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Working Paper Series

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AUGUST 2021

CEEPR WP 2021-013

MASSACHUSETTS INSTITUTE OF TECHNOLOGY

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July 2021

Abstract
The cost and revenue earnings potential of alternative power generation sources has shifted considerably in recent years. Here we introduce the concept of Levelized Profit Margins (LPM) to capture the changing unit economics of both intermittent and dispatchable generation technologies. We apply this framework in the context of the California and Texas wholesale power markets. Our LPM estimates indicate that solar photovoltaic and wind power have both substantially improved their competitive position over the years 2012–2019, primarily due to falling life-cycle costs of production. In California, these gains far outweigh an emerging "cannibalization" trend that results from substantial additions of solar power having made energy less valuable in the middle of the day. We also find the competitiveness of natural gas power plants to have either improved or held steady. For this generation technology, declining capacity utilization rates have effectively been counterbalanced by a "dispatchability price premium" that reflects the growing market share of intermittent renewables.

Keywords: Renewable Energy, Intermittency, Dispatchable Power, Levelized Cost, Profit Margins
JEL Codes: M1, O33, Q41, Q42, Q48, Q54, Q55

1 Introduction

The costs of replacing dispatchable power sources based on fossil fuels with intermittent renewable power sources remain controversial. The life-cycle cost of renewables, in particular wind and solar power, is known to have fallen substantially over time[1–5]. Once deployed, these power sources also have effective priority in the marketplace due to their zero short-run production cost. In contrast, the life-cycle cost of traditional dispatchable generation sources tends to increase due to lower capacity utilization as these facilities are increasingly relegated to delivering output during hours when intermittent renewables are not available[6;7]. While all of these cost effects favor renewable power, countervailing effects emerge on the revenue side[8;9]. First, renewables increasingly experience a "cannibalization" effect in jurisdictions where significant additions of wind or solar power capacity cause market prices to fall during hours when renewable sources are at peak capacity[10–13]. A second effect favoring the value generated by dispatchable energy sources is the price premium they earn at times of limited supply capacity due to the intermittency of renewables[6;14;15].

This paper provides an integrated assessment of the cost and value dynamics of solar photovoltaic (PV), onshore wind, and natural gas combined-cycle (NGCC) power plants in the context of the wholesale electricity markets in Texas and California. Our empirical findings are based on a novel metric termed the *Levelized Profit Margin* (LPM). This metric is shown to capture the relevant unit economics in terms of dollars per kilowatt-hour (kWh) for assessing the competitiveness of alternative power generation technologies. Key to the calculation of this profit margin is that the average market price for electricity in a particular year and jurisdiction is adjusted by a technology-specific factor that captures the covariance between real-time fluctuations in electricity prices and optimized capacity utilization rates. The economic profitability of a power generation facility thus hinges on a weighted average of the future technology-adjusted unit revenues to exceed the life-cycle cost of energy generation. A dynamic LPM analysis thus integrates the countervailing competitive effects due to technological improvements, shifts in capacity utilization, cannibalization, and the dispatchability price premium.

Our findings indicate that for the most part new capacity investments in both renewables or natural gas plants undertaken during the years 2012–2019 are thus far not on track to become economically profitable. This finding may reflect that new investments were based on criteria that extend beyond expected net present values, such as renewable portfolio standards in California or the presence of "impact investors", such as technology firms investing in renewable energy projects[16;17].

At the same time, our results indicate that the estimated LPMs of new wind and solar energy projects have improved considerably and, by 2019, approached or exceeded the break-even value of zero. This finding is primarily due to substantial reductions in the life-cycle costs of these power sources. In California, the LPM improvements of solar PV have been partially offset by a tangible cannibalization effect[18;19]. In contrast, solar PV has achieved a growing price premium in Texas, a state where solar power today still has a relatively modest market share.

For NGCC power plants in California, we find that falling capacity utilization rates have been counterbalanced by increasing dispatchability price premia. These two countervailing trends have resulted in steady but distinctly negative LPMs. In Texas, by contrast, profit margins for NGCC plants have improved due to higher utilization rates at times of higher power prices. This finding is consistent with the general observation that in Texas natural gas and wind power have gradually replaced coal-fired generation[20].

2 Unit Economics of Power Generation Plants

Our model framework considers a market for electricity where prices are determined hourly based on supply and demand. Electricity supply is provided by competing power generation technologies that differ in terms of cost and the ability to generate electricity at specific points in time. Individual suppliers are assumed to be price-takers who can idle their capacity during times when the prevailing market price falls below the short-run marginal cost. A comprehensive list of all symbols and acronyms is provided in Supplementary Table 1.

On the cost side, alternative generation technologies can be ranked in terms of the Levelized Cost of Electricity (LCOE)[21]. This metric aggregates a share of upfront capacity expenditures and all periodic cash outflows after taxes to arrive at the unit cost of 1 kWh of electricity for a facility that has a life cycle of T years[22]. A critical variable in calculating the LCOE is the anticipated number of hours that the facility will be generating power. Let CF_i denote the share of the available capacity that is expected to be utilized on average in year i. To highlight the dependence of the LCOE on the anticipated sequence of future capacity factors $\vec{CF} \equiv (CF_1, ..., CF_T)$, we use the notation $LCOE(\vec{CF})$. The formal definition of the LCOE (see *Methods*) shows that if all electricity output generated over the entire lifetime of the facility were to be sold for $LCOE(\vec{CF})$ per kWh, an investor would break even, because the stream of discounted future after-tax cash flows will be exactly zero.

On the revenue side, let $p_i(t)$ denote the market price for electricity per kWh at which power is sold at time t of year i. Here, $t \in [0, m]$ hours, with $m = 8,760$ hours per year. In addition to the instantaneous market price $p_i(t)$, wind power in the United States (U.S.) is eligible for production tax credits in the after-tax amount of PTC_i per kWh of power generated in year i[23].

Our base model assumes that the capacity utilization factor can be chosen flexibly at each point in time, subject to not exceeding an upper bound $b(t) \in [0, 1]$. For a dispatchable energy source $b(t) = 1$ for all t, while for intermittent renewable sources the upper bound $b(t)$ is determined exogenously by the availability of the natural resource, i.e., solar insolation or wind speed. Our base model here ignores frictions such as maintenance or delays in the up- or down-ramping of traditional baseload generation facilities, like nuclear or coal-fired power plants. The base model is readily extended to incorporate such frictions[24].

The optimized capacity factor $CF_i^*(t)$ at time t in year i is chosen so as to maximize:

$$\big[p_i(t) + PTC_i - w_i\big] \cdot CF_i(t) \quad \text{subject to:} \quad 0 \leq CF_i(t) \leq b(t), \tag{1}$$

where w_i denotes the variable costs incurred during year i. For traditional generation technology, these costs include fuel, labor, and possibly charges for carbon dioxide (CO_2) emissions, while for intermittent renewables, they are effectively zero. Thus, $CF_i^*(t) = b(t)$ if $p_i(t) + PTC_i \geq w_i$, while $CF_i^*(t) = 0$ otherwise. This capacity utilization rule reflects the "merit-order approach" in electricity markets: if a particular plant produces at capacity, other plants with a lower short-run unit cost w_i will do the same.

To reflect that a technology in a given market environment will be more valuable if it can achieve higher capacity utilization during periods of relatively high power prices, let $\epsilon_i^*(t)$ denote the multiplicative deviation of $CF_i^*(t)$ from the annual average value CF_i^*, while $\mu_i(t)$ represents the deviation factor of $p_i(t)$ from the annual average price, p_i. Thus

$$\epsilon_i^*(t) \cdot CF_i^* \equiv CF_i^*(t), \text{ and } \mu_i(t) \cdot p_i \equiv p_i(t), \tag{2}$$

where

$$\frac{1}{m}\int_0^m \epsilon_i^*(t)\, dt = \frac{1}{m}\int_0^m \mu_i(t) dt = 1.$$

Synergies (positive or negative) between prevailing market prices and capacity utilization at select hours of the year can then be captured by the technology-specific *co-variation coefficients*:

$$\Gamma_i^* \equiv \frac{1}{m} \int_0^m \epsilon_i^*(t) \cdot \mu_i(t)\, dt. \tag{3}$$

The adjusted average unit revenue in year i of a particular generation technology is given by $\Gamma_i^* \cdot p_i$. By construction, Γ_i^* is above (below) 1.0 whenever a facility produces the majority of its output during periods of above-average (below-average) electricity prices. In contrast, Γ_i^* would be equal to 1.0 if either all energy is sold at a constant price, or the facility operates at constant capacity throughout the year[25;26].

The annual *Levelized Profit Margin* is the difference between the adjusted unit revenue, $\Gamma_i^* \cdot p_i$, in year i and the LCOE. The significance of this unit profit measure is that investment in a particular energy generation technology is economically profitable, i.e., generates a positive net present value for a given market environment, if the aggregate LPM, defined as a properly weighted average of the annual LPMs, is positive. To state this result formally (see *Methods* for the proof), we denote the applicable cost of capital by r and the corresponding discount factor by $\gamma = \frac{1}{1+r}$. Since for some generation technologies productive capacity degrades over time, we introduce the degradation factor x_i, representing the fraction of the initial capacity that is still available in year i.

Proposition: *Given a trajectory of future annual electricity price distributions,* $(p_1(\cdot), ..., p_T(\cdot))$, *and the corresponding optimized annual capacity factors* $\vec{CF}^* \equiv (CF_1^*, ..., CF_T^*)$, *investment in a particular power generation technology is economically profitable if and only if:*

$$LPM \equiv \sum_{i=1}^{T} \beta_i^* \cdot [\Gamma_i^* \cdot p_i + PTC_i] - LCOE(\vec{CF}^*) \geq 0, \tag{4}$$

where $\beta_i^* \equiv \frac{CF_i^* \cdot x_i \cdot \gamma^i}{\sum_{j=1}^{T} CF_j^* \cdot x_j \cdot \gamma^j}$.

Since the capacity factors of intermittent energy sources with zero short-run marginal cost are exogenous, both the weights β_i^* and the LCOE are fixed and effectively sunk at the time of investment for wind and solar PV facilities. The revenue terms, $\Gamma_i^* \cdot p_i$, reflect an investor's expectation regarding the average future prices as well as the degree to which hourly fluctuations in those prices co-vary with a higher capacity utilization for the technology in question. For dispatchable generation technologies, both future revenue and cost depend on the optimized capacity factors, reflecting the share of hours for which the prevailing market price exceeds the short-run marginal cost.

The aggregate LPM reduces to a single annual profit margin in the hypothetical scenario where both the distributions of prices $p_i(t)$ and the unit variable costs w_i are expected to be constant across the years. In such a "stationary environment", the aggregate LPM is given by:

$$LPM^o = \Gamma^* \cdot p + ptc - LCOE(CF^*),$$

where $ptc \equiv \sum_{i=1}^{T} \frac{x_i \cdot \gamma^i}{\sum_{j=1}^{T} x_j \cdot \gamma^j} \cdot PTC_i$. For stationary environments, we thus obtain a concise condition for a competitive equilibrium with normal, that is, zero LPMs: the ratios $\frac{LCOE(CF^*)-ptc}{\Gamma^*}$ must be the same for all active generation technologies and equal to the average market price, p. For the reasons explained above, we do not expect the zero economic profit condition to hold in either Texas or California. Nonetheless, we find that for the generation technologies considered in our empirical analysis the LPMs generally do approach the benchmark value of zero by the year 2019.

3 Market Dynamics in California and Texas

This section reports numerical values for the main constructs underlying the levelized profit margins. We do so for natural gas combined-cycle turbines as well as utility-scale solar PV and onshore wind power installations. Our calculations are based on the day-ahead wholesale markets in California and Texas. Both states have deregulated their electricity markets and traditionally obtained a significant share of their electricity from natural gas. Furthermore, California's considerable investments in renewable energy have focused on solar PV, while wind power became the dominant renewable source in Texas[27]. As detailed in *Methods*, our calculations rely on data collected from multiple sources including industry databases, technical reports, and journal articles. For these sources, the requisite data became available in their entirety in the year 2012.

Table 1 shows the trajectory of the main cost and price parameters for the years 2012–2019 (details in *Methods*). The decline in variable costs of NGCC turbines in Texas reflects the impact of hydraulic fracking on the price of natural gas[28]. While NGCC plants in California also experienced falling fuel costs, the resulting variable cost figures remained almost unchanged because of rising CO_2 emission charges under California's cap-and-trade system[29]. NGCC plants in Texas experienced slightly increasing capacity factors and co-variation coefficients that were consistently above one, as these plants began to substitute for coal-based power generation[20]. In contrast, NGCC plants in California experienced a relegation effect in terms of falling utilization rates as renewables expanded their market share[6]. This comports with the notion that gas power plants were crowded out by intermittent renewables whenever these were available[30]. At the same time, the corresponding drop in capacity factors was counterbalanced by rising price premia in the form of co-variation coefficients increasing from about 1.0 to about 1.2.

Table 1. Dynamics of the central cost and price parameters.

		NGCC			Solar PV			Wind			
Year	p_i	w_i	CF_i^*	Γ_i^*	v	CF_i^*	Γ_i^*	v	CF_i^*	Γ_i^*	ptc
California											
2012	3.17	2.87	58.75	1.06	4,088	20.83	1.19	2,532	32.13	0.94	2.04
2013	4.48	4.06	55.59	1.03	3,504	21.78	1.06	2,382	34.25	0.97	2.08
2014	5.01	4.56	54.40	1.04	2,967	26.75	1.01	2,198	31.62	0.99	2.05
2015	3.37	3.11	53.80	1.05	2,593	27.67	0.95	2,000	30.99	0.99	2.05
2016	2.96	2.93	44.83	1.11	2,161	27.67	0.90	2,044	33.69	0.98	2.05
2017	3.48	3.41	39.94	1.19	1,986	29.23	0.81	1,959	32.44	0.96	1.67
2018	3.96	3.54	43.45	1.19	1,565	29.59	0.81	1,747	37.74	0.99	1.07
2019	3.55	3.39	42.61	1.15	1,343	28.69	0.70	1,678	34.70	0.92	0.70
Texas											
2012	3.01	2.54	52.77	1.11	3,838	21.78	1.45	2,377	39.76	0.89	1.86
2013	3.49	3.10	50.48	1.09	3,289	19.25	1.20	2,236	39.11	0.95	1.89
2014	4.16	3.50	50.11	1.10	2,785	20.82	1.16	2,063	37.72	0.92	1.87
2015	2.74	2.23	56.73	1.10	2,434	20.02	1.35	1,877	33.93	0.89	1.87
2016	2.36	2.05	52.35	1.11	2,028	18.66	1.39	1,918	38.47	0.91	1.86
2017	2.59	2.39	47.71	1.10	1,864	24.39	1.28	1,839	44.37	0.93	1.53
2018	3.37	2.34	53.85	1.17	1,469	26.38	1.48	1,640	41.99	0.85	0.98
2019	3.76	1.87	57.04	1.27	1,261	25.48	1.92	1,575	44.78	0.76	0.64

w_i: variable cost in year i ($¢/kWh), CF_i^*: capacity factor in year i (%), v: system price ($/kW), $-values are in 2019 $US. System prices for gas turbines are omitted here since they remained relatively constant over the past decade. Differences in ptc_i between California and Texas result from diverging state rules for corporate income taxes (details in *Methods*). The ptc values reflect the scheduled phase-out of this tax credit, beginning in 2017.

For both wind and solar PV, Table 1 indicates that system prices, denoted by v in $ per kilowatt (kW), fell rapidly while the exogenous capacity factors increased over the past decade due to technological improvements. This is consistent with the widely reported learning-by-doing effects associated with the cumulative deployments of these relatively new renewable power sources[31]. The increased capacity factors for solar PV are largely due to the introduction of axis trackers[32], while the higher utilization rates for wind turbines stem from larger rotors and turbine towers[33].

Table 1 shows that for the two dominant renewable power sources, i.e., solar PV in California and wind energy in Texas, the co-variation coefficients have fallen to 0.70 and 0.76, respectively, by 2019. While in 2012 wind power in Texas already faced a penalty of 5–10% for primary generation at night, solar PV in California still exhibited synergies of 10–20% with market prices that used to be above-average during the day[25;26]. The steady and significant decline in the coefficients Γ_i^* in California provides a clear illustration of the cannibalization effect[10;19]. In contrast, the co-variation coefficients for solar PV in Texas remained well above one throughout the past decade. Particular peaks occurred in the years 2012, 2018, and 2019 when heat waves in Texas led to strong electricity demand from air conditioning[34].

4 Levelized Profit Margins

We now assess the competitive position of renewable and natural gas power plants in California and Texas by estimating their levelized profit margins following the model framework laid out in Section 2. Our analysis yields a trajectory showing how the LPMs for new capacity investments have evolved in these two jurisdictions over the years 2012–2019. When investors in Texas sought to gauge the competitiveness of a new wind farm in 2016, for example, they needed to forecast the distributions of future wholesale market prices. In considering a natural gas power plant in 2016, investors also needed to forecast the future operating costs of such facilities. Since we have no direct knowledge of the forecasts and expectations investors had at these points in time, our estimates are based on alternative *expectation scenarios*. In the first scenario, investors are assumed to have anticipated the distributions of electricity prices, $p_i(t)$, and variable costs, w_i, with perfect foresight up to the horizon date of 2019. Beyond that date, investors are assumed to have anticipated a steady state in which the price distributions and variable operating costs remain constant at values given by their average across the last three years, that is, 2017–2019. While clearly ad-hoc, such an expectation scenario amounts to a terminal value calculation, as frequently employed in equity valuation models[35].

The dashed colored lines in Figure 1 show the trajectories of the LCOE of the three technologies we consider in Texas and California. These LCOE estimates are generally within the range reported in journal articles and by industry analysts[32;33;36;37]. As one might expect, the LCOE estimates of renewables have exhibited particularly fast declines due to progressively lower system prices and higher capacity factors. Starting in 2018, all generation technologies experienced a lower unit cost of capacity due to a lower corporate income tax rate and the possibility of immediate expensing of all new capital investments for tax purposes (details in *Methods*). The pattern of weakly decreasing LCOEs for NGCC plants in both jurisdictions reflects three factors pointing in opposite directions: lower prices for natural gas and, in the case of California, higher CO_2 emissions charges as well as the relegation effect corresponding to lower capacity utilization at NGCC facilities.

One of the surprising findings shown in Figure 1 is that, except for solar PV in Texas, the LPMs of the three technologies (given as the difference between the solid and the dashed colored lines) are for the most part negative in both states. Unless the investing parties had more favorable future expectations than assumed in our calculations, factors beyond the expected economic profitability must have motivated new capacity additions. In that context, it should be noted that in California utilities were subject to a renewable portfolio standard, and furthermore, NGCC plants could earn revenues by participating in the state's capacity market, which are not included in our measure of overnight spot prices. We also note, however, that there were relatively few capacity additions for NGCC plants in California during the past decade[38]. Furthermore, many new renewable power facilities built in both states were viewed as impact investments. Technology firms, in particular, have long made voluntary decarbonization pledges. Carbon-free energy delivered by renewable energy facilities is then counted as carbon offsets for the emissions associated with grid electricity[16;17].

Another general pattern emerging from the findings depicted in Figure 1 is that while the estimated LPMs were mostly negative for the last decade, they were also consistently improving, and, except for solar PV in Texas and natural gas in California, all LPMs have been approaching the benchmark value of zero in recent years. For the renewable power sources, this must be attributed to the observation that the gains in the LCOE were much more consequential than any cannibalization effects, even the relatively strong effect on Γ_i^* for solar PV in California. In contrast, Figure 1e shows that solar PV in Texas achieved substantially positive LPMs due to relatively high co-variation coefficients Γ_i^* (Table 1).

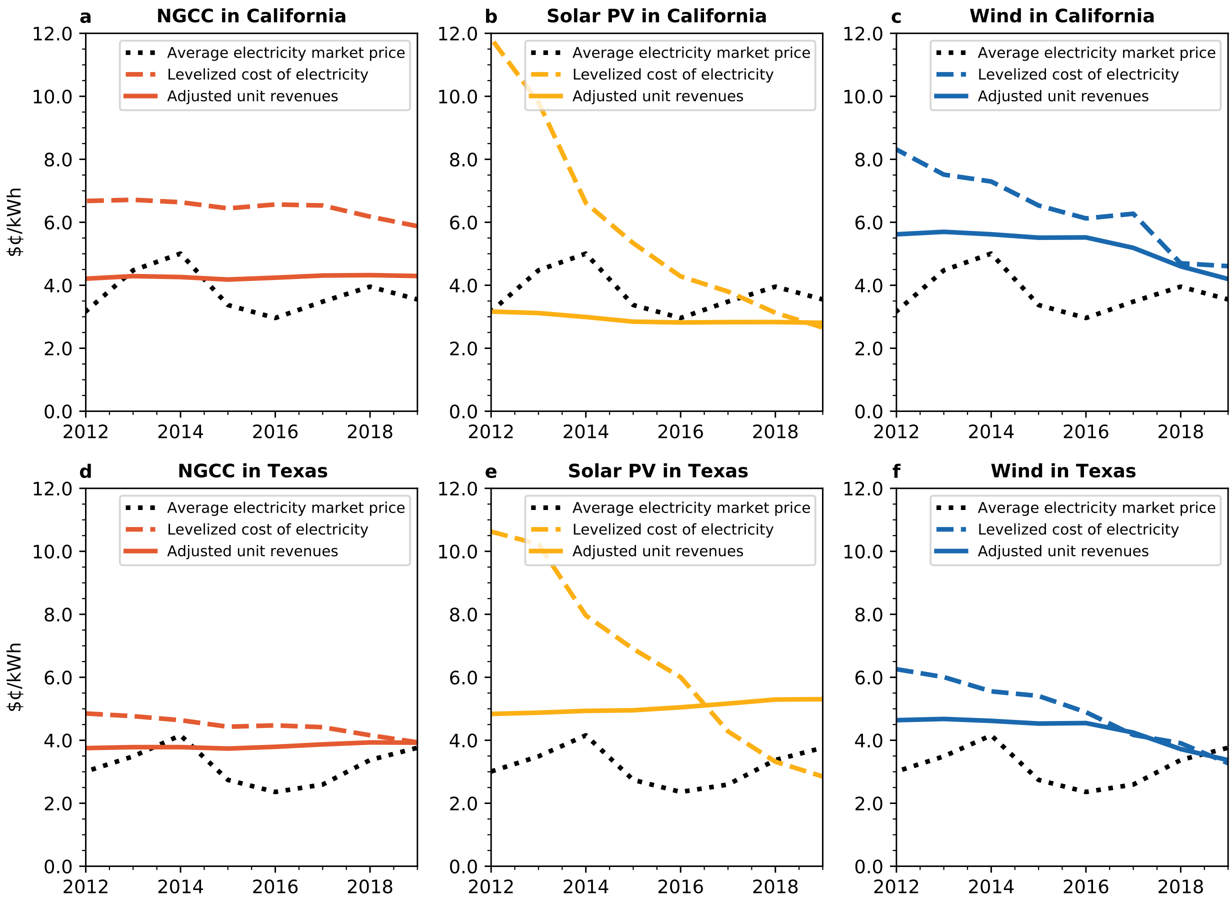


Figure 1. Trajectory of levelized profit margins (scenario 1). a, b, c, d, e, f, This figure shows the trajectory of levelized profit margins for NGCC turbines in California (**a**), solar PV in California (**b**), onshore wind in California (**c**), NGCC turbines in Texas (**d**), solar PV in Texas (**e**), and onshore wind in Texas (**f**) as the difference between the weighted average of adjusted unit revenues (colored solid lines) and LCOE (colored dashed lines).

Consistent with this trend, recent projections forecast about 5 Gigawatt of new solar capacity in Texas in 2021, on par with the new additions for wind power[39].

As a robustness check to the preceding expectation scenario, we also consider the following scenario: investors are assumed to again have had perfect foresight until 2019, while beyond that they are assumed to have relied on external forecasts by the U.S. Energy Information Administration[27]. These forecasts project the average price for natural gas to increase moderately over the coming years. Furthermore, average wholesale power prices are expected to fall slightly due to the growing shares of low-cost renewables. For the hourly distributions of electricity prices in a particular year, investors are assumed to have extrapolated the recent price dynamics (details in *Methods*). These extrapolations effectively magnify the growing volatility in daily and seasonal wholesale electricity prices[40;41].

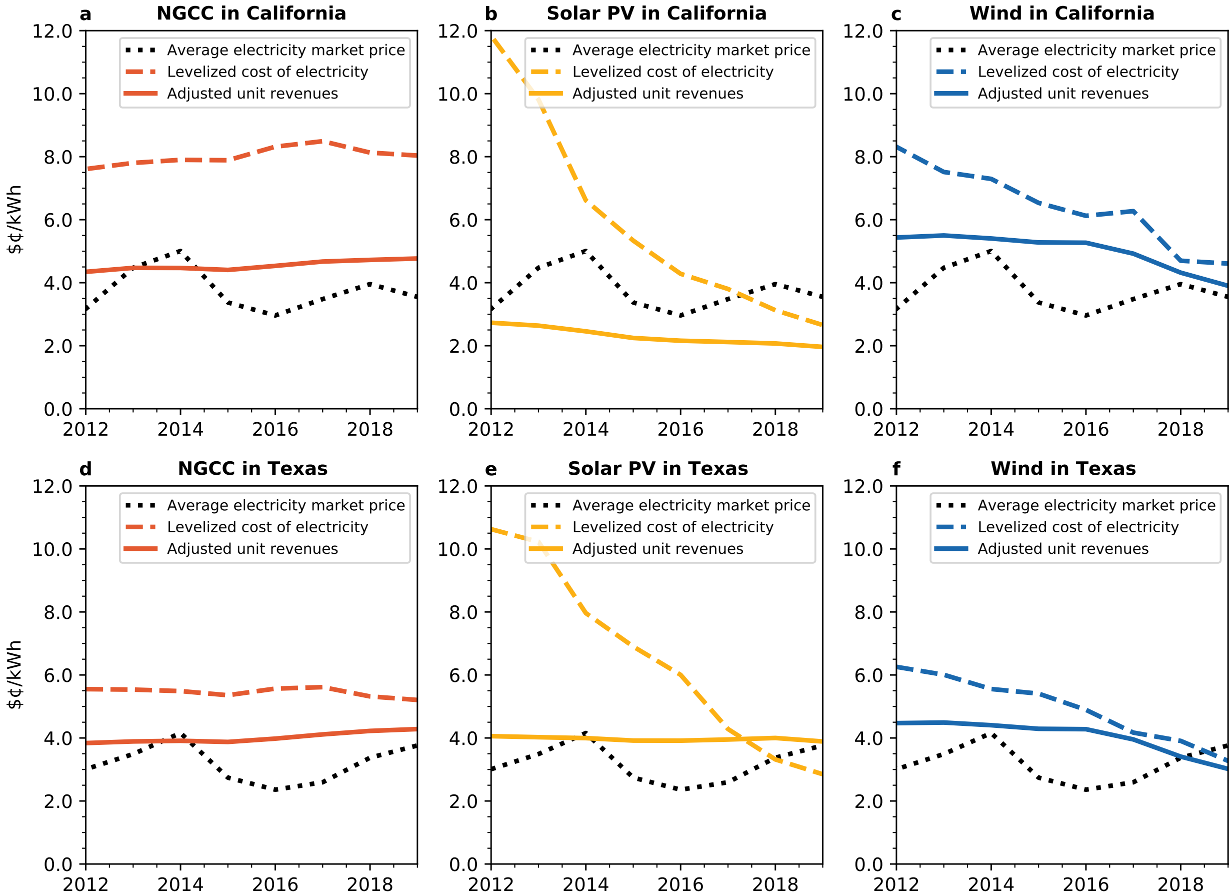


Figure 2. Trajectory of levelized profit margins (scenario 2). a, b, c, d, e, f, This figure shows the trajectory of levelized profit margins for NGCC turbines in California (**a**), solar PV in California (**b**), onshore wind in California (**c**), NGCC turbines in Texas (**d**), solar PV in Texas (**e**), and onshore wind in Texas (**f**) as the difference between the weighted average of adjusted unit revenues (colored solid lines) and LCOE (colored dashed lines).

The resulting trajectories of levelized profit margins shown in Figure 2 are generally consistent with those projected in Figure 1. By construction, the levelized cost estimates of renewables remains unchanged in this alternative scenario. One notable difference is that NGCC plants fare worse in this scenario because of the embedded expectation that their optimized capacity factors will continue to decline in the future. Conversely, the recent LPM estimates for solar PV are less favorable because the adjusted unit revenues now incorporate the expectation of a growing cannibalization effect going forward. Our analysis here does not take into considerations that investors may have anticipated that the installation of storage devices will ultimately provide limits on the magnitude of the cannibalization effect[42;43].

As a final robustness check, we also calculate the LPMs that would emerge in a scenario in which investors had the naive expectation at each point in time that the future of electricity prices would remain unchanged from hereon. As argued in Section 2, in such a stationary environment, the aggregate LPMs reduce to a single annual LPM. As can be seen from Extended Data Figure 1 shown in *Methods*, the implied findings are similar to those in Figure 1 and Figure 2.

5 Concluding Remarks

It is widely understood that an intermittent power generation facility is not necessarily cost competitive once the average price for electricity in a particular market exceeds the LCOE[44]. The levelized profit margin introduced in this paper captures the unit economics of both intermittent and dispatchable power sources competing with each other in real time. For both solar PV and wind power in Texas and California, our LPM estimates indicate major competitive improvements over the past decade, despite the emergence of a cannibalization effect for solar PV in California. At the same time, the projected profitability of NGCC plans has improved in Texas, and held steady in California, because losses from lower capacity utilization have been counterbalanced by temporary price premia available to dispatchable power sources.

Prospective investors can principally rely on the LPM methodology to forecast the economic profitability and the risks associated with further capacity additions in particular electricity markets. Policymakers can also use an LPM analysis as a tool to "back out" the subsidies needed for investors to justify additions in renewable generation capacity. As such, an LPM analysis could extend and complement earlier studies that sought to solve for a scheduled phase-out of federal tax credits to leave the LCOE of wind and solar power unchanged over time[45].

The analysis in this paper has not taken into consideration the possibility of making intermittent renewable power generation partly dispatchable by adding energy storage capabilities[46;47]. Combined solar PV and battery storage projects have become increasingly attractive due to recent advances in battery technology and the U.S. federal tax code designating stationary batteries as solar equipment that is eligible for the same investment tax credit as solar power installations[48;49]. We expect an expanded analysis that includes such combined intermittent generation and storage facilities to generate upper bounds on the magnitude of both the cannibalization effect and the dispatchability price premium identified in our analysis.

Methods

Levelized Cost of Electricity. Our definition of the LCOE is consistent with the verbal definition provided in the well known MIT study[21] and the formal representation in earlier life-cycle cost studies[26]. Suppose the upfront cash expenditure per kW of power generation capacity is v. This upfront capacity investment inherently reflects a joint cost shared by all kWhs produced in subsequent periods. To obtain the cost per kWh, this joint cost, v, is divided by a life-cycle levelization factor that is defined in terms of anticipated hours of operation by:

$$L \equiv m \cdot \sum_{i=1}^{T} CF_i \cdot x_i \cdot \gamma^i. \tag{5}$$

A parallel approach is taken for fixed and variable costs incurred during the subsequent years of operation. Applicable examples of fixed operating costs include insurance and maintenance expenditures. In contrast, expenses such as fuel and labor or charges for carbon dioxide emissions are variable and assumed to increase proportionally with output produced. For intermittent renewable energy sources, like wind and solar power, variable costs are effectively zero. With F_i as the fixed costs per kW of installed capacity and w_i as the variable cost per kWh in year i, the three principal components of the LCOE metric are:

$$c \equiv \frac{v}{L}, \qquad f \equiv \frac{\sum_{i=1}^{T} F_i \cdot \gamma^i}{L}, \qquad w \equiv \frac{m \cdot \sum_{i=1}^{T} w_i \cdot CF_i \cdot x_i \cdot \gamma^i}{L}. \tag{6}$$

Investments returns are affected by corporate income taxes through i) the corporate tax rate, $0 < \alpha < 1$, and ii) the allowable tax shields for debt and depreciation. If the cost of capital is taken to be the weighted average cost of capital, the debt tax shield is incorporated by applying the after-tax cost of debt. The impact of corporate income taxes, including the influence of applicable investment tax credits, can be summarized by a tax factor, denoted by Δ that scales the unit cost of capacity c. We denote by $d_i \geq 0$ the percentage of the initial capital expenditure that can be deducted as a depreciation charge in year i from revenues in the calculation of taxable income. By construction, $\sum d_i = 1$. If the tax code allows for full expensing, $d_0 = 1$. The impact of corporate income taxes can then be summarized by:

$$\Delta = \frac{1 - ITC - \alpha \cdot (1 - \delta \cdot ITC) \cdot \sum_{i=0}^{T} d_i \cdot \gamma^i}{1 - \alpha}. \tag{7}$$

Here, ITC denotes the investment tax credit that the U.S. federal tax code grants for some renewable energy sources, specifically for solar PV installations[50]. The ITC reflects a percentage subsidy on the system price that is deducted from the investor's income tax liability. At the same time, the book value of the initial investment expenditure is reduced by a factor of $\delta \cdot ITC$ for tax depreciation purposes. In the U.S., $\delta = 50\%$ so that an ITC of 30% implies that for tax purposes the investor can only capitalize 85% of the initial investment.

We also note that the U.S. federal government made two changes to the federal tax code in 2018 that apply to both traditional and renewable energy facilities: the corporate income tax rate was lowered from 35.0% to 21.0% and upfront capacity expenditures for new energy facilities can be fully depreciated in the year of investment[51]. The derivation of the tax factor in equation (7) applies to a setting without different tax depreciation and tax credit rules at the state level. A generalized formulation with both federal and state income taxes, as applies in California, is provided below.

Combining the preceding elements, we obtain the following definition for the levelized cost of electricity:

$$LCOE(\vec{CF}) = c \cdot \Delta + f + w, \tag{8}$$

where $\vec{CF} = (CF_1, ..., CF_T)$ highlights the dependence of the LCOE on the entire sequence of capacity utilization rates for the years $1 \leq i \leq T$.

Proof of the Proposition. For 1 kW of power installed initially, the operating revenue at time t in year i is given by:

$$Rev_i(t) = x_i \cdot CF_i(t) \cdot \left[p_i(t) + PTC_i^o\right],$$

where $p_i(t)$ is the price at time t in year i for $t \in [0, m]$, $m = 8,760$, and PTC_i^o denotes the nominal production tax credit in year i. Since these subsidies are not subject to corporate income taxation, it will be useful to introduce the effective after-tax production tax credits:

$$PTC_i = \frac{PTC_i^o}{(1 - \alpha)}.$$

The overall pre-tax cash flows in year i per kW of power installed will be represented by CFL_i^o. It comprises operating revenues and operating costs:

$$CFL_i^o = x_i \int_0^m \left[p_i(t) + PTC_i^o - w_i\right] \cdot CF_i(t)\, dt - F_i,$$

By definition, the investment in 1 kW of power capacity is cost-competitive if and only if the present value of all after-tax cash flows is non-negative, that is:

$$\sum_{i=1}^{T} CFL_i \cdot \gamma^i - v \cdot (1 - ITC) \geq 0, \tag{9}$$

where CFL_i denotes the after-tax cash flow in year i:

$$CFL_i = CFL_i^o - \alpha \cdot I_i.$$

The firm's taxable income in year i, with $0 \leq i \leq T$ is given by:

$$I_i = CFL_i^o - v \cdot (1 - \delta \cdot ITC) \cdot d_i + x_i \int_0^m PTC_i^o \cdot CF_i(t)\, dt.$$

The capacity factor at time t in year i will be chosen so as to maximize:

$$\left[p_i(t) + PTC_i - w_i\right] \cdot CF_i(t),$$

where, as defined above, $PTC_i = \frac{PTC_i^o}{(1-\alpha)}$. Thus, $CF_i^*(t) = b(t)$ if $p_i(t) + PTC_i \geq w_i$ and $CF_i^*(t) = 0$ otherwise. Direct substitution shows that the inequality in (9) holds if and only if:

$$\begin{aligned}(1-\alpha)\sum_{i=1}^{T}\left[x_i \int_0^m \left[p_i(t) + PTC_i - w_i\right] \cdot CF_i^*(t)\, dt - F_i\right]\gamma^i \\ \geq v \cdot \left[1 - ITC - \alpha \cdot (1 - \delta \cdot ITC) \cdot \sum_{i=0}^{T} d_i \cdot \gamma^i\right].\end{aligned} \tag{10}$$

Dividing by $(1-\alpha)$ and recalling the definition of the tax factor in (7), the inequality in (10) reduces to:

$$\sum_{i=1}^{T}\left[x_i \int_0^m \left[p_i(t) + PTC_i - w_i\right] \cdot CF_i^*(t)\ dt - F_i\right]\gamma^i \geq v \cdot \Delta. \tag{11}$$

Since $p_i(t) \equiv p \cdot \mu_i(t)$ and $CF_i^*(t) \equiv CF_i^* \cdot \epsilon_i^*(t)$, it follows that:

$$\int_0^m \epsilon_i^*(t)\ dt = \int_0^m \mu_i(t)\ dt = m.$$

Thus inequality (11) holds provided:

$$\begin{aligned}\sum_{i=1}^{T} CF_i^* \cdot x_i \cdot \gamma^i \cdot &\left[p_i \cdot \int_0^m \epsilon_i^*(t) \cdot \mu_i(t)\ dt + m \cdot PTC_i\right] \\ &\geq m \cdot \sum_{i=1}^{T} w_i \cdot CF_i^* \cdot x_i \cdot \gamma^i + \sum_{i=1}^{T} F_i \cdot \gamma^i + v \cdot \Delta.\end{aligned} \tag{12}$$

By construction of the co-variation coefficients Γ_i^*, the left-hand side of (12) is equal to:

$$\sum_{i=1}^{T} CF_i^* \cdot x_i \cdot \gamma^i \cdot m \cdot \left[p_i \cdot \Gamma_i^* + PTC_i\right].$$

Dividing by $L^* \equiv m \cdot \sum_{i=1}^{T} CF_i^* \cdot x_i \cdot \gamma^i$ and recalling the definitions of w, f, and c in (6), the right-hand side of (12) reduces to:

$$w + f + c \cdot \Delta \equiv LCOE(\vec{CF}^*),$$

where $\vec{CF}^*$ denotes the vector of optimized average capacity factors, $\vec{CF}^* = (CF_1^*, ..., CF_T^*)$. Thus, inequality (12) is satisfied if and only if:

$$\sum_{i=1}^{T} \beta_i^* \cdot [\Gamma_i^* \cdot p_i + PTC_i] - LCOE(\vec{CF}^*) \geq 0,$$

where $\beta_i^* = \frac{CF_i^* \cdot x_i \cdot \gamma^i}{\sum_{j=1}^{T} CF_j^* \cdot x_j \cdot \gamma^j}$. ■

Corporate Income Taxes at the State Level. Since businesses in California are also subject to a corporate income tax rate at the state level, we extend the definition of the effective after-tax production tax credit and the tax factor. Let α_f denote the federal income tax rate and α_s the state income tax rate. State taxes are thereby deductible from the federal taxable income. It is then convenient to define $PTC_i = \frac{PTC_i^o}{1-\alpha_s-\alpha_f\cdot(1-\alpha_s)}$, with PTC_i^o denoting the nominal production tax credit.

The allowable tax depreciation factors in year i at the federal and state level are denoted by $d_{f,i}$ and $d_{s,i}$, respectively. If depreciation schedules are shorter than the economic lifetime, $d_{s,i}$ and $d_{f,i}$ are equal to zero in the remaining years. The integrated tax factor comprising both federal and stae income taxes is then given by:

$$\Delta = \frac{1 - ITC - \alpha_s \cdot \sum_{i=0}^{T} d_{s,i} \cdot \gamma^i - \alpha_f \cdot \sum_{i=0}^{T} \left[d_{f,i} \cdot (1 - \delta \cdot ITC) \cdot \gamma^i - \alpha_s \cdot d_{s,i} \cdot \gamma^i \right]}{1 - \alpha_s - \alpha_f \cdot (1 - \alpha_s)}. \tag{13}$$

We note that the federal ITC only reduces a firm's federal tax liability. The tax factor Δ is increasing and convex in both tax rates. It is bounded above by $1/(1 - \alpha_s - \alpha_f \cdot (1 - \alpha_s))$. A more accelerated tax depreciation schedule reduces Δ. For instance, the federal U.S. tax code currently allows for new power generation plants to be fully expensed in the year of investment ($d_{f,0} = 1$)[51]. Thus, $\Delta = 1$ if both $\alpha_f = 0$ and $ITC = 0$, as is the case for wind turbines and NGCC plants in Texas.

Data Collection. Supplementary Tables 2–7 provide annual input parameters for each technology and state. System prices and fixed operating costs reflect the average values calculated across the respective power plants installed in a particular year for all three generation technologies. While system prices for solar PV and wind turbines are provided by the Lawrence Berkeley National Laboratory[32;33], system prices for NGCC turbines are calculated from data by ABB Velocity Suite[38]. For solar PV, these system prices include installations with fixed tilt and axis trackers. Fixed operating costs are calculated for all technologies from data by ABB Velocity Suite[38]. Variable costs of NGCC plants comprise fuel cost, variable expenses for operation and maintenance, and, in the case of California, charges for CO_2 emissions. Variable expenses for operation and maintenance of NGCC turbines are calculated from data by ABB Velocity Suite[38] and reflect national averages of NGCC plants built in the U.S. in the respective year. All national average values are adjusted to the price level in either state using averaged city cost indexes by RSMeans[52].

Fuel cost for NGCC plants (in \$/kWh) are calculated from data by ABB Velocity Suite[38] as the average across reported annual average fuel cost per kWh of individual NGCC plants operating in the respective year in either state. We include in this calculation NGCC plants built since the year 2000, because only few new plants have been built in recent years and the fuel consumption of newer NGCC plants built within the years 2000–2019 does not appear to differ substantially from the fuel requirements of older plants in the same time period. Fuel usage thereby refers to the fuel required per kWh of power produced in the respective year of comparison. Cost of emission allowances for CO_2 equivalents in California reflects the annual average price per ton of CO_2 allowance of a particular year[29]. Annual average values for the emission performance (in kg CO_2/kWh) of NGCC turbines are calculated from hourly performance data retrieved from the ABB Velocity Suite[38] of individual plants located in either state.

Capacity factors are also calculated with data from the ABB Velocity Suite[38] for all technologies respectively in two stages. We first obtain the average hourly capacity factors as reported by individual plants located in either state in a particular year. We then compute the annual averages across all hours. These reported capacity factors yield close approximations to the annual average values that are obtained by referring to equation (1). We thus consider our estimates of the capacity factors to be optimized. This finding is consistent with the fact that NGCC turbines exhibit a relatively brief and symmetric delay in up- and down-ramping. While the data available to us provides hourly capacity factors for NGCC turbines at the individual plant level, our data for the capacity factors of solar and wind only reflect averages across all solar PV and wind facilities operating in a particular state. Our capacity factors for renewables thus reflect a blend of older and newer plants. Any potential bias here appears mitigated by the fact that renewable energy capacity additions have been grown quickly over the period 2012–2019[36].

Scenario Calculations. Supplementary Tables 2–7 provide the relevant annual parameters for the three expectation scenarios. In the second scenario, investors are first assumed to have anticipated the distributions of electricity prices, $p_i(t)$, and variable costs, w_i, with perfect foresight until 2019. Beyond that year, they are assumed to have relied on forecasts by the U.S. Energy Information Administration[27] to obtain the annual average fuel cost for NGCC plants and the annual average price for electricity, p_i. In addition, they are assumed to have extrapolated the recent dynamics in hourly electricity prices to calculate the future optimized annual capacity factors of gas turbines, CF_i^*, and the future co-variation coefficients, Γ_i^*, for three generation technologies in question. We recall that the optimized annual capacity factors of wind and solar power remain unchanged across the lifetime of a facility. Our estimation approach for the future values of Γ_i^* in Texas and California are essentially identical for both states. Unless stated otherwise, we therefore describe the procedures in the subsequent paragraphs in the context of California. Our projections cover the years 2020–2049, where 2049 marks the end of the useful life for facilities built in 2019.

The U.S. Energy Information Administration provides trajectories of national annual average natural gas prices and national annual average costs for wholesale power generation[27]. These trajectories comprise observations until 2019 and projections from 2020 through 2050. To obtain future average fuel costs for NGCC turbines in California, we proceed as follows. The average fuel cost of NGCC turbines in the year 2022, for instance, is given by the projected price for natural gas in 2022, divided by the observed gas price in 2019 and multiplied with the observed fuel cost of NGCC turbines in California averaged across the years 2017–2019. This approach entails the implicit assumptions that the fuel consumption of NGCC turbines remains constant and that regional price markups are proportional the change in natural gas prices. A parallel approach is taken to obtain the trajectory of future annual average wholesale power prices, p_i. The projected values are provided in Supplementary Tables 8 and 9.

Our trajectories of optimized annual capacity factors, CF_i^*, of gas turbines and the annual co-variation coefficients, Γ_i^*, for all three generation technologies are derived in three main steps. The first two steps estimate the hourly distributions of electricity prices, $p_i(t)$, in a future year. Since we have already estimated future annual average electricity prices, p_i, we determine future hourly electricity prices in accordance with equation (2), that is: $p_i(t) = p_i \cdot \mu_i(t)$. In the first main step, we estimate future hourly multiplicative deviation factors, $\mu_i(t)$. In doing so, we focus, for simplicity, on obtaining these hourly factors for an average day for each month (January–December) in a projected year (2020–2049). We denote these average hourly multiplicative deviation factors by $\bar{\mu}_{ij}(\tau)$, where i refers to the year, j to the month with $j \in \{1, 2, ..., 12\}$, and τ to the hour of a day with $\tau \in \{0, 1, ..., 23\}$.

We estimate the average hourly multiplicative deviation factors, $\bar{\mu}_{ij}(\tau)$, for future years $i \in \{2020, ..., 2049\}$ by extrapolating the dynamics observed in $\bar{\mu}_{ij}(\tau)$ over the past years. These extrapolations are conducted separately for each hour $\tau \in \{0, 1, ..., 23\}$ and month $j \in \{1, ..., 12\}$. To do that, we calculate the hourly multiplicative deviation factors, $\mu_i(t)$, of past years according to equation (2) based on the observed electricity price distributions, $p_i(t)$ for the years 2010–2019 in California. For Texas, the requisite data is only available for the years 2011–2019. We then calculate $\bar{\mu}_{ij}(\tau)$ for a given hour τ, month j, and past year i as the average of the corresponding factors across all days in that month.

Next, we estimate the evolution of these average factors, $\bar{\mu}_{ij}(\tau)$, for a given hour τ and month j across the past years i based on a univariate regression with constant elasticity model of the form: $\bar{\mu}_{ij}(\tau) = \bar{\mu}_{0j}(\tau) \cdot \beta^i$. Based on the resulting parameters, we then project $\bar{\mu}_{ij}(\tau)$ for a given hour τ and month j for the future years between 2020 and 2049. These simple regression estimations yield an average R^2 for California of above 0.5 for the hours between 10:00am–2:00pm, above 0.25 for the hours between 3:00am–9:00am and 3:00pm–8:00pm, and above 0.1 for the hours between 0:00am–2:00am and 9:00pm–11:00pm. Further details on these regression results are available upon request.

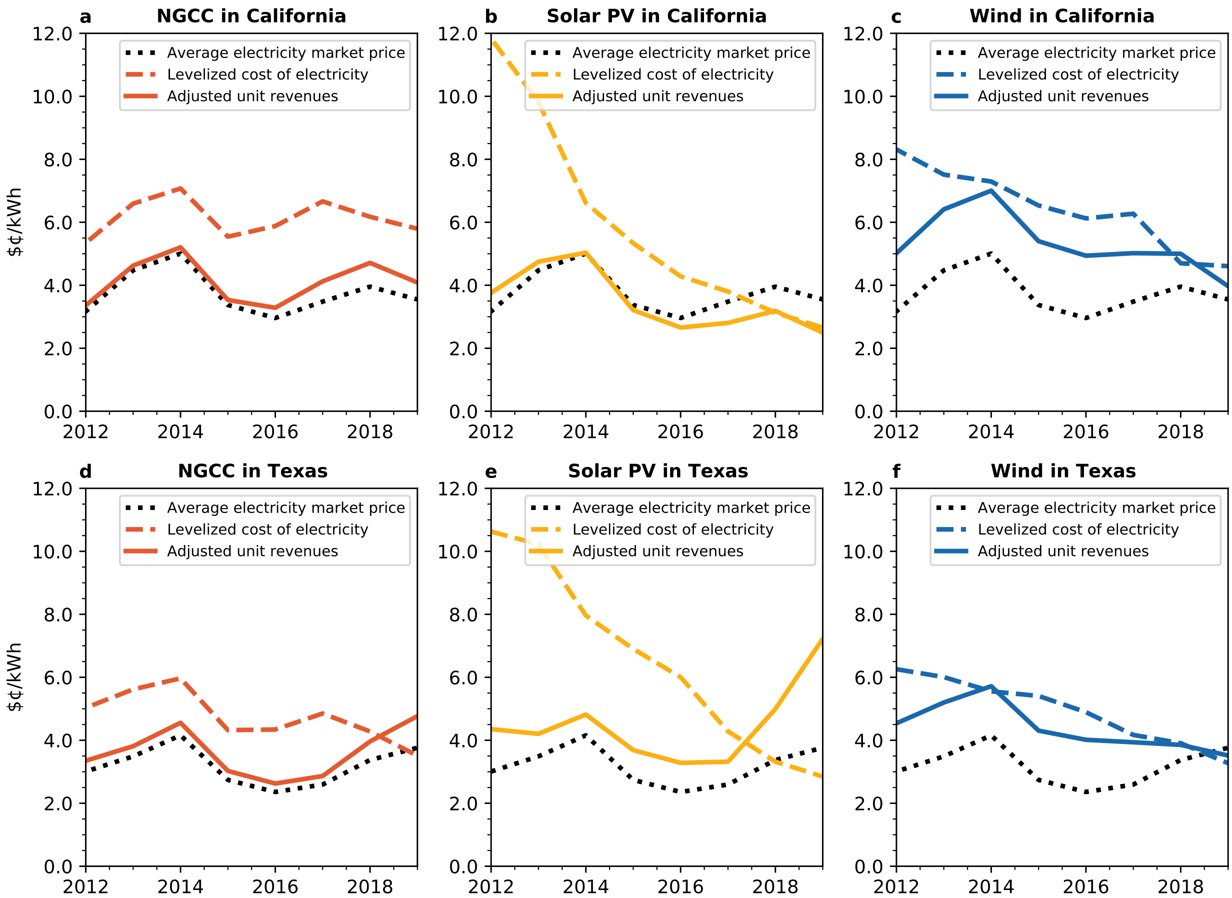
In the second main step, we winsorize the preceding extrapolations to prevent outlier values far into the future. Specifically, we restrict the average hourly multiplicative deviation factors, $\bar{\mu}_{ij}(\tau)$, for a given hour τ and month j in the year 2020 to lie within $\pm$ 10% of a base value. Thus, if an extrapolated value were to be outside this range, it is set at the nearest limit. The base value is set as the average of the values for $\bar{\mu}_{ij}(\tau)$ for a given hour τ and month j across the years 2017–2019. A parallel approach is taken for the values for $\bar{\mu}_{ij}(\tau)$ in the last year of the projection (i.e., 2049), whereby the accepted range is $\pm$ 80% of the corresponding base value. The two range limits of $\pm$ 10% and $\pm$ 80% appear reasonable, though admittedly ad-hoc. If a vector of $\bar{\mu}_{ij}(\tau)$ values for a given hour τ and month j was adjusted at the beginning and/or the end, we calculate the constant growth parameter β^i that is required to get from the beginning to the end, according to a constant elasticity function. With this growth parameter and the values for $\bar{\mu}_{ij}(\tau)$ in 2020 and 2049, we then interpolate the values for $\bar{\mu}_{ij}(\tau)$ for the years 2020–2049. Given the projections for $\bar{\mu}_{ij}(\tau)$ and p_i, we finally calculate future hourly electricity prices by multiplying the two parameters for each hour τ, month j, and year i, respectively.

In the third main step, we calculate the optimized annual capacity factors, CF_i^*, for NGCC turbines and co-variation coefficients, Γ_i^*, for all three generation technologies. To obtain the optimized annual capacity factors, CF_i^*, of NGCC turbines, we first determine optimized hourly capacity factors for an average day for each month in a future year analogous to the optimization described in equation (1) in Section 2. This calculation relies on the future hourly electricity prices and cost of fuel calculated before. The variable costs for operation and maintenance are included in the variable operating cost of NGCC turbines. These costs are assumed to remain constant at their averages for the years 2017–2019. In California, variable operating cost further comprise the price for CO_2 allowances which are based on the emissions of NGCC plants. Introduced in 2012 at \$10.0 per ton of CO_2, the price floor for CO_2 allowances is set to increase at least 5.0% annually over inflation[29]. We assume that the effective annual increase amounts to 5.5% going forward and that the prices for CO_2 allowances continue to be equal to the price floor, as they have for the most part since 2012. The emission rates are assumed to remain at the average value of the years 2017–2019. Optimized annual capacity factors of NGCC turbines for a given year are then calculated as the average across the optimized hourly capacity factors in that year.

To finally obtain future annual co-variation coefficients, Γ_i^*, of NGCC turbines, we first calculate hourly multiplicative deviation factors of capacity utilization, denoted by $\bar{\epsilon}_{ij}^*(\tau)$, analogous to equation (2) based on the optimized hourly and annual capacity factors of NGCC turbines, as shown above. These deviation factors, $\bar{\epsilon}_{ij}^*(\tau)$, and the hourly multiplicative deviation factors for electricity prices, $\bar{\mu}_{ij}(\tau)$, then allow us to calculate monthly co-variation coefficients for each month in a given year. Annual co-variation coefficients, Γ_i^*, are finally obtained as the average across the monthly coefficients.

For wind and solar PV power, we again first calculate average hourly multiplicative deviation factors of capacity utilization, $\bar{\epsilon}_{ij}^*(\tau)$. These calculations are based on the hourly multiplicative deviation factors, $\epsilon_i^*(t)$, of past years (2012–2019) according to equation (2) and the observed hourly capacity factors, $CF_i^*(t)$. We then calculate $\bar{\epsilon}_{ij}^*(\tau)$ for a given hour τ, month j, and past year i as the average of the corresponding factors across all days in that month. This approach mirrors that of calculating the past $\bar{\mu}_{ij}(\tau)$, as described above. The hourly deviation factors, $\bar{\epsilon}_{ij}^*(\tau)$ allow us to estimate for each renewable source the monthly co-variation coefficients and, by implication, the annual co-variation coefficients, Γ_i^*.

The third alternative expectation scenario considers the LPMs that would emerge if investors assumed at each point in time that future cost and price distributions will remain unchanged in the future. The resulting trajectory of levelized profit margins is shown in Extended Data Figure 1.



Extended Data Figure 1. Trajectory of levelized profit margins (scenario 3). a, b, c, d, e, f, This figure shows the trajectory of levelized profit margins for NGCC turbines in California (**a**), solar PV in California (**b**), onshore wind in California (**c**), NGCC turbines in Texas (**d**), solar PV in Texas (**e**), and onshore wind in Texas (**f**) as the difference between the weighted average of adjusted unit revenues (colored solid lines) and LCOE (colored dashed lines).

Data availability

The data used in this study are referenced in the main body of the paper and the Supplemental Information. Data that generated the plots in the paper are provided in the Supplemental Information. Additional data and information is available from the authors upon reasonable request.

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Acknowledgments

We gratefully acknowledge financial support through the Deutsche Forschungsgemeinschaft (DFG, German Research Foundation) – Project-ID 403041268 – TRR 266 and the Joachim Herz Stiftung. Helpful comments were provided by Stefanie Burgahn, Stephen Comello, Yadira Funk, Rebecca Meier, Ekaterina Savchenko, Nikolas Wölfing, and colleagues at the University of Mannheim and Stanford University. We also thank Yadira Funk, Lucas Politycki, and Philipp Scherer for providing valuable assistance with data collection.

Author contributions

The authors jointly developed the research question, the model framework and the analytical findings. G.G. lead the literature review, the data collection, and the calculations. Both authors contributed substantially to the writing of the paper.

Conflicts of interest

The authors declare no competing financial or non-financial interests.

Supplementary Information:

Dispatchable versus Intermittent Power Sources: An Integrated Competitive Assessment

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Supplementary Table 1. List of symbols and acronyms.

α	Corporate income tax rate (%)
β_i	Intertemporal weights (–)
$b(t)$	Bound on capacity utilization at time t (–)
c	Unit cost of capacity (\$/kWh)
$CF_i(t)$	Capacity factor at time t in year i (%)
CFL_i	Cash flow in year i (\$/kW)
CO_2	Carbon dioxide
d_i	Allowable tax depreciation in year i (%)
δ	ITC capitalization for depreciation purposes (%)
Δ	Tax factor (–)
$\epsilon_i(t)$	Multiplicative deviation of generation at time t in year i (–)
f	Levelized fixed operating cost (\$/kWh)
F_i	Fixed operating cost per kW in year i (\$/kW)
γ	Discount factor (–)
Γ_i	Co-variation coefficient in year i (–)
I_i	Taxable income in year i (\$/kW)
ITC	Investment tax credit (%)
kW	Kilowatt
kWh	Kilowatt hour
L	Levelization factor (–)
LCOE	Levelized cost of electricity
LPM	Levelized profit margin
m	Number of hours per year (–)
$\mu_i(t)$	Multiplicative deviation of prices at time t in year i (–)
NGCC	Natural gas combined-cycle
$p_i(t)$	Selling price for electricity at time t of year i (\$/kWh)
ptc	Levelized production tax credit (\$/kWh)
PTC_i	Production tax credit in year i (\$/kWh)
PV	Photovoltaic
r	Cost of capital (%)
$Rev_i(t)$	Operating revenue at time t in year i (\$/kW)
T	Useful life of capacity (years)
U.S.	United States
v	System price of capacity (\$/kW)
w	Levelized variable operating cost (\$/kWh)
w_i	Variable operating cost in year i (\$/kWh)
x_i	Degradation of capacity in year i (%)

Supplementary Table 2. Cost and Price Dynamics for NGCC in California.

in 2019 $US	Source	2012	2013	2014	2015	2016	2017	2018	2019
Input Parameters									
Useful lifetime, T (years)	[1]	30	30	30	30	30	30	30	30
System price, v ($/kW)	[2]	1,187	1,166	1,164	1,145	1,204	1,186	1,165	1,119
Fixed operating cost, F ($/kW)	[2]	19.75	18.05	17.69	18.39	18.13	15.78	16.42	14.89
Variable operating cost (ex. fuel) ($¢/kWh)	[2]	0.10	0.11	0.11	0.09	0.10	0.08	0.09	0.08
Fuel cost ($¢/kWh)	[2]	2.35	3.45	4.00	2.54	2.38	2.88	2.97	2.77
CO_2 emission cost ($/t CO_2)	[3]	11.18	13.97	12.65	13.30	13.42	14.84	15.21	16.84
Emission Performance (kg/kWh)	[2]	0.38	0.35	0.36	0.36	0.34	0.31	0.31	0.32
Capacity factor, CF_i^* (%)	[2]	58.75	55.59	54.40	53.80	44.83	39.94	43.45	42.61
Cost of capital, r (%)	[4, 13]	5.47	5.46	5.25	4.92	4.68	4.80	5.15	4.50
Degradation factor, x (%)	[1, 5, 6]	99.60	99.60	99.60	99.60	99.60	99.60	99.60	99.60
Investment tax credit, ITC (%)		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
ITC capitalization, δ (%)		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Production tax credit, PTC_i^o ($¢/kWh)		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
State tax rate, α_s (%)	[9]	8.84	8.84	8.84	8.84	8.84	8.84	8.84	8.84
Federal tax rate, α_f (%)	[10]	35.00	35.00	35.00	35.00	35.00	35.00	21.00	21.00
State tax depreciation method (–)*	[11]	3	3	3	3	3	3	3	3
Federal tax depreciation method (–)*	[11]	3	3	3	3	3	3	5	5
Average wholesale power price, p_i ($¢/kWh)	[2]	3.17	4.48	5.01	3.37	2.96	3.48	3.96	3.55
Scenario 1									
Cost of capacity, c ($¢/kWh)		2.13	2.13	2.12	2.05	2.14	2.14	2.18	1.95
Tax factor, Δ (–)		1.26	1.26	1.25	1.24	1.23	1.23	1.03	1.03
Fixed operating cost, f ($¢/kWh)		0.52	0.48	0.48	0.51	0.51	0.45	0.46	0.42
Variable operating cost, w ($¢/kWh)		3.49	3.55	3.50	3.39	3.43	3.44	3.46	3.44
LCOE ($¢/kWh)		6.68	6.71	6.64	6.44	6.57	6.53	6.18	5.88
Adjusted unit revenue ($¢/kWh)		4.21	4.29	4.26	4.18	4.24	4.31	4.32	4.29
Levelized profit margin ($¢/kWh)		-2.47	-2.42	-2.38	-2.26	-2.32	-2.22	-1.86	-1.58
Scenario 2									
Cost of capacity, c ($¢/kWh)		2.58	2.66	2.74	2.77	3.01	3.13	3.27	3.12
Tax factor, Δ (–)		1.26	1.26	1.25	1.24	1.23	1.23	1.03	1.03
Fixed operating cost, f ($¢/kWh)		0.63	0.60	0.62	0.69	0.72	0.65	0.70	0.68
Variable operating cost, w ($¢/kWh)		3.74	3.86	3.85	3.77	3.89	3.98	4.04	4.14
LCOE ($¢/kWh)		7.61	7.80	7.90	7.89	8.32	8.49	8.13	8.04
Adjusted unit revenue ($¢/kWh)		4.35	4.47	4.47	4.41	4.53	4.67	4.72	4.77
Levelized profit margin ($¢/kWh)		-3.26	-3.33	-3.43	-3.48	-3.78	-3.82	-3.41	-3.27
Scenario 3									
Cost of capacity, c ($¢/kWh)		1.65	1.71	1.71	1.64	2.01	2.25	2.11	1.92
Tax factor, Δ (–)		1.26	1.26	1.25	1.24	1.23	1.23	1.03	1.03
Fixed operating cost, f ($¢/kWh)		0.40	0.39	0.39	0.41	0.48	0.47	0.45	0.42
Variable operating cost, w ($¢/kWh)		2.87	4.06	4.56	3.11	2.93	3.41	3.54	3.39
LCOE ($¢/kWh)		5.35	6.59	7.07	5.54	5.88	6.66	6.17	5.79
Co-variation coefficient, Γ_i^* (–)		1.06	1.03	1.04	1.05	1.11	1.19	1.19	1.15
Production tax credit, ptc ($¢/kWh)		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Adjusted unit revenue ($¢/kWh)		3.36	4.62	5.20	3.53	3.29	4.12	4.71	4.09
Levelized profit margin ($¢/kWh)		-1.99	-1.97	-1.87	-2.01	-2.59	-2.54	-1.46	-1.71

*3: 20 year 150%-declining balance depreciation schedule, 5: 100% bonus depreciation.
[1] [53], [2] [38], [3] [54], [4] [55], [5] [56], [6] [57], [7] [58], [8] [23], [9] [59], [10] [60], [11] [51], [12] [32], [13] [33].

Supplementary Table 3. Cost and Price Dynamics for Solar PV in California.

in 2019 $US	Source	2012	2013	2014	2015	2016	2017	2018	2019
Input Parameters									
Useful lifetime, T (years)	[1]	30	30	30	30	30	30	30	30
System price, v ($/kW)	[12]	4,088	3,504	2,967	2,593	2,161	1,986	1,565	1,343
Fixed operating cost, F ($/kW)	[2]	12.39	12.90	11.28	9.15	6.92	6.79	8.27	8.81
Variable operating cost (ex. fuel) ($¢/kWh)		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fuel cost ($¢/kWh)		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
CO_2 emission cost ($/t CO_2)	[3]	10.09	12.83	11.65	12.44	12.73	14.30	14.91	16.84
Emission Performance (kg/kWh)		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Capacity factor, CF_i^* (%)	[2]	20.83	21.78	26.75	27.67	27.67	29.23	29.59	28.69
Cost of capital, r (%)	[4, 13]	5.47	5.46	5.25	4.92	4.68	4.80	5.15	4.50
Degradation factor, x (%)	[1, 5, 6]	99.50	99.50	99.50	99.50	99.50	99.50	99.50	99.50
Investment tax credit, ITC (%)	[7]	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00
ITC capitalization, δ (%)	[1]	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00
Production tax credit, PTC_i^o ($¢/kWh)		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
State tax rate, α_s (%)	[9]	8.84	8.84	8.84	8.84	8.84	8.84	8.84	8.84
Federal tax rate, α_f (%)	[10]	35.00	35.00	35.00	35.00	35.00	35.00	21.00	21.00
State tax depreciation method (–)*	[11]	3	3	3	3	3	3	3	3
Federal tax depreciation method (–)*	[11]	2	2	2	2	2	2	5	5
Average wholesale power price, p_i ($¢/kWh)	[2]	3.17	4.48	5.01	3.37	2.96	3.48	3.96	3.55
Scenario 1									
Cost of capacity, c ($¢/kWh)		16.20	13.26	8.94	7.28	5.91	5.21	4.22	3.47
Tax factor, Δ (–)		0.69	0.69	0.68	0.68	0.67	0.68	0.66	0.66
Fixed operating cost, f ($¢/kWh)		0.72	0.71	0.51	0.40	0.30	0.28	0.34	0.37
Variable operating cost, w ($¢/kWh)		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
LCOE ($¢/kWh)		11.84	9.81	6.61	5.34	4.28	3.80	3.13	2.66
Adjusted unit revenue ($¢/kWh)		3.16	3.12	2.99	2.84	2.82	2.83	2.83	2.81
Levelized profit margin ($¢/kWh)		-8.67	-6.70	-3.62	-2.49	-1.46	-0.97	-0.29	0.15
Scenario 2									
Cost of capacity, c ($¢/kWh)		16.20	13.26	8.94	7.28	5.91	5.21	4.22	3.47
Tax factor, Δ (–)		0.69	0.69	0.68	0.68	0.67	0.68	0.66	0.66
Fixed operating cost, f ($¢/kWh)		0.72	0.71	0.51	0.40	0.30	0.28	0.34	0.37
Variable operating cost, w ($¢/kWh)		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
LCOE ($¢/kWh)		11.84	9.81	6.61	5.34	4.28	3.80	3.13	2.66
Adjusted unit revenue ($¢/kWh)		2.73	2.64	2.46	2.25	2.16	2.12	2.07	1.96
Levelized profit margin ($¢/kWh)		-9.11	-7.18	-4.16	-3.09	-2.12	-1.68	-1.05	-0.69
Scenario 3									
Cost of capacity, c ($¢/kWh)		16.20	13.26	8.94	7.28	5.91	5.21	4.22	3.47
Tax factor, Δ (–)		0.69	0.69	0.68	0.68	0.67	0.68	0.66	0.66
Fixed operating cost, f ($¢/kWh)		0.72	0.71	0.51	0.40	0.30	0.28	0.34	0.37
Variable operating cost, w ($¢/kWh)		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
LCOE ($¢/kWh)		11.84	9.81	6.61	5.34	4.28	3.80	3.13	2.66
Co-variation coefficient, Γ_i^* (–)		1.19	1.06	1.01	0.95	0.90	0.81	0.81	0.70
Production tax credit, ptc ($¢/kWh)		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Adjusted unit revenue ($¢/kWh)		3.76	4.75	5.03	3.21	2.66	2.80	3.19	2.50
Levelized profit margin ($¢/kWh)		-8.08	-5.06	-1.58	-2.13	-1.62	-1.00	0.06	-0.16

*2: 5-year MACRS DDB depreciation, 3: 20 year 150%-declining balance depreciation, 5: 100% bonus depreciation.
[1] [53], [2] [38], [3] [54], [4] [55], [5] [56], [6] [57], [7] [58], [8] [23], [9] [59], [10] [60], [11] [51], [12] [32], [13] [33].

Supplementary Table 4. Cost and Price Dynamics for Wind in California.

in 2019 $US	Source	2012	2013	2014	2015	2016	2017	2018	2019
Input Parameters									
Useful lifetime, T (years)	[1]	30	30	30	30	30	30	30	30
System price, v ($/kW)	[13]	2,532	2,382	2,198	2,000	2,044	1,959	1,747	1,678
Fixed operating cost, F ($/kW)	[2]	21.30	25.27	22.10	20.04	24.35	25.76	23.07	21.94
Variable operating cost (ex. fuel) ($¢/kWh)		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fuel cost ($¢/kWh)		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
CO_2 emission cost ($/t CO_2)	[3]	10.09	12.83	11.65	12.44	12.73	14.30	14.91	16.84
Emission Performance (kg/kWh)		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Capacity factor, CF_i^* (%)	[2]	32.13	34.25	31.62	30.99	33.69	32.44	37.74	34.70
Cost of capital, r (%)	[4, 13]	5.47	5.46	5.25	4.92	4.68	4.80	5.15	4.50
Degradation factor, x (%)	[1, 5, 6]	99.20	99.20	99.20	99.20	99.20	99.20	99.20	99.20
Investment tax credit, ITC (%)		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
ITC capitalization, δ (%)		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Production tax credit, PTC_i^o ($¢/kWh)	[8]	2.22	2.26	2.26	2.30	2.33	1.90	1.45	0.98
State tax rate, α_s (%)	[9]	8.84	8.84	8.84	8.84	8.84	8.84	8.84	8.84
Federal tax rate, α_f (%)	[10]	35.00	35.00	35.00	35.00	35.00	35.00	21.00	21.00
State tax depreciation method (–)*	[11]	3	3	3	3	3	3	3	3
Federal tax depreciation method (–)*	[11]	2	2	2	2	2	2	5	5
Average wholesale power price, p_i ($¢/kWh)	[2]	3.17	4.48	5.01	3.37	2.96	3.48	3.96	3.55
Scenario 1									
Cost of capacity, c ($¢/kWh)		6.71	5.91	5.78	5.18	4.74	4.78	3.81	3.70
Tax factor, Δ (–)		1.12	1.12	1.11	1.11	1.10	1.10	1.03	1.03
Fixed operating cost, f ($¢/kWh)		0.82	0.92	0.87	0.80	0.90	0.99	0.76	0.79
Variable operating cost, w ($¢/kWh)		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
LCOE ($¢/kWh)		8.31	7.51	7.29	6.53	6.12	6.27	4.70	4.61
Adjusted unit revenue ($¢/kWh)		5.62	5.70	5.62	5.51	5.52	5.19	4.60	4.20
Levelized profit margin ($¢/kWh)		-2.69	-1.82	-1.68	-1.02	-0.60	-1.08	-0.10	-0.41
Scenario 2									
Cost of capacity, c ($¢/kWh)		6.71	5.91	5.78	5.18	4.74	4.78	3.81	3.70
Tax factor, Δ (–)		1.12	1.12	1.11	1.11	1.10	1.10	1.03	1.03
Fixed operating cost, f ($¢/kWh)		0.82	0.92	0.87	0.80	0.90	0.99	0.76	0.79
Variable operating cost, w ($¢/kWh)		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
LCOE ($¢/kWh)		8.31	7.51	7.29	6.53	6.12	6.27	4.70	4.61
Adjusted unit revenue ($¢/kWh)		5.43	5.50	5.40	5.28	5.27	4.92	4.32	3.90
Levelized profit margin ($¢/kWh)		-2.88	-2.02	-1.89	-1.26	-0.85	-1.35	-0.38	-0.71
Scenario 3									
Cost of capacity, c ($¢/kWh)		6.71	5.91	5.78	5.18	4.74	4.78	3.81	3.70
Tax factor, Δ (–)		1.12	1.12	1.11	1.11	1.10	1.10	1.03	1.03
Fixed operating cost, f ($¢/kWh)		0.82	0.92	0.87	0.80	0.90	0.99	0.76	0.79
Variable operating cost, w ($¢/kWh)		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
LCOE ($¢/kWh)		8.31	7.51	7.29	6.53	6.12	6.27	4.70	4.61
Co-variation coefficient, Γ_i^* (–)		0.94	0.97	0.99	0.99	0.98	0.96	0.99	0.92
Production tax credit, ptc ($¢/kWh)		2.04	2.08	2.05	2.05	2.05	1.67	1.07	0.70
Adjusted unit revenue ($¢/kWh)		5.01	6.41	7.00	5.40	4.94	5.02	5.00	3.97
Levelized profit margin ($¢/kWh)		-3.30	-1.10	-0.29	-1.13	-1.19	-1.25	0.30	-0.64

*2: 5-year MACRS DDB depreciation, 3: 20 year 150%-declining balance depreciation, 5: 100% bonus depreciation.
[1] [53], [2] [38], [3] [54], [4] [55], [5] [56], [6] [57], [7] [58], [8] [23], [9] [59], [10] [60], [11] [51], [12] [32], [13] [33].

Supplementary Table 5. Cost and Price Dynamics for NGCC in Texas.

in 2019 $US	Source	2012	2013	2014	2015	2016	2017	2018	2019
Input Parameters									
Useful lifetime, T (years)	[1]	30	30	30	30	30	30	30	30
System price, v ($/kW)	[2]	1,114	1,094	1,093	1,075	1,130	1,113	1,094	1,050
Fixed operating cost, F ($/kW)	[2]	18.54	16.94	16.61	17.26	17.02	14.81	15.41	13.97
Variable operating cost (ex. fuel) ($¢/kWh)	[2]	0.10	0.10	0.10	0.08	0.09	0.07	0.08	0.07
Fuel cost ($¢/kWh)	[2]	2.45	2.99	3.39	2.15	1.96	2.32	2.25	1.80
CO_2 emission cost ($/t CO_2)	[3]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emission Performance (kg/kWh)	[2]	0.39	0.40	0.39	0.41	0.38	0.36	0.37	0.39
Capacity factor, CF_i^* (%)	[2]	52.77	50.48	50.11	56.73	52.35	47.71	53.85	57.04
Cost of capital, r (%)	[4, 13]	5.47	5.46	5.25	4.92	4.68	4.80	5.15	4.50
Degradation factor, x (%)	[1, 5, 6]	99.60	99.60	99.60	99.60	99.60	99.60	99.60	99.60
Investment tax credit, ITC (%)		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
ITC capitalization, δ (%)		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Production tax credit, PTC_i^o ($¢/kWh)		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
State tax rate, α_s (%)	[9]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Federal tax rate, α_f (%)	[10]	35.00	35.00	35.00	35.00	35.00	35.00	21.00	21.00
State tax depreciation method (–)*	[11]	3	3	3	3	3	3	3	3
Federal tax depreciation method (–)*	[11]	3	3	3	3	3	3	5	5
Average wholesale power price, p_i ($¢/kWh)	[2]	3.01	3.49	4.16	2.74	2.36	2.59	3.37	3.76
Scenario 1									
Cost of capacity, c ($¢/kWh)		1.73	1.69	1.65	1.56	1.60	1.60	1.62	1.45
Tax factor, Δ (–)		1.20	1.20	1.19	1.19	1.18	1.18	1.00	1.00
Fixed operating cost, f ($¢/kWh)		0.42	0.38	0.37	0.39	0.38	0.33	0.35	0.31
Variable operating cost, w ($¢/kWh)		2.36	2.35	2.29	2.19	2.20	2.19	2.19	2.17
LCOE ($¢/kWh)		4.85	4.77	4.64	4.43	4.47	4.42	4.16	3.94
Adjusted unit revenue ($¢/kWh)		3.75	3.78	3.78	3.74	3.79	3.87	3.93	3.92
Levelized profit margin ($¢/kWh)		-1.10	-0.98	-0.85	-0.69	-0.68	-0.55	-0.23	-0.01
Scenario 2									
Cost of capacity, c ($¢/kWh)		2.12	2.13	2.14	2.11	2.26	2.33	2.42	2.31
Tax factor, Δ (–)		1.20	1.20	1.19	1.19	1.18	1.18	1.00	1.00
Fixed operating cost, f ($¢/kWh)		0.51	0.48	0.49	0.52	0.54	0.49	0.52	0.50
Variable operating cost, w ($¢/kWh)		2.49	2.49	2.44	2.34	2.36	2.37	2.38	2.40
LCOE ($¢/kWh)		5.55	5.54	5.49	5.36	5.57	5.61	5.32	5.21
Adjusted unit revenue ($¢/kWh)		3.84	3.89	3.91	3.87	3.98	4.11	4.22	4.28
Levelized profit margin ($¢/kWh)		-1.71	-1.65	-1.58	-1.48	-1.59	-1.50	-1.09	-0.92
Scenario 3									
Cost of capacity, c ($¢/kWh)		1.72	1.77	1.74	1.46	1.62	1.77	1.60	1.35
Tax factor, Δ (–)		1.20	1.20	1.19	1.19	1.18	1.18	1.00	1.00
Fixed operating cost, f ($¢/kWh)		0.42	0.40	0.39	0.36	0.39	0.37	0.34	0.29
Variable operating cost, w ($¢/kWh)		2.54	3.10	3.50	2.23	2.05	2.39	2.34	1.87
LCOE ($¢/kWh)		5.03	5.62	5.97	4.32	4.34	4.85	4.28	3.51
Co-variation coefficient, Γ_i^* (–)		1.11	1.09	1.10	1.10	1.11	1.10	1.17	1.27
Production tax credit, ptc ($¢/kWh)		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Adjusted unit revenue ($¢/kWh)		3.35	3.81	4.56	3.03	2.63	2.86	3.96	4.77
Levelized profit margin ($¢/kWh)		-1.68	-1.81	-1.41	-1.30	-1.72	-1.99	-0.32	1.26

*3: 20 year 150%-declining balance depreciation schedule, 5: 100% bonus depreciation.
[1] [53], [2] [38], [3] [54], [4] [55], [5] [56], [6] [57], [7] [58], [8] [23], [9] [59], [10] [60], [11] [51], [12] [32], [13] [33].

Supplementary Table 6. Cost and Price Dynamics for Solar PV in Texas.

in 2019 $US	Source	2012	2013	2014	2015	2016	2017	2018	2019
Input Parameters									
Useful lifetime, T (years)	[1]	30	30	30	30	30	30	30	30
System price, v ($/kW)	[12]	3,838	3,289	2,785	2,434	2,028	1,864	1,469	1,261
Fixed operating cost, F ($/kW)	[2]	12.98	10.12	11.16	8.58	7.22	6.70	8.52	9.03
Variable operating cost (ex. fuel) ($¢/kWh)		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fuel cost ($¢/kWh)		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
CO_2 emission cost ($/t CO_2)	[3]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emission Performance (kg/kWh)		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Capacity factor, CF_i^* (%)	[2]	21.78	19.25	20.82	20.02	18.66	24.39	26.38	25.48
Cost of capital, r (%)	[4, 13]	5.47	5.46	5.25	4.92	4.68	4.80	5.15	4.50
Degradation factor, x (%)	[1, 5, 6]	99.50	99.50	99.50	99.50	99.50	99.50	99.50	99.50
Investment tax credit, ITC (%)	[7]	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00
ITC capitalization, δ (%)	[1]	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00
Production tax credit, PTC_i^o ($¢/kWh)		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
State tax rate, α_s (%)	[9]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Federal tax rate, α_f (%)	[10]	35.00	35.00	35.00	35.00	35.00	35.00	21.00	21.00
State tax depreciation method (–)*	[11]	3	3	3	3	3	3	3	3
Federal tax depreciation method (–)*	[11]	2	2	2	2	2	2	5	5
Average wholesale power price, p_i ($¢/kWh)	[2]	3.01	3.49	4.16	2.74	2.36	2.59	3.37	3.76
Scenario 1									
Cost of capacity, c ($¢/kWh)		14.54	14.08	10.77	9.45	8.22	5.86	4.44	3.67
Tax factor, Δ (–)		0.68	0.68	0.68	0.68	0.67	0.67	0.66	0.66
Fixed operating cost, f ($¢/kWh)		0.72	0.63	0.65	0.52	0.47	0.33	0.39	0.43
Variable operating cost, w ($¢/kWh)		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
LCOE ($¢/kWh)		10.63	10.23	7.96	6.90	6.00	4.28	3.32	2.85
Adjusted unit revenue ($¢/kWh)		4.84	4.88	4.93	4.95	5.05	5.17	5.29	5.30
Levelized profit margin ($¢/kWh)		-5.79	-5.35	-3.03	-1.95	-0.96	0.88	1.97	2.46
Scenario 2									
Cost of capacity, c ($¢/kWh)		14.54	14.08	10.77	9.45	8.22	5.86	4.44	3.67
Tax factor, Δ (–)		0.68	0.68	0.68	0.68	0.67	0.67	0.66	0.66
Fixed operating cost, f ($¢/kWh)		0.72	0.63	0.65	0.52	0.47	0.33	0.39	0.43
Variable operating cost, w ($¢/kWh)		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
LCOE ($¢/kWh)		10.63	10.23	7.96	6.90	6.00	4.28	3.32	2.85
Adjusted unit revenue ($¢/kWh)		4.06	4.03	4.00	3.92	3.92	3.95	4.00	3.89
Levelized profit margin ($¢/kWh)		-6.57	-6.20	-3.97	-2.98	-2.09	-0.33	0.68	1.04
Scenario 3									
Cost of capacity, c ($¢/kWh)		14.54	14.08	10.77	9.45	8.22	5.86	4.44	3.67
Tax factor, Δ (–)		0.68	0.68	0.68	0.68	0.67	0.67	0.66	0.66
Fixed operating cost, f ($¢/kWh)		0.72	0.63	0.65	0.52	0.47	0.33	0.39	0.43
Variable operating cost, w ($¢/kWh)		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
LCOE ($¢/kWh)		10.63	10.23	7.96	6.90	6.00	4.28	3.32	2.85
Co-variation coefficient, Γ_i^* (–)		1.45	1.20	1.16	1.35	1.39	1.28	1.48	1.92
Production tax credit, ptc ($¢/kWh)		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Adjusted unit revenue ($¢/kWh)		4.35	4.20	4.82	3.69	3.28	3.32	4.99	7.22
Levelized profit margin ($¢/kWh)		-6.27	-6.02	-3.14	-3.21	-2.72	-0.97	1.67	4.37

*2: 5-year MACRS DDB depreciation, 3: 20 year 150%-declining balance depreciation, 5: 100% bonus depreciation.
[1] [53], [2] [38], [3] [54], [4] [55], [5] [56], [6] [57], [7] [58], [8] [23], [9] [59], [10] [60], [11] [51], [12] [32], [13] [33].

Supplementary Table 7. Cost and Price Dynamics for Wind in Texas.

in 2019 $US	Source	2012	2013	2014	2015	2016	2017	2018	2019
Input Parameters									
Useful lifetime, T (years)	[1]	30	30	30	30	30	30	30	30
System price, v ($/kW)	[13]	2,377	2,236	2,063	1,877	1,918	1,839	1,640	1,575
Fixed operating cost, F ($/kW)	[2]	25.51	24.97	20.88	18.33	23.12	24.02	23.50	20.79
Variable operating cost (ex. fuel) ($¢/kWh)		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fuel cost ($¢/kWh)		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
CO_2 emission cost ($/t CO_2)	[3]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Emission Performance (kg/kWh)		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Capacity factor, CF_i^* (%)	[2]	39.76	39.11	37.72	33.93	38.47	44.37	41.99	44.78
Cost of capital, r (%)	[4, 13]	5.47	5.46	5.25	4.92	4.68	4.80	5.15	4.50
Degradation factor, x (%)	[1, 5, 6]	99.20	99.20	99.20	99.20	99.20	99.20	99.20	99.20
Investment tax credit, ITC (%)		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
ITC capitalization, δ (%)		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Production tax credit, PTC_i^o ($¢/kWh)	[8]	2.22	2.26	2.26	2.30	2.33	1.90	1.45	0.98
State tax rate, α_s (%)	[9]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Federal tax rate, α_f (%)	[10]	35.00	35.00	35.00	35.00	35.00	35.00	21.00	21.00
State tax depreciation method (–)*	[11]	3	3	3	3	3	3	3	3
Federal tax depreciation method (–)*	[11]	2	2	2	2	2	2	5	5
Average wholesale power price, p_i ($¢/kWh)	[2]	3.01	3.49	4.16	2.74	2.36	2.59	3.37	3.76
Scenario 1									
Cost of capacity, c ($¢/kWh)		5.09	4.86	4.55	4.44	3.90	3.28	3.21	2.69
Tax factor, Δ (–)		1.07	1.07	1.07	1.07	1.06	1.07	1.00	1.00
Fixed operating cost, f ($¢/kWh)		0.80	0.79	0.69	0.67	0.75	0.67	0.70	0.58
Variable operating cost, w ($¢/kWh)		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
LCOE ($¢/kWh)		6.26	6.01	5.55	5.41	4.89	4.17	3.91	3.27
Adjusted unit revenue ($¢/kWh)		4.64	4.68	4.62	4.53	4.55	4.25	3.72	3.37
Levelized profit margin ($¢/kWh)		-1.62	-1.33	-0.94	-0.88	-0.35	0.07	-0.19	0.10
Scenario 2									
Cost of capacity, c ($¢/kWh)		5.09	4.86	4.55	4.44	3.90	3.28	3.21	2.69
Tax factor, Δ (–)		1.07	1.07	1.07	1.07	1.06	1.07	1.00	1.00
Fixed operating cost, f ($¢/kWh)		0.80	0.79	0.69	0.67	0.75	0.67	0.70	0.58
Variable operating cost, w ($¢/kWh)		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
LCOE ($¢/kWh)		6.26	6.01	5.55	5.41	4.89	4.17	3.91	3.27
Adjusted unit revenue ($¢/kWh)		4.47	4.49	4.41	4.29	4.28	3.95	3.41	3.02
Levelized profit margin ($¢/kWh)		-1.79	-1.52	-1.15	-1.12	-0.61	-0.22	-0.50	-0.25
Scenario 3									
Cost of capacity, c ($¢/kWh)		5.09	4.86	4.55	4.44	3.90	3.28	3.21	2.69
Tax factor, Δ (–)		1.07	1.07	1.07	1.07	1.06	1.07	1.00	1.00
Fixed operating cost, f ($¢/kWh)		0.80	0.79	0.69	0.67	0.75	0.67	0.70	0.58
Variable operating cost, w ($¢/kWh)		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
LCOE ($¢/kWh)		6.26	6.01	5.55	5.41	4.89	4.17	3.91	3.27
Co-variation coefficient, Γ_i^* (–)		0.89	0.95	0.92	0.89	0.91	0.93	0.85	0.76
Production tax credit, ptc ($¢/kWh)		1.86	1.89	1.87	1.87	1.86	1.53	0.98	0.64
Adjusted unit revenue ($¢/kWh)		4.54	5.20	5.72	4.31	4.02	3.94	3.85	3.52
Levelized profit margin ($¢/kWh)		-1.72	-0.81	0.16	-1.10	-0.88	-0.23	-0.05	0.24

*2: 5-year MACRS DDB depreciation, 3: 20 year 150%-declining balance depreciation, 5: 100% bonus depreciation.
[1] [53], [2] [38], [3] [54], [4] [55], [5] [56], [6] [57], [7] [58], [8] [23], [9] [59], [10] [60], [11] [51], [12] [32], [13] [33].

Supplementary Table 8. Projected cost and price parameters in California.

		NGCC			Solar PV	Wind
Year	p_i	w_i	CF_i^*	Γ_i^*	Γ_i^*	Γ_i^*
2020	3.47	3.34	44.44	1.19	0.74	0.92
2021	3.45	3.44	40.97	1.23	0.72	0.92
2022	3.40	3.47	39.93	1.25	0.70	0.92
2023	3.35	3.53	38.54	1.28	0.68	0.93
2024	3.36	3.67	36.11	1.31	0.67	0.93
2025	3.39	3.96	31.94	1.36	0.65	0.94
2026	3.41	4.27	25.35	1.42	0.63	0.94
2027	3.42	4.47	22.57	1.47	0.62	0.95
2028	3.37	4.61	20.49	1.51	0.60	0.95
2029	3.32	4.67	19.10	1.55	0.59	0.96
2030	3.28	4.67	20.14	1.57	0.58	0.97
2031	3.23	4.66	20.14	1.60	0.57	0.98
2032	3.18	4.74	19.44	1.63	0.55	0.98
2033	3.18	4.86	19.10	1.67	0.54	0.99
2034	3.17	4.97	18.75	1.70	0.53	1.00
2035	3.12	5.03	18.40	1.74	0.52	1.01
2036	3.09	5.09	18.40	1.77	0.51	1.02
2037	3.07	5.21	17.36	1.81	0.51	1.03
2038	3.07	5.31	17.01	1.85	0.50	1.05
2039	3.05	5.39	16.32	1.89	0.49	1.06
2040	3.01	5.48	15.28	1.94	0.48	1.07
2041	2.99	5.56	15.28	1.98	0.47	1.08
2042	2.97	5.67	14.93	2.03	0.47	1.10
2043	2.95	5.79	14.58	2.07	0.46	1.11
2044	2.95	5.90	14.58	2.11	0.46	1.12
2045	2.94	6.03	14.24	2.16	0.45	1.14
2046	2.92	6.18	13.19	2.21	0.45	1.15
2047	2.93	6.34	12.85	2.26	0.44	1.17
2048	2.93	6.50	12.50	2.32	0.44	1.18
2049	2.92	6.65	11.81	2.37	0.43	1.20

p_i: average electricity market price in year i ($¢/kWh), w_i: variable operating cost in year i ($¢/kWh), CF_i^*: capacity factor in year i (%), Γ_i^*: co-variation coefficient in year i (–), $-values are in 2019 $US.

Supplementary Table 9. Projected cost and price parameters in Texas.

		NGCC			**Solar PV**	**Wind**
Year	p_i	w_i	CF_i^*	Γ_i^*	Γ_i^*	Γ_i^*
2020	3.08	2.10	61.46	1.17	1.36	0.88
2021	3.05	2.15	60.07	1.17	1.34	0.87
2022	3.01	2.15	55.21	1.20	1.33	0.86
2023	2.97	2.17	53.47	1.21	1.32	0.85
2024	2.97	2.25	47.57	1.26	1.31	0.85
2025	3.00	2.44	40.28	1.34	1.30	0.84
2026	3.02	2.63	30.56	1.50	1.29	0.83
2027	3.03	2.76	26.74	1.58	1.28	0.83
2028	2.99	2.83	25.00	1.62	1.28	0.82
2029	2.94	2.84	23.61	1.66	1.27	0.81
2030	2.91	2.80	23.61	1.66	1.26	0.81
2031	2.86	2.77	23.61	1.66	1.26	0.80
2032	2.82	2.78	22.22	1.70	1.25	0.80
2033	2.82	2.83	21.18	1.74	1.25	0.79
2034	2.80	2.87	20.49	1.77	1.24	0.79
2035	2.76	2.87	19.44	1.81	1.24	0.78
2036	2.74	2.86	19.10	1.83	1.23	0.78
2037	2.72	2.90	18.40	1.86	1.23	0.78
2038	2.72	2.92	18.40	1.87	1.23	0.77
2039	2.70	2.93	16.67	1.95	1.23	0.77
2040	2.67	2.94	16.32	1.98	1.22	0.77
2041	2.65	2.93	16.32	1.99	1.22	0.76
2042	2.63	2.95	15.97	2.02	1.22	0.76
2043	2.61	2.97	15.97	2.03	1.22	0.76
2044	2.61	2.98	15.97	2.04	1.22	0.75
2045	2.60	3.00	15.63	2.07	1.22	0.75
2046	2.59	3.02	15.63	2.09	1.22	0.75
2047	2.60	3.06	15.28	2.12	1.22	0.75
2048	2.59	3.09	15.28	2.14	1.22	0.75
2049	2.58	3.10	15.28	2.15	1.22	0.74

p_i: average electricity market price in year i (\$¢/kWh), w_i: variable operating cost in year i (\$¢/kWh), CF_i^*: capacity factor in year i (%), Γ_i^*: co-variation coefficient in year i (–), \$-values are in 2019 \$US.

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