The Value of Concentrating Solar Power and Thermal Energy Storage

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***Abstract*—This paper examines the value of concentrating solar power (CSP) and thermal energy storage (TES) in a number of regions in the southwestern United States. Our analysis shows that TES can increase the value of CSP by allowing more thermal energy from a CSP plant's solar field to be used, allowing a CSP plant to accommodate a larger solar field, and by allowing CSP generation to be shifted to hours with higher energy prices. We analyze the sensitivity of this value to a number of factors, including the optimization period, price and solar forecasting, ancillary service sales, and dry cooling of the CSP plant, and also estimate the capacity value of a CSP plant with TES. We further discuss the value of CSP plants and TES net of capital costs.**

***Index Terms*—Solar power generation, economics, thermal energy storage**

I. Nomenclature

Parameters:

T	number of time periods
$\bar{s}$	charging power capacity of TES (MW-t)
$\bar{d}$	discharging power capacity of TES (MW-t)
h	hours of storage
ρ	hourly TES heat losses (%)
ϕ	roundtrip TES efficiency losses (%)
$P_h(\cdot)$	HTF pump parastic function
$\bar{e}$	rated electric capacity of powerblock (MW-e)
$\bar{\tau}$	rated thermal capacity of powerblock (MW-t)
τ^-, τ^+	minimum and maximum operating capacity of powerblock, respectively (% of capacity)
SU	powerblock startup energy (% of capacity)
$\bar{u}$	powerblock minimum up time
$f(\cdot)$	powerblock heat rate function
$P_b(\cdot)$	powerblock parasitic function
c	variable generation cost ($/MWh-e)
M_t	market-clearing price of energy in hour t ($/MWh-e)
SF_t	energy from solar field in hour t (MWh-t)

Variables:

l_t	energy in TES at the end of hour t (MWh-t)
s_t	energy put into TES in hour t (MWh-t)
d_t	energy taken out of TES in hour t (MWh-t)
τ_t	energy put into powerblock in hour t (MWh-t)
e_t	electric energy sold in hour t (MWh-e)
u_t	binary variable indicating powerblock is up in hour t
r_t	binary variable indicating powerblock is started in hour t

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II. Introduction

Recent and ongoing improvements in thermal solar generation technologies coupled with the need for more renewable sources of energy have increased interest in concentrating solar thermal power (CSP). Unlike solar photovoltaic (PV) generation, CSP uses the thermal energy of sunlight to generate electricity.[1] Two common designs of CSP plants—parabolic troughs and power towers—concentrate the sunlight onto a heat-transfer fluid (HTF), which is used to drive a steam turbine. An advantage of CSP over many renewables is that it can also be built with thermal energy storage (TES), which can make the CSP plant semi-dispatchable.[2] The TES can allow generation to be shifted to periods without solar resource and to provide backup energy during periods with reduced sunlight that can be caused by cloud cover.[3] The storage medium is typically a molten salt, which have extremely high storage efficiencies in demonstration systems.

Adding TES provides several additional sources of value to a CSP plant. First, the plant can shift electricity production to periods of highest prices compared to a plant that must sell electricity whenever solar energy is available. Second, TES may provide firm capacity to the power system, replacing conventional power plants as opposed to just supplementing their output. Finally, the dispatchability of a CSP plant with TES allows for the provision of high-value ancillary services (AS), such as spinning reserves. Building a CSP plant with TES introduces several decisions in terms of sizing the plant, since the plant essentially consists of three independent but interrelated components that can be sized differently: the power block, the solar field, and the thermal storage tank. The size of the power block is the rated power capacity of the steam turbine, and is typically measured in either the rated input of the power block in megawatts of thermal energy (MW-t) or the rated output of the power block in megawatts of electric energy (MW-e). The size of the solar field, in conjunction with solar irradiance, determines the amount of thermal energy that will be available to the power block. The sizing of the solar field is an important decision, since the relative size of the solar field and power block will determine the capacity factor of the CSP plant and the extent to which thermal energy and the powerblock will be wasted. Undersizing the solar field

[1] See [1] for a more detailed discussion of CSP technologies and ongoing research efforts.

[2] See [2]-[4] for surveys of TES technologies and capabilities.

[3] The HTF in a CSP plant will also have some thermal inertia that can help the CSP plant 'ride out' a brief reduction in sunlight from an isolated cloud.

will result in the power block being underused and a low capacity factor for the CSP plant, due to the lack of thermal energy during all but hours with the highest solar resource.[4] An oversized solar field, on the other hand, will tend to result in thermal energy being wasted since the power block will not have sufficient capacity to use the thermal energy from the solar field in many hours. The size of the solar field can either be measured in the actual area of the field or by using the solar multiple (SM)—which normalizes the size of the solar field in terms of the power block size. A solar field with an SM of one is sized to provide sufficient energy to operate the power block at its rated capacity under reference conditions. The areas of solar fields with a higher or lower SM will be scaled based on the solar field with a multiple of one (i.e. a field with an SM of two will cover twice the area of a field with an SM of one). The size of storage determines both the thermal power capacity of the heat exchangers between the storage tank and the HTF, measured in MW-t, and the total energy capacity of the storage tank. While the energy capacity of the storage tank can be measured in MWh-t, it is often more convenient to measure it in terms of the number of hours of storage. We define the storage capacity as the number of hours that the storage tank can be charged at maximum capacity, which is very similar to the number of hours of discharge capacity since the roundtrip efficiency of TES is about 98.5%. It is worth noting that another benefit of building a CSP plant with TES is that storage can allow the plant to be built with a larger solar field, since excess thermal energy can be placed into storage for use later.

For a merchant CSP developer, the decision to build and the choice of the size of a CSP plant will governed not only by the amount of solar energy available, but also by the pattern (coincidence) of solar resource and electricity prices. Clearly, high electricity prices and an abundance of solar resource are necessary for CSP to be economic, but a lack of correlation between solar availability and electricity prices can make CSP economically unattractive. TES can help improve the economics by shifting generation to higher-priced hours, but this adds capital costs and some efficiency losses from energy going through the storage cycle.

In this paper we examine the value of adding TES to CSP plants in a number of power systems in the southwestern United States. Using a model that optimally dispatches CSP with TES into existing electricity markets, we examine the potential operating profits (i.e. revenues from energy sales less variable costs, but not accounting for fixed capital costs) that a CSP plant can earn and show how these profits vary as a function of plant size. We also show the sensitivity of operating profits to different assumptions of our analysis, including the possibility of selling AS, the optimization process used, and the use of a dry- as opposed to wet-cooled plant. We show that while the current cost of CSP technologies make them uneconomic on the basis of energy value alone, addition of TES improves the economics of CSP. We also show that when the value of AS and capacity are taken into account, TES and CSP can be economic even with current technology costs. This paper, which presents selected results of and expands on [5], adds to a growing literature examining the value of energy storage coupled with renewables [6]-[17].

The remainder of this paper is organized as follows: section III describes our model and the assumptions underlying our analysis. Section IV presents our analysis of CSP operating profits under the base scenario while section V discusses the sensitivity of those profits to these assumptions. Section VI discusses the net profitability of TES and CSP plants and section VII concludes.

[4] CSP plants can be designed with a fossil-fueled backup system. With such a design, natural gas or another fuel can be used to supplement solar thermal energy. Because our interest is in renewable resources, we focus on a pure CSP plant.

III. CSP Model

We model the capabilities and costs of CSP plants using a mixed-integer program (MIP), which is based on the Solar Advisor Model (SAM) [18] developed by the National Renewable Energy Laboratory (NREL). SAM is a software package that can model in detail the hourly energy production of PV, concentrating PV, and CSP plants, with different configurations and in different locations. This production data can be coupled with cost data to compute different economic benchmarks for solar systems, such as the levelized cost of energy. SAM also has some capabilities to optimize the dispatch of a CSP plant with TES, by using heuristic 'time-of-day' type rules, and these heuristics can be used to compare the cost of energy from a CSP plant to other conventional generators.

Unlike SAM, our MIP is formulated to fully optimize the dispatch of a CSP plant to maximize net revenues from energy sales, as opposed to using heuristic rules.[5] The model assumes that the CSP plant is a price-taking generator that treats prices as being fixed. Since we are modeling only a single CSP plant, this price-taking assumption is reasonable, as the operation of the CSP plant would have at most a marginal impact on the dispatch of other generators. The CSP optimization model is formulated to maximize profits:

$$\max \sum_{t \in T} (M_t - c) \cdot e_t, \tag{1}$$

subject to the following constraints:

$$l_t = \rho \cdot l_{t-1} + s_t - d_t, \tag{2}$$
$$s_t - \phi \cdot d_t + \tau_t + SU \cdot \bar{\tau} \cdot r_t \leq SF_t, \tag{3}$$
$$e_t = f(\tau_t) - P_h(d_t) - P_b(f(\tau_t)), \tag{4}$$
$$\tau^- \cdot \bar{\tau} \cdot u_t \leq \tau_t \leq \tau^+ \cdot \bar{\tau} \cdot u_t, \tag{5}$$
$$r_t \geq u_t - u_{t-1}, \tag{6}$$
$$u_t \geq \sum_{j=t-\bar{u}}^{t} r_j, \tag{7}$$
$$0 \leq l_t \leq h \cdot \bar{s}, \tag{8}$$
$$0 \leq s_t \leq \bar{s}, \tag{9}$$
$$0 \leq d_t \leq \bar{d}, \tag{10}$$
$$u_t, r_t \in \{0, 1\}. \tag{11}$$

[5] For purposes of comparison, the default heuristic dispatch rule in SAM is able to capture between 87% and 94% of the operating profits that our MIP model earns with a CSP plant with an SM of 2.0 and six hours of TES.

Constraint (2) defines the storage level in each hour as a function of the previous storage level and the charging and discharging decisions made. Constraint (3) relates the total amount of thermal energy used in the CSP plant to the thermal energy made available by the solar field. Constraint (4) relates net electricity sold by the CSP plant to net electricity production of the CSP plant. Constraint (5) imposes bounds on the amount of thermal energy that can be put into the powerblock. Constraint (6) defines the powerblock startup variable in terms of the commitment variables, while constraint (7) imposes the minimum up-time requirement on the powerblock. Constraints (8) through (10) impose restrictions on the total amount of energy that can be stored in TES, and on the amount of energy that can be charged into and discharged from TES in an hour. Constraint (11) imposes integrality restrictions on the commitment and startup variables.

The capabilities and costs of the CSP plants are simulated using the baseline CSP system in SAM, which has a wet-cooled powerblock with a design capacity of 110 MW-e, and we simulate a set of CSP plant sizes with SMs ranging between 1.5 and 2.7 and between zero and twelve hours of TES. We use SAM to model the amount of thermal energy collected by the solar field in each hour that is available to be put into TES or powerblock (which we denote as SF_t). This available thermal energy is determined by ambient sunlight as well as solar field size and the efficiencies of the components such as concentrators, collectors, and the HTF used in the solar field. We use this hourly available solar data as an input to our model. We model CSP plants in four different locations, which are summarized in table I. The plants are all simulated using energy price and solar data from 2005. The solar data are obtained from NREL's Renewable Planning Model.[6] [7] For the Daggett and Texas CSP plants, hourly real-time energy and day-ahead AS price data from their respective wholesale electricity markets are used. In the case of Daggett, price data from the California ISO's (CAISO's) SP15 zone are used, whereas the Texas plant uses prices from the Electricity Reliability Council of Texas's (ERCOT's) western zone. For the locations in Arizona and New Mexico, load lambda data from 2005 for the incumbent utilities—Arizona Public Service and Public Service New Mexico, respectively—are used. Load lambda data are obtained from Form 714 filings with the Federal Energy Regulatory Commission.

TABLE I
LOCATION OF CSP PLANTS STUDIED

CSP Site	Location
Arizona	Gila Bend, Arizona (32°57' N, 112°57' W)
Daggett	Daggett, California (34°51' N, 116°51' W)
New Mexico	Southern New Mexico (31°39' N, 108°39' W)
Texas	Western Texas (32°21' N, 102°21' W)

The TES is modeled as a stock and flow system with losses—which accounts for the loss of thermal energy that is kept in storage over time. Furthermore, energy that goes through the storage cycle will experience some additional losses due to inefficiencies in heat transfer from the solar field to the TES and then to the powerblock. We assume that hourly energy losses in TES will be 0.031%, based on tests conducted of storage efficiencies from the Solar Two CSP plant in California. SAM models efficiency losses from using TES by multiplying the gross output of the powerblock by a term that is a non-linear function of the fraction of thermal energy delivered to the powerblock that comes from TES. In order to maintain linearity of our MIP model, we instead assume that 1.5% of energy taken through the storage cycle will be lost—which roughly approximates the non-linear term in SAM. The TES system is assumed to be sized to allow the powerblock to operate at its maximum load using energy from storage alone. For the 110 MW-e powerblock, this corresponds to a power capacity of approximately 340 MW-t. We also assume that the TES system has the same power capacity for charging and discharging.

The powerblock is modeled using a heat-rate curve, which gives gross electric output as a function of thermal energy put into the powerblock. SAM uses a third-order polynomial heat rate curve, but because the second- and third-order terms are negligible, we approximate the curve as a linear function in our dispatch model. SAM allows the powerblock to be operated at up to 115% of its design capacity (126.5 MW-e), and we similarly assume that the powerblock can generate up to this level. We further assume that the powerblock must be run at a minimum load of 40% of its design point (i.e. gross generation of at least 44 MW-e) whenever the powerblock is operating. We further require that the powerblock be online for a minimum of two consecutive hours whenever it is started up and assume that 58.3 MWh-t of thermal energy is required to startup the powerblock,[8] which takes one hour.

The output given by the heat rate curve is gross electricity production, and does not account for the parasitics of various components in the CSP plant. These parasitics include energy expended for operating the HTF pumps in the TES system, the cooling tower, and balance of plant.[9] As with the heat-rate curve, these parasitics are represented as third-order polynomials in SAM, and we approximate these as four-segment piecewise-linear functions in our MIP model. SAM also includes an operating cost estimate of $0.70 per MWh-e generated, which is included in the objective function of the dispatch model.

IV. OPERATING PROFITS OF CSP PLANTS WITH TES IN ENERGY-ONLY MARKETS

As discussed in section II, the addition of TES to a CSP plant provides three separate sources of value: energy, capacity, and ancillary services. Our analysis first considers the case of a CSP plant being used solely to sell energy into the wholesale market. We first consider the case of a CSP plant being operated with perfect foresight of future solar availability and

[6] Available at http://rpm.nrel.gov/

[7] Solar direct normal irradiance in 2005 at the sites we consider was approximately 1%-4% below the average over the period 1998-2006.

[8] 58.3 MWh-t corresponds to 20% of the energy required to run the powerblock at its design point of 110 MWh-e.

[9] There are also parasitics associated with operating the solar field, such as HTF pumps in the solar field. These parasitics are already accounted for and netted out of the hourly thermal energy data we input from SAM into our dispatch model.

energy prices. Following [19] the optimization is done one day at a time using a rolling two-day planning horizon. Thus we assume that dispatch decisions are made one day at a time, however the next day's energy prices and solar availability are accounted for in making dispatch decisions each day. This use of a two-day planning horizon ensures that energy in TES at the end of the day has carryover value—without this use of a two-day optimization horizon, energy would never be kept in TES at the end of a day, since it would have no value. Figure 1 shows an example dispatch of a CSP plant at the Texas site with six hours of TES and an SM of 2.0 over the course of a winter day, along with available energy from the solar field and hourly energy prices. The figure shows a typical winter price profile, which has highest demand and prices at the beginning and end of the day. The figure shows that the dispatch follows expected patterns, using energy storage for both the morning and evening demand and price peaks. For instance, in the morning (hours eight through 10) the powerblock is operated with energy from TES, which was carried over from the previous day to catch the high early-morning prices. The powerblock is shutdown in hours 15 and 16, when energy prices are relatively low, and the solar field energy is put into TES. The plant then provides energy in the evening peak, using both energy from the solar field and from storage.

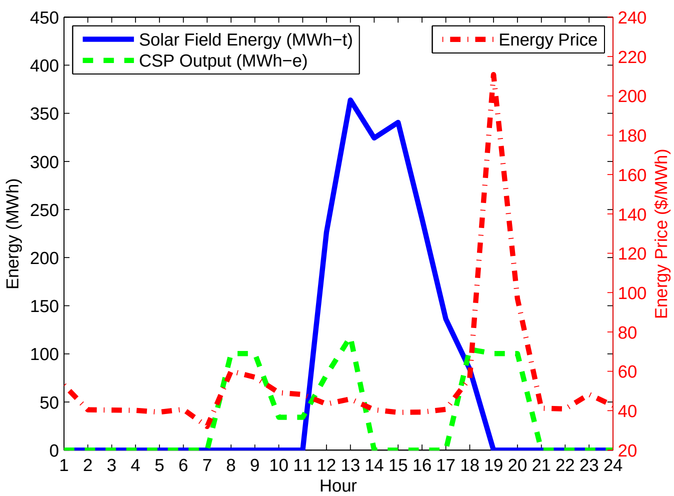

Fig. 1. Sample dispatch of a CSP plant at Texas site with six hours of TES and an SM of 2.0.

Figures 2 through 5 show the operating profits of CSP plants with different-sized solar fields and different amounts of TES at the four CSP sites described in table I. The figures highlight the fact that the value of a CSP plant can vary significantly by location, with a CSP plant at the Arizona site earning about 60% of the operating profits of the Texas plant. The figures also show how the operating profits vary with plant size. At all of the sites, the value of TES tapers off at about six to eight hours of storage. Moreover, we see that increasing the size of the solar field only yields noticeable profit increases if there is sufficient TES available to shift the solar resource to periods with less sunlight available.

Table II shows the underlying cause of the differences in

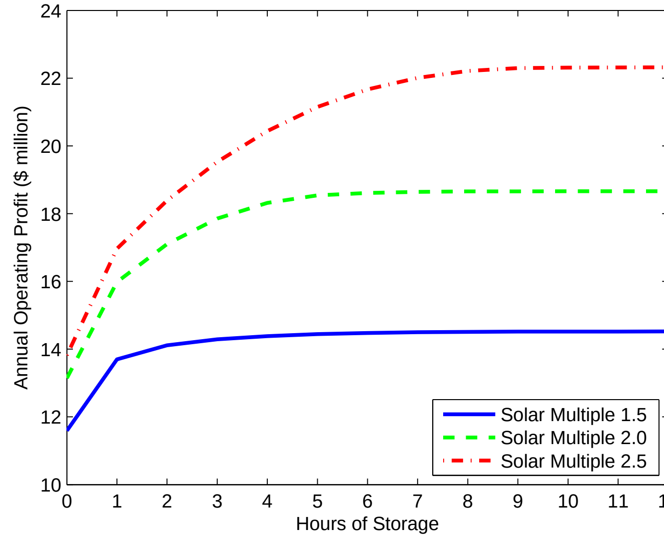

Fig. 2. Annual operating profits of a CSP plant at Arizona site.

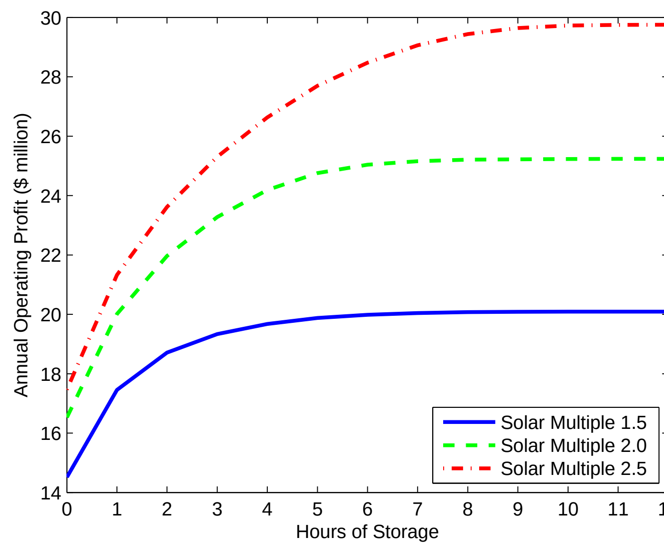

Fig. 3. Annual operating profits of a CSP plant at Daggett site.

the operating profits of the CSP plants at the different sites, by comparing among the four sites the average electricity price and the total annual thermal energy produced by different-sized CSP plants. The table shows that the price of energy tends to be a more important factor in determining the profitability of a CSP plant than the amount of solar energy available. Indeed, the Texas site produces the least amount of solar energy, yet the relatively high price of electricity makes it the most profitable site. The table also shows that due to the coincidence of solar insolation with load patterns, CSP without TES is between 7% and 35% more valuable than the average price of electricity in the cases evaluated. The table further shows that adding TES increases this value by another 7% to 16%.

The energy-related value of TES is actually derived from two sources. The first is that TES allows more of the energy collected by the solar field to be used by placing excess energy that would overload the powerblock into TES for future use.

TABLE II
SOLAR ENERGY AVAILABLE AND AVERAGE PRICE OF ENERGY FOR DIFFERENT CSP SITES

CSP Site	Solar Field Energy with SM 2.0 (GWh-t)	Simple Average Energy Price ($/MWh)	Average CSP Selling Price ($/MWh) SM 1.5 No TES	SM 2.0 Six Hours TES	Annual Operating Profits ($ million) SM 1.5 No TES	SM 2.0 Six Hours TES
Arizona	1,150	41.2	47.0	50.5	11.6	18.6
Daggett	1,181	55.9	58.5	67.9	14.5	25.0
New Mexico	1,088	57.3	61.2	66.2	13.5	23.0
Texas	961	66.4	89.4	98.4	18.2	30.1

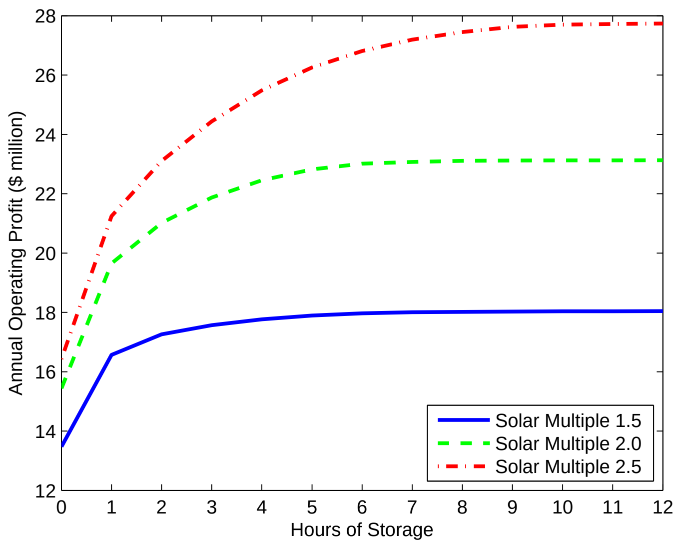

Fig. 4. Annual operating profits of a CSP plant at New Mexico site.

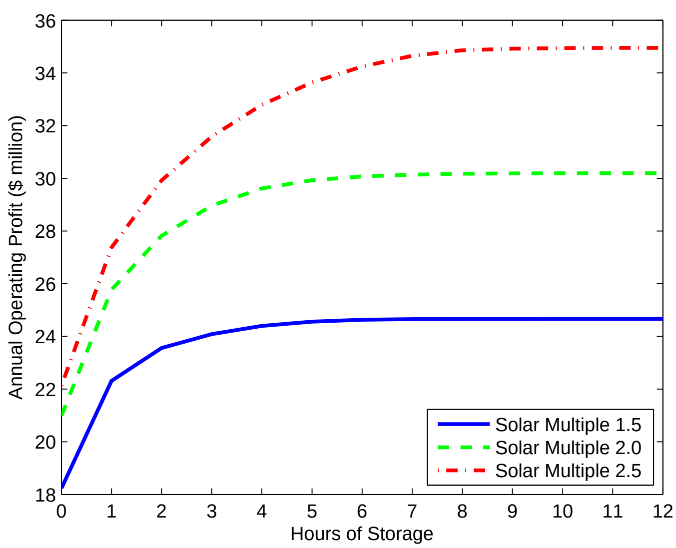

Fig. 5. Annual operating profits of a CSP plant at Texas site.

This then allows for a relatively larger solar field to be used with a powerblock. The second value of TES is that it allows generation to be shifted from periods with lower prices to those with higher prices. Figure 6 demonstrates these two effects for a CSP plant in Texas with an SM of 2.0. It shows that as TES is added to the CSP plant, more solar field energy is able to used, with this benefit of TES flattening at about four hours of storage. Moreover, it shows that adding TES helps to increase the average selling price of energy from the CSP plant—since the TES allows generation to be shifted between hours. This use of TES increases the average selling price of energy from the CSP plant by about $5/MWh with three hours of storage.

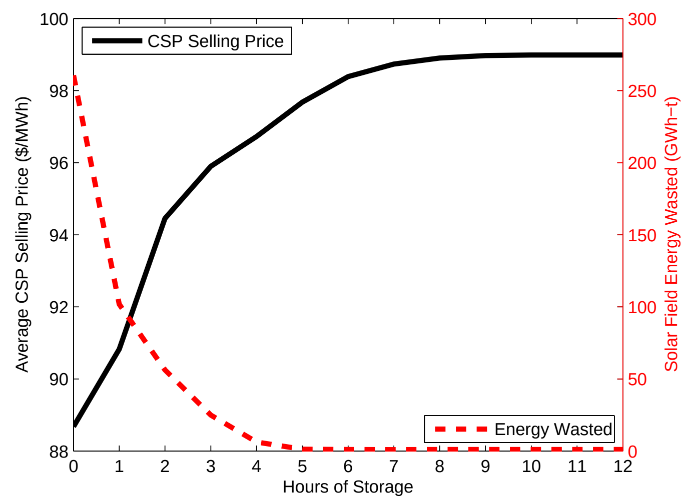

Fig. 6. Average selling price of energy ($/MWh) and solar field energy wasted (GWh-t) for a CSP plant at Texas site with an SM of 2.0.

V. Sensitivity of CSP Profits to Base Case Assumptions

The results presented thus far represent a base case with a set of assumptions regarding the optimization horizon, perfect foresight of solar availability and energy prices, the markets in which the CSP plant participates, and the availability of water for wet cooling of the powerblock. We now examine the impact of relaxing these base assumptions on the profitability of CSP and the value of TES.

A. *Impact of Optimization Horizon*

The results presented in section IV assume that the CSP plant would be dispatched using a rolling one-day optimization period (we also assume that each one-day planning problem would account for the second day). These assumptions allow generation to be shifted between hours within a day and allow for energy to be stored at the end of each day in anticipation of energy prices the following day. These assumptions do not, however, account for the fact that a CSP plant may store energy in anticipation of prices multiple days in the future. For example, [19] describes a ‘weekend effect,’ in which more energy tends to be stored over weekends in anticipation of the fact that energy prices tend to be higher on weekdays. As such, our assumption of a one-day planning horizon may understate the potential profitability of a CSP plant, since it does not fully allow for interday generation shifting.

We examine the sensitivity of CSP profits by comparing our base case with a one-day planning horizon to one with a rolling one-week planning horizon. As with the one-day model, the week-long model assumes that the CSP plant has perfect foresight of solar availability and energy prices, and we use an eight-day horizon in the dispatch model in order to ensure that energy in TES has carryover value at the end of each week. Figure 7 shows the increase in annual operating profits if a CSP plant at the Texas site uses a week- as opposed to day-long planning horizon in its dispatch optimization. The profit increases are given as a percentage of the profits from using a day-long planning period. The figure shows that profits are largely insensitive to the optimization period, with less than a 2.4% increase in profits from switching to a week-long optimization period, implying that most of the generation shifting with TES is done within or between adjacent days. The other sites show even less sensitivity to the optimization horizon—with a less than a 1.3% increase in profits from week-long planning. It is interesting to note that the profit increase from week-long planning is greatest for a CSP plant configuration with a low SM and more TES. The reason for this result is that with a lower SM, the TES is used less for storing excess solar field energy since there are fewer hours in which the capacity of the powerblock is binding. Thus a CSP plant with such a configuration uses TES primarily for shifting generation to higher-priced hours—which will be more sensitive to the planning horizon used.

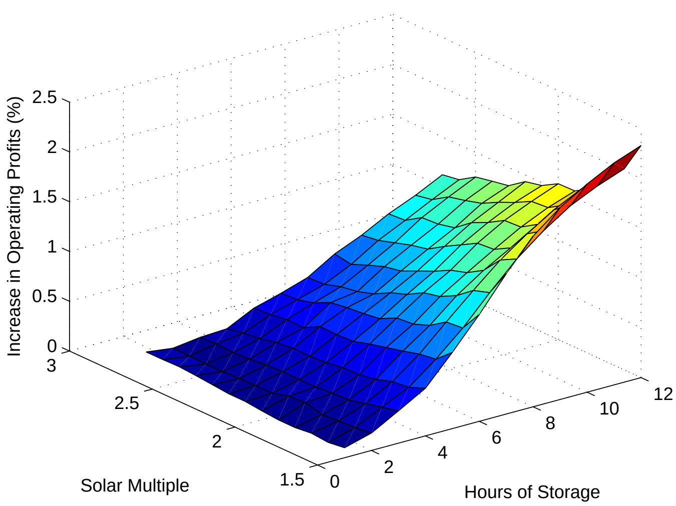

Fig. 7. Increase in annual operating profits of a CSP Plant at Texas site from using week-long as opposed to day-long optimization period. Profit increases are given as a percentage of profits with day-long optimization.

B. Impact of Solar Availability and Energy Price Forecasting

A major assumption of our base case is that the CSP plant has perfect foresight of future energy prices and solar availability in conducting its optimization. In practice, however, storage operators will only have a forecast of these data to use. Clearly the profitability of a CSP plant will be closely related to the quality of forecasts that are available, which may vary based on the type of forecasting models used. Rather than trying to approximate the effectiveness of different forecasting techniques in optimizing the dispatch of a CSP plant, we use the 'backcasting' technique described in [19]. This backcasting technique assumes that the CSP plant will be dispatched using historical data only. More specifically, we assume the operation of the CSP plant is optimized one hour at a time using a rolling one-day planning horizon. In hour t the dispatch of the CSP plant is optimized using solar availability and price data from the previous twenty-four hours, assuming that those price and solar patterns will exactly repeat themselves. This day-long dispatch is used to determine the operation of the plant in hour t and the process is iteratively repeated. Once the dispatch of the CSP plant is determined, actual price and solar availability data are used to determine the plant's revenues. Figure 8 compares the operating profits of a CSP plant at the Texas site using the backcasting technique to that achievable with perfect foresight. The results demonstrate that for all of the CSP plant sizes considered, this backcasting technique earns at least 87% of the profits that are theoretically attainable with perfect foresight. The same analysis shows the Daggett site to perform slight better—earning at least 89% of the perfect-foresight profits for the different TES configurations.

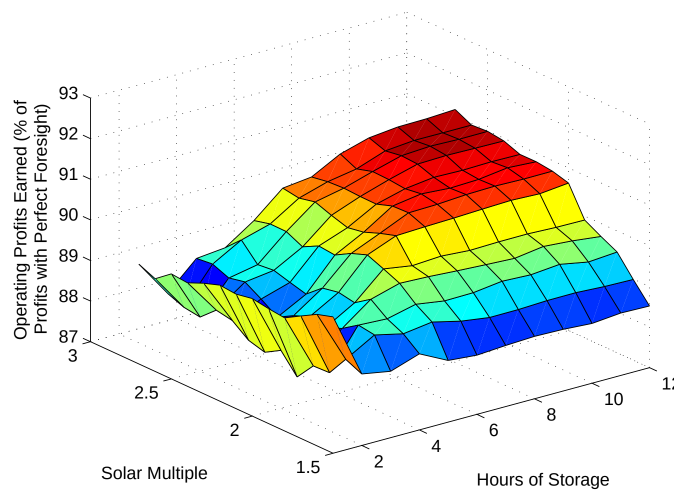

Fig. 8. Annual operating profits earned by a CSP plant at Texas site using daily backcasting technique. Profits given as a percentage of profits with perfect foresight.

The relatively good performance of the backcasting technique relative to perfect foresight is not entirely surprising given the fact that energy prices and solar availability have rather predictable diurnal patterns—which is in line with the findings of [19]. In the summer, energy prices tend to have a peak midday or in the afternoon (due to cooling loads), and peak more in the morning and evening (due to heating and lighting loads) in the winter . Solar availability follows predictable patterns as well, with solar tending to peak in midday or in the afternoon (during the summer when cooling loads are driving the load peak, the peak in energy prices tends to lag the solar peak by an hour or two). Thus, price and solar data from the previous day will tend to capture the correct diurnal pattern of the following day. Moreover, while energy prices and solar availability can differ on longer-term bases, for instance due to seasonal or even annual differences, the use of data from the previous twenty-four hours will tend to capture these effects. Finally, it is important to note that the backcasting technique we examine here does not incorporate any solar or price forecasting in operational decision making. Since weather and prices tend to be somewhat predictable, especially on a short-term day-ahead basis, the value capture shown in figure 8 should be viewed as a lower-bound on what can be achieved with the use of state-of-the-art forecasting techniques.

C. Impact of AS Sales

The analysis thus far has assumed that the CSP plants will only provide energy, whereas in practice they could also provide AS—such as regulation, spinning, and non-spinning reserves. Although these AS are used in all of the regions we consider in our analysis, AS price data are only available from the CAISO and ERCOT markets. Thus we only consider AS sales for the Daggett and Texas CSP sites. We assume that the CSP plant will not be eligible to provide regulation services or non-spinning reserves, due to limitations in the rate at which the powerblock and TES can be started and ramped. We consider two cases in which the plant can provide either 25% or 50% of its generating capacity in the form of spinning reserves, which is meant to represent the fact that a CSP plant may have limited ramping capabilities. In both cases we limit the CSP plant such that the total of its energy and spinning reserves sales must be within the power and energy capacity of the plant. These restrictions ensure that if the plant's spinning reserves are deployed in real-time, it can feasibly serve that load in addition to its energy sales. Since [20] shows that spinning reserves are deployed very infrequently, we do not explicitly model the probability of spinning reserves being deployed nor the revenues from that energy being sold (or the effect of an AS deployment on subsequent energy sales).

Figure 9 shows the dispatch of the CSP plant at the Texas site with an SM of 2.0, six hours of TES, and the ability to sell up to 50% of its capacity in spinning reserves over the same one-day period shown in figure 1 and contrasts it with CSP operations without spinning reserve sales. Several differences in CSP operations can be noted. For example, the powerblock is run in hours 15 and 16 with AS sales in order to allow spinning reserves to be sold, whereas in hours eight through 13 and hours 18 and 20 the CSP plant produces less energy than the case without AS sales in order to allow it to sell spinning reserves.

Figure 10 summarizes the effect of allowing the CSP plants to sell spinning reserves on the operating profits of the Texas plant. The figure shows the increase in annual profits from the sale of spinning reserves as a percentage of profits with energy sales alone. The figure shows that, depending on the plant size, these profit increases can be non-trivial, and that the increase is greatest for a CSP plant with a low SM and large TES. This result is due to the fact that a CSP plant with this configuration will use TES less to store excess thermal energy

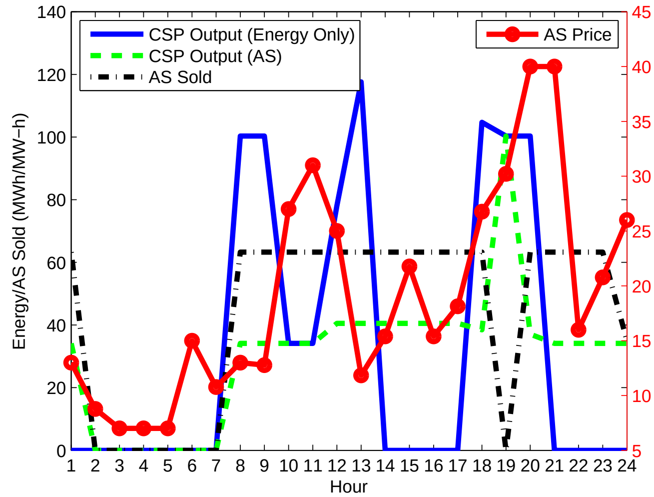

Fig. 9. Sample dispatch of a CSP plant with eight hours of TES and an SM of 2.0 at Texas site when energy and spinning reserve sales are co-optimized.

from the solar field, meaning that there is greater relative value from selling AS. Spinning reserves are even more valuable at the Daggett site—increasing profits by up to more than 11%—demonstrating the higher relative value of AS than energy in the CAISO market compared to in ERCOT.

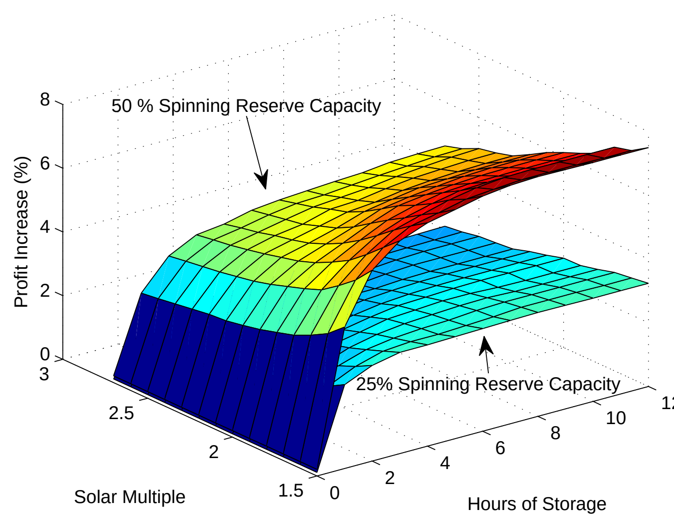

Fig. 10. Increase in annual operating profits of a CSP plant at the Texas site if spinning reserves can be sold. Increase in profits is given as a percentage of profits with energy sales alone.

D. Impact of Capacity Credit

CSP plants, especially those with TES, will generally provide capacity to the system, which is valuable in that it reduces the need for other capacity to be built or procured by the utility, load-serving entity, or system operator (SO). Properly valuing this capacity can pose some difficulties in electricity markets, however, as capacity is not necessarily priced in the market or market distortions can suppress these prices. In theory, restructured energy-only markets, such as the CAISO or ERCOT markets, value capacity through scarcity pricing, whereby prices increase with loads to reflect the cost of capacity constraints. Thus in such a market the value of capacity should be captured in energy prices. In practice, however, price caps and other regulatory interventions in the market tend to suppress energy prices, and as such capacity may not be properly priced in the market. Indeed, even in the ERCOT market, which has a much higher price cap than the CAISO, [21] argues that the threat of regulatory intervention has served to suppress energy prices below levels that profit-maximizing behavior would support. Vertically-integrated markets, such as those in Arizona and New Mexico, pose an even greater problem in estimating the value of capacity, since the load lambda data we use as proxies for energy prices do not capture the value of capacity at all.

Since capacity is not properly valued in the energy prices used in our analysis, we use the capital cost of a new gas combustion turbine (CT) to compute a proxy for the value of capacity. The current capital cost of a CT is estimated to be about $625/kW, which translates to a cost of $68.75 million for a 110 MW turbine [22]. We can translate this capital cost of a CT into an annual cost of capacity by using an annual capital charge rate (CCR), which captures all of the financing parameters and other costs that would go into building such capacity. Following [23] we assume an 11% CCR, which gives an annual cost of $7.56 million for a 110 MW CT. If the availability of a CSP plant is equivalent to that of a CT, this value of $7.56 million would represent the capacity value of a CSP plant, which represents a 25%-41% increase in the annual value of a CSP plant with TES compared to the base values in table II.

In practice the annual capacity value of a CSP plant would be some fraction of this $7.56 million, depending upon the actual availability of the CSP plant. The availability of a CSP plant will depend on many factors, such as its scheduled and forced outage rate, and the availability of thermal energy from the solar field and TES. While solar field energy is not controllable, the availability of energy from the TES will be a function of the dispatch of the plant. Depending on whether the CSP plant is being given a capacity payment and how those payments are determined, the dispatch of the the plant would presumably be altered to maximize the sum of energy and capacity revenues. Further work is needed to assess the actual capacity value of CSP plants as a function of location and TES size.

E. Impact of Powerblock Dry Cooling

Our analysis thus far has assumed that the CSP plants will use a wet-cooled powerblock. Due to the arid climates of the southwestern United States, an important consideration is what effect dry cooling would have on the profitability of the CSP plants and the value of TES. Dry cooling the powerblock will tend to increase cooling tower energy losses, with the efficiency reduction depending upon the ambient temperature. This decrease in efficiency will tend to increase the value of TES, since high ambient temperatures (which give greater efficiency losses with dry cooling) will tend to be correlated with the availability of solar energy. Without TES, the solar energy must be put into the powerblock, which will produce less energy due to cooling losses. With TES, however, energy from the solar field can be stored and generation shifted to hours later in the day when ambient temperatures are reduced. SAM accounts for dry cooling energy losses by multiplying gross powerblock output by a term which is a fourth-order polynomial function of the ambient temperature. We model dry-cooling energy losses in the same manner, and use the correction factors from SAM as an input to our dispatch model.

Figure 11 summarizes the annual operating profit loss from using a dry- as opposed to wet-cooled CSP plant with an SM of 2.0 at the four sites. As the figure shows, dry cooling can have a noticeable impact on CSP profits, especially for smaller-sized plants. The figure shows that the profit losses are highest for CSP plants without TES (or with very little TES). This greater profit reduction is due to the fact that with TES, generation can be shifted to hours with lower efficiency losses from dry cooling (i.e. hours with lower ambient temperatures).

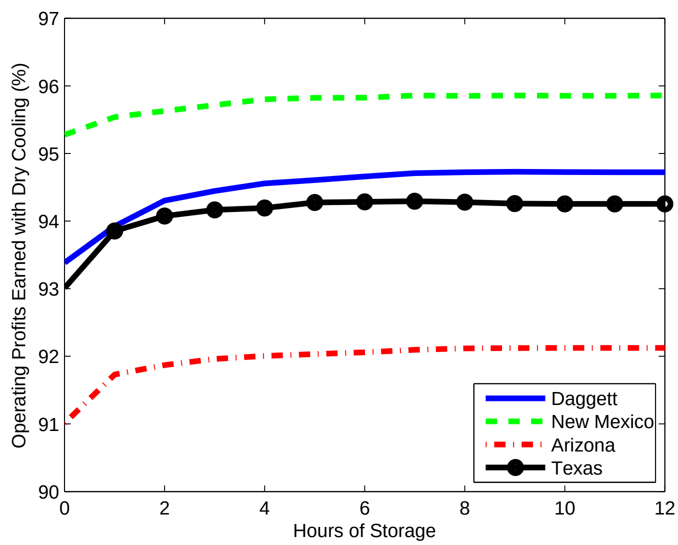

Fig. 11. Net operating profits lost from dry- as opposed to wet-cooled CSP plants with SMs of 2.0. Profit losses given as a percentage of profits with wet cooling.

VI. Breakeven Cost of CSP Plants

Our analysis thus far has only considered operating profits (i.e. profits from energy or AS sales less variable operating costs). A complete analysis of the value of CSP and TES must trade operating profits against the capital costs of the plant. The cost of large-scale CSP is still highly uncertain due to large fluctuations in commodities prices and the potential for substantial cost reductions from engineering and manufacturing improvements. Furthermore, the overall cost competitiveness of CSP will depend on future changes in fuel prices and carbon policies. Moreover, a cost analysis would require multiple years of energy price and solar data to determine the operating profits of the plant over its lifetime. Instead of making these assumptions regarding operating profits, we instead focus on the tradeoff between estimates of CSP and

TES capital costs and the year-1 profits of a CSP plant based on our 2005 reference case.

Reference [24] presents estimates of present and future CSP and TES costs in 2005 dollars, which can be directly compared to the operating profits estimated thus far since these estimates use 2005 energy price and load lambda data. We use the 2009 cost estimates for present costs and the 2015 estimates for future costs. We assume that without TES the solar field has an SM of 1.5 and with TES it has six hours of storage and an SM of 2.0. We scale the costs of the TES and the solar field because [24] assumes a 100 MW-e powerblock for the 2009 CSP plant and a 200 MW-e powerblock for the 2015 CSP plant, whereas we assume a 110 MW-e powerblock throughout our analysis. These assumptions give an estimated present cost of $339.2 million for a CSP plant without TES and a cost of $495.5 million for a plant with TES, which amounts to an incremental cost of $156.3 million for adding TES and the expanded solar field to a CSP plant, and a future cost of $229.6 million and $347.3 million for a CSP plant without and with TES, respectively, which amounts to an incremental cost of $117.6 million for TES. We also assume that the CSP plant will be eligible for an investment tax credit (ITC) of either 30% or 10%. The 30% reflects the current ITC for solar generators, whereas the 10% reflects a potential future scenario in which the ITC is reduced (for instance, due to future CSP cost reductions).

Table III summarizes the year-1 breakeven cost and return on investment of the TES component of the CSP plant, assuming an 11% CCR. The breakeven cost is defined as the maximum incremental cost of the TES component of the CSP plant which is justified by the increase in annual operating profits of the CSP plant (as derived from table II). The return on investment is defined as the percentage of the annual cost of the TES component (using the same 11% CCR) that is recovered by the increase in year-1 operating profits of the CSP plant. Thus a return of investment of 100% or greater indicates that the TES 'pays for itself,' through higher energy revenues. Clearly whether the increased revenues from TES will justify the cost of TES will be highly sensitive to the site of the CSP plant, ITC rate, and cost of the TES, but substantial cost reductions appear to be necessary to justify the addition of TES on the basis of energy sales alone.

Table III does not include the non-energy value of CSP and TES, especially the value of more firm capacity. As discussed in section V, the operating profits of CSP can potentially be increased by AS sales or a capacity credit. Table IV summarizes the breakeven cost when accounting for these sources of revenues. The AS sales case assumes that 50% of the CSP plant's power capacity can be sold as spinning reserves, so long as sufficient energy is available from the solar field or TES. For the Arizona and New Mexico sites, for which we do not have spinning reserve price data, we scale up the breakeven cost from the costs in table III based on the increase in the breakeven cost of the Daggett and Texas sites—which is a roughly 16% increase. The capacity credit case assumes that the CSP plant has the same availability as a CT, which gives an annual capacity value of $7.56 million. In practice this availability may be lower, which would reduce the breakeven cost, but we use this value to provide an upper bound. We also implicitly assume in this calculation that the addition of TES to a CSP plant allows it to provide AS sales and receive a capacity credit. This is likely since an SO may not consider a CSP plant without TES to be a sufficiently 'firm' resource that can provide AS and capacity.

TABLE IV
YEAR-1 BREAKEVEN COST OF TES ($ MILLION) WITH AS SALES AND AS SALES AND CAPACITY CREDIT

	AS Sales		AS Sales and Capacity Credit	
CSP Site	30% ITC	10% ITC	30% ITC	10% ITC
Arizona	105.2	81.8	203.5	158.2
Daggett	160.7	125.0	259.0	201.4
New Mexico	142.8	111.1	241.1	187.5
Texas	176.0	136.9	274.2	213.3

Comparing table IV to table III and the cost estimates above shows that a greater cost of TES is justified with AS sales and capacity value. With the 30% ITC the revenues associated with TES from AS sales alone at the Daggett and Texas sites are greater than its present cost, and if the capacity credit is included TES is justified at all of the sites with both a 10% and 30% ITC.

Because the breakeven cost of TES in table IV are greater than the cost estimates from [24] in a number of cases, this incremental value of TES above its cost will improve the cost competitiveness of the entire CSP plant. Table V compares the year-1 breakeven cost of a CSP plant without TES to the breakeven cost of the non-TES components of a CSP plant with TES under the various cost and ITC assumptions. The case without TES assumes that the CSP plant sells energy only, whereas with TES the plant is assumed to provide both capacity and AS. For the TES case the incremental cost of adding TES to the CSP plant is subtracted from the maximum breakeven cost justified by the sum of capacity, energy, and AS profits. Thus, the values given are the highest cost for the base CSP plant (SM 1.5 and no TES) that can be justified if the TES component is added as well. Table V shows us that CSP without TES is justified only at the Texas site with future costs and a 30% ITC. When TES is added to the CSP plant, however, it is justified at its present cost with the current 30% ITC rate in Texas, and is justified at a number of sites with the future cost estimates.

VII. CONCLUSIONS

This paper presented a detailed analysis of the value of CSP plants with TES in southwestern regions of the United States. Our results showed how operating profits of CSP plants vary as a function of plant size and location. Locational profit differences were shown to be mainly due to differences in energy prices in the different SO and utility systems considered, with differences in solar resource being a smaller determinant of CSP value. We showed that TES can increase CSP value both by allowing generation to be shifted to higher-priced hours and by increasing the use of thermal energy from the solar field.

We also showed the effect of relaxing several of our base assumptions on CSP profitability. The operating profits of the

TABLE III
YEAR-1 BREAKEVEN COST AND RETURN ON INVESTMENT OF TES USING BASE CASE PROFIT AND COST ASSUMPTIONS

	Breakeven Cost ($ million)		Return on Investment (%)			
			Present Cost		Future Cost	
CSP Site	30% ITC	10% ITC	30% ITC	10% ITC	30% ITC	10% ITC
Arizona	90.9	70.7	58.1	45.2	77.3	60.1
Daggett	136.4	106.1	87.3	67.8	115.9	90.2
New Mexico	123.4	96.0	78.9	61.4	104.9	81.6
Texas	154.6	120.2	98.9	76.9	131.4	102.2

TABLE V
YEAR-1 BREAKEVEN COST OF NON-TES COMPONENTS OF CSP PLANT ($ MILLION)

CSP Site	Without TES		With TES			
			Present Cost		Future Cost	
	30% ITC	10% ITC	30% ITC	10% ITC	30% ITC	10% ITC
Arizona	150.7	117.2	200.1	120.9	238.8	159.6
Daggett	188.3	146.5	293.3	193.4	332.0	232.1
New Mexico	175.3	136.4	261.1	168.4	299.8	207.1
Texas	236.4	183.8	355.3	241.6	394.0	380.3

CSP plant seemed relatively insensitive to the assumption that TES dispatch decisions are made a day at a time, which suggests that most generation shifting is done within a day or between adjacent days. Longer-term generation shifting over the course of the week and the so-called ‘weekend effect’ were not noticeably apparent for CSP plants, except for plants with a small solar field and large amounts of storage. We also demonstrated that the perfect foresight of energy prices and solar availability assumed throughout our analysis is a relatively good approximation of actual CSP operations, since at least 87% of the profits with perfect foresight can be attained by using a very simple backcasting technique. We expect that including price and weather forecasts in the dispatch process can significantly improve the profitability of an operating CSP plant above the level of this backcasting technique. We also showed that adding AS sales and capacity credit can increase CSP profits and examined the effect of dry cooling—showing that TES can reduce some efficiency losses associated with dry cooling by shifting generation to hours with a lower ambient temperature.

Despite these benefits of CSP, our analysis suggests that with current capital costs TES cannot be justified on the basis of energy value alone, except at the Texas site. Moreover, without TES CSP is only justified at the Texas with future lower costs and the current 30% ITC rate—showing that TES is an important component in increasing the economic viability of CSP. Adding TES to a CSP plant makes it economic with current costs and the 30% ITC at the Texas and Daggett sites, and CSP will become more economic at the other sites with further cost reductions.

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