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An assessment of the net value of CSP systems integrated with thermal energy storage

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Abstract

Within this study, we evaluate the operational and capacity value—or total system value—for multiple concentrating solar power (CSP) plant configurations under an assumed 33% renewable penetration scenario in California. We calculate the first-year bid price for two CSP plants, including a 2013 molten-salt tower integrated with a conventional Rankine cycle and a hypothetical 2020 molten-salt tower system integrated with an advanced supercritical carbon-dioxide power block. The overall benefit to the regional grid, defined in this study as the net value, is calculated by subtracting the first-year bid price from the total system value.

Results of this study indicate a positive net value for a variety of scenarios, depending on technology assumptions and assumed values for natural gas price and tax incentives. We provide results for the 2013 and 2020 CSP configurations as a function of thermal energy storage capacity and solar field size. We provide a sensitivity of these results to natural gas price, which influence the operation value and thus the total system value. We also investigate the sensitivity of the net value to current and anticipated tax incentives.

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Keywords: concentrating solar power; power tower; thermal energy storage; grid integration

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1. Introduction

A great deal of literature is devoted to the economic analysis of concentrating solar power (CSP) systems with thermal energy storage (TES), with an emphasis on determining the levelized cost of energy (LCOE). Although the LCOE is generally emphasized when assessing the economic viability of renewable energy systems, it ignores the operational and capacity value of CSP. CSP-TES can be dispatched similarly to conventional thermal generation, which can cause incomplete economic comparisons between CSP-TES and variable-generation renewable technologies such as photovoltaics (PV) when using only LCOE. More comprehensive analysis includes comparisons of both costs and benefits of different technologies. This includes consideration of how the value of a resource changes as a function of penetration, which can be particularly important for variable resources [1]. Analysis explicitly assessing or optimizing the operational and capacity value, or grid value, provided by CSP integrated with TES has relied primarily on the use of existing market data [2–4]. At increasing levels of renewable energy penetration, the value of variable-generation technologies such as PV has been shown to decline whereas CSP systems integrated with TES maintain their high value. Several researchers have demonstrated this value under scenarios involving varying future generation mixes, technology types, load shapes, and regional resources [5–8]. However, the pool of researchers and regions chosen for analysis is limited given the importance of this topic.

Before important stakeholders can fully support CSP with TES, the benefits purported by the ongoing research described above must be analyzed. The National Renewable Energy Laboratory (NREL) has published several technical reports and papers based on the use of the commercial production-cost modeling software PLEXOS and related tools to quantify the operational and capacity value of CSP with TES. However, there is a recognized need to integrate this work with a delivered cost of energy analysis to fully assess the “net value” [9] of CSP for scenarios of interest to developers, energy off-takers, and state and local regulators/policy-makers. The net value of a particular CSP system can be calculated by subtracting the cost of a particular CSP configuration, portrayed by the LCOE or bid price, from the grid value. Such an analysis can be helpful in optimizing the configuration of a CSP system, e.g., hours of storage and solar multiple (SM), for a particular region under specified deployments of conventional and/or renewable energy technologies.

2. Methodology

2.1. Modeling CSP operational and capacity value

This section describes two sources of value for CSP or other generation technologies: operational value and capacity value. Operational value represents the avoided costs of operating the grid, which include fuel costs, start-up costs, variable operation and maintenance costs, and emissions costs. Capacity value reflects the ability of CSP-TES to avoid the costs of building new conventional generators in systems that need capacity in response to growing energy demand or plant retirements.

2.1.1 Operational value

In this paper, we evaluated the operational value of adding an additional CSP-TES plant using a grid model developed by the California state energy agencies and maintained by the California Independent System Operator (CAISO). This model uses PLEXOS, a commercially available production-cost modeling software, to simulate the power grid in California. Production-cost modeling software allows grid planners and operators to assess many aspects of power generation, including system costs and emissions. The database contains generator-level details of California’s electricity sector as well the rest of the U.S. Western Interconnection because California is highly interconnected with several western states and historically imports a significant amount of power from neighboring regions. CAISO utilized the database in analyses of the original 20% renewable portfolio standard (RPS) as well as the 33% renewable integration study for the California Public Utilities Commission (CPUC) [10,11].

Production-cost models such as PLEXOS are formulated to minimize the total cost of generating electricity to serve energy demand in every time step by committing (determining whether a generator is on or off) and dispatching (adjusting the output of the committed generators). The model includes a large number of constraints including operating reserves, which are typically provided by partially loaded generators with the ability and necessary capacity to change their output. The model also includes transmission constraints that enforce the minimum and maximum allowable power flow into or out of a region. Finally, the model specifies constraints on the individual generators, which include ramp rates, minimum generation levels, outage profiles, heat rates, and many more. The model solves an optimal least-cost dispatch for the entire geography, with defined flow limits and wheeling charges for interchanges between regions. In reality, many individual utilities outside CAISO operate their power systems individually, subject to various agreements with their neighbors; hence, the actual dispatch may not be least cost for the entire region, as was modeled here.

In this analysis, we first compared the base-case system described above with and without the addition of incremental CSP-TES with equal annual energy. We calculated the difference in total production cost (which includes fuel costs, variable operation and maintenance [VO&M] costs, and start-up costs) between the two runs and attributed the marginal system savings to the new solar plant.

To correctly capture the dispatch and value of CSP-TES, we integrated and connected the three aspects of a solar thermal plant to the storage depicted in Figure 1: the solar field and receiver, storage tank, and power block. First, we quantified the solar resource of a typical good solar resource location in California. Meteorological data for the site chosen, located near Daggett, California, originated from the National Solar Radiation Database for the year 2006. These data are an input to NREL's System Advisor Model (SAM) version 2013-1-15 [12,13]. The molten-salt power tower model within SAM converts hourly irradiance into thermal energy and then into net electrical energy based on the rated gross thermal-to-electric efficiency of the dry-cooled turbine [14]. Downtime, outages, start-up energy, and part-load efficiency decrements were neglected in SAM to be taken into account during dispatch modeling. The electrical equivalent energy then served as a dispatchable resource in PLEXOS within the constraints of the thermal power block characteristics of the CSP-TES plant. PLEXOS was used to simulate dispatched storage and CSP-TES generator operation. Specifically, in each hour, the model can send electrical energy into storage, immediately into the grid through the CSP power block, or a combination of the two. The model can also choose to draw energy from storage to feed the power block. This framework accounts for three types of losses within the plant: start-up losses incurred when warming up the plant, part-load efficiency losses resulting from operating below the design point, and storage losses that result from transferring and storing heat. In addition, the plant has operational parameters, such as a ramp rate and minimum generation level, similar to conventional steam turbine generators. Incorporating the CSP-TES plant into PLEXOS allows the model to optimally schedule both the output of solar energy and co-optimize the plant's capacity to provide operating reserves.

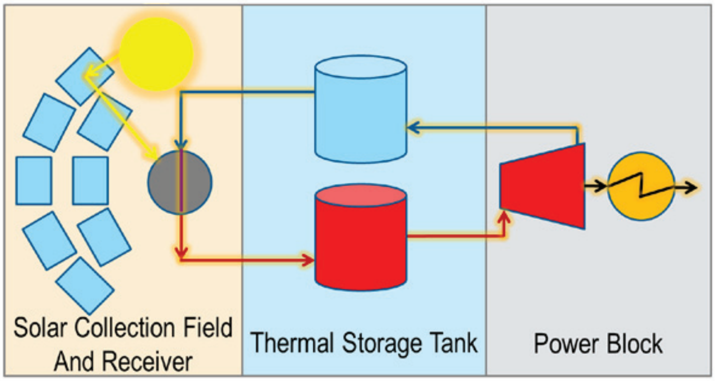


Fig. 1. Three major operations within a CSP-TES plant: solar field and receiver, thermal storage tank, and power block.

Previous findings indicate that reducing the ratio of the solar collection field size to the power block capacity—a design parameter often called the solar multiple (SM)—in combination with sufficient thermal storage provides the most benefit to the power system per unit of energy produced [7,8]. To evaluate the operational value of different SMs, we changed the rated capacity of the power block instead of the size of the solar field. Therefore, the electrical equivalent solar energy available for use in each scenario remained constant, but the rated capacity of the power block varied. We also increased the storage capacity to quantify the additional system benefit provided by increased storage capacity. Table 1 shows the studied parameters. As previously described, we calculated the system benefits by calculating the avoided production costs as a direct result of adding the CSP-TES plant to the system discussed earlier. We then normalized by the amount of energy produced by each plant.

Table 1. The Solar Multiples and Corresponding Plant Characteristics of CSP-TES Plants Modeled

Solar Multiple	Rated Capacity of Plant (MW)	Electrical Equivalent Inflow from Field (GWh)	Hours of TES Capacity Tested
1.3	1,172	3,667	0, 3, 6
1.7	896	3,667	3, 6, 9
2	762	3,667	6, 9, 12
2.3	663	3,667	9, 12, 15
2.7	564	3,667	12, 15

2.1.2 Capacity value

Calculating the avoided operational costs as discussed above captures only one source of value for solar technologies. Next, we examined another source of potential value: firm capacity. The capacity value reflects the ability of CSP-TES to avoid the costs of building new conventional thermal generators to meet demand. Note that firm capacity has value only in systems that need capacity to respond to growing energy demand or plant retirements. Capacity value in overbuilt systems with large amounts of excess capacity is essentially zero.

In this system, we added over 1 GW of CSP-TES. However, this is the plants' rated, or nameplate, capacity, and does not necessarily reflect the generator's availability during periods of peak demand. The actual effective load-carrying capability (ELCC) for a generator is the amount of load that could be added to the system with the presence of a new generator while still meeting reliability targets.

We used an NREL tool to conduct a full ELCC calculation to determine the capacity credit of PV [15,16]; however, the traditional ELCC calculation becomes more complicated for CSP-TES because of the presence of dispatchable thermal storage. We used an approximation method for estimating capacity credit for CSP-TES and thus the actual capacity value that a plant may earn. First, we considered the solar resource and dispatch of the CSP-TES plant during the hours with the highest net load, and then considered the contribution of stored energy to increase output during those hours, as discussed by Tuohy and O'Malley [17]. The calculation also reflects the energy limitations on the CSP-TES plant in increasing output in subsequent hours. The result of this approximation of CSP-TES capacity value is shown below in Table 2. The plants with higher solar multiples have higher capacity credits because of their surplus of solar energy relative to rated capacity, and plants with more thermal storage capacity have higher capacity credits because of their ability to shift solar energy to the hours of highest net load. These results generally follow similar work by Madaeni et al. investigating the capacity value of CSP-TES plants in the Southwest U.S. [18].

Table 2. Capacity Credit Assigned to Various Configurations of CSP-TES Plants (SM=Solar Multiple)

Hours of TES	SM				
	1.3	1.7	2	2.3	2.7
0	0.145				
3	0.89	0.94			
6	0.93	0.95	0.99		
9		0.99	0.98	0.99	
12			0.99	1.0	1.0
15				1.0	1.0

Using the data in Tables 1 and 2, we calculated the capacity value by multiplying the rated capacity (MW) by the capacity credit and capacity cost ($/MW-yr), dividing this value by the annual plant output (MWh/yr). For this calculation, we used an annualized capacity cost of $190/kW-yr based on the cost of a new combustion turbine in California [11].

2.2. Modeling CSP system bid price and system net-value

We used SAM to analyze the cost and performance of CSP systems used for the net-value analysis. SAM supports performance predictions and cost-of-energy estimates for grid-connected power projects based on installation and operating costs, in addition to design parameters specified as inputs to the model. Creating a SAM project involves choosing both a performance model and a financial model to represent a project. For this analysis, we used the previously mentioned molten-salt power tower model as a proxy for assessing the cost and performance of current and future CSP systems. We used the "Utility Independent Power Producer" or IPP model to calculate relevant financial metrics such as the LCOE (real and nominal) and power purchase agreement (PPA) or "bid" price. Financial assumptions, described in Table 3 below, were based on the SunShot Vision Study [19]. Performance parameters are provided in Section 3.2 later in this paper. As previously described, the net value of a generating system can be calculated by subtracting the cost of generation, portrayed by the LCOE or bid price, from the grid value. For this analysis, we use the first-year PPA price generated from SAM as the closest counterpart to the single-year analysis derived for the operational and capacity values described in Section 2.1.

Table 3. Financial Assumptions used for Baseline and Future CSP Tower Scenarios (IRR=Internal Rate of Return; DSCR=Debt Service Coverage Ratio; MACRS=Modified Accelerated Cost Recovery System; DC=Direct Cost)

Case	2013 Tower, CSP Baseline	2020 Tower 600C sCO_2
Plant life	30 years	30 years
Inflation rate	3.0%	3.0%
Real discount rate	5.5%	5.5%
Federal / State tax	35% / 5%	35% / 5%
Sales tax	5% on 80% of DC	5% on 80% of DC
Project loan period and interest rate	15 yr at 4%	15 yr at 4%
Construction loan period and interest rate	24 mo at 5%	24 mo at 5%
Debt fraction	60%	60%
Required IRR and DSCR	15% and 1.4	15% and 1.4
MACRS	yes	yes
Investment Tax Credit (ITC)	30%, 10%	10%
Location (weatherfile)	CA (Daggett)	CA (Daggett)

3. Grid and technology scenarios

3.1. 33% renewable energy penetration grid scenario

As mentioned, the PLEXOS model contains a representation of the entire U.S. Western Interconnection. However, given the market size, we focused on California and added the CSP plants to the southern region of that state. For consistency with the database, the CAISO footprint was modeled as the area served by the three largest investor-owned utilities in the state of California, which represents 80% of total load in the state. Table 4 describes the installed capacity in the CAISO region for the base 33% RPS scenario, with the RPS-eligible generators separated. The assumed generation-averaged fuel prices are $1.71/MMBtu for coal and $4.38/MMBtu for natural gas. The fuel prices varied by region, and the natural gas prices also varied by month to reflect seasonal demand. In addition, carbon dioxide (CO_2) emissions within California were priced at $21.9/ton. Carbon dioxide emissions outside of California had no modeled cost, although energy imported to California had a small added cost to reflect the incoming cost of carbon.

Table 4. Description of the Installed Capacity of the Modeled CAISO Region

	Capacity Installed (MW)	
	Non RPS	RPS
Biomass	-	1,080
Coal	138	-
CSP	-	1,400
Demand Response	2,730	-
Gas Combined-Cycle	17,900	-
Gas Combustion Turbine	7,430	-
Geothermal	-	2,460
Hydropower	7,350	1,380
Nuclear	2,240	-
PV	2,080	9,950
Steam/Other	615	-
Storage	3,025	-
Wind	-	10,400
Total	42,300	26,600

3.2. 2013 and 2020 CSP technology scenarios

CSP technology scenarios were developed to calculate the LCOE and power purchase bid prices for use in the net-value analysis. Current cost and performance values were based on a 2013 CSP molten-salt power tower integrated with a conventional Rankine cycle power block [20]. A second, advanced power tower case for 2020 assumed integration with a supercritical CO_2 (s-CO_2) Brayton cycle operating at a receiver outlet temperature of 600°C. For the 2020 scenario, the salt was assumed to be pure sodium nitrate, rather than the conventional sodium nitrate/potassium nitrate blend known as "Solar Salt." Pure sodium nitrate offers a small cost and heat capacity benefit vs. Solar Salt, with the detriment of a higher melting point. This tradeoff is assumed to be favorable for a plant using the s-CO_2 power cycle. Cost and performance values assumed for the s-CO_2 power cycle were taken from the work of NREL and Abengoa Solar under DE-EE-0001589 [21]. The 2020 tower is not a "SunShot" case, but rather, is intended to represent deployment of solar field, heat-transfer fluid (HTF), and storage technologies known to exist. However, the cost of heliostats in 2020 was assumed to achieve the SunShot installed cost target of \$75/m^2. The general assumptions of the two power tower cases are presented in Table 5. All the CSP cases assume air-cooled power cycles.

Table 5. Performance and Cost Assumptions for Current and Projected Molten-Salt Towers (BOS=Balance of System; EPC=Engineering, Procurement, and Construction; O&M=Operation and Maintenance)

Design Assumptions		
Technology	**Solar Salt receiver at 574°C**	**$NaNO_3$ Salt receiver at 600°C**
Performance Assumption:		
Availability	96%	96%
Solar Multiple	1.3–2.7	1.3–2.7
TES (hours)	0–15	0–15
Plant Capacity (MW, net)	100	100
Power Cycle Gross Efficiency	0.412	0.447
Cooling Method	Dry	Dry
Cost Assumptions:		
Site Preparation Cost (\$/m^2)	16	16
Solar Field Cost (\$/m^2)	163	75
Power Plant & BOS Cost (\$/kW)	1,540	965
HTF System or Tower/Receiver Cost (\$/m^2 or \$/kW-t)	168	168
Thermal Storage Cost (\$/kWh-t)	23	26
Contingency	7%	7%
Indirect, including EPC and Owner's costs, land, sales tax (as % of direct costs+contingency)	18.1%	19.2%
Interest During Construction (as % overnight installed cost)	6.0%	6.0%
Fixed O&M (\$/kW-yr)	73	62
Variable O&M (\$/MWh)	4	4

4. Results

4.1 Total grid value of CSP-TES

Figure 2 describes the combined operational and capacity value, or total value, of a proxy molten-salt CSP plant as a function of hours of TES and SM. The figure indicates two trends that have been previously reported [7,8]. First, the value of CSP-TES energy per unit produced generally increases with thermal energy storage capacity. Each of these plants has a SM greater than 1, meaning that the solar field is oversized compared to the power block. Therefore, during hours with high insolation and with insufficient (or no) thermal storage capacity, some solar energy must be curtailed. Increasing the storage capacity reduces the amount of this curtailed energy. In addition, thermal energy storage allows the energy to be shifted to periods with higher energy prices, which occur in the evening after or during sunset.

Second, the figure indicates that the marginal value of plants with lower SMs is generally higher than plants with higher SMs per unit energy delivered. Because power-block size decreases as SM increases (to maintain the same level of generation from each of the TES/SM configurations), plants with higher SMs are forced to store an increasing fraction of solar energy, even during periods of high energy prices. In this case, the size of the power block limits the amount of energy that can be generated during the highest-priced hours of the day, which generally occur after sundown. As SM increases, the plant is forced to flatten its output and behave more like a baseload power plant that exhibits a relatively flat output profile. However, the plants with smaller SMs can act as peaking plants that displace more expensive generation sources during the highest-priced hours.

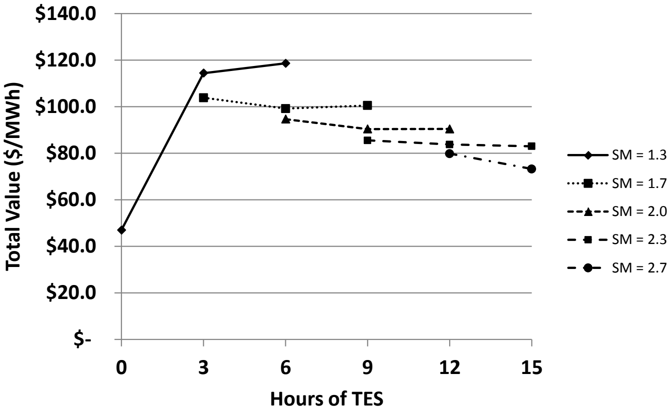


Fig. 2. Combined operational and capacity value from a proxy molten-salt power tower as a function of solar multiple and hours of thermal energy storage demonstrates increased total value for low solar-multiple configurations.

4.1 Sensitivity of operational value of CSP to natural gas price

Figure 2 describes total system value using the default natural gas price of $4.38/MMBtu. Natural gas is the marginal source of generation during most hours of the year, and CSP technologies tend to displace mostly gas-fired generation. Understanding this, we investigated the sensitivity of the operational value component of the total value to natural gas price. Table 6 summarizes the operational value for each of the TES/SM combinations for the default (1x), 1.5x, and 2x values for natural gas price.

Table 6. Sensitivity of Total Value to Natural Gas (NG) Price

Operational Value ($/MWh)				
CSP Configuration		Natural Gas Price Multiplier		
SM	*TES*	*Base NG*	*1.5x NG*	*2x NG*
1.3	0	$ 46.9	$ 65.9	$ 83.4
1.3	3	$ 114.4	$ 137.9	$ 156.2

1.3	6	$ 118.6	$ 140.8	$ 161.5
1.7	3	$ 103.8	$ 127.1	$ 147.7
1.7	6	$ 99.1	$ 123.8	$ 142.0
1.7	9	$ 100.5	$ 123.7	$ 143.5
2.0	6	$ 94.6	$ 116.9	$ 135.4
2.0	9	$ 90.4	$ 113.9	$ 130.3
2.0	12	$ 90.4	$ 112.9	$ 129.4
2.3	9	$ 85.5	$ 107.7	$ 126.2
2.3	12	$ 83.7	$ 105.6	$ 122.5
2.3	15	$ 83.0	$ 104.4	$ 120.9
2.7	12	$ 79.8	$ 100.4	$ 118.5
2.7	15	$ 73.2	$ 97.8	$ 113.3

4.2 CSP tower bid price results

Using SAM, we determined the first-year PPA price for the 2013 and 2020 molten-salt tower configurations based on the finance assumptions provided in Table 3 and technology cost and performance assumptions provided in Table 6. Because the current U.S. federal investment tax credit (ITC) significantly influences the resulting PPA price, we investigated two levels for this value. For the 2013 tower, we assumed a 30% ITC (current policy) as well as the anticipated 10% ITC likely to recommence at the end of 2016. For the 2020 tower case, results are based solely on application of the 10% ITC assuming no extension of the existing 30% credit past the 2016 end date.

Figure 3 shows the results for first-year PPA price for each of the TES/SM configurations described previously in Section 2. The figure portrays the typical trend found for CSP tower systems in which the LCOE and PPA price drops with increasing solar multiple and level of storage. This drop is due to better utilization of the power block (increased capacity factor), allowing amortization of capital costs over a greater number of megawatt hours.

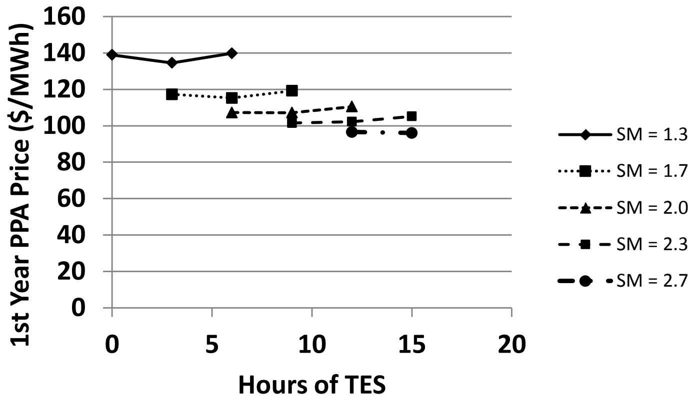


Fig. 3. 2013 first-year PPA price for 2013 molten-salt tower under assumed 30% investment tax credit.

Table 7 provides results for each of the technology configurations and appropriate ITC values, based on the same TES/SM values used for the operational and capacity value analyses.

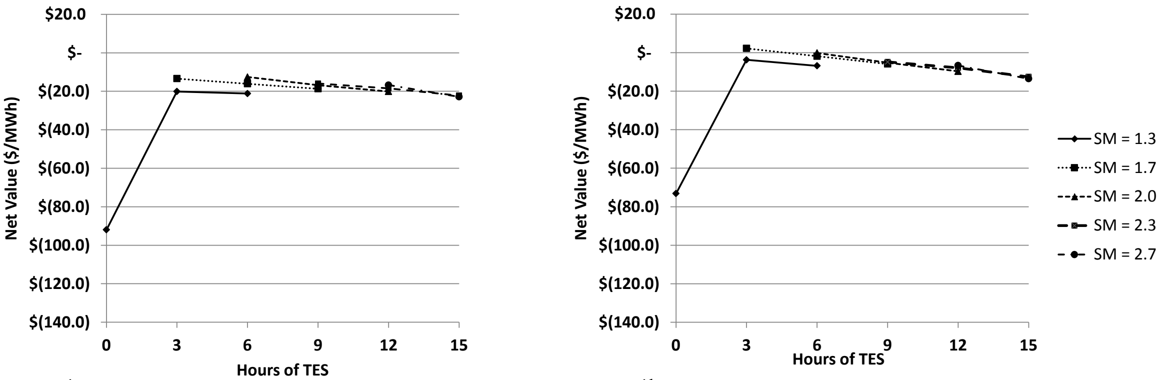
Table 7. 1st-Year PPA Price by Technology Type and Incentive

1st-Year PPA Price				
CSP Configuration		Technology/Incentive		
SM	*TES*	*2013 Tower (30%)*	*2013 Tower (10%)*	*2020 Tower (10%)*
1.3	0	$138.9	$170.3	$120.1
1.3	3	$134.5	$165.4	$119.0
1.3	6	$139.8	$172.27	$125.4
1.7	3	$117.2	$145.0	$101.6
1.7	6	$115.2	$142.8	$101.0

1.7	9	\$119.2	\$148.0	\$106.3
2	6	\$107.2	\$133.3	\$ 94.8
2	9	\$107.2	\$133.5	\$ 95.6
2	12	\$110.5	\$137.9	\$100.1
2.3	9	\$101.5	\$126.7	\$ 90.3
2.3	12	\$102.2	\$127.7	\$ 91.6
2.3	15	\$105.2	\$131.4	\$ 95.5
2.7	12	\$ 96.6	\$120.7	\$ 86.5
2.7	15	\$ 96.0	\$120.1	\$ 86.7

4.3 Net-value results

The net-system value is calculated by subtracting the first-year PPA prices in Table 7 from the total system value given by Table 6. Figures 4.a. and 4.b. graphically portray the results for both the 2013 and 2020 towers assuming 30% and 10% ITCs, respectively, and assuming the default natural gas price of \$4.38/MMBtu. The figures indicate that, although the power purchase prices described by Table 7 fall with increasing capacity factor, this effect is countered by the decrease in total grid value for such configurations. The overall result, somewhat counter-intuitive based on typical LCOE-based analyses, is that the net value reaches a maximum at relatively low storage levels (but sufficient levels to achieve nearly full capacity credit), followed by a moderate drop in value as the level of storage and solar multiple is increased.



4a. 4b.

Fig. 4. Net System Values for a 2013 molten-salt power tower integrated with a conventional Rankine cycle power block (4.a) and a 2020 hypothetical advanced molten-salt power tower integrated with a s-CO_2 power block (4.b). The 2013 results assume the current 2013 ITC. The 2020 results assume a 10% ITC anticipated to continue after 2016.

Table 10 provides the net-value results for each of the technology configurations, ITC assumptions, and natural gas price sensitivities investigated. While not a guarantee of financial viability, those configurations that achieve a net-value greater than zero would be positively considered from the standpoint of utilities, system operators, or regulators since the goal of such entities is to seek to maximize the net-benefit to the system. Within Table 10, positive values have been bolded for emphasis. The results indicate that, assuming today's natural gas prices and allowing for a fall back to the permanent 10% ITC, an advanced s-CO_2 based tower utilizing a conventional molten salt heat transfer fluid, can provide a positive net-benefit for a system configured as a peaking plant. For higher natural gas prices, positive net values are generated for both the 2013 (30% ITC) and 2020 (10% ITC) towers for a wide range of TES/SM configurations.

Table 10. Net Value (Total Value minus PPA Price) for 2013 and 2020 Tower Configurations and Varying Natural Gas Price

Net Value (Base NG)				
CSP Configuration		Technology/Incentive		
SM	*TES*	*2013 Tower (30%)*	*2013 Tower (10%)*	*2020 Tower (10%)*
1.3	0	$ (92.0)	$ (123.4)	$ (73.2)
1.3	3	$ (20.1)	$ (51.0)	$ (3.7)
1.3	6	$ (21.2)	$ (53.6)	$ (6.8)
1.7	3	$ (13.4)	$ (41.2)	**$ 2.2**
1.7	6	$ (16.1)	$ (43.6)	$ (1.8)
1.7	9	$ (18.7)	$ (47.5)	$ (5.0)
2	6	$ (12.6)	$ (38.7)	$ (0.1)
2	9	$ (16.8)	$ (43.2)	$ (5.2)
2	12	$ (20.1)	$ (47.5)	$ (9.7)
2.3	9	$ (16.0)	$ (41.2)	$ (4.8)
2.3	12	$ (18.5)	$ (43.9)	$ (7.9)
2.3	15	$ (22.2)	$ (48.5)	$ (12.6)
2.7	12	$ (16.7)	$ (40.9)	$ (6.7)
2.7	15	$ (22.8)	$ (46.9)	$ (13.5)
Net Value (1.5x NG)				
CSP Configuration		Technology/Incentive		
SM	*TES*	*2013 Tower (30%)*	*2013 Tower (10%)*	*2020 Tower (10%)*
1.3	0	$ (73.0)	$ (104.4)	$ (54.2)
1.3	3	**$ 3.4**	$ (27.4)	**$ 19.8**
1.3	6	**$ 1.0**	$ (31.5)	**$ 15.4**
1.7	3	**$ 9.8**	$ (17.9)	**$ 25.5**
1.7	6	**$ 8.6**	$ (19.0)	**$ 22.8**
1.7	9	**$ 4.5**	$ (24.3)	**$ 17.3**
2	6	**$ 9.7**	$ (16.4)	**$ 22.1**
2	9	**$ 6.7**	$ (19.7)	**$ 18.3**
2	12	**$ 2.4**	$ (24.9)	**$ 12.8**
2.3	9	**$ 6.2**	$ (19.0)	**$ 17.4**
2.3	12	**$ 3.3**	$ (22.1)	**$ 14.0**
2.3	15	$ (0.8)	$ (27.1)	**$ 8.8**
2.7	12	**$ 3.8**	$ (20.3)	**$ 13.9**
2.7	15	**$ 1.7**	$ (22.3)	**$ 11.0**
Net Value (2x NG)				
CSP Configuration		Technology/Incentive		
SM	*TES*	*2013 Tower (30%)*	*2013 Tower (10%)*	*2020 Tower (10%)*
1.3	0	$ (55.5)	$ (86.9)	$ (36.7)
1.3	3	**$ 21.7**	$ (9.2)	**$ 38.1**
1.3	6	**$ 21.7**	$ (10.7)	**$ 36.1**
1.7	3	**$ 30.5**	**$ 2.7**	**$ 46.1**
1.7	6	**$ 26.8**	$ (0.8)	**$ 41.0**
1.7	9	**$ 24.3**	$ (4.5)	**$ 37.1**
2	6	**$ 28.1**	**$ 2.0**	**$ 40.6**
2	9	**$ 23.1**	$ (3.2)	**$ 34.7**
2	12	**$ 18.9**	$ (8.5)	**$ 29.3**
2.3	9	**$ 24.7**	$ (0.5)	**$ 35.9**
2.3	12	**$ 20.3**	$ (5.1)	**$ 30.9**
2.3	15	**$ 15.7**	$ (10.5)	**$ 25.4**
2.7	12	**$ 22.0**	$ (2.2)	**$ 32.0**
2.7	15	**$ 17.2**	$ (6.8)	**$ 26.6**

5. Conclusions

For this study, we evaluated the operational and capacity value of multiple CSP tower configurations under an assumed 33% RPS scenario in California. Using NREL's System Advisor Model, we derived the first-year power purchase agreement price for multiple CSP technologies, including a 2013 case assuming cost and performance of today's molten-salt towers in addition to a hypothetical 2020 molten-salt tower configured with an advanced supercritical carbon-dioxide power block. The resulting net value, calculated by subtracting the first-year PPA price from the total system value, was analyzed for the 2013 and 2020 technologies scenarios and included sensitivities to natural gas price and investment tax credit.

The results indicate that—assuming today's natural gas prices and allowing for a fall back to the permanent 10% ITC—an advanced s-CO_2-based tower using a conventional molten-salt heat-transfer fluid can provide a positive net benefit for a system configured as a peaking plant (1.7 SM with 3 hours TES). For higher natural gas prices, positive net values are generated for both the 2013 (30% ITC) and 2020 (10% ITC) towers for a wide range of SM/TES configurations.

This paper provides results for scenarios specific to California; however, the methodologies described in this paper can be used to assess the net value for regions of interest worldwide. Such analyses are important if regional stakeholders are to fully capture the value of CSP-TES relative to less dispatchable renewable energy options.

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