as electrical storage, may also be needed over time.

9.2 Avoided integration costs

As renewable portfolios expand, estimates of integration requirements and costs are increasingly being used by utilities and regulators to influence the mix of renewable resources that they procure. The integration costs are just one component of the net system cost equation. However, these costs have attracted more policy attention recently as some power systems attempt to move rapidly to very high penetrations of renewable energy. In regions where CSP with thermal energy storage is a viable technology, avoided integration costs, including renewable curtailments, should thus be considered in the evaluation. Several recent papers have provided initial estimates of comparative solar integration costs, some identified explicitly while others are embedded in aggregate economic benefits (e.g., Denholm et al., 2013; Denholm and Mehos, 2011; Mills and Wiser, 2012b).

Analogous to the calculation of the value of thermal energy storage, the calculation of integration costs associated with variable energy resources requires a baseline case. As discussed in Section 3, several such baselines have been used in the current literature, including a "flat block" of energy and a base-case in which no additional renewables are added to the power system to meet load growth (Milligan et al. 2011; Mills and Wiser, 2012b; Denholm et al., 2013). Another approach is to make incremental adjustments to the renewable portfolio – by comparing equal energy contributions from different technologies, with accompanying changes in integration requirements – and measure the changes in production costs or market value (e.g., Denholm et al., 2013).

The actual and forecast costs of integrating wind and solar PV generation into the grid range widely based on the region and the level of penetration of the technologies. In the northwestern U.S., several utilities charge wind balancing fees, which currently range from $3.60-$9.50/MWh, depending on the utility (e.g., GE Energy and Exeter Associates, 2012). Other estimates of wind integration costs are from simulations. A semi-annual survey of wind integration costs (DOE 2012) finds a wide range of costs depending on the penetration up to about $11/MWh, but with most costs in the range of $2-8/MWh.

To date, there are fewer studies to date focused on integration of solar generation. Variable solar generation creates daily morning and evening production ramps, which increase as the portfolio expands. These ramps interact with load curves and wind generation in those periods to both reduce and increase the magnitude and rate of aggregate system ramps. With respect to

[50] E.g., surveys in Milligan, et al., (2009) and DOE (2012). On solar integration costs used by western U.S. utilities, see Mills and Wiser (2012a).

production variability due to transient clouds, this can create a high need for regulation to balance individual plants, but when smaller PV plants are spatially distributed, and in the absence of congestion, the net impact of this variability is diminished.

Mills and Wiser (2012a) cite a range of $2.50-10/MWh of integration costs used in solar valuation by the utilities that they surveyed but noted that some estimates were based on "rules of thumb." A simulation of the NV Energy utility in Nevada, U.S., found that PV integration costs increase from $3/MWh to just under $8/MWh as installed capacity of grid-based and distributed PV increases from 150 MW to 1042 MW; the higher end representing approximately 20% of annual energy sales (including the costs of having to curtail some of the PV facilities to maintain reliability) (Navigant et al., 2011). Since NV Energy is a vertically-integrated utility, the study only calculated changes in production costs.[51]

Mills and Wiser (2012b) calculate that the day-ahead forecast errors associated with CSP with 6 hours of thermal storage and impose a cost of $1-2/MWh up to a penetration of 20% annual energy, which is $3-5/MWh less than the corresponding costs of day-ahead forecast errors for CSP without storage or PV.

Table 9-1: Selected Solar Integration Costs Calculated for LSEs

Planning Studies and Procurement Valuations	Integration Cost Added to Production Costs ($/MWh)		
	PV	CSP without thermal storage	CSP with thermal storage
California IOUs	$0*	$0*	$0*
Public Service of Colorado (PSCo)	$5.15	N/A	$0
Arizona Public Service (APS)	$2.5	$2	$0
Tucson Electric Power	$4	$0	$0
Tri-State Generation and Transmission**	$5-$10	N/A	$5-$10
Portland General Electric	$6.35	N/A	N/A
Northwest Power and Conservation Council (NPCC)	$8.85-$10.9	N/A	$0
NV Energy***	$3-$8	N/A	N/A

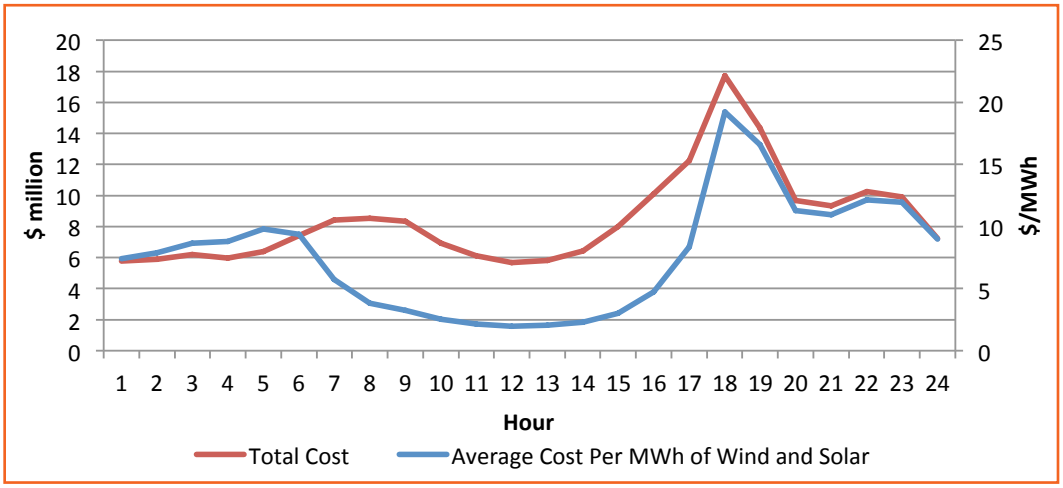
Sources: Mills and Wiser (2012a) unless otherwise indicated. * Pending approval of positive values by CPUC; ** Higher costs used for scenarios with more renewables. *** Navigant et al., (2011).

Most of these studies provide average integration costs. Because CSP with thermal storage can be dispatched to provide energy and reserves in the highest value hours, and these hours are likely to reflect increase requirements for renewable integration, it could potentially avoid *higher than average* integration costs. Pending more complete system studies, the authors evaluated data and cost estimates prepared for the 2010 long-term procurement planning (LTPP) studies conducted by the CPUC and CAISO to get an indicative estimate of how integration costs might be distributed over the day. The assumptions and methodology are presented in Appendix B of this report. Based on the numbers used in that regulatory proceeding, the total costs of regulation and load following for renewable integration at 33% RPS appears to be over $200 million per year. On average, the costs are about $5-6/MWh of variable wind and solar energy, using these data sets and assumptions, although other studies have suggested both lower and higher costs for the same scenarios.

[51] Note that the study does not include other actual integration costs, such as additional O&M costs or emissions associated with increased starts and stops, ramping, or maintaining gas-fired generation at minimum operating levels, nor does it address the integration costs of distributed PV, as it focused only on grid-based projects.

While these very preliminary estimates are for illustration, the distribution of the costs could still be indicative. Figure 9-1 shows how the total integration costs are distributed on average by hour of day, as well as in $/MWh of the modeled wind and solar production during that hour. Using this methodology during the hours when most solar energy is produced, hourly integration costs can be as low as $1-2/MWh of wind and solar production in those hours (that is, if the integration costs were all assigned to wind and solar production). However, hourly integration costs can also rise to $16/MWh (per MWh of variable renewable energy) during the solar ramp down and evening load pick-up (due in part to the smaller quantity of renewable energy on the system in that hour). Hence, reductions in those early evening integration requirements would create more value than the average.

Figure 9-1: Estimated hourly distribution of integration costs in $ million and $/MWh, caused by wind and solar resources in California under 33% RPS



Source: CAISO (2011) 33% RPS simulation data with the authors' calculations.

Most of the estimates discussed above are the variable costs of providing additional regulating reserves and ramping and assume that no new infrastructure is needed for renewable integration. Some studies add simulated curtailed wind and solar production to the calculation of integration costs (e.g., Navigant et al., 2011).

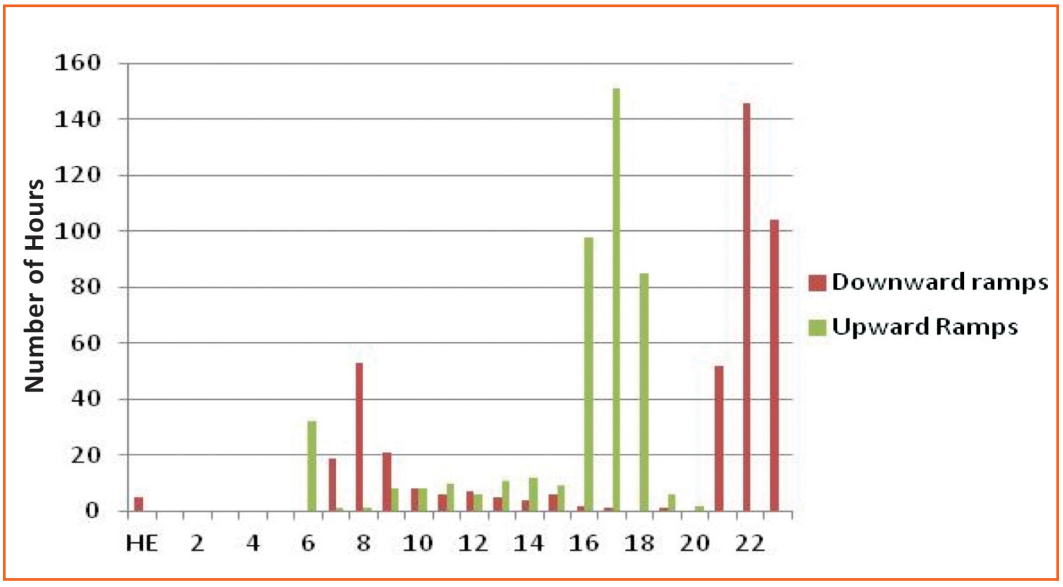
One of the few long-term, high penetration renewable integration studies currently available is NREL (2012), in which a 50%-80% renewable penetration is modeled for the entire United States (see also Denholm et al., 2012). In the study, CSP with thermal storage comprises up to 14% of energy in its 80% penetration scenarios. As shown in Table 5-2, CSP with storage achieves one of its highest penetrations in the "Constrained Flexibility" scenario where wind and PV were assigned a reduced capacity value as a penalty for variability. In the same study, conventional generation was assumed to be less flexible (e.g., higher minimum loads) and there was no additional interruptible load. Although modeled at an aggregated level, this study is the only one to explicitly model CSP with thermal storage as a cost-effective solution to integration requirements at high renewable penetrations.

9.3 Mitigation of System Ramps

A key measure of future grid operational needs is the rate and persistence of system ramps that occurs from the interaction of load and the sum of wind and PV production. Figure 9-2 shows that this interaction will exacerbate current system ramps, particularly in the late afternoon when the ramp down of solar production can coincide with increasing load and decreasing wind production. At other times, significant net load ramps can occur at the mid-morning when solar production increases ahead of the load increase or even in the overnight hours on high wind days.

The rate and persistence of system ramps as wind and solar production increase are key measures of the future grid operational needs.

Figure 9-2: Top 10% of upward and downward net load ramp hours, by hour of day, from California ISO 2020 33% RPS Trajectory Case simulation



Source: CAISO (2011) 33% RPS simulation data, with assumptions about net loads by the authors.

To illustrate the potential for mitigation of system ramps, the authors created a simple optimization model using data from the 33% RPS system simulations conducted by the California ISO. As a starting point, the data sets for the 2010 33% RPS "Trajectory" scenario were used. To gain insight into the effect of progressive increases in thermal energy storage within the portfolio, three new CSP portfolios were created, while keeping total solar energy unchanged: the first 2,500 MW of CSP was modified to include 2 hours of thermal storage, the second added 4 hours of storage and the third added 6 hours of storage. The conversion was made so as to maintain equivalent annual energy output, so the capacity (MW) of the storage units was reduced as energy output was expanded. Table 9-2 shows the final adjusted capacity for each case. As a further assumption, in the cases with storage, the storage facility was assumed to be fully charged on each day.

Table 9-2: Modifications of the CPUC 33% RPS Trajectory Scenario to include CSP with thermal energy storage

Storage Duration	Change in CSP capacity without storage reduction	Change in CSP capacity with storage addition
2 hour	– 2500 MW	+2107 MW
4 hour	– 2500 MW	+ 1816 MW
6 hour	– 2500 MW	+ 1593 MW

In this analysis, the objective is to illustrate the use of thermal energy storage specifically to affect system ramps, so the available stored thermal energy was dispatched to reduce net load hourly variance.[52] In addition, as shown in the figures below, by substituting CSP with thermal energy storage for CSP without storage but keeping the total energy the same, the solar profile is "flattened" and solar energy is pushed to low or non-sunlight hours further reducing the net load ramps.

[52] That is, the objective function for dispatch of storage was to minimize $\sum_{h=1}^{24}(l_h - l_{h-1})^2$ where l is the hourly net load and h is the hour (time interval).

To identify interesting days, the California ISO data sets were searched for days with particularly high sustained multi-hour net load ramps and other examples of significant variability. The results for three such days are discussed below. Each figure accompanying the example day shows the following components. At the bottom of the figures labeled (a) are the:

- wind profile for the day (which remains fixed in all cases),
- the base aggregate solar (CSP plus PV) production profile (before adjustment), and
- profiles for the three cases with CSP with thermal energy storage shown in Table 10.

At the top of the figures labeled (a) are the:

- base hourly load profiles (which remains fixed in all cases), and
- net load profiles corresponding to the three cases with CSP with storage.

The figures labeled (b) are closer views of the load and net load profiles from each figure (a). In each case, figure (b) uses the same legend as figure (a).

Example 1 – Reducing the Late Afternoon Net Load Ramp

The first example, shown in Figure 9-3, uses data for an autumn day with fairly stable wind production and high solar production as well as a peak load after dark. On this day, an extreme "net load" ramp up occurs in Hours 15-18 because of the normal diurnal solar ramp down and a simultaneous decrease in wind production. As shown in the generation curves in the lower part of the upper graph, production from thermal energy storage allows CSP output to extend into the evening, progressively mitigating the magnitude and duration of the ramp. The lower graph, Figure 9-4 shows a close-up of the load and net load graphs.

Figure 9-3: Example 1(a) - Impact of Thermal Energy Storage on High Late Afternoon – Net Load Ramp

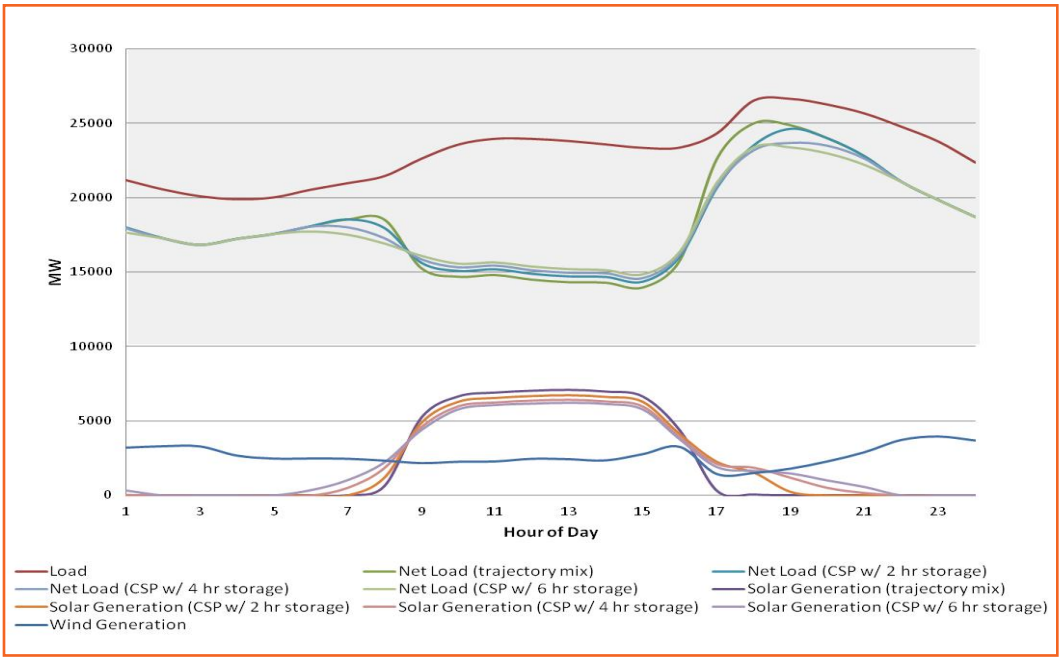
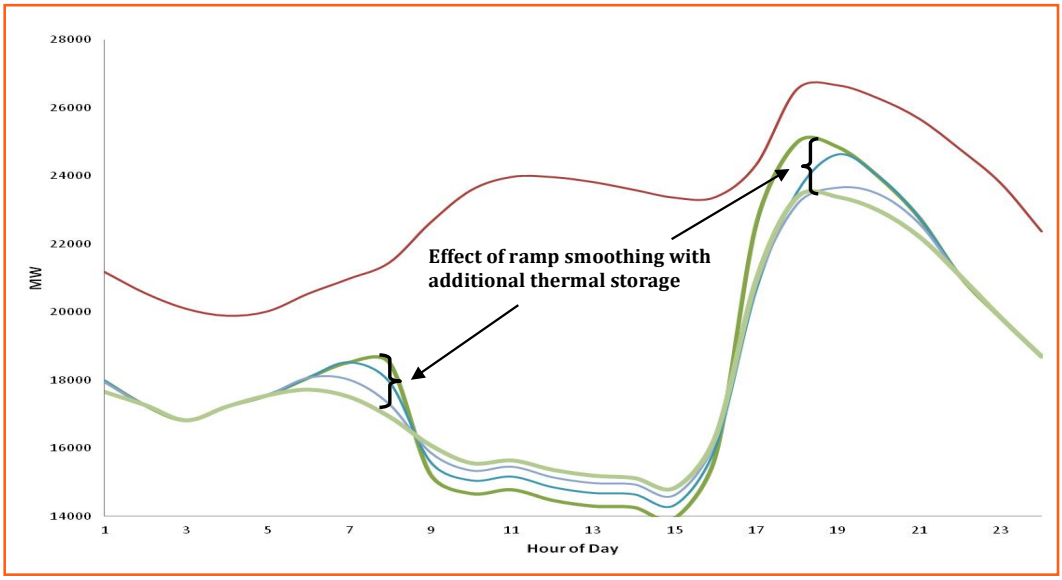


Figure 9-4: Example 1(b) - Impact of Thermal Energy Storage on High Late Afternoon – Net Load Ramp – additional detail on net load ramps



Example 2 – Intermittent Cloudy Day, Large Variation in Solar Generation

The next example, shown in Figures 9-5 and 9-6, is of a mid-summer day in which aggregate solar production is highly correlated with the load curve throughout much of the day. However, cloudy weather causes solar production (from plants without storage) to vary significantly during some hours. In this case, the thermal energy storage has been dispatched primarily to address the large ramps in the afternoon, in hours 17-20, resulting in significant smoothing of the net load curve.

Figure 9-5: Example 2(a) - Impact of Thermal Energy Storage on High Midday Variability

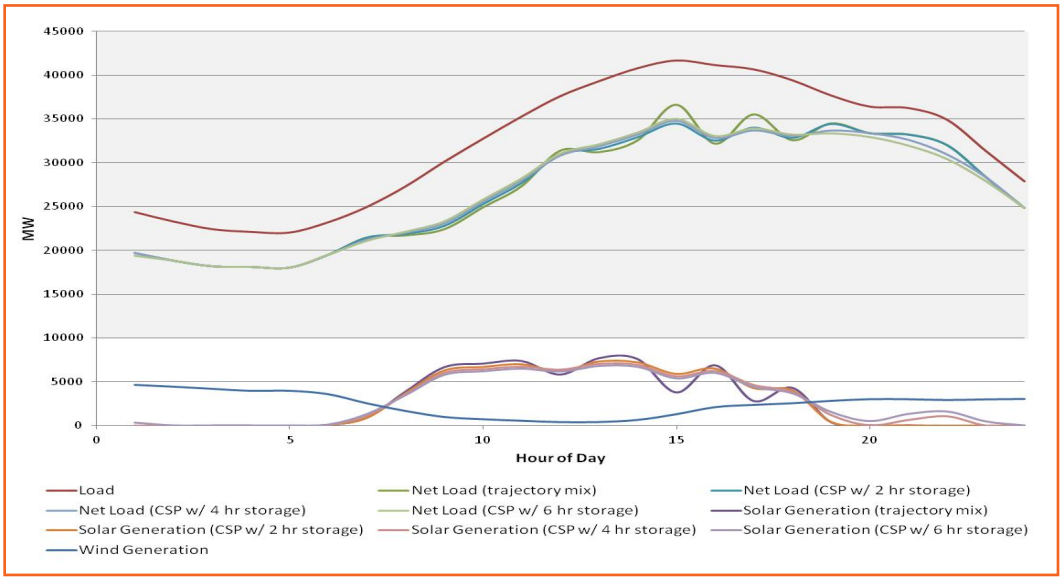
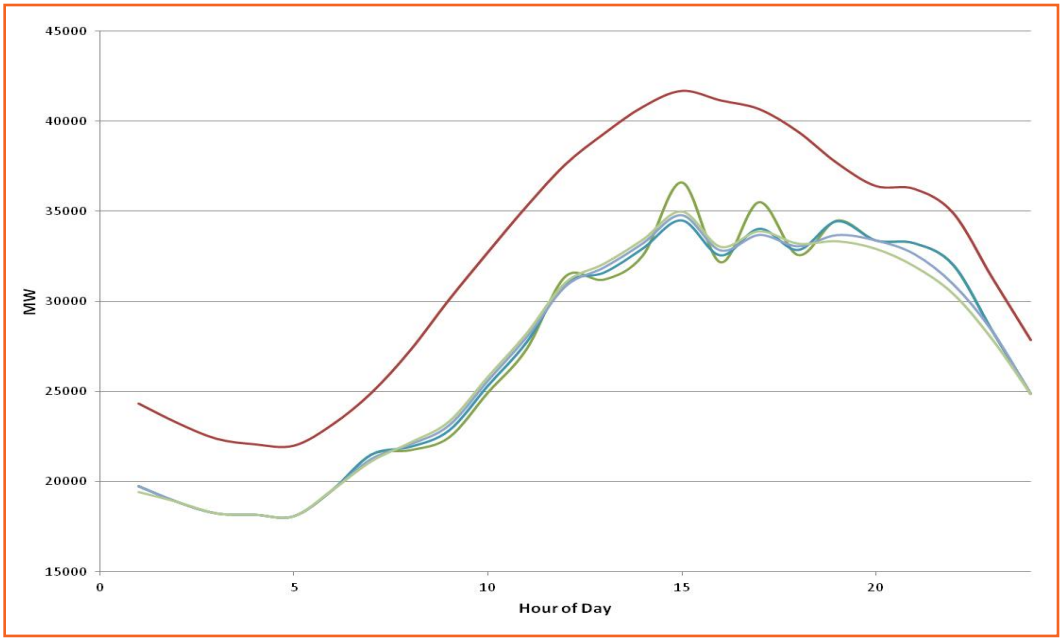


Figure 9-6: Example 2(b) - Impact of Thermal Energy Storage on High Midday Variability - additional detail on net load ramps



Example 3 – Rapid Changes in Net Load Ramp Direction

System operators are concerned with predictable ramps of increasing magnitude and duration, but they are even more concerned about rapid, significant ramps that change directions in a short time. This effect was illustrated to some degree in Example 2, and Example 3 shown in Figures 9-7 and 9-8 shows a more extreme example. On this spring day in California, light load is combined with relatively stable wind but more variable solar output. Most notably, solar output drops off sharply in the mid-morning around hour 9 before recovering in hour 10. The coincidence of the solar ramp down with the morning load ramp up exacerbates the "net load" ramp. This creates a "V" shape that first requires dispatchable generators to ramp up followed by an immediate ramp down. As the figures show, CSP energy from thermal storage can be dispatched against such variability. The net load variation in the cases with storage is greatly diminished. Because the event is of relatively short duration, even the 2 hour storage system is able to significantly improve the V-shaped ramp. The additional energy from 4 and 6 hour storage is mostly dispatched in the later hours of the day – hours 18-22 – to reduce the net load ramp in those hours.

Figure 9-7: Example 3(a) - Impact of Thermal Energy Storage on rapid changes in net load – ramp direction

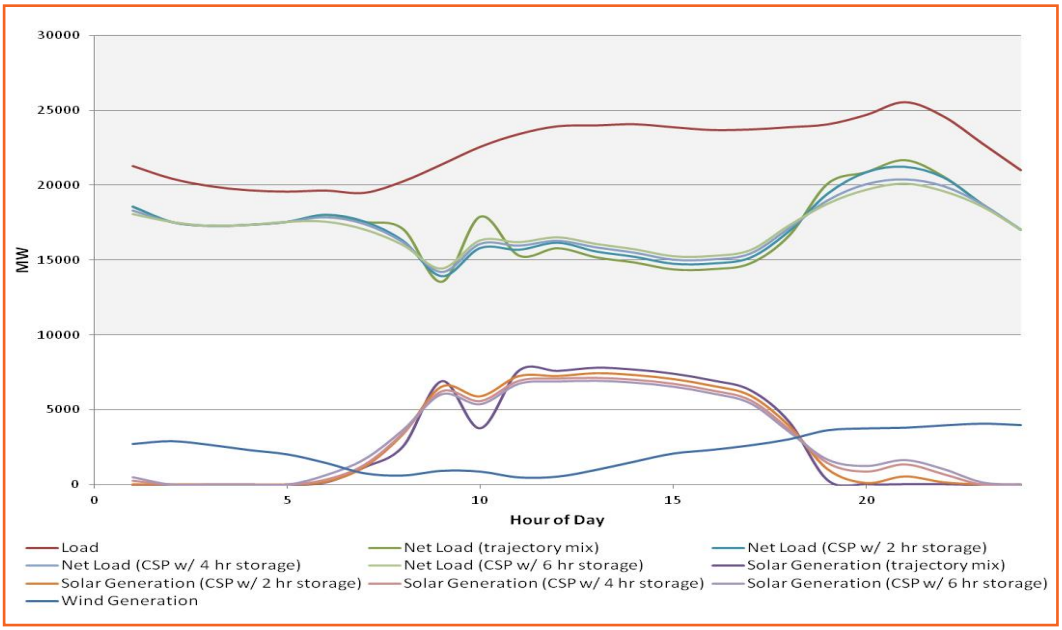
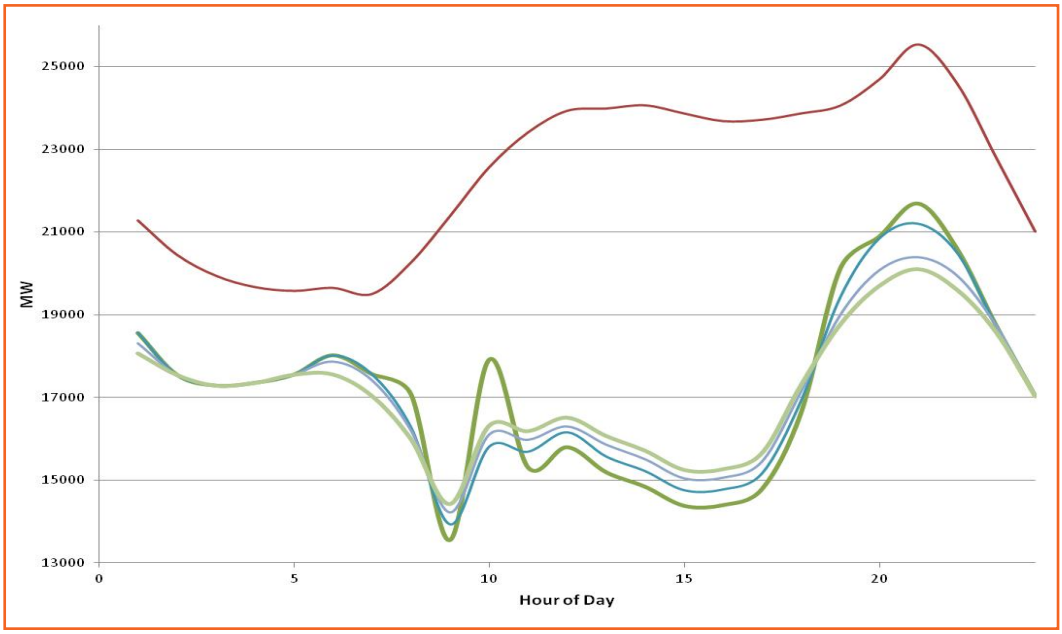


Figure 9-8: Example 3(b) - Impact of Thermal Energy Storage on rapid changes in net load ramp direction – additional detail on net load ramps



These examples demonstrate the ability of CSP with thermal energy storage to respond to system ramps for individual days, but detailed simulation is needed to provide a more detailed view of its impact on system performance. Denholm et al., (2013) is the first study to use these same data sets for annual simulations, but modeled only a marginal CSP resource with thermal storage which would not have shifted the net load ramps as significantly as in these figures.

9.4 Curtailment of Solar Energy

When a power system experiences operational and/or transmission constraints on renewable energy scheduling (or other types of generation), there may be surplus energy on the system which necessitates backing down or curtailing some renewable generation. The cost of the lost renewable energy is another type of integration cost (see, e.g., Navigant et al., 2011; Denholm and Mehos, 2011).

To date, only studies of very high penetration scenarios of solar energy in the western U.S., have resulted in high potential solar curtailments. The recent studies of California at 33% RPS, with about 11-15% solar energy, run by the CPUC and the CAISO did not find any significant curtailment (see also Denholm et al., 2013). However, these models are generally fairly aggregated, and as actual solar penetration increases, there may be increased curtailment of marginal solar additions.

The prior studies are still useful as indicators of potential issues that should be considered in renewable procurement. Denholm and Mehos (2011) model two high penetration solar portfolios on the southwestern U.S. grid: (a) 20% PV energy and no CSP and (b) 15% PV energy and 10% energy from CSP with 6 hours of thermal storage, both cases representing a total of 25% energy from solar resources. Each scenario also assumes 10% wind penetration. For the first case, 5% of total annual PV energy is curtailed, because dispatchable generators cannot be backed down sufficiently to accommodate the influx of solar energy. They also find that curtailment increases rapidly beyond 20% PV penetration, with substantial reductions in production (i.e., greater than

50% of energy from incremental PV resources) reached by about 25% penetration. In the second case, solar energy comprises 5% more of total annual energy needs but experiences only 2% curtailment of annual solar production due to the energy shifting of CSP with thermal storage.

Mills and Wiser (2012b) corroborate these general findings in a model of the California power system in 2030. They calculate not only the amount of renewable energy curtailment but also the amount of production at very low energy prices; in other words, production during hours when economic value is very low, which may indicate that curtailment is more likely. They find that CSP with 6 hours of thermal storage is required to curtail only at very high renewable penetration -- 30% of annual energy -- and even then at less than 1% of its available energy. Moreover, only 2% of production is sold in hours with low energy prices. In contrast, CSP without storage and PV experience increasing curtailment with greater penetration – approximately 7% curtailment at 30% penetration – as well as selling 48% of their energy at low energy prices. The Mills and Wiser result is thus more optimistic than the earlier Denholm and Mehos study about solar integration; however, both of these studies use simplified models of the power grid and thus need to be followed by more detailed network modeling.

To date, there remains uncertainty about when PV curtailment rates will rise sufficiently in California to significantly increase the comparative value of CSP with thermal storage. Jorgenson et al., (2014) model both 33% and 40% RPS scenarios with solar penetrations of about 12% and 16%, respectively, on the California and western US grid in 2022. They find negligible PV curtailment in the 40% case if exports from California are allowed, but rising to about 0.1% of total solar energy under the assumption that no solar energy can be exported from California, a strict bounding assumption. In this case, the operational value of a marginal CSP plant with storage increases by only about $1/MWh over a marginal PV plant. However, based on the growing frequency of negative prices in the CAISO markets, actual power system operations may provide a real test of the need for curtailment earlier than is suggested in these studies.

9.5 Summary and Additional Research Needs

CSP with thermal energy storage can provide renewable energy with greatly reduced variability and forecast errors, when compared to solar PV and wind generation. The operational flexibility of CSP with storage also supports increased aggregate production by other variable energy resources. While the simulations conducted by NREL and LBNL have greatly advanced the analytical framework, to fully characterize the potential of CSP with thermal storage, additional regional power system simulations are needed to evaluate the integration requirements of high penetration scenarios with and without CSP with thermal energy storage. Further work is also needed to validate the sub-hourly operational capabilities of CSP with thermal energy storage, particularly to provide Regulation and intra-hourly load-following.

There is still substantial uncertainty about integration costs for high renewable energy scenarios on the power system. If such costs are not considered, then CSP with thermal energy storage could be disadvantaged when compared to other renewable resources. Hence, until there is greater clarity on these costs, utilities and regulators considering CSP with thermal energy storage will have to apply judgment about the possible range of avoided integration costs based on available simulations of the power system.

10. The Total Economic Benefits of CSP with Thermal Storage

As the transition to cleaner power systems accelerates, and especially as system operations and reliability become more salient factors in renewable procurement decisions, net system costs will become a key metric for comparison of alternative renewable technologies. The prior sections of the report reviewed the valuation of the individual economic benefit and integration cost components of the net system cost equation. This section examines the summation of these values to allow for more accurate estimates of comparative net system costs for different solar technologies, across future scenarios.

To date, the research literature on western U.S. power systems under renewable penetrations of 33% to 40% of annual energy suggests that incremental CSP with thermal storage plants provide total economic benefits in the range of $30-60/MWh greater than incremental variable solar resources, whether CSP without storage or PV. There may also be changes on the cost side of the equation that favor CSP with storage, in the event of increased curtailment of energy from variable solar resources. The initial analyses of renewable penetration scenarios greater than 33% of annual energy in California and elsewhere suggest that this difference in net system costs could become higher, due in part to such curtailment (in the absence of mitigating measures).

Incremental CSP with thermal storage plants provide total economic benefits in the range of $30-60/MWh greater than incremental variable solar resources, whether CSP without storage or PV.

This section is organized as follows:

- Section 10.1 briefly reviews the methodology for calculating total economic benefits.
- Section 10.2 surveys study results.
- Section 10.3 summarizes and identifies research needs.

10.1 Advances in integrated system modeling for comprehensive analysis of CSP economic benefits

As discussed in Section 4, in the past, different simulation models have been required to quantify different components of plant operations and economic benefits. More recently, there has been further development of integrated modeling approaches which can capture additional hourly and sub-hourly operational benefits as well as capacity value in a single modeling framework. Such integrated analyses have been demonstrated by Denholm and associated researchers at NREL (e.g., Denholm and Hummon, 2012; Denholm et al., 2013; Jorgenson et al., 2013) and Mills and Wiser (2012b). These studies have greatly improved the understanding of potential economic benefits from alternative solar resources within a consistent set of assumptions. They also provide a foundation for building further models to examine plant capabilities on subhourly time-frames.

California has been a particular focus of these recent studies, in part because of its aggressive renewable policies and also because of the expectation until recently of significant near-term CSP development. The models used by Denholm et al., (2013) and Jorgenson et al., (2014) are based on an evolving methodological framework being used for long-term procurement planning in California, which can capture not only hourly energy and spinning reserve benefits, but also simultaneously, the reservation of capacity to provide regulation and ramping reserves (load-following) on a sub-hourly basis. This model can also be further used to conduct sensitivities on resource portfolios and CSP technology configurations. Jorgenson et al., (2013) also demonstrate some of these applications in a Colorado test system.

Mills and Wiser (2012b) have also developed an integrated valuation model, which incorporates additional operational factors not considered by Denholm et al., such as day-ahead forecast errors. The model also builds capacity based on long-term equilibrium assumptions. However, their model has less network and operational detail compared to those used by Denholm et al. In addition, unlike Denholm's work, the resource portfolios used by Mills and Wiser are not directly related to the actual California utility portfolios.

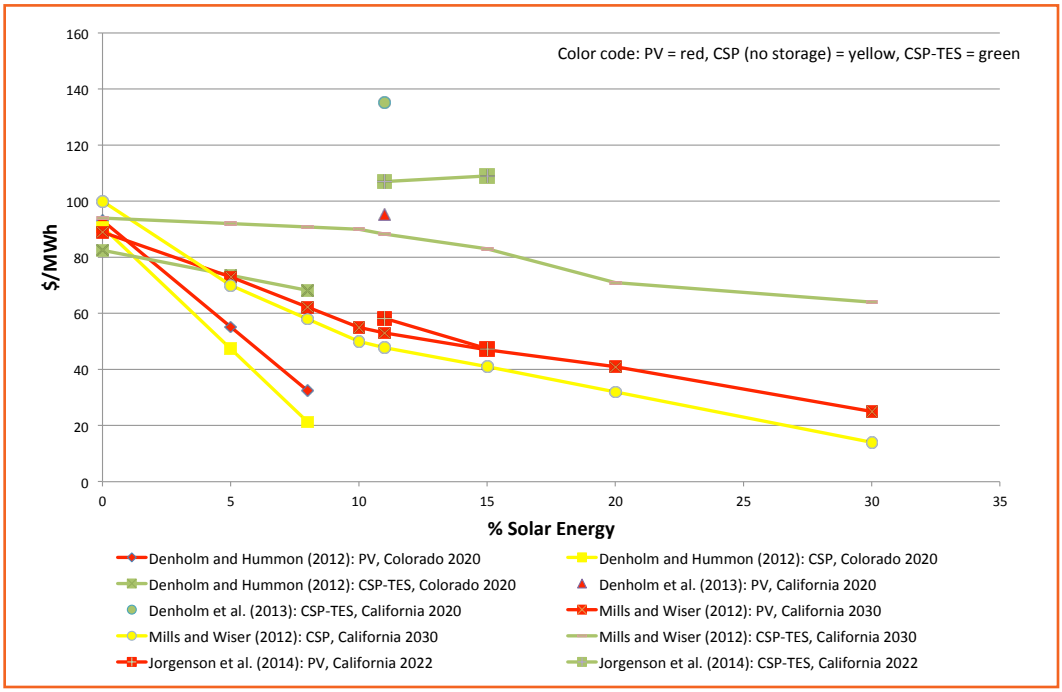
Other studies reviewed here have addressed some but not all categories of benefits. Madaeni et al., (2012b) added together energy, spinning reserves and capacity value using an hourly model, but their exogenous fixed price model does not extend to evaluating alternative renewable portfolios and the impact on system operations and production costs. On the other hand, in market regions, results based on modeling using historical market prices incorporate the effect of additional power system constraints and bidding behaviors which influence market prices, which the system models may not capture.

Hence, the calculation of net system costs (costs minus benefits) by a utility could require consideration of results from different models or settings, with due attention to how those results are derived.

10.2 Total economic and reliability benefits in recent studies

As shown in Figure 10-1, a key finding in the studies surveyed is that economic benefits of variable energy resources decline as a function of increasing penetration, although not necessarily linearly. As solar penetration increases and displaces fossil-fuel generation, the energy benefit of incremental solar resources during the sunlight hours declines, while the capability of CSP with thermal storage to shift energy allows it obtain $13-25/MWh in higher energy benefits (Jorgenson et al., 2013, 2014; Denholm et al., 2013; Denholm and Hummon, 2012; Mills and Wiser, 2012b). For similar reasons, studies predict a significant decline in capacity value of incremental PV and CSP without storage as penetration increases. While U.S. studies appear to agree that PV capacity value declines sharply in the range of 5-10% penetration by energy, there are differences in the rate of change among studies of particular regions that need to be resolved. CSP with thermal energy storage has a higher retained capacity value in the high penetration scenarios, in the range of $10-20/MWh, and possibly higher (Jorgenson et al., 2013; Denholm et al., 2013; Denholm and Hummon, 2012; Mills and Wiser, 2012b). At least one study has found an increase in CSP with thermal storage capacity value as PV penetration increases, due to counter-intuitive changes in the shape of the peak net load hours (Jorgenson et al., 2014).

Figure 10-1: Total economic benefits ($/MWh) of alternative solar resources from selected studies of increasing solar penetration



Source: based on a figure in Helman (2014).

The sum of these economic benefits is significant at higher solar penetration. Table 10-1 at the end of this section summarizes some of these results. Of the studies listed in the table, Mills and Wiser (2012b) offer the most detail in how these benefits cumulate over time. They calculate that in California, CSP with 6 hours of storage offers a $35/MWh benefit greater than PV by 10% penetration – roughly the penetration levels currently being planned towards in California under the 33% RPS – and then remains between $30-40/MWh in the higher solar scenarios that they model.

Figure 10-2: Difference in marginal economic value in California between CSP with thermal storage and PV as solar penetration increases – Mills and Wiser (2012b)

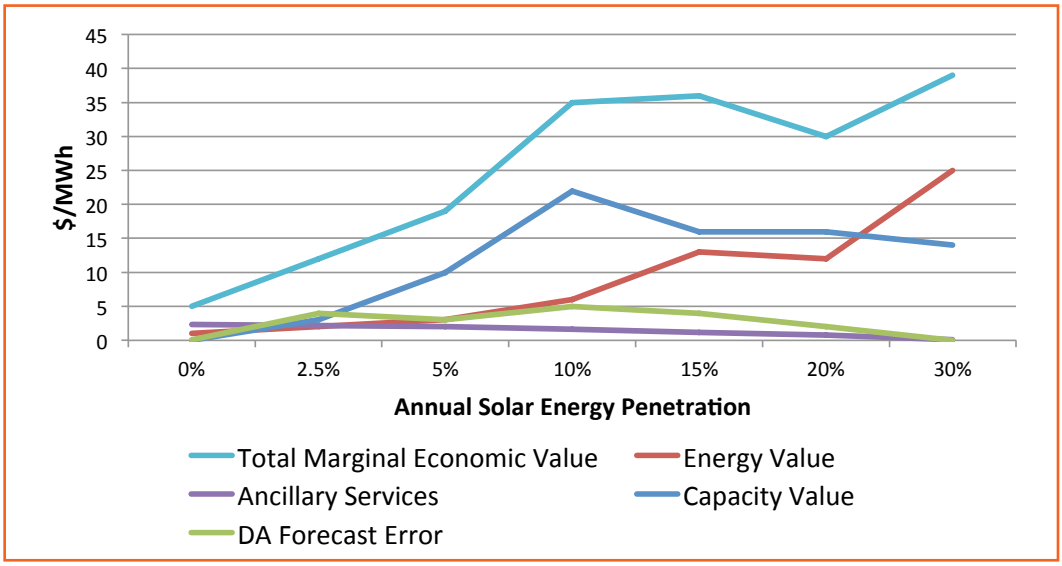


Figure 10-2 shows the difference in the individual economic value components – such as energy, ancillary services, capacity, and integration costs (represented partially as day-ahead forecast error) – and the sum of those components, between CSP with 6 hours of thermal storage and PV.

Total benefits are summarized below in Table 10-1. Similar total benefits, of around $40/MWh, have been found by Denholm et al., (2013) for a California 33% RPS scenario in 2020, with Jorgenson et al., (2014) finding a $49/MWh difference for a 33% RPS case in 2022, that also included several differences in assumptions (including avoided fuel and capacity costs in 2022). In a Colorado test system, Denholm and Hummon (2012) only sum energy and capacity benefits, but find a $25-43.8/MWh increase over PV in their scenario with around 33% wind and solar penetration, with the high capacity value based on the avoided cost of a new combined cycle. Jorgenson et al., (2013) find a higher difference with PV for the same system using a larger range of plant designs for CSP with thermal storage, although the exact numbers are difficult to extract from the report. Jorgenson et al., (2014) find the highest difference in studies to date, with a $62/MWh difference in a 40% RPS scenario with 16% solar energy.

Table 10-1: Calculation of the difference in total economic benefits between CSP with thermal storage and PV from selected studies

Study	Location and Date Modeled	Technology	Economic benefits measured	Baseline Solar	Renewable penetration	Difference in Economic Benefits from Baseline
Jorgenson et al., 2014	California 2022	Tower with 0-15 hours of storage, Solar Multiples 1.3-2.7	Energy, ancillary services, capacity, some integration costs	Single axis tracking PV	33% RPS, ~12% solar energy	~$48/MWh (optimal tower configuration)
					40% RPS; ~16% solar energy	$62-64/MWh (optimal tower configuration)
Denholm et al., 2013	California 2020	Trough with 6 hours of storage, Solar Multiple 2.0	Energy, ancillary services, capacity, some integration costs	Single axis tracking PV	33% RPS; ~11% solar	$32-40.2/MWh
Denholm and Hummon, 2012	Colorado-Wyoming 2020	Trough with 6 hours of storage, Solar Multiple 2.0	Energy, capacity	Single axis tracking PV	25.5% wind, 8.2% PV	$25-43.8/MWh
Mills and Wiser, 2012b (see Figure 10-2)	California 2030	Trough with 6 hours of storage, Solar Multiple 2.5	Energy, ancillary services, capacity, some integration costs	Single axis tracking PV	5% solar	$19/MWh
					10% solar	$35/MWh
					15% solar	$36/MWh
					20% solar	$30/MWh
					30% solar	$39/MWh

Simulation studies of CSP with thermal storage to date (e.g., Mills and Wiser, 2012b) have not determined a high value for avoided integration costs, and accurate long-term analysis is difficult due to many factors that can influence the result (Milligan et al., 2011). But other studies of integration costs have suggested values for wind and solar integration costs in the range of $5-10/MWh for higher penetration scenarios, when utilizing existing system resources to provide integration services (e.g., survey in Mills and Wiser, 2012a; Navigant et al., 2011). In Denholm et al., (2013), these integration costs are not identified but are factored into the difference in production costs between scenarios with PV and CSP with storage. As shown in Figure 10-2, Mills and Wiser (2012b) do explicitly value certain integration cost components, such as day-ahead

forecast errors, but their results appear lower than comparable studies. Curtailment of PV energy due to constraints in power system operations could also increase at higher solar penetrations, and there is the potential for CSP with thermal energy storage to reduce overall solar energy curtailment (Denholm and Mehos, 2011). Studies suggest that these avoided integration and curtailment costs should be considered when comparing CSP with thermal energy storage to other renewable technologies.

10.3 Summary and Additional Research Needs

The studies surveyed in this report suggest similar ranges of total economic benefits for CSP with thermal storage as well as similar differences with the total benefits of comparable PV projects. In the earlier studies of CSP with thermal storage, total benefits were summed using plant-level dispatch models. In the most recent studies, network models at different levels of aggregation, and incorporating different assumptions about scheduling, have allowed a more detailed look at comparative benefits of alternative solar technologies under different scenarios.

Analysis of sub-hourly operational benefits will require combinations of production simulation and other models. A forthcoming study sponsored by the California Energy Commission will utilize the model framework in Denholm et al., (2013), but link it to a detailed sub-hourly model of system frequency control that can explicitly model the CSP plants with storage operating to provide frequency response, frequency regulation and economic dispatch. When new types of system requirements are identified, such as frequency response requirements, additional re-formulation of power system simulation models used for valuation will be needed, to add new constraints.

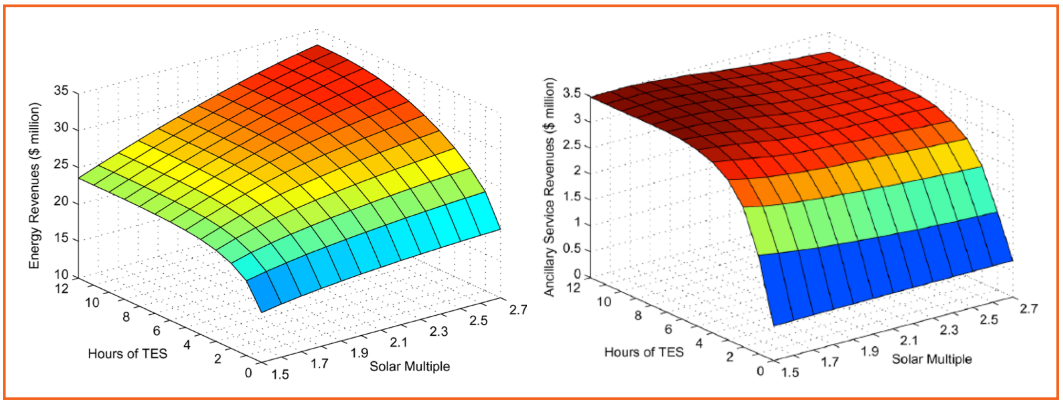
There also needs to be further development of portfolio planning models, such as NREL (2012), to examine in more detail how CSP with thermal storage fits into the next generation of renewable and integration solutions. The portfolios developed by those models then need to be evaluated using production cost models to allow for greater insight into the economic benefits of different technologies.

11. Incorporating Market and Reliability Valuation into CSP Plant Design

Historically, the types of economic and reliability valuation reviewed in this report were not direct inputs to the engineering design processes of CSP firms (nor, generally, to the procurement decisions of buyers). However, these recent studies have shown how both plant-level and system-level simulation studies can guide innovation in CSP plant design. Particularly with the release of the most recent studies by NREL (e.g., Jorgenson et al., 2013, 2014; Denholm et al., 2013), a fairly detailed framework is presented to allow economic analysis to support more sophisticated engineering design and utility procurement processes.

Using plant-level models optimized against external prices, Madaeni et al., (2012b) and Brand et al., (2012) model market valuation of a 110 MW trough plant by varying the solar multiple and number of hours of storage, and then estimate the design options that are most likely to result in a positive benefit-cost ratio based on public CSP cost estimates. Figure 11-1 shows Madaeni et al.'s total simulated revenues from energy and spinning reserves in the California ISO in 2005 plotted against the hours of storage and solar multiple. The design approach is to conduct cost-benefit analysis across a range of design parameters to reach the optimal design. Extensions of this approach could be to include other operational characteristics, such as ramp rates, minimum operating levels, and regulating ranges.

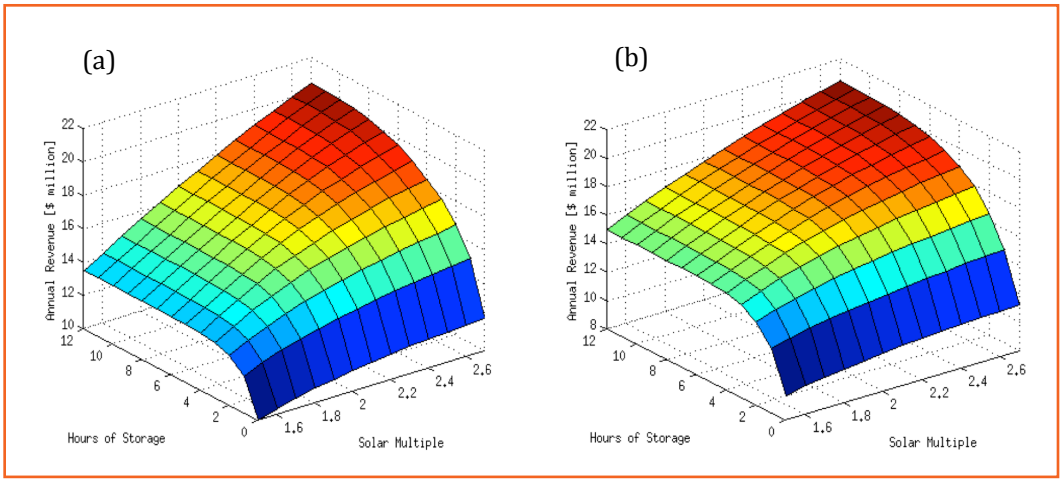
Figure 11-1: Annual revenues from energy and spinning reserves for different configurations of a parabolic trough plant, CAISO 2005 prices



Source: Madaeni et al. (2012b).

Multiple years can be tested to examine the robustness of the design decision. For example, Figure 11-2 shows the same model but run against California ISO market prices in 2010 and 2011 to examine any revenue changes as well gain insight into configuration changes.

Figure 11-2: Annual revenues from energy and spinning reserves for different configurations of a parabolic trough plant, CAISO 2010 (a) and 2011 (b) prices



Source: Helman and Sioshansi (2012, unpublished).

More recent studies, including Jorgenson et al., (2013, 2014), Denholm et al., (2013), Mills and Wiser (2012b) and Denholm and Hummon (2012), dispatch CSP with thermal storage in power system models that capture a range of benefit components under different renewable penetration scenarios and future years. Denholm et al., (2013), Mills and Wiser (2012b) and Denholm and Hummon (2012) only evaluate 0 and 6 hours of storage. Jorgenson et al., (2013, 2014) extend these earlier studies to model different configurations of storage capacity and solar multiples on both parabolic troughs and power towers. These studies then calculate economic benefits for plants characterized by different solar multiples, installed capacity (MW), and storage capacity, using the more robust system modeling framework offered by production simulation.

These recent studies demonstrate that insight into CSP plant design options can be advanced both by plant-level models, which allows consideration of detailed plant-level constraints, and by modeling of CSP plants in full power systems. As these study results become available, the CSP industry needs to engage utilities and regional system operators in a more detailed discussion about plant attributes and potential benefits. Individual companies can take advantage of this model development to conduct internal design evaluation. Moreover, there are now demonstrations that storage capacity decisions need to be robust to additional scenarios of high renewable penetrations, which may further reward operational flexibility (e.g., Jorgenson et al., 2014).

12. Conclusions and Next Steps

The study findings reviewed here demonstrate that a more comprehensive approach to cost-benefit analysis is needed for accurate comparison among renewable technologies and integration solutions.

CSP with thermal energy storage combines the operational flexibility of a conventional thermal power plant with a completely renewable fuel source and long duration storage, resulting in improved availability and reliability. There are over 20 utility-scale parabolic trough and power tower plants with storage currently in commercial operation globally, with several more under construction or in advanced planning stages. As wind and solar PV costs have decreased, the future applications of this solar technology are increasingly focused on its operational characteristics. CSP plants are expected to obtain higher value when compared to other renewable resources as power systems transition to higher penetration of renewable generation. CSP with thermal storage is particularly well suited to help manage key operational challenges on the planning horizon, including mitigating the diurnal net load system ramps created by variable solar generation, surplus generation conditions during the sunlight hours, increased requirements for ancillary services, such as frequency regulation, and new requirements for frequency response and inertial response services.

Consideration of net system costs in utility procurement

The early phases of renewable procurement around the world focused primarily on rapid deployment of available technologies at the lowest levelized cost of energy (LCOE), and less so on planning towards long-term, reliable clean power systems. The study findings reviewed here demonstrate that a more comprehensive approach to cost-benefit analysis is needed for accurate comparison among renewable technologies and integration solutions (e.g., Jorgenson et al., 2013, 2014; Mills and Wiser, 2012b; Denholm et al., 2013; Joskow 2010). Without such analysis, CSP with thermal energy storage will be significantly under-valued in renewable procurement.

Recently, utilities and regulators in California and other parts of the western U.S. have begun to conduct more detailed, scenario-based planning studies, some of which have directly included CSP with thermal storage or have been used by other parties to conduct such analysis (e.g., Jorgenson et al., 2014; Denholm et al., 2013). These studies have improved perception of the technology's applications and economic benefits. CSP with thermal storage may also be assisted by other policy requirements, such as the storage mandate in California, which has included it as an eligible technology.

The studies surveyed in this report suggest similar ranges of total absolute economic benefits for CSP with thermal storage as well as similar differences with the total benefits of comparable PV projects under the same scenarios. There are differences in some results that require further investigation, but the comparison of total benefits remain similar, in the range of $30-60/MWh, for solar penetrations of 10%-16% and greater. A number of factors could shift this range up. Most notably, if the potential for curtailment of incremental variable solar resources increases in higher penetrations, such as the 40-50% RPS now being modeled in California, then the lost solar energy will increase the net cost difference with CSP with thermal storage, which should be sufficiently dispatchable to minimize its own curtailments. CSP with storage will also gain advantages with the establishment of flexible capacity requirements and ramping reserves. Finally, any new ancillary services could further improve the valuation of CSP with thermal storage, compared to inverter-based renewable plants that could have to curtail some energy to provide these services.

Summary of Specific Recommendations

In addition to the general recommendations above, this survey suggests a number of researchable topics:

- Replication of study results at higher renewable penetration levels, such as the 40%-50% RPS currently under evaluation in California. Jorgenson et al. (2014) addresses one scenario for the 40% case (with some results shown in this report), and there are several other such studies underway, although not necessarily focused on CSP with thermal energy storage.
- Improved understanding of the ancillary service capabilities and operational characteristics of actual CSP plants with thermal storage. Additional industry input is needed to refine the studies to date.
- Modeling of sub-hourly dispatch of energy from CSP with thermal energy storage on a 5-minute and 15-minute basis. Plant level models are needed first to ensure sufficient operational detail to validate plant operations. Power system models, such as production simulation models, can then be run with validated operational parameters to measure the potential economic benefits.
- Modeling of regulation dispatch from CSP with thermal storage using dynamic subhourly models; to date, the research has focused on maintaining regulating reserve capacity, but has not examined the actual dispatch of regulation (up and down) in response to 4-second signals.
- Addition of a frequency responsive reserve to the co-optimized ancillary services in subsequent research. Although quantities of such a reserve have not been finalized, at least some indicative reserve level based on published estimates should be added to reflect the potential contribution of CSP with thermal storage.
- Analysis of the inertial response contribution of CSP with thermal storage in high renewable penetration power systems, in which much conventional spinning generation is off-line.

Next Steps

This survey has benefited from review by CSP experts. Collectively, these experts have recommended that the U.S. research program on CSP continue the large-scale simulation initiatives by the California Energy Commission (CEC), the National Renewable Energy Lab (NREL), the Lawrence Berkeley National Labs (LBNL), the California ISO (CAISO) and other entities. Such work will further quantify the benefits identified in this report and the studies to date. The national labs and other research entities are also conducting valuation studies of other types of bulk storage and other integration solutions, using similar modeling approaches, which will be useful for comparison.

Most recently, NREL has conducted studies of California at high RPS using a model of the regional western U.S. that incorporates detailed operating constraints for several parabolic trough and power tower configurations (Jorgenson et al., 2014, and Denholm et al., 2013). The next phase of this work considers the interaction of CSP with thermal storage with additional resource portfolios, including other types of storage.

Another study sponsored by the California Energy Commission promises to expand simulation of CSP with thermal energy storage operating on sub-hourly time-frames to provide Regulation and 5-minute economic dispatch.

The CSP industry needs to carefully examine and contribute to refining the results of NREL's 2012 study of high penetration renewable electricity futures (NREL, 2012; Denholm et al., 2012), which utilizes a capacity expansion model that constructs CSP with thermal energy storage in response to both lower cost forecasts but also operational and other constraints that are emphasized in certain sensitivities.

While there are recent studies of the economic benefits of CSP with thermal energy storage in other countries (e.g., Brand et al., 2012; Rutovitz, J., et al. 2013), additional research is needed, perhaps sponsored by national agencies and international cooperative research networks, such as SolarPACES.[53] In addition, the World Bank has recently concluded that the "value-based" criteria for CSP evaluation is obtaining only limited consideration in procurement processes in developing countries (Kulichenko and Wirth, 2011). Clearly, industry support is needed to improve such analyses. This is important because several countries, including South Africa, several Middle Eastern and North African countries, and Chile are proceeding with further deployment of CSP, including plants with thermal storage. Moreover, China has set new targets for CSP development.

[53] For further details on SolarPACES, see http://www.solarpaces.org/.

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Appendix A: Methodologies for Calculating Capacity Value of CSP with Thermal Energy Storage

This appendix provides a brief review of the methodologies for calculating the capacity credits and capacity value of solar technologies, with a focus on CSP with thermal energy storage. There are several surveys available on this topic and this appendix benefits in particular from the reviews in Sioshani and Denholm (2010), NERC (2011), Madaeni et al., (2012a,b) and Mills and Wiser (2012a,b). The appendix also expands on the surveys in those papers to include the method used by Denholm et al., (2013) and also discusses the evolving flexible capacity metrics under discussion in some regions, which would apply to CSP with thermal storage. Table A-1 below surveys actual applications of these methods to capacity ratings of renewable resources by U.S. and Canadian utilities, ISOs and regulatory entities.

Capacity ratings or credits (MW) are a measure of the contribution of individual resources – generation, storage, and demand response – and the full portfolio of available resources to meeting demand during periods in which there is a high probability of loss-of-load. As discussed further below, each individual resource obtains a capacity credit as a percentage of its rated maximum seasonal production, or its actual or forecast production in some period. The conventional loss-of-load criterion is availability of sufficient resources to ensure no more than one loss-of-load event in 10 years, typically evaluated probabilistically. This criterion is interpreted differently in different regions; in the United States, it is generally a conservative requirement which has long been debated in the effort to align the actual, economic benefits of different levels of resource adequacy with consumers demand for reliability (Pfeifenberger et al., 2013). Not all regions use a explicit probabilistic approach to determine resource adequacy requirements. For example, California currently establishes its requirement based on regional reliability standards that result from approximate measures, in this case forecast peak load plus a 15-17% reserve margin.

Once the capacity requirement has been determined, capacity value ($/kW-year or $/MW) is the bilateral or market clearing price of existing or new capacity. In the event that new capacity resources are needed to meet the requirements, capacity value is measured with respect to the avoided cost of either procuring capacity from a market (where any new qualified resource can set the price), or a generic generation technology assumed to be the benchmark “new entrant”, which in the United States is a 50-100 MW combustion turbine.

When there is a shortage of supply to ensure the loss-of-load standard or other defined capacity requirement, the value of capacity will be the net cost of a new entrant. When there is a surplus of supply and new entrants are not required, the capacity value of existing capacity resources should be at least the net going-forward costs of the marginal capacity resource. Capacity prices are also a function of how utilities structure forward contracts. In California, monthly and annual capacity prices are also based on residual capacity offers from resources that obtain long-term bundled contracts and can be substantially lower than the going-forward costs. In most of the studies reviewed in this report, the capacity price used for valuation was the cost of new entry.

The methods for evaluating the long-term reliability of power systems have developed over many decades (e.g., Billinton and Allan, 1994) and there are substantial regional differences in methods (e.g., Pfeifenberger et al., 2013). Hence this appendix will only lightly review basic methodology,

particularly as applicable to solar technologies. The appendix examines the two primary approaches for measuring capacity credits – statistical methods based on meeting the loss-of-load criterion and approximation methods. In several of the CSP studies reviewed, the approximation method is coupled with a dispatch model, which can replicate dispatch results in a market that is "energy-only" or one in which both energy and capacity are separately procured. The appendix also reviews the related topics of flexible capacity, locational capacity requirements, and the choice of resource to use as the avoided new entry resource.

Basic definitions

A "resource" is any generator, storage technology or demand response provider that is qualified as a capacity resource; this generally entails the resource being available during the period being evaluated and either being able to follow the system operator's dispatch instructions or otherwise having some known probability of production. A resource is labeled generically as R (whereas most papers refer to generation, G) because in many regions, demand response and storage are also providing capacity, which merits the more generic term.

The loss of load probability (LOLP) is defined as the probability of a loss-of-load event where available resources are insufficient to meet load, designated as L. The loss of load expectation (LOLE) is the expected loss-of-load over all of the periods being evaluated or the sum of the LOLPs over all time intervals being evaluated, $i \in T$.

As noted above, the capacity credit or capacity rating for a resource is expressed typically as a percentage of nameplate capacity (MW). For the case of a conventional fossil-fired or nuclear generator, the hourly capacity rating is the plant's maximum operating level de-rated by an expected forced outage rate (EFOR). Conventional plants or limited energy plants, such as many hydroelectric plants, obtain a capacity rating derated also by the availability of the generator subject to emission, fuel, or environmental restrictions. A variable energy resource such as wind or solar obtains a rating based on the coincidence of its forecast production with the hours of highest loss-of-load risk. Notably, CSP with thermal storage is operationally a conventional thermal generator with a variable fuel stock, which requires additional methods for calculating availability as a function of direct normal insolation and plant design, particularly storage capacity, as discussed further below.

Some studies (e.g., Madaeni et al, 2012a,b) refer to the capacity rating as the "capacity value." Generally, capacity value or capacity payment ($/kW-year or $/MW) refers to the market revenue or economic benefits calculated for a plant with a particular capacity credit.

LOLE/ELCC Methods

CSP with thermal storage is a more complicated resource for analysis than either a conventional generator or a CSP plant without thermal storage. For a CSP plant without storage, the hourly capability is based on the design of the plant and the forecast direct normal insolation. However, CSP with thermal storage has a variable fuel stock, similar to some hydro plants, but on daily and hourly time-frames, which has to be dispatched, or otherwise estimated, to determine its operations to meet capacity requirements. The modeling should also assume an EFOR on the powerblock.

Effective load carrying capability (ELCC) methods modify the LOLE calculations to measure the additional load that can be added for each MW of wind and/or solar while maintaining the same reliability standard. The general steps used to calculate the ELCC of a CSP generator without storage are as follows (e.g., Madaeni et al., 2012a):

First, calculate the LOLE of the system without the CSP plant, such that

$LOLE = \sum_{i=1}^{T} P(R_i < L_i)$.

Second, calculate the LOLE with the CSP plant by adding it to the resource portfolio, such that

$LOLE_{CSP} = \sum_{i=1}^{T} P(R_i + C_i < L_i)$.

Third, calculate the LOLE with the CSP plant removed and a conventional generator, G, included, such that

$LOLE_{G} = \sum_{i=1}^{T} P(R_i + G_i < L_i)$.

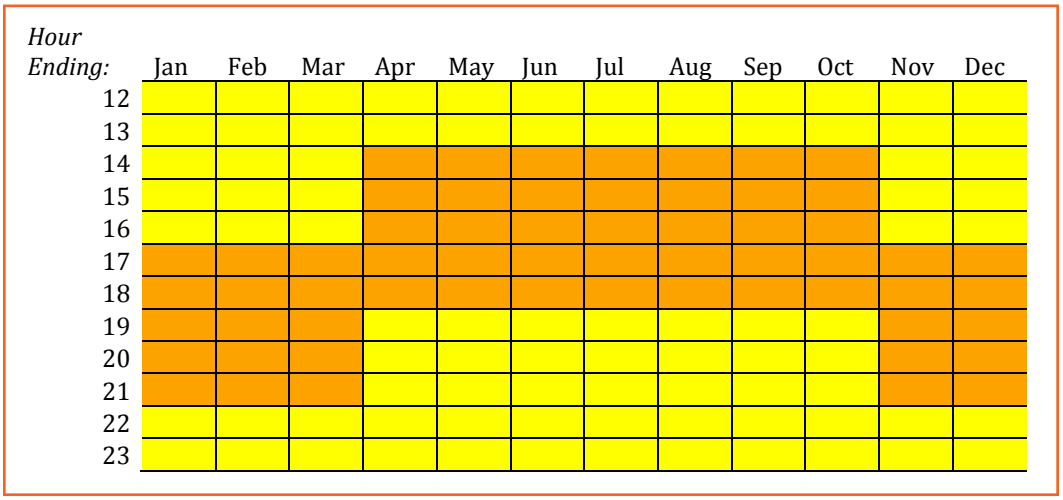
To fully capture its operational flexibility, modeling CSP with thermal storage requires a method for determining whether the plant has available energy from thermal storage during the hours with high risk of loss-of-load. This requires an optimization model of the plant.

Approximation-Based Methods

Because LOLE/ELCC calculations are analytically intensive and often require substantial stakeholder review of inputs and results, the operators of many power systems utilize simpler, approximation methods for setting capacity credits for renewable resources. In approximation methods, the capacity value of a resource is estimated during a set of hours that correspond to the highest probabilities of loss-of-load. These are typically the seasonally adjusted, highest load hours, or variants that use the highest LOLP hours or LOLP-weighted highest load hours (Madaeni et al., 2012a). Table A-1 lists the actual hours used for these approximations by different system operators in the United States. For illustration, Figure A-1 shows the hours currently used by the California Public Utilities Commission (CPUC) (note that no hours before 12 pm are measured). In California, a higher weight is put on the mid-afternoon hours (hours 14-18) from April to October while in the remaining months, a higher weight is placed on the early evening hours because of the higher loads in those hours. In practice, the annual system peak loads occur in the summer in most years in California and so the summer capacity hours are currently considered more important as measures of total available system resources. The CPUC is also currently developing a probabilistic modeling method to calculate wind and solar ELCC.

The advantages of the approximation-based methods for variable energy resources is that only the production of the individual wind or solar resource during the hours being evaluated needs to be simulated or measured in actual operations. One of the issues with highest-load-hour approximations is that, if the number of hours being measured is too large, averaging can result in capacity ratings that over-estimate actual performance during high-load hours. In certain regions, the solution has been to reduce the number of hours being considered using a statistical approach. For example, in California, the original approximation method, which counted average production in the hours shown in Figure A-1, has been modified to include an "exceedance" method where only the 70th percentile capacity credit is used to determine the capacity rating. Madaeni et al. (2012) evaluated alternative approximations, including a range between the top 10 load hours and the top 10% of load hours and their convergence to the hours identified by ELCC models. They find that the top 10 hours is closest to more robust techniques.

Figure A-1: Resource Adequacy capacity credit hours (orange shading) for energy-limited resources in California, by month



Source: California Public Utilities Commission

The approximation methods also become problematic if the set of hours remains fixed, ignoring that as renewable penetration increases, the "net load" peak hours become the highest LOLP hours. One solution discussed below is that the hours are updated based on simulations of the highest net load hours. Alternatively, an ELCC method can be used to calculate capacity ratings of wind and solar plants under the renewable portfolio expected in each year.

Estimating capacity value of CSP with thermal storage using dispatch models

To determine the capacity rating of a CSP plant with thermal energy storage requires a methodology to forecast the availability of energy from the plant during high LOLP hours or a proxy for such hours, such as high price hours. The studies reviewed in this report have used several methods:

a plant-level, exogenous, fixed-price dispatch model to optimize energy production from storage in relationship to either energy prices or energy and capacity prices during the hours identified using the approximation method (Madaeni et al., 2011);

a system-level dispatch model with endogenous prices to optimize energy production from storage during hours identified exogenously using an approximation method (e.g., Denholm et al., 2013; Denholm and Hummon, 2012); and

a system-level dispatch model with endogenous prices to optimize energy production from storage in response to scarcity pricing hours signaling need for new entry in equilibrium (Mills and Wiser, 2012b).

Since CSP with thermal energy storage can also provide ancillary services, it is important to note that the capacity valuation would be done with an energy-only optimization, which confirms the option to dispatch the plant for energy to meet capacity needs. In actual operations, the plant could provide ancillary services instead during those high-price periods and the utility or the system operator would have the option to dispatch as needed to provide energy.

Plant-level dispatch models

Using an approximation methodology, a plant-level dispatch model of CSP with thermal energy storage can be used to determine the plant's hourly availability to provide energy whether during the hours set for capacity rating by a system operator/utility , operating at the highest load hours in some year, or another metric.

Madaeni et al. (2011) develop a dispatch model for a parabolic trough plant with thermal energy storage and show three applications:

a baseline energy production model with an energy accounting equation that verifies the availability of energy production during capacity hours identified with using an approximation method;

an "energy-only" market model in which the plant is dispatched against exogenous fixed prices for energy; and

an "energy and capacity" market model in which the plant is jointly dispatched against exogenous fixed prices for energy and capacity, as realized by production in hours identified with an approximation method.

The addition of thermal storage to a CSP plant (starting from a model without storage) increases the plant's capacity value although with declining marginal value as storage capacity increases beyond some point – and which will be unique to each plant design. The results of the Madaeni et al.'s (2011) "energy-only" dispatch, using prices from the California ISO and "system lambdas" from western U.S. utilities, demonstrate that the energy dispatch may not be aligned with the highest capacity value hours. In other words, there may be high capacity value hours when energy prices are lower than subsequent hours with low capacity value. In contrast, the results of the "energy and capacity" market model suggest that, if the CSP plant is provided with a capacity payment based on production during the hours with high capacity value, it would shift energy to those hours (even if energy revenues were lower) and thus earn the higher capacity rating.

One implication of these results is that the capacity rating of a CSP plant with thermal energy storage should not be based on the dispatch history of the plant, which may not accurately reflect its availability to meet the highest capacity value hours.

Another implication is that the market design should allow for better alignment between plant operations and maintenance of resource adequacy. That is, going into the operating day during peak load or "net load" peak hours, the plant should receive incentives to retain sufficient energy in storage for the highest LOLP hours. In many wholesale markets, this has been achieved by introducing scarcity pricing during periods of reserve shortage.

One limitation of plant-level, dispatch models is that they are not able to evaluate the changes in relative capacity values as renewable penetrations increase over time, as can be captured in system models such as Denholm et al., (2013) or Mills and Wiser (2012b). The plant-level models can be used to test changes in relative capacity values through parameter sensitivities. For example, Madaeni et al., (2011) conduct a test of how shifting net load peak hours to one hour later in the day could affect the capacity valuation results in a plant-level dispatch model. However, more accurate analysis requires utilizing system-level models. One approach under discussion is to have system-level models generate market prices and capacity requirements for a range of future scenarios, while using plant-level models for subsequent testing of detailed plant operations against those future prices.

System-level dispatch models

Detailed system-level dispatch models can be used to estimate capacity value of CSP with thermal energy storage under different renewable scenarios as well as to evaluate the impact of additional operational constraints on the value of capacity resources. For example, Denholm et al., (2013) utilize a production cost model and measure the capacity factors of the CSP with thermal storage plants during the highest price hours in the model, as a proxy for the highest LOLP hours.

Variants on expansion planning models can be used to measure the capacity value of incremental CSP resources. Using a variant of the "energy-only" market framework, Mills and Wiser (2012b) utilize a dispatch model of the California power system with endogenous capacity expansion in response to exogenous market scarcity prices triggered by reserve shortages. The capacity value ($/MWh) of each renewable resource is measured as their short-run profits from energy and ancillary services earned during hours with scarcity prices (defined to be equal or greater than $500/MWh),

The equilibrium relationship between LOLE, scarcity pricing and the cost of new entry is represented in the following equation from Mills and Wiser (2012b: p.111):

$$LOLE = \sum_{i=1}^{T} P(R_i < L_i) = \sum_{i=1}^{T} P_i^s = FC^p / \lambda^s = constant,$$

where the LOLE is assumed to be held constant in equilibrium as a function of the ratio of the fixed costs of a peaker plant FC^p to the allowed maximum scarcity price λ^s. In other words, the scarcity price is used as an exogenous parameter to set the level of reliability.

In most wholesale power markets, bid caps prevent energy and ancillary service prices from reaching sufficient levels to encourage long-term entry equilibrium. More recently, the market entry of wind and solar power supported by production or capacity-based incentives have also started to suppress market prices. Hence, many of these markets are using separate capacity markets to make up the revenues that would otherwise have been available during scarcity. In such a model, caps on λ^s would be made up by capacity payments tuned to achieve the same *LOLE* at equilibrium.

Other Determinants of Capacity Value

Locational Value

Capacity requirements are generally divided into two categories differentiated by transmission transfer capability: local and system. A local capacity resource is qualified to serve load in a location that is transmission-import constrained, sometimes called a load pocket or local area. It may also be qualified to serve load outside of the specified location. A system capacity resource is qualified to serve loads outside of local areas and may serve those inside the local area up to the available transmission transfer capability. The power flow studies needed to qualify capacity resources for different locations are conducted by system operators. The final capacity value for a resource may thus be derated by the availability of transmission transfer capability.[54]

For capacity value studies of regional power systems, further analysis is thus needed about how the solar technology capacity value for incremental projects serving particular utilities and subregions is derived. In some cases, CSP plants with thermal storage may be located in areas where transmission limitations would reduce their capacity value to certain utility buyers in the absence of transmission upgrades.

[54] In California, this is known as the "net qualifying capacity."

Flexible Capacity

As noted in Section 8 of this report, several regions of the U. S. that have high penetration of renewables are considering modifying their capacity requirements from generic MW to MW plus operational characteristics. New metrics are being developed to measure flexible capacity, such as Effective Ramping Capability (ERC) as the operational analogue to ELCC (e.g., Lannoye et al., 2012). In California, an initial requirement for flexible capacity is the ability to support a continuous 3 hour net load ramp for certain hours of the day, incorporating the diurnal solar ramps.

None of the studies examined here have attempted to measure the flexible capacity ratings of CSP with thermal storage against a range of possible metrics. However, any of the system models that can dispatch the plants against system ramps can be utilized to do so.

Avoided Cost of New Generation

The avoided cost of new generation used in the analysis is a major driver of the resulting long-term capacity value. There are many generic and regional surveys of the cost of new generation, some updated on a periodic basis. For generation in particular regions, surveys particular to that region are preferred to more generic estimates, as local taxes, insurance, and land costs may be significant components of the final cost.

Conventionally, the marginal "new entrant" in the U.S. power markets is assumed to be a new peaker, typically a 50 MW-100 MW combustion turbine. However, some studies also conduct sensitivity studies for combined cycles as the new entrant (e.g., Denholm and Hummon, 2012). The avoided capacity cost estimates used in the studies surveyed here are shown in Table 8-2. For studies examining capacity value in wholesale markets into which generation will also sell energy and ancillary services, the cost of new entry is often adjusted to reflect the net capacity cost once the plant's other net market revenues (market payments minus operating costs) have been determined (see, e.g., CAISO 2013b). This is the residual capacity payment that the plant would have to recover. In models where equilibrium entry is determined (e.g., Mills and Wiser 2012b), the net cost of new capacity is determined endogenously in the model.

Conclusions

Over the past few years, several methods for capacity valuation of solar resources, including CSP with thermal energy storage, have been presented in the research literature. These include applications and extensions of conventional LOLE models, such as the ELCC models, and a number of approximation methods. CSP with thermal storage requires either a plant-level or system-level dispatch model to account for the dispatchability of the thermal storage system. The system-level dispatch simulations include the operations of resources required for renewable integration, and thus can also measure the "flexible capacity" capabilities of the CSP plants.

Using any of these capacity valuation methodologies, CSP with thermal energy storage is shown to obtain a high capacity rating and capacity value as a function of the storage capacity. These results are reviewed in Section 8.

Table A-1 summarizes the methods used in different regions of North America for capacity valuation and resource procurement. The table is based on a table in Porter et al., (2012) and updated with data from similar surveys in Mills and Wiser (2012a), and other sources. In some cases the description is a direct quote from one of these sources.

Table A-1: Methods for Wind and Solar Capacity Valuation

Organization or Study	Method	Description
Arizona Public Service (APS)	LOLE /ELCC	Base capacity credit for different solar options is 50% for fixed PV, 70% for single axis tracking PV and CSP without storage (with a site-specific range of 65-77%), and 100% for CSP with 6 hours of storage. ELCC method is used to estimate value of alternative resource portfolios, including solar resources.
BC Hydro	ELCC	24% for onshore and offshore wind. Solar assumed to have the same value as onshore wind. ELCC method using wind output-duration tables based on synthesized chronological hourly wind data for different regions.
Bonneville Power Administration	Approximation method w/exceedance measure	0%. Summer monthly capacity factor between 2003 and 2008, 85% and 95% exceedance.
City of Toronto Case Study	Various	Garver ELCC approximation for solar PV ranged from 23% to 37%, depending on location, orientation and penetration level. Two other methods based on time period and peak load estimated a capacity value of 40% for solar PV.
CPUC/CAISO	Approximation method w/exceedance measure	70% exceedance factor. Capacity values set monthly. Uses monthly hourly wind and solar production data from previous three years between 4:00 p.m. and 9 p.m. January through March and November through December and between 1:00 p.m. and 6:00 p.m. April through October. Diversity benefits added to capacity value.
Eastern Wind Integration and Transmission Study	ELCC	Ranged from 16.0% to 30.5% (with existing transmission system) and from 24.1% to 32.8% (with a transmission overlay).
ERCOT	ELCC	ELCC based on random wind data, compromising correlation between wind and load (8.7%). New ELCC study began in 2012.
Hydro-Québec	Monte Carlo Simulation	30%. Monte Carlo model chronologically matches wind and load data for 36-year period.
Idaho Power	Peak Period	5% capacity value for wind during peak load that generally occurs in summer months between 3:00 p.m. and 7:00 p.m.
ISO-NE	Peak Period	For existing wind: rolling average of median net output 1:00 p.m. to 6:00 p.m. June through September for past five years for summer capacity credit; 5:00 p.m. to 7:00 p.m. October through May for past five years for winter capacity credit. For new wind: based on summer and winter wind speed data, subject to verification by ISO-NE and adjusted by operating experience.
MISO	ELCC	12.9% for 2011 planning year; 14.7% for 2012 planning year.
NorthWestern Energy	Peak Period	Assigned capacity value of 0 based on wind generation during top 100 load hours from January 2006 through December 2010.
NPPD		17% (method not stated).
NREL Study	Various	CSP with no TES: 45% to 95%, depending on SM and location. CSP with TES: usually above 90% in all cases; used capacity-factor based method.
NW Resource Adequacy Forum	Peak Period	5% sustained wind ELCC, 30% annual wind ELCC. Being studied further for potential revision.
NY PV Study	ELCC and Solar Load Control Capacity	Solar PV capacity value varied by penetration level, location and orientation. ELCC method: ranged from 31% to 90%. Solar Load Control Capacity method: ranged from 32% to 88%.
NYISO	Peak Period	Existing wind: capacity factor between 2:00 p.m. and 6:00 p.m. June through August and between 4:00 p.m. and 8:00 p.m. December through February. New onshore wind: assigned summer capacity credit of 10%, winter capacity credit of 38% for both winter and summer.
Ontario IESO	Peak Period	Seasons and monthly shoulder periods wind output from the top five contiguous daily peak demand hours taken for two data sets (ten years simulated wind data and wind production data since 2006). Smaller capacity value selected for each season and shoulder period month.
PacifiCorp	ELCC	Sequential Monte Carlo method. In July 2008, averaged about 8.53% per 100 MW of nameplate capacity (decreased as the amount of wind increased).
PGE	Rule of Thumb	5% for wind and solar. To be modified as more data becomes available.
PJM	Peak Period	Existing wind and solar: June through August, hour ending 2:00 p.m. to 6:00 p.m. local time, capacity factor using 3-year rolling average. New wind assigned 13%; fold in actual data when available. New solar assigned 38%; fold in actual data when available.
PNM	Peak Period	Wind 5%, solar 55%. Assessed by the amount of capacity supplied at peak.

Additional References

Billinton, R., and R.N. Allan, *Reliability Evaluation of Power Systems, Second Edition,* New York: Plenum Press, 1994.

Milligan, M., and K. Porter, Determining the Capacity Value of Wind: An Updated Survey of Methods and Implementation, Conference Paper, NREL/CP-500-43433, June 2008.

NERC, Methods to Model and Calculate Capacity Contributions of Variable Generation for Resource Adequacy Planning (Princeton, NJ: NERC, March 2011), http://www.nerc.com/pa/RAPA/ra/Reliability Assessments DL/IVGTF1-2.pdf.

Perez, R., M. Taylor, T. Hoff, and J.P. Ross. "Reaching Consensus in the Definition of Photovoltaics Capacity Credit in the USA: A Practical Application of Satellite-Derived Solar Resource Data." *IEEE Journal of Selected Topics in Applied Earth Observations and Remote Sensing,* 1 (1): 28–33, 2008.

Appendix B: Simplified Calculation of Integration Costs in California under 33% RPS

To date, most wind and solar integration studies have reported average integration costs in the ranges discussed in Section 9 of this report, but have not reported costs on an hourly basis across the year. Because CSP with thermal energy storage charges during daylight hours, it can generally be available to generate during hours with high system ramps in the late afternoon and early evening. In this case, there can be above-average value for the energy, in terms of avoided integration costs. To evaluate this hypothesis, the authors examined the data from the simulations conducted by the California ISO of integration under 33% RPS and derived simplified estimates of hourly integration costs, as shown below. These results are intended to illustrate the finding but need further testing and validation.

To date, the California Public Utility Commission (CPUC) has not allowed integration costs to be considered in renewable energy procurement by its jurisdictional utilities, although such costs may be considered in 2015 procurement. As such, the California ISO simulations (conducted in 2010-11) were not used to explicitly calculate integration costs but rather focused on simulating whether additional resource "needs" could be defined. These "needs" were evaluated using a set of operational requirements and assumptions about future load and resources needed to meet the planning reserve margin in 2020. The study evaluated four "core" 33% RPS scenarios as well as several sensitivity cases on both input assumptions (e.g., forecast errors) and scenario definitions. While the study did not result in findings of new resource needs, it did define additional integration requirements for hourly system operations. The integration requirements were defined as the capacity (MW) of Regulation Up (RU), Regulation Down (RD), Load-following Up (LFU) and Load-following Down (LFD) needed for reserves on an hourly basis. In actual practice, only a portion of the future load-following requirement is likely to be procured as a load-following ramping reserve with the remainder procured through 5-minute economic dispatch. However, the calculated load-following requirements in the data sets still indicates the likely hours of greatest real-time market price impact.

Methodology

The methodology for assessing integration costs was to calculate on a per-period basis the cost of integration (defined as the incremental cost of load following and regulation over and above historical levels) and divide it by the RPS energy production for the period resulting in a $/MWh integration cost.

Hourly ancillary service (AS) prices and requirements for the LTPP 33% RPS Trajectory scenario (and other scenarios) were available directly from the publicly released CAISO and joint IOU integration study files. The CAISO system currently procures a certain quantity of Regulation and provides a certain range of load-following without having to commit additional ramping reserves. To isolate the incremental requirements associated with integrating RPS energy, the typical current-day quantities for the required load following and regulation requirements were deducted from the total quantities in the CAISO data: 350 MW for each of regulation up and regulation down, and 1000 MW for each of load following up and down.

The denominator in the calculation, the hourly RPS energy, is calculated using the following methodology:

Capacities (MW) and annual generation (GWh) for each category of renewable resource are provided in the LTPP documentation. Because some of these resources are out of state (OOS) and the CAISO only modeled management of the integration for 15% of the OOS resources, the net capacity to be integrated for each resource type was calculated as total MW – 0.85 × OOS MW.

Hourly output profiles for an array of wind, large solar, and solar DG resource were available in the California ISO study input files (in the "Fixed Dispatch" folders). From the available resource profiles, we selected those that were easily identified as being in California and normalized their output to an hourly capacity factor. The normalization was performed using the stated capacity of the resource, if it was available in the file. If there was no stated capacity in the input file, the highest hourly output of the year was assumed to represent the capacity of the given resource.

For CSP solar, the authors used their own non-storage hourly capacity factors.

For each resource type of wind, large solar, solar DG, and CSP, the hourly capacity factors were scaled to meet the LTPP planning capacity for the given scenario, then used to generate hourly output curves.

All the curves were summed to yield an aggregate renewable energy quantity (MWh) on an hourly basis.

Using these 8784 hour strips (2020 is a leap-year) for AS requirements, AS-prices, and RPS MWh, integration costs were calculated as shown below.

$$\text{Integ\_cost}[t] = \text{Prc\_LFU}[t] \times (\text{Req\_LFU\_scenario}[t] - \text{Req\_LFU\_baseline}[t]) +$$

$$\text{Prc\_LFD} \times (\text{Req\_LFD\_scenario}[t] - \text{Req\_LFD\_baseline}[t]) +$$

$$\text{Prc\_RU}[t] \times (\text{Req\_RU\_scenario}[t] - \text{Req\_RU\_baseline}[t]) +$$

$$\text{Prc\_RD} \times (\text{Req\_RD\_scenario}[t] - \text{Req\_RD\_baseline}[t]).$$

Where t is the hour and $t \in 8784$ hours, LFU is load-following up, LFD is load-following down, RU is Regulation Up, RD is Regulation Down, Req means "requirement", Prc means "price", and baseline refers to the historical quantity deducted to isolate the incremental requirement for variable energy resources. From these quantities, the costs assignable to wind and solar were calculated.

$$\text{Hourly integration cost assigned to renewable (\$/MWh) [i]} = \text{Integ\_cost[i]} / \text{RPS\_energy[i]}$$

This calculation was performed on an hourly basis but the results can be somewhat misleading because the cost to integrate a resource is not necessarily tied to its behavior in that hour alone but also to the duration and magnitude of the system ramps caused in the hours preceding and following the hour in question. Ideally, a full system dispatch model would be used to gain better insight into the full range of integration costs, as shown, e.g., in Denholm et al., 2013 or Mills and Wiser, 2012a.

In the next two figures, some of the relationships between absolute hourly integration costs, integration costs in $/MWh assigned to wind and solar, and renewable production found by this analysis are plotted. The results are discussed in Section 9.

Figure B-1: Absolute Hourly Integration Costs against Hourly Renewable Production, Trajectory Case

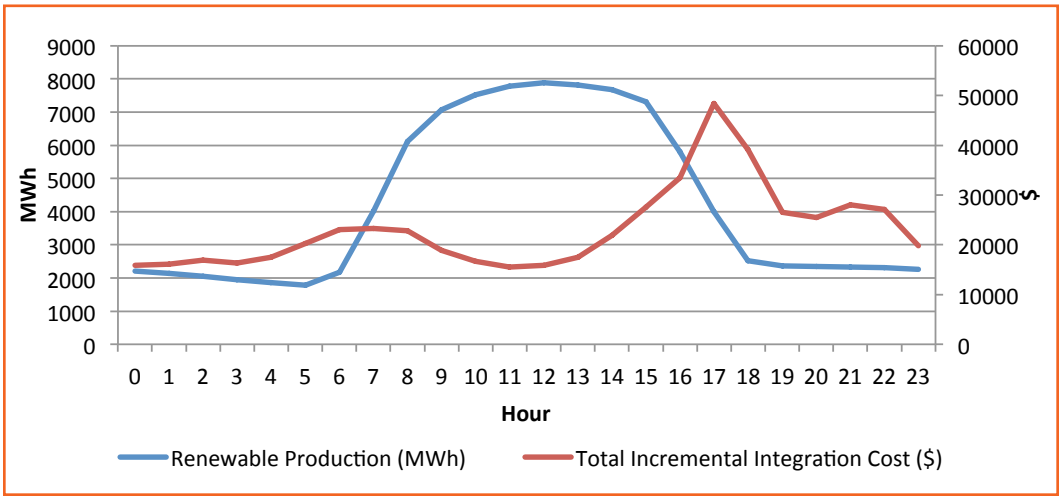
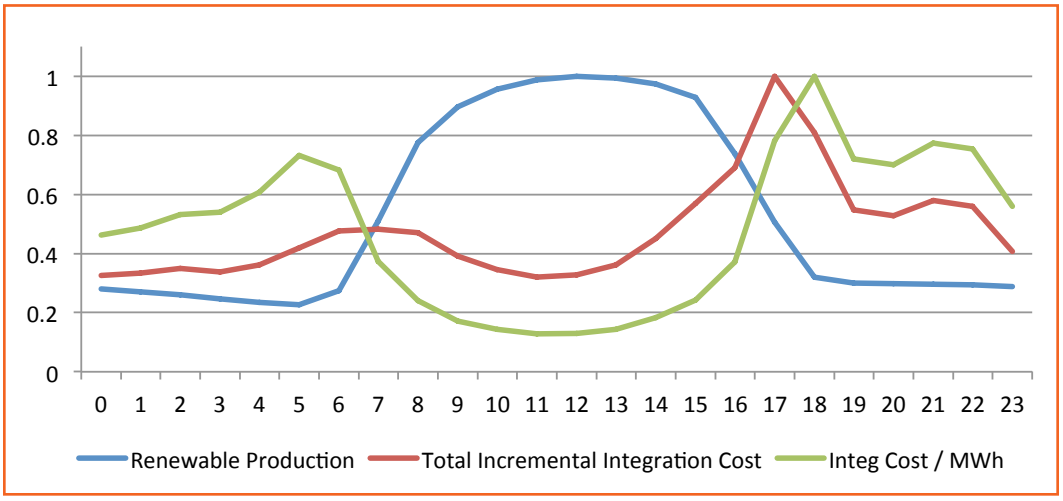


Figure B-2: Normalized Average Hourly Renewable Production (MWh), Hourly Average Integration Costs ($) and Hourly Average Integration Costs Divided by Renewable – Production ($/MWh)



Appendix C: Index of Figures & Tables

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