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Integrated Solar Combined Cycle Power Plants: Paving the way for thermal solar

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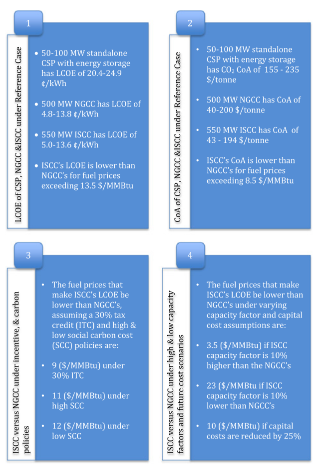
HIGHLIGHTS

- Quantified the economic and environmental benefits of an ISCC power plant.
- Compared with a CSP, an ISCC reduces the cost of solar electricity by 35–40%.
- ISCC is more economical than a NGCC for natural-gas prices above 13.5 $/MMBtu.
- ISCC achieves a lower Cost of Carbon Abatement for fuel prices above 8.5 $/MMBtu.
- ISCC's benefits relative to an NGCC are greatly dependent on their capacity factors.

GRAPHICAL ABSTRACT



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ABSTRACT

Integrated Solar Combined Cycle Power Plants (ISCCs), composed of a Concentrated Solar Power (CSP) plant and a Natural Gas-Fired Combined Cycle (NGCC) power plant, have been recently introduced in the power generation sector as a technology with the potential to simultaneously reduce fossil fuel usage and the costs of integrating solar power in an electricity system. This study quantifies the economic and environmental benefits of an ISCC power plant relative to a stand-alone CSP with energy storage, and a NGCC plant. The corresponding levelized cost of electricity (LCOE) and the Cost of Carbon Abatement (CoA) are estimated by simulating hourly operations for five U.S. locations with different solar resources and ambient temperature, under varying assumptions regarding natural gas prices, tax incentives, capacity factors, and capital costs. Results show that integrating the CSP into an ISCC reduces the LCOE of solar-generated electricity by 35–40% relative to a stand-alone CSP plant, and provides the additional benefit of dispatchability. An ISCC also outperforms a CSP with energy storage in terms of LCOE and CoA. The current LCOE of an ISCC is lower than that of a stand-alone NGCC when natural gas prices reach 13.5 $/MMBtu, while its CoA is lower at a fuel price of 8.5 $/MMBtu. Although, under low to moderate natural gas price conditions, a NGCC generates electricity and abates carbon emissions at a lower cost than an ISCC; small changes in the capacity factor of an ISCC relative to the NGCC, or capital cost reductions for the CSP components significantly tilt the balance in the ISCC's favor. Hence, this technology should be seriously considered as a cost-effective baseload electricity generation alternative to speed up the transition to sustainable energy systems.

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1. Introduction

The Integrated Solar Combined Cycle Power Plant (ISCC) has been introduced in the power generation sector as a technology with the potential to help reduce the costs of solar energy for electricity generation. An ISCC power plant combines a Concentrated Solar Power (CSP) plant and a Natural Gas-Fired Combined Cycle (NGCC) power plant. The CSP energy is used to either produce additional steam for use in the NGCC's steam turbine to generate electricity [1], or to heat the compressed air in the gas turbine before entering the combustion chamber [2]. ISCC plants effectively integrate solar power into the grid by circumventing the non-dispatchability of the CSP [3] and reducing operating and capital costs, with the possibility of increased operational flexibility when compared to a standalone NGCC [4].

The concept of the ISCC as a parabolic trough solar plant integrated with modern combined cycle power plants was initially proposed in the early 1990s by Luz Solar International, the builders of the SEGS trough plants in California 1,5. The first plant materializing this concept was the Archimede Project in Sicily Italy, which consists of two 380 MWe gas-fired combined cycle power plants and a 5 MWe parabolic trough solar field that uses molten salts as heat transfer fluid (HTF) [5]. As of 2015, there are at least 157 MW of thermal solar plants integrated with a natural gas combined cycle plant, including the 75 MW Martin Next Generation Solar Energy Center in Indiantown Florida, 20 MW ISCC Ain Beni Mathar in Morocco, 20 MW ISCC Hassi R'me in Algeria, 20 MW ISCC Kuraymat in Egypt and the 17 MW ISCC Yazd in Iran [6–9].

Previous literature offers valuable insights into the advantages of the ISCC technology and the best configurations, but the need for an analysis making use of the most recent data and offering comparative information with similar baseload electricity generation alternatives persists. Most previous studies evaluate the technical and economic advantages of the ISCC, explore different solar thermal technologies, and discuss alternative setups to optimize performance. Peterseim et al. [6] evaluated all suitable CSPs technologies for integration with Rankine cycle power plants. The study concluded that: (a) line focusing systems such as Fresnel and parabolic trough are ideal for integration of lower temperature steam (<400 °C), (b) Fresnel systems are the most efficient for medium temperatures (380–450 °C), and (c) Direct Steam Generation solar towers are the best for higher temperatures (>450 °C). Kelly et al. [10] studied two integrated plant designs using Gate Cycle modeling software and concluded that: (a) annual solar contributions of up to 12% in an ISCC offer economic advantages over conventional solar-only parabolic trough power plants, and (b) that the most efficient use of solar thermal energy is the production of high-pressure saturated steam for addition to the heat recovery steam generator. Rovira et al. [11] assessed a number of ISCC configurations with solar parabolic trough collectors and found that the direct steam generation (DSG) configuration is the best choice for solar energy integration although there may be problems with (a) the control of the solar field during solar radiation transients, (b) the two-phase flow inside the receiver tubes, and (c) temperature gradients in the receiver tubes. Montes et al. [12] and Nezammahalleh et al. [13] conducted techno-economic assessments of an ISCC using Direct Steam Generation (DSG) in parabolic trough collectors demonstrating the importance of optimizing the solar field size as a function of the power cycle capacity (i.e. the solar multiple) to improve daily operations, annual performance, and costs. Li and Yang [14] proposed and investigated a new ISCC system with a two-stage solar DSG input to increase the solar share. Compared with a one-stage ISCC plant, the two-stage ISCC presented better performance and increased net solar-to-electricity efficiency (to up to 30%). Recently, Mokheimer et al. [15] investigated the technical and economic feasibility of integrating a Parabolic Trough Collector (PTC) system with a gas turbine cogeneration system considering different generating capacities of gas turbine and areas of PTCs. They concluded that hybrid systems with gas turbine generating capacities less than 110 MWe result in a negligible increase in the LCOE but are more economically attractive compared to cogeneration coupled with a CO_2 capturing technology. Behar et al. [5] conducted a worldwide technical review of ISCC plants and the status of related research development and deployment (RD&D), and concluded that there has been an exponential increase in the RD&D especially on the DSG–ISCC technology which may offer better performance than the widely installed parabolic trough-ISCC plants.

Other studies discuss operational alternatives and present costs and benefits for extant ISCC plants in Egypt [7], Spain [8], and Algeria [9]. Antonanzas et al. [8] analyzed the overall potential for solar thermal integration in 51 NGCC plants in mainland Spain under different operating scenarios concluding that the ISCC technology offers enormous opportunity to improve yield and efficiency in peak periods and to reduce CO_2 emissions. The study analyzed the penalty of solar dumping when ISCC is operated in solar boosting mode and also gas turbine efficiency when ISCC is operated in solar dispatching mode. Also, Antonanzas et al. [16] looked at the feasibility of integrating CSP parabolic trough systems with 21 Algerian open cycle gas turbines and combined cycle gas turbines concluding that a yield increase of 24.9 GW h/year and CO_2 emission savings of 9.91 kton/year are feasible with solar field sizes ranging from 30 to 37 loops in combined cycle centrals. For open cycle gas turbines, a solar potential of 1085.7 GW h/year and CO_2 emission savings of 652.1 kton/year were found possible with annual solar electricity shares in the range of 3–4%.

Previous studies conducted a static analysis of the performance of ISCC plants without accounting for the temporal variation of solar energy production and other factors likely to significantly affect the economics of this technology. One exception is a study conducted by Dersch et al. [17] which compares the costs and CO_2 emissions of ISCC plants to both CSP and conventional combined cycle (CC) power plants, assuming different configurations and operating modes. By using hourly data of solar radiation and ambient conditions for a typical meteorological year in both Barstow, California and Tabernas, Spain, the authors conclude that (a) for the same location and operating conditions, ISCC plants have lower CO_2 emissions than CC plants, and (b) for baseload (i.e. 24 h operations), ISCC plants have lower costs and CO_2 emissions than CSP plants with supplementary firing. The other exception to the common ISCC static analyses is the work of Moore and Apt [18] who simulated one year of hourly operations of an ISCC located in Phoenix Arizona, receiving prices that vary in the same way as the median of all nodal hourly prices in California ISO. The plant is run to maximize hourly marginal profits so for every hour any of three situations occurs: (1) the plant runs only with natural gas (i.e. "at base load"); (2) the plant operates as an ISCC with both gas and whatever solar energy is available (i.e. "with duct firing"); or (3) the plant does not run at all. A parametric analysis that varies natural gas prices between 2 and 12 $/MMBtu and adjusts hourly electricity prices to reach annual averages between 35 and 85 ($/MW h), results in ISCC capacity factors of 3–90% and unsubsidized Levelized Cost of Electricity (LCOE) from the solar portion of the ISCC in the range 170–380 ($/MW h).

In the vein of [17] and [18], we simulate hourly operations of ISCC- configured for solar-dispatching operation mode-, NGCC and CSP plants providing baseload generation. Our goal is to present a comprehensive view of how this technology compares to other sources of baseload power when two important metrics for policy makers and industry investors are considered: LCOE and the cost of CO_2 abatement (CoA). Different from previous studies our analysis uses the most up-to-date data and considers the effect of ambient temperature, solar resources, and a range of fuel prices that could be possible in the future. It also examines the dramatic effect that plausible changes in capital costs, tax incentives and capacity factors can have in the profitability of ISCC. We conclude that the ISCC is a cost effective way to harness solar power and reduce air emissions from electricity generation. Hence, although only a relatively small amount of solar capacity share (3–15%) can be economically incorporated in an ISCC, including this technology in the several NGCC plants that may be built in the U.S. to replace coal-fired power plants is an alternative that should be seriously considered in regions with good solar resources.

2. Method

We consider an ISCC that integrates the most efficient NGCC and CSP technologies available in today's market, and estimate its LCOE, air-emissions, and CoA by simulating operations over one typical year in each of five possible U.S. locations. The ISCC is compared to a stand-alone NGCC and to a CSP with and without energy storage. A custom-made thermodynamic model of an ISCC plant composed of a 500-MW NGCC plant and a 50-MW solar field is developed to properly represent operations under different temperature and solar radiation conditions. Set in this way, the solar capacity share in the ISCC plant, which is defined in this paper as the ratio of CSP installed capacity to NGCC installed capacity, is 10% (i.e. 50 MW of the CSP divided by 500 MW of the NGCC). Depending on the location, this capacity will result in an annual solar electricity share (i.e. solar share of annual ISCC's electricity generation) of between 2.1% and 3.5%. Typically, the CSP capacity share of the ISCC plants installed around the world does not exceed 15% of the total nameplate capacity [5]. This is consistent with previous studies that show this share minimizes the steam turbine efficiency reduction when solar-generated steam is not available [10,19]. Our analysis of the tradeoffs between capital and operating costs for different CSP capacity shares also confirms that 10% is an optimal choice (See Supporting Information (SI) Section S.3.3).

The specifications of the NGCC plant (both the one integrated in the ISCC and the one examined as a stand-alone technology) are those of the GE FlexEfficiency-60 Combined Cycle power plant [20], while the solar component of the ISCC (i.e. solar field) is assumed to be identical to that of a CSP with parabolic trough solar collectors. Fig. 1 presents a schematic of the ISCC analyzed in this paper.

Although other CSP technologies, such as the linear Fresnel lens and solar tower, could be used as the solar component of the ISCC [21], we choose a parabolic trough system because it is a technology widely deployed today with an installed capacity six times larger than other CSP technologies combined [22], has an excellent operating history of more than 30 years [3,22], and offers the most economical alternative for large power plant applications [23]. We assume the CSP (both the one integrated into the ISCC and the stand-alone CSP analyzed) is similar to the 64 MW Nevada Solar One CSP Trough plant in Boulder city, NV [24].

2.1. NGCC assumptions

Consistent with the GE specifications, the NGCC plant is assumed to achieve 61% efficiency in typical conditions when generating electricity at 80% of its nameplate capacity or more [20], a ramp rate of 50 MW/min, a start-up time of less than 30 min, and an availability factor of 87% (see SI Section S.1 for details on the NGCC model). The capital cost of a 500 MW NGCC is assumed to be 917 k$/MW of net installed capacity while the fixed O&M cost is estimated to be 13.1–14.91 k$/MW annually [25–27]. We assume a range of 4–18 $/MMBtu for gas prices when calculating the LCOE and CoA, consistent with the AEO 2014 projections of natural gas prices rising from $4.52/MMBtu in 2014 to $13.82/MMBtu in 2040 under the reference case, and to $8.65/MMBtu and $18.6/MMBtu in 2040 under the high and low oil and gas resources cases respectively [25].

2.2. CSP assumptions

We assume the capital cost of the CSP is 4000 $/kW (in 2012 US dollars) which is the actual cost of the recently completed Genesis Solar Energy Project in Blythe, California [22,28] (see CSP modeling in SI Section S.2 and sensitivity on capital costs in Section 3.4.4). Having excellent solar resources and the optimal solar field size,

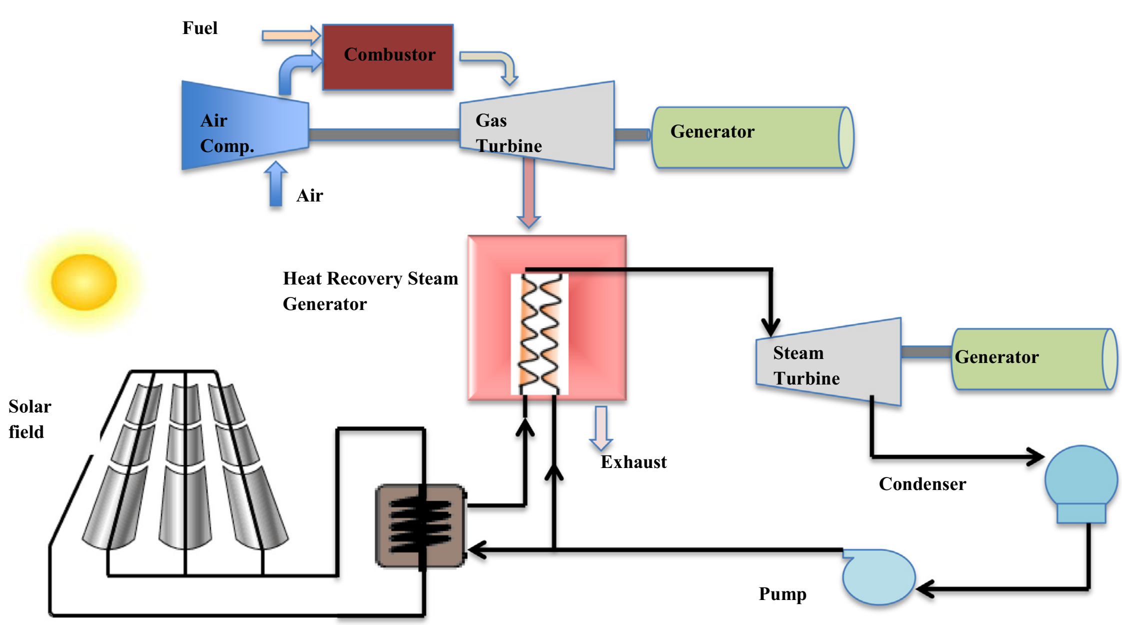

Fig. 1. Diagram of an ISCC plant.

the annual CSP plant capacity factor would be between 25% and 30% and the CSP plant would generate between 100 and 122 GW h/year [19,23]. The analysis of a stand-alone CSP assumes placement in Las Vegas, NV. For the analysis of a CSP plant with energy storage (i.e. CSP + ES), we assume the CSP is coupled with a properly sized Molten Salt System (MSS) – a thermal energy storage technology commercially available at unit storage cost of 80 $/kW ht [24].

2.3. ISCC assumptions

The ISCC power plant is assumed to operate in a dispatching mode where the solar steam generated by the CSP is augmented and expanded in the NGCC steam turbine to generate additional power. We choose to represent this mode of operation because of its economic and environmental advantages (see SI Section S.3.4 for more details). The ISCC under this study is composed of two gas turbines (each one has 165 MWe), heat recovery steam generators (HRSGs) that produce steam at high pressure (16,547 kPa), intermediate pressure (2482 kPa) and low pressure (552 kPa), a steam turbine (220 MWe), and a solar field (50 MWe). The technical and economic parameters of the ISCC studied are summarized in Table 1.

The solar field is comprised of parallel rows of Solar Collector Assemblies (SCA) and requires an area of 255 acres, where 74 acres (299,540 m^2) are used for the aperture reflective area (i.e. the area of the collector that reflects sunlight toward the receiver). SCAs supply thermal energy to produce steam to drive a steam turbine in a Rankine cycle with solar to thermal efficiency of 60.6%. The concentration factor of solar radiation on the absorber is about 80 (calculated by dividing reflector area by focal area) [29], and the maximum temperature in the absorber is about 400 °C. The solar field design-point adopted is based on an assumption of direct solar irradiance of 900 W/m^2 and air temperature of 25 °C. The parabolic trough plant is coupled to the high-pressure level in the HRSGs.

A thermodynamic model developed in MATLAB simulates plant operations by applying mass and energy balances to every component of the combined cycle and the parabolic trough collector field for different input data (see SI Sections S.1 and S.2). The model has been validated by comparing the NGCC simulation results with DOE/NETL cost and performance baseline estimates for NGCC plants [30] and also by comparing the CSP simulation results with NREL SAM model's output. The comparison of results is presented in the SI Section S.3.2.

To properly account for varying solar resources (as measured by the Direct Normal Irradiance DNI) and temperature conditions likely to affect the performance of the CSP component, it is assumed that the ISCC plant could be located in one of five different locations in the U.S.; Barstow, CA; Honolulu, HI; Las Vegas, NV; San Antonio, TX; and San Diego, CA. Hourly solar radiation data and hourly temperature for a typical year for these sites has been obtained from the NREL System Advisor Model (SAM) database [24] which generates a typical year data file based on satellite-derived data over the period 1998–2005. The annual average solar energy resource (DNI) and temperatures for each site are summarized in Table 2.

2.4. Levelized Cost of Electricity (LCOE) calculation

LCOE ¢/kW h for all the technologies considered in this study is estimated using Eq. (1):

$$LCOE = \frac{CC_{annual} + O\&M_{annual} + FC_{annual}}{E_{annual}} \tag{1}$$

where

CC_{annual} is the total annualized capital cost ($), obtained by multiplying the Capital Cost by the Fixed Charge Factor (FCF) which is a levelizing factor that depends on the expected life time of the investment and a number of financial variables. A Fixed Charge Factor (FCF) of 0.1128 (excluding any Investment Tax Credits) is assumed which is the default FCF used in [31]. This assumption is based on economic figures and equations explained in SI Section S.1.3.
$O\&M_{annual}$ is the annual operational & maintenance cost – both fixed and variable, excluding fuel costs-($)
FC_{annual} is the annual fuel expenses ($)
E_{annual} is the annual electricity generation (MW h)

2.5. Cost of Carbon Abatement (CoA) calculation

CoA in $/ton CO_2 for a technology k is estimated by using Eq. (2):

$$\textit{Cost of } CO_2 \textit{ abatement of technology } k \left(\frac{\$}{tonne}\right) = \frac{LCOE\,k - LCOE\,ref}{(CO_{2\,emissions\,rate\,ref}) - (CO_{2\,emissions\,rate\,k})} \tag{2}$$

Table 1
ISCC plant's technical and economic parameters.

Parameter	Value [45,46]	Parameter	Value
Overall gross plant capacity (MW)	550	NGCC capital cost (2012 $/kW)*	876–1050 [25–27] (917)
Gas turbine capacity (MW)	330	NGCC O&M fixed cost (2012 $/kW yr)*	13.1–14.91[25–27] (14)
HRSG capacity (MW)	220	NGCC O&M variable cost (2012 $/MW h)*	2–3.6 [25–27] (3)
Solar field capacity (MW)	50	CSP capital cost (2012 $/kW)*	3000–5067 [25,29,38,39] (4000)
Gas turbine isentropic efficiency (%)*	80–90 (90)	CSP fixed O&M cost (2012 $/kW yr)*	60–67.26 [25,47] (65)
Compressor isentropic efficiency (%)*	75–90 (87.5)	Discount rate (before tax) (%)	7.5
Gas turbine inlet temp. (°C)*	1280–1400 (1370)	Insurance rate (%)	0.5
Fuel higher heating value (kJ/kg)	52,288	Plant lifetime (years)	25
Air compressor outlet/inlet pressure ratio*	1–25 (18.5)	Real bond interest rate (%)	5.83
Steam turbine isentropic efficiency (%)*	80–90 (85%)	Real preferred stock return (%)	5.34
Steam turbine inlet temp. (°C)*	280–600 (570)	Real common stock return (%)	8.74
Steam turbine inlet pressure (kPa)*	12,755–17,237 (16,547)	Percent debt (%)	45
Boiler pressure (kPa)	17,237	Percent equity "preferred stock" (%)	10
Boiler efficiency (%)	80	Percent equity "common stock" (%)	45
Condenser pressure (kPa)*	3.45–13.79 (10.34)	Federal tax rate (%)	34
Condensate pump efficiency (%)*	75–90 (80)	State tax rate (%)	4.2
Solar field outlet oil temp. (°C)	390	Property tax rate (%)	2
ISCC capacity factor (%)	87	Inflation (%)	2.5

* Some parameters have a range of operating or estimated values. Values in parentheses are those used in all the base-case simulations.

Table 2
Descriptive statistics of solar resources and temperature for the typical year data reported in [24].

Location	Solar hours per day			Direct normal irradiance			Ambient temp. (°C)		
	Annual average	Range	Standard deviation	Annual average (kW h/m^2)	Daily range (W/m^2)	Standard deviation (W/m^2)	Annual average	Range	Standard deviation
Barstow, CA	9.3	0–13	4.0	2981	0–1016	395	20.1	1.2–41.9	9.4
Honolulu, HI	6.7	0–11	3.0	2102	0–965	326	23.7	9.6–26.4	1.3
Las Vegas, CA	8.8	0–13	3.1	2802	0–1004	387	18.9	−0.6 to 40.4	9.7
San Antonio, TX	5.4	0–11	3.5	1714	0–964	302	20.0	−1.6 to 38	8.1
San Diego, CA	6.7	0–12	3.2	2082	0–951	332	16.8	7.9–31.5	4.0

where $CO_{2\,emissions\,rate\,k}$ is the rate at which CO_2 is emitted by technology k, expressed in tonnes/MW h, and $CO_{2\,emissions\,rate\,ref}$ is the rate at which CO_2 is emitted from a reference technology. The estimates of CoA in this study assume a reference CO_2 emissions rate of 1950–2210 lb/MW h, which are the average emissions of coal-fired power plants observed in years 2007–2010 in the U.S. [32]. The LCOE of this reference technology $LCOE_{ref}$ is assumed to range between 2.5 (for an existing coal-fired power plant with no capital charges) and 5.6 ¢/kW h (for a coal plant still paying its capital costs) [31]. Although there is uncertainty about the emissions of the plants that are or will be shutdown or ramped down during the operation of an ISCC (i.e. uncertainty about emissions displaced), estimating the CoA relative to an average coal plant offers useful information particularly for comparison with other carbon abatement alternatives. Also it is worth noting that, for the purpose of comparing the ISCC's CoA relative to other dispatchable technologies such as the NGCC or CSP + Storage, any choice of reference technology in the CoA estimation yields identical results.

3. Results

3.1. Standalone Concentrated Solar Power (CSP)

The levelized cost of electricity (LCOE) of a standalone CSP located in Las Vegas, Nevada is 20–23 ¢/kW h. If a 50 MW CSP plant displaced the average U.S. coal-fired power plant in the US it would abate 103,487–117,285 tonnes of CO_2 annually and the abatement of CO_2 emissions would come at a cost of 150–215$/$CO_2$ tonne. If instead of replacing a coal plant the CSP replaced the highly efficient NGCC considered in this study, then it would reduce carbon emissions by only 0.34–0.40 tonne/MW h, which combined with an assumption of NG prices in the range 4–18 $/MMBtu, the range of the projected average NG prices under all AEO 2014 scenarios over the next 25 years, results in a CO_2 abatement cost CoA of 270–480 $/$CO_2$.

3.2. Concentrated Solar Power with Energy Storage (CSP + ES)

The costs and performance of a CSP equipped with different sizes of MSS ranging from 2 to 18 h of energy storage capacity located in Las Vegas, NV have been examined using the SAM model. In order to have a fully dispatchable CSP, the MSS should back up 300% of the solar field nameplate capacity, which would increase the LCOE from 20.4 to 24.9 ¢/kW h and the corresponding CO_2 abatement costs to 155–235 $/ton, assuming the emissions and LCOE of a reference plant equal to the average coal-fired power plant in the U.S.

3.3. Standalone NGCC

The LCOE ranges from 4.8 to 13.8 ¢/kW h when natural gas prices range from 4 to 18 $/MMBtu. Assuming the NGCC replaces a U.S. coal-fired power plant with average costs and emissions, its CO_2 abatement cost is 40–200 $/ton. These LCOE estimates assume the plant operates at a capacity factor equal to its availability.

3.4. Integrated Solar Combined Cycle (ISCC)

Results show that an ISCC reduces the costs of harnessing solar power for electricity generation. Integrating the solar component of a conventional parabolic trough CSP plant into a NGCC leads to significant reductions in the capital cost and operating and maintenance costs due to utilization of common equipment such as the steam turbine, heat sink and balance of plant (BOP) and also to the elimination of thermal inefficiencies from daily start-up and shut-down of solar steam-turbine. NREL [19] has estimated the expected reduction in the capital and O&M costs are about 28% and 67%, respectively. From our results we are able to estimate the reductions on capital and O&M as reductions in LCOE. Comparing the levelized cost of solar electricity (LCOE-solar) of a 50 MW CSP integrated into a NGCC (i.e. in an ISCC) with the 50 MW standalone CSP power plant described in Section 2.2, we find that the LCOE-solar of the ISCC is 35–40% less than that of a standalone CSP. For example, the LCOE-solar of an ISCC at Barstow, CA is about 11.3 ¢/kW h while the LCOE of a standalone CSP is 19.1 ¢/kW h.

3.4.1. ISCC efficiency reductions from partial loading during cloudy days and non-solar hours

An ISCC configured for solar-dispatching operation mode has a steam turbine capable of handling all the steam generated by the NGCC as well as the steam generated by the solar field when operating at full capacity. Hence the steam turbine will operate away from its optimal design point during nights or cloudy days when the input stream from the solar field is diminished or absent. For the ISCC considered in this study, at non-solar hours, the steam turbine will operate at 77% of its capacity (i.e. 170 MW out of its 220 MW of nameplate capacity) which, according to the Bartlett equation [33], results in an efficiency reduction of 0.01% (see Appendix A-1.2). The reduction is taken into account by the thermodynamic model used to simulate ISCC performance. For example, for an ISCC in Las Vegas, the total annual electricity generation – in a "typical year"- is estimated to be 3858 GW h/year from which 125 GW h/year are generated by the solar field. Thus, the solar generation contributes about 3.2% of the total electricity generated annually by the ISCC plant. Also, the electricity generation reduction in the steam turbine cycle due to inefficiencies that result from partial loading when the solar field goes off is 48.3 MW h/year.

3.4.2. Impact of solar resources and ambient temperature on ISCC performance

Fig. 2(a) depicts the difference in LCOE between the ISCC and NGCC plants at the selected sites and for different assumptions

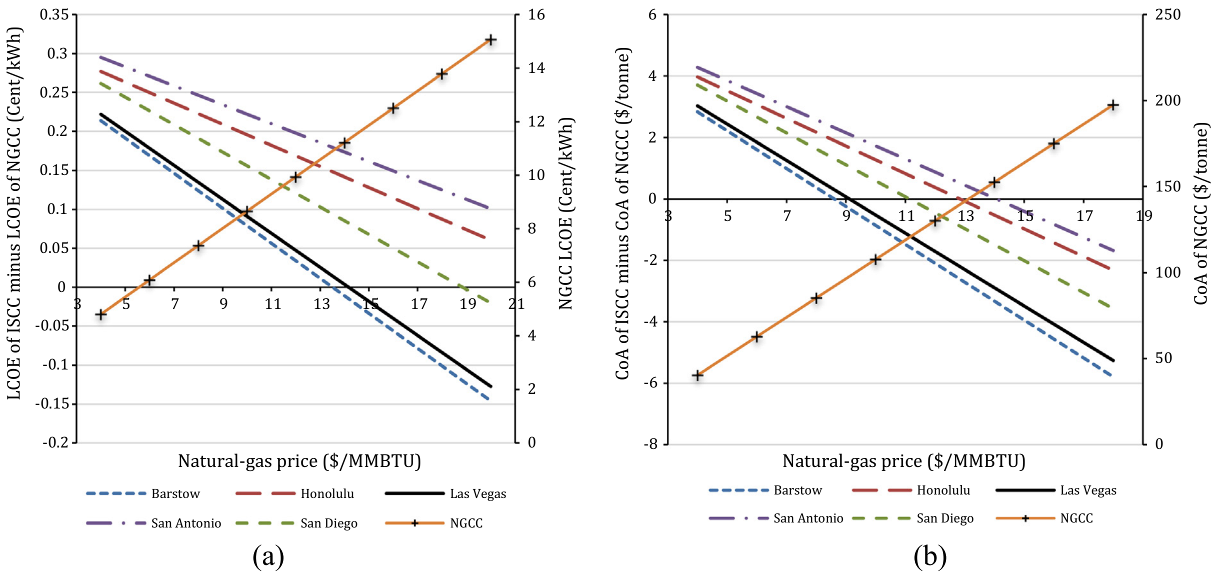

Fig. 2. Differences in LCOE (a) and CoA (b) of 500 MW NGCC & 550 MW ISCC plants at different fuel prices (assumed constant over 25 years), and locations. The fuel price at which the difference in LCOE (or CoA) is zero, is the "break-even natural gas price".

about natural gas prices. It shows that sites with higher average DNI, ceteris-paribus, result in lower LCOE. At a natural gas price of $6/MMBtu, the LCOE of an ISCC in Barstow, CA – the highest annual average DNI of the considered five sites at 2981 kW h/m^2 – is 6.26 ¢/kW h, while the LCOE of an identical plant located in San Antonio, TX -annual average DNI of 1714 kWh/m^2–is 6.36 ¢/kW h. The ambient temperature, on the other hand, has significant but conflicting impact on the two main components of the ISCC plant. While increasing the ambient temperature reduces the gas turbine efficiency, it boosts the solar field conversion efficiency. For the ISCC of this study, the percent reduction in gas turbine efficiency is lower than the percent increase in solar conversion efficiency; however, because of the small contribution of the solar field to the annual electricity generation at the ISCC, in general, higher average temperatures mean higher LCOEs. This is illustrated by the plants in Honolulu, HI (6.34 ¢/kW h) and San Diego, CA (6.31 ¢/kW h); two sites that almost have the same annual average DNI of 2080–2100 kW h/m^2, but differing average ambient temperatures of 23.7 °C and 16.8 °C, respectively. Indeed, while the turbine cycle efficiency operating at Honolulu (23.7 °C) is 0.69% lower than when operating at San Diego (16.8 °C) (consistent with results reported by [34,35]), the electricity generation of the solar field at Honolulu is 1.4% higher. However, because the contribution of the solar field to the annual electricity generation at the ISCC plant is less than 3%, a 1.4% increase in the electricity from the solar field results on just a 0.042% increase in total electricity generation.

While comparing LCOE gives information about the economic benefits of an ISCC under high natural gas prices, it fails to account for the ISCC's environmental superiority in reducing CO_2 and other emissions. Fig. 2(b) shows the CoA of an ISCC in the five considered locations and a NGCC, relative to the average U.S. coal-fired power plant. The figure shows the natural gas prices that are required for the ISCC and the NGCC to have identical CoA (i.e. the breakeven natural gas prices).

Interestingly, the breakeven NG prices found for CoA are much lower than those for LCOE. For example, while $13.5/MMBtu is the breakeven NG price for LCOE at Barstow, CA, just $8.5/MMBtu is the breakeven NG price for CoA at this location.

Another way to compare the ISCC and NGCC accounting for their differences in CO_2 emissions is by assuming a carbon price. Fig. 3 depicts the LCOE of ISCC at Las Vegas, NV, assuming carbon

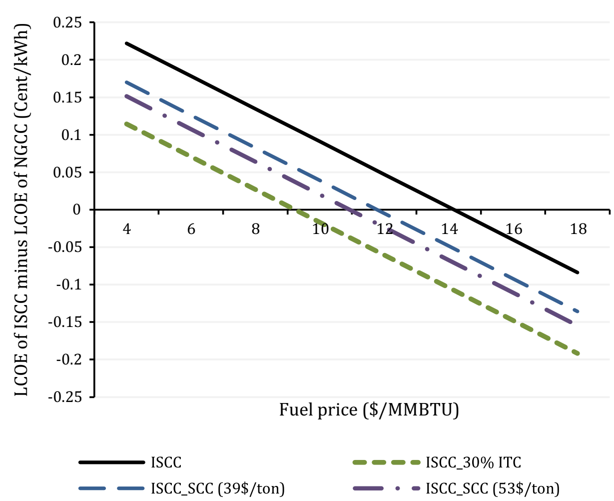

Fig. 3. Difference in the LCOE of 550 MW ISCC plant and LCOE of 500 MW NGCC at Las Vegas, NV, under different fuel prices, carbon prices, with and without ITC.

prices of $39 and $53 per tonne which are representative of the estimated social cost of carbon (SCC) in 2015, and of the average SCC over the years of 2015–2040 [36]. The figure also shows the effect of a 30% reduction in capital costs due to the Solar Investment Tax Credit (ITC) which provides investors with a 30% tax credit for installation expenses of qualifying renewable energy facilities including CSP plants installed by the end of 2016.

3.4.3. Effect of capacity factors in the comparison of LCOE and CoA of different technologies

So far, the LCOE estimates presented assume the plants operate at a capacity factor equal to their availability. This assumption fails to capture the fact that, instead of operating as baseload plants, they may be ramped up and down by an electricity system operator to balance electrical demand and supply. Made uniformly across the plants compared, this assumption does not affect their relative profitability, however, it ignores the fact that differences in marginal costs and operational flexibility will determine the ultimate dispatch order, affecting capacity factors and LCOE values.

For example, a NGCC that is dispatched less than an ISCC, will have a lower capacity factor and hence, relatively higher LCOE values compared to the ISCC. In general, because of its zero marginal cost, a CSP with energy storage (ES) would be dispatched before a NGCC or ISCC. So for the purposes of estimating the relative LCOE and CoA costs, it is safe to assume that the capacity factor of the CSP + ES is equal to its availability. There is not a clear indication of the relative dispatch order between the NGCC and the ISCC. An accurate estimation of the capacity factor of the NGCC and ISCC in a power system requires simulation of balancing authority operations and/or electricity market outcomes using unit commitment/economic dispatch models [37] that properly account for the need to balance generation with time-varying electrical load, and for the costs and performance of all power generators when dispatched at different output levels.

To appreciate the difficulty of correctly inferring the relative capacity factors of the ISCC and NGCC without a proper modeling framework, it is useful to consider that given that the marginal costs of the NGCC are lower than those of the ISCC at non-solar hours, and higher during solar hours, one could conclude that in cases of lower electrical demand, the ISCC should operate during the day and shutdown at night when the NGCC can operate more efficiently. However, this conclusion may be wrong as it does not account for path-dependencies that are considered in a multi-period optimization framework. A cold start of the ISCC in the morning could offset the gains from reduced natural gas consumption during the day. It may be that the systems' costs over the full day period are minimized when the ISCC is kept operating at night even if its fuel efficiency is lower than that of the NGCC, because this avoids the morning start-up costs and takes advantage of the low marginal costs of the ISCC during solar hours.

To explore how the LCOE and CoA comparisons would change we consider higher and lower ISCC's capacity factor relative to a NGCC plant. We assume that the change in capacity factor does not affect the ISCC's efficiency but instead changes the amount of time it remains shutdown, affecting in the same proportion, its electrical output and operating variable costs. The results, as depicted in Fig. 4(a) and (b), show that the change in the capacity factor has a significant impact on the LCOE and CoA. As the capacity factor of the ISCC is 10% higher than the capacity factor of the NGCC, the CoA and LCOE of the ISCC are less than those of the NGCC for natural gas prices in the range considered (i.e. 4–18 $/MMBtu). On the contrary, when the ISCC's annual capacity factor is lower than that of the NGCC by 10%, the LCOE of the ISCC is higher than the LCOE of the NGCC for all natural gas prices in the range 4–18 $/MMBtu, while the CoA of the ISCC is only lower than the CoA of the NGCC for gas prices that exceed 17 $/MMBtu. If the capacity factor of ISCC is just 5% higher than that of the NGCC, the breakeven gas prices for CoA and LCOE of the ISCC are about $5.5/MMBtu and $8/MMBtu, respectively.

3.4.4. Uncertainty on future capital costs of a CSP and its impact on relative LCOE and CoA estimates

Estimates of the capital costs of a CSP plant reported in the literature are between 3000 and 5067 2012$/kWe [25,28,29,38–41]. IEA [38] estimates the capital cost of a CSP plant in 2014 to be around 4200 $/kW, decreasing to 3000 $/kW by 2020. Similarly, a study published by the International Renewable Energy Agency (IRENA) in 2013 reported that the costs of installed parabolic trough systems were 3400–4600 $/kW for load factors of 20–27% [39], and projected a 30–50% reduction in capital costs by 2020 due to technological learning and economies of scale following the increasing deployment of CSPs. This projection of capital cost reductions was also consistent with the ambitions of the SunShot Initiative, an aggressive R&D plan launched by the U.S. DOE in 2011 [41], to make large-scale solar energy systems cost competitive (6 cents/kW h or less) without subsidies, by the end of the decade. This would have required a reduction of more than 50% in capital costs, estimated to be about $4000/kW in early 2012. However, during the last 4 years, the EIA estimates of capital costs reported in the Annual Energy Outlook reports (AEO) for a CSP have been significantly revised up and down, due to changes in both the forecast of deployment, and the expected cost reductions that would result from each unit of deployment [42,43].

To explore the effect that lower CSP costs would have on ISCC economics, Fig. 5(a) and (b) shows how the breakeven NG price changes – from the LCOE and CoA perspectives- when the capital cost of a CSP is assumed to be on the low range of the capital cost estimates (i.e. $3000/kWe). At this lower CSP capital cost case, the LCOE of an ISCC located in places with excellent solar resources areas such as Barstow, CA and Las Vegas, NV is found to be 6.18 ¢/kW h (at a natural gas price of $6/MMBtu) compared with

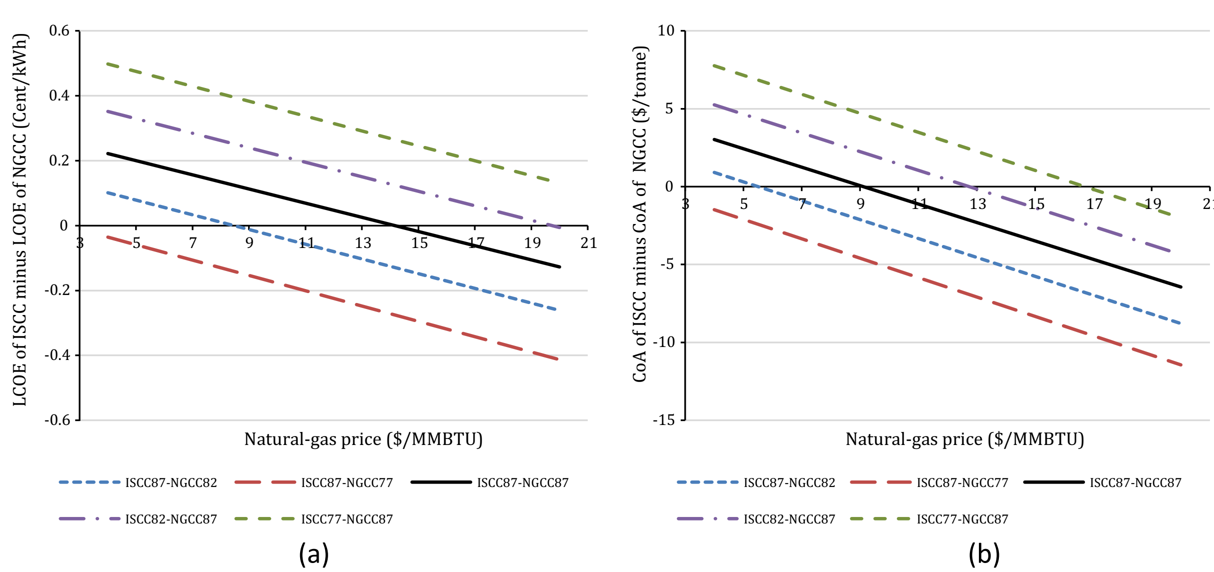

Fig. 4. Difference in LCOE (a) and CoA (b) for 550 MW ISCC Plants and 500 MW NGCC at different capacity factors of ISCC and NGCC. The number after the plant type refers to capacity factor. For example, ISCC87 refers to an ISCC operated at an 87% capacity factor.

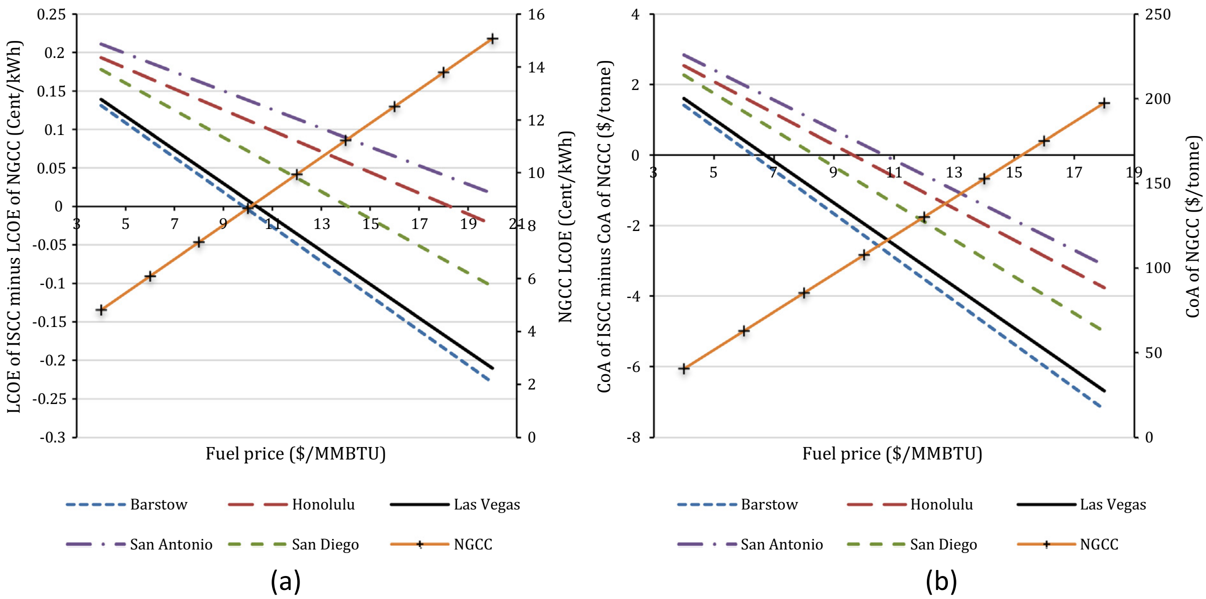

Fig. 5. Differences in LCOE (a) and CoA (b) between 500 MW NGCC & 550 MW ISCC plants for different fuel prices and locations, assuming a CSP capital cost of 3000 $/kW.

Table 3
NGCC, ISCC, CSP and CSP + ES comparisons summary.

	NGCC[a]		ISCC[a]		CSP[a]	CSP + ES[b]	
	@4 $/MMBtu	@18 $/MMBtu	@4 $/MMBtu	@18 $/MMBtu	No storage	2 h ES	18 h ES
Nameplate Capacity (MW)	500	500	550	550	50	50	50
LCOE[c] (Cent/KW h)	4.8	13.8	5.0	13.7	19.94	20.42	24.9
CoA[d] ($/ton)	40	198	43	192	152	157	205

[a] Base-case assumptions as reported in Table 1.
[b] Cost assumptions as reported in Section 2.2.
[c] LCOE calculated as described in Section 2.4.
[d] The CoA as described in Section 2.5, assuming that these technologies are replacing a coal-fired power plant (with no capital charges) whose LCOE is 2.5 ¢/kW h, and CO_2 emissions rate is 2080 lb/MW h, which is the average emission rate of coal-fired power plants observed in years 2007–2010 in the U.S. [32].

6.26 ¢/kW h in the base case (refer to Section 3.4.2). Accordingly, the breakeven gas prices for CoA and LCOE of ISCC become about $6.5/MMBtu and $10/MMBtu, respectively. In comparison, the breakeven gas prices for CoA and LCOE of ISCC in the base case are $8.5/MMBtu and $13.5/MMBtu, respectively.

4. Discussion

Table 3 summarizes the comparison between NGCC, ISCC, CSP and CSP + ES technologies for the base-case assumptions on costs, capacity factors and emissions reported in Section 2, and assuming they are all located at Las Vegas, NV. At current U.S. NG prices (below 4 $/MMBtu), assuming identical capacity factors, and in the absence of a carbon price, the ISCC is not cost competitive with a NGCC plant, so investors considering this technology must have other incentives such as the need to comply with Renewable Portfolio Standard (RPS) targets. Indeed, the most cost effective way to reduce the electricity costs of a CSP is by coupling it with a NGCC into an ISCC system. The levelized cost of electricity from a CSP that is part of an ISCC plant is 35–40% lower than the LCOE of a stand-alone CSP. Also, the ISCC provides a modest hedge against high natural gas price fluctuations since the break-even natural gas price assuming excellent solar resources such as those in Barstow, CA and Las Vegas, NV varies between 13.5 $/MMBtu and 14 $/MMBtu which are high values, but not implausible as it can be judged from the prices projected by EIA [25] under the Low Oil and Gas Resource Scenario.

The advantages of an ISCC over a NGCC are clearer when CO_2 emissions are considered. In a world where the goal is to reduce CO_2 emissions at the lowest possible cost, an ISCC in Barstow would be more economic than a NGCC for natural gas prices above 8.5 $/MMBtu. If the current scheme of the solar investment tax credit (ITC) [44], which provides a 30% tax credit for projects that are placed in service prior to January 2017, was extended, the LCOE of the CSP and ISCC would be reduced by 25–28% and 3–4%, respectively, which would make the ISCC more economical than a NGCC at fuel prices in the range 8.5–9.5 $/MMBtu, even in the absence of a carbon price. (See a Table of LCOE and CoA values in S.I. Section S.4.)

5. Conclusion

This study provides a comparative assessment of the economic and carbon abatement advantages of ISCC plants, a technology that integrates solar thermal energy into efficient and widely installed natural gas combined cycle power plants. The benefits of integration include reduction in the capital and fixed and variable operations and maintenance costs resulting from shared equipment and personnel, and from CSP and NGCC efficiency improvements.

The analysis shows that the ISCC is a much better way to harness thermal solar electricity than a stand-alone CSP or a CSP with energy storage. However, under low and moderate natural gas prices and in the absence of carbon prices, capacity factor differences or subsidies, the NGCC generates electricity at lower costs. Considering a price for carbon emissions would significantly reduce the gap between ISCC and NGCC LCOEs and would make the breakeven gas price to be in the range of 10.5–12 $/MMBtu at locations with excellent solar resources. Breakeven gas prices would be even lower, in the range 8.5–9.5 $/MMBtu under the 30% ITC program.

The ISCC environmental advantages can be further appreciated when looking at its ability to reduce the costs of carbon abatement. The CoA of an ISCC is lower than that of a CSP and NGCC in locations with good solar resources, when natural gas prices are 8.5–9 $/MMBtu. If the capacity factor of the ISCC were 10% higher than the capacity factor of a NGCC, then its CoA would be lower – even if natural gas is priced at 4 $/MMBtu.

If the CSP capital costs were to go down to $3000/kW, a plausible event in the next decade, then the ISCC plant would be more competitive with a lower LCOE than a NGCC for gas prices in the range of 9.5–10.5 $/MMBtu, even if there are no subsidies or carbon pricing. The CoA of the ISCC would be competitive for NG prices at 6.5 $/MMBtu. Such break-even gas prices could be much lower if CSP achieves higher capital cost reduction as expected by DOE, IEA and IRENA.

We conclude that although only a relatively small amount of solar capacity share (3–15%) can be economically incorporated in an ISCC, deploying this technology in the several NGCC plants potentially built in the U.S. to replace coal-fired power plants is an alternative that should be seriously considered in regions with good solar resources. The results presented can be used by policy makers and investors in an analysis considering a diverse set of scenarios with differing future fuel prices, air emissions regulations, and power plant dispatch practices.

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Appendix A. Supplementary material

Supplementary data associated with this article can be found, in the online version, at http://dx.doi.org/10.1016/j.apenergy.2016.02.083.

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