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The economic dynamics of competing power generation sources

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ABSTRACT

Competing power generation sources have experienced considerable shifts in both their revenue potential and their costs 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 during the years 2012–2019, primarily due to falling life-cycle costs of production. In California, these gains far outweigh an emerging "cannibalization" effect that results from substantial additions of solar power having made energy less valuable in the middle of the day. As such, intermittent renewables in both states have been approaching or exceeding the break-even value of zero for the estimated LPMs. We also find the competitiveness of natural gas power plants to have either improved in Texas or held steady at negative LPMs in California. For these plants, declining capacity utilization rates have effectively been counterbalanced by a "dispatchability price premium" that reflects the growing market share of intermittent renewables.

1. Introduction

As countries around the world seek to decarbonize their grids, it remains a matter of debate how competitive renewable power sources are in comparison to those based on fossil fuels. The life-cycle cost of renewables, in particular wind and solar power, is widely acknowledged to have fallen substantially over time [1–4]. Once deployed, these power sources also have effective priority in the marketplace due to their zero short-run production cost. At the same time, dispatchable generation sources have experienced higher average costs on account of their lower capacity utilization rates at times when renewables are near peak capacity [5–7]. While these cost effects favor renewable power, countervailing effects emerge on the revenue side [8]. First, renewables are increasingly subject to 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 near peak capacity [9–15]. Correspondingly, dispatchable energy sources earn a price premium at times of limited supply capacity due to the intermittency of renewables [16–18].

Here we introduce a profitability metric, termed the *Levelized Profit Margin* (LPM), that captures the relevant unit economics of both intermittent and dispatchable power sources on a life-cycle basis. Earlier studies have pointed out that the profitability and value creation of intermittent renewables cannot be assessed by simply comparing average market prices to the Levelized Cost of Electricity (LCOE). The reason is that such comparisons do not appropriately capture that intermittent renewables are subject to time-varying capacity constraints [13,19]. A similar argument applies to dispatchable generation technologies that optimize their capacity utilization in response to the revenues and variable operating costs available at different points in time. The LPM, in contrast, is based on two constituent metrics: the Levelized Revenue of Electricity (LROE) and the LCOE. Investment in a new power plant is shown to be economically profitable if and only if the LROE exceeds the LCOE.

For both intermittent and dispatchable power sources, the concept development of the LROE and the LCOE metric hinges on optimized and endogenous capacity factors, reflecting that capacity will be utilized only at times when the attainable revenue exceeds the short-run production cost. Key to the calculation of the LROE 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 factors [20]. These adjustments vary by year but take the same form for intermittent and dispatchable generation technologies.

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List of symbols and acronyms

α	Corporate income tax rate (%)
$b(t)$	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 (–)
$I_i(t)$	Indicator variable specifying an hour of critical peak demand (–)
Inc_i	Taxable income in year i ($/kW)
ITC	Investment tax credit (%)
kW	Kilowatt
kWh	Kilowatt hour
L	Levelization factor (–)
$LCOE(\cdot)$	Levelized cost of electricity ($/kWh)
$LROE(\cdot)$	Levelized revenue of electricity ($/kWh)
$LPM(\cdot)$	Levelized profit margin ($/kWh)
m	Number of hours per year (–)
$\mu_i(t)$	Multiplicative deviation of prices at time t in year i (–)
NGCC	Natural gas combined-cycle
$p_i(t)$	Unit revenue of electricity at time t of year i ($/kWh)
PTC_i	Production tax credit in year i ($/kWh)
PV	Photovoltaic
q_i	Effective capacity price ($/kWh)
r	Cost of capital (%)
$Rev_i(t)$	Operating revenue at time t in year i ($/kW)
T	Useful life of capacity (years)
US	United States
v	System price of capacity ($/kW)
w	Levelized variable operating cost ($/kWh)
w_i	Variable operating cost in year i ($/kWh)
x_i	Degradation of capacity in year i (%)

Earlier studies in the energy economics literature have proposed different measures for capturing select changes in the competitiveness of alternative power generation sources (e.g., [20–23]). Our analysis unifies these studies by developing a generic profitability metric for assessing the unit economics of both intermittent and dispatchable power generation sources. Importantly, this metric is demonstrated to align with the criterion of discounted after-tax cash flows in order to assess economic profitability. Applying this profitability analysis to overlapping generations of new power plants built over a decade allows us to integrate and quantify the countervailing effects that have resulted from technological improvements [1–4], shifts in capacity utilization [5–7], cannibalization [9–15,24], and the dispatchability price premium [16–18].

Our calculations focus on solar photovoltaic (PV), onshore wind, and natural gas combined-cycle (NGCC) power plants in the context of the Texas and California wholesale electricity markets for the years 2012–2019. California has achieved a comparatively high penetration of solar PV in its electricity mix, while a similar trend has emerged for onshore wind in Texas. Furthermore, both states have long relied on natural gas for power generation. Some new capacity investments in wind and solar farms in both states were presumably based on criteria that extend beyond basic net present value considerations, e.g., the renewable portfolio standard in California. In addition, some "impact investors", such as technology firms, have justified investments in renewable energy projects with an eye to carbon offsets for their own energy consumption [25,26].

Our main empirical results indicate that the economic profitability of new wind and solar energy projects has improved considerably during the years 2012–2019, recently approaching or exceeding the break-even value of zero for the estimated LPM. This finding primarily reflects substantial declines in the life-cycle costs of these power sources. In California, these cost reductions of solar PV far outweigh a growing cannibalization effect [9–11,21], bringing the LPM close to the benchmark value of zero by 2019. In Texas, a state where solar power still has a relatively modest market share, recent new solar plants are projected to be the most profitable on account of the falling LCOE and a growing price premium.

For NGCC power plants in California, we find that falling capacity utilization rates have been counterbalanced by an increasing dispatchability price premium. In conjunction with higher variable costs resulting from carbon pricing, these countervailing trends have resulted in steady, though continually negative LPMs. In contrast, NGCC plants in Texas have become more profitable on account of the dispatchability price premium associated with higher utilization rates at times of higher power prices.

A common assumption maintained in earlier studies [21,24,27] is that of "stationary environments," where investors at each point in time assume that current revenues and costs in the first year of operation will also prevail in future years. Our analysis, in contrast, allows for non-stationary environments by specifying alternative belief scenarios regarding investors' expectations for the future market dynamics. In particular, we present three scenarios that are intended to capture a range of potential beliefs that investors may have held. While all three belief scenarios deliver a consistent assessment regarding the magnitudes and trends in profitability, our results also show that the assumption of a hypothetical stationary environment can lead to markedly different LPM estimates. In the case of solar PV, for instance, this is because the LCOE is reflective of cost reductions achieved so far, while the LROE ignores the potential of a growing cannibalization effect going forward.

2. Unit economics of power generation

Consider an electricity market in which multiple generation technologies compete in terms of cost and the ability to generate power at different points in time. Individual suppliers are assumed to be price-takers who can idle generation capacity whenever the attainable revenue falls below the short-run marginal cost.

2.1. Levelized cost of electricity

A standard metric for comparing the cost of alternative power generation technologies is the *Levelized Cost of Electricity* (LCOE). This metric aggregates a share of upfront capacity expenditures and all periodic cash outflows after taxes to arrive at the unit cost of 1 kilowatt hour (kWh) of electricity for a facility that has a useful life of T years [28,29]. A critical variable for the LCOE is the anticipated number of hours that the facility in question will be generating power. To that end, denote by $m \equiv 8,760$ the hours per year and by CF_i the capacity factor in year i, that is the power actually generated in that year as a percentage of the available capacity. Since for some generation technologies productive capacity degrades over time, we introduce the factor x_i representing the fraction of the initial capacity that is still available in year i.

Suppose the upfront cash expenditure per kilowatt (kW) of power generation capacity is v. This upfront capacity investment inherently reflects a joint cost shared by all kWh 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. Let r denote the applicable cost of capital and $\gamma = \frac{1}{1+r}$ the corresponding discount factor. With $\vec{CF} = (CF_1, \dots, CF_T)$, the levelization factor is given by:

$$L(\vec{CF}) \equiv m \cdot \sum_{i=1}^{T} CF_i \cdot x_i \cdot \gamma^i. \quad (1)$$

In addition to upfront capacity expenditures, the power plant incurs fixed and variable costs 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 (CO_2) emissions are variable and assumed to increase proportionally with the output produced. For wind and solar power, variable costs are effectively zero. If F_i denotes the fixed costs per kW of installed capacity and w_i the variable cost per kWh in year i, the three principal components of the LCOE metric are:

$$c \equiv \frac{v}{L(\vec{CF})}, \qquad f \equiv \frac{\sum_{i=1}^{T} F_i \cdot \gamma^i}{L(\vec{CF})}, \qquad w \equiv \frac{m \cdot \sum_{i=1}^{T} w_i \cdot CF_i \cdot x_i \cdot \gamma^i}{L(\vec{CF})}. \quad (2)$$

Investment 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. The overall cost of capital, r, equals the weighted average cost of capital, provided the cost of debt is incorporated on an after-tax basis to reflect the debt tax shield [30]. The impact of corporate income taxes, including any 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:

$$\Delta = \frac{1 - ITC - \alpha \cdot (1 - \delta \cdot ITC) \cdot \sum_{i=0}^{T} d_i \cdot \gamma^i}{1 - \alpha}. \quad (3)$$

Here, ITC denotes the investment tax credit that the United States (US) federal tax code grants for some renewable energy sources, specifically for solar PV installations [31]. 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 US, $\delta = 50\%$ 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 US 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 [32]. The derivation of the tax factor in Eq. (3) applies to a setting in which the firm is only subject to federal taxation. A generalized formulation with both federal and state income taxes, as is applicable in California, is provided in Supplementary Note 1.

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

$$LCOE(\vec{CF}) \equiv c \cdot \Delta + f + w, \quad (4)$$

where $\vec{CF} = (CF_1, \dots, CF_T)$ highlights the dependence of the LCOE on the entire sequence of capacity utilization rates for the years $1 \leq i \leq T$. It is readily verified that, consistent with the verbal definition of the LCOE, an investor would exactly break even in terms of discounted cash flows if hypothetically all electricity generated over the useful life of the facility were sold at the constant price equal to $LCOE(\vec{CF})$ per kWh.

2.2. *Levelized revenue of electricity*

To capture the value generation potential of a power source, we introduce a corresponding value metric termed the *Levelized Revenue of Electricity* (LROE). To that end, let $p_i^o(t)$ denote the market price for electricity per kWh at which power is sold in hour t of year i, where $t \in [0, m]$. In addition to the spot market price, some US states, including California, pay producers a capacity premium for making power available during critical hours of peak demand during the year. This introduces an indicator variable $I_i(t)$ that is equal to 1 if t refers to such a critical hour and zero otherwise. The effective capacity premium for 1 kW made available for 1 h, denoted by q_i, is fixed for each calendar year in California [11,33]. The overall revenue that the facility can therefore obtain per kWh in hour t of year i then becomes $p_i(t) \equiv p_i^o(t) + q_i \cdot I_i(t)$. Furthermore, wind power in the US is eligible for production tax credits in the after-tax amount of PTC_i per kWh of power generated in year i [34].[1]

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, $b(t)$ is determined exogenously by the availability of the natural resource, i.e., solar insolation or wind speed. The base model 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. Such frictions can readily be incorporated into the model (see, for instance, exercise 17.2 in [35]). Our numerical analysis relies on observed capacity factors, which can be assumed to be optimized as we will discuss.

Given the hourly revenues the facility will choose the capacity factor $CF_i^*(t)$ to maximize:

$$\left[p_i(t) + PTC_i - w_i\right] \cdot CF_i(t) \quad \text{subject to:} \quad 0 \leq CF_i(t) \leq b(t). \quad (5)$$

Efficient capacity utilization thus requires that $CF_i^*(t) = b(t)$ if $p_i(t) + PTC_i > w_i$, while $CF_i^*(t) = 0$ if $p_i(t) + PTC_i < w_i$. 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:

$$\epsilon_i^*(t) \cdot CF_i^* \equiv CF_i^*(t), \text{ and } \mu_i(t) \cdot p_i \equiv p_i(t), \quad (6)$$

where

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

Any synergies, positive or negative, between optimized capacity utilization and the unit revenues available at different hours of the year can be captured by a technology-specific *co-variation coefficient*:

$$\Gamma_i^* \equiv \frac{1}{m} \int_0^m \epsilon_i^*(t) \cdot \mu_i(t)\, dt. \quad (7)$$

[1] Power plants in some jurisdictions may obtain additional revenues, for instance, from providing ancillary services or, in the case of renewable energy sources, from the sale of renewable energy credits.

By construction, Γ_i^* is above (below) 1.0 whenever a plant produces most of its annual output during periods of above-average (below-average) unit revenues. As such, the co-variation coefficient quantifies any value penalty that intermittent renewables may exhibit during periods of above-average power generation, once they have achieved significant market share. It also captures the value premium that dispatchable plants can earn at times of limited power supply, possibly due to renewables being inactive.

Earlier studies on the cannibalization effect for renewables often rely on a "value factor" [9,11–13,17,21]. This factor is described as the ratio between the average value of electricity produced and the average price of electricity. It is consistent with our specification of co-variation coefficients if (i) the average value of electricity produced is calculated as the revenue resulting from the sale of electricity in one year divided by the amount of electricity produced in that year, and (ii) the average price of electricity reflects the average of prices across the hours of the year.

Our LROE metric aggregates the sequence of optimized average future revenues, as obtained from annual average revenues and the technology-specific co-variation coefficients. On a levelized basis, the LROE is calculated as the total discounted optimized annual revenue obtained over the life of the facility divided by the total discounted amount of electricity produced. The LROE is thus given by:

$$LROE(\vec{CF}^*) \equiv \frac{m \cdot \sum_{i=1}^{T} [p_i \cdot \Gamma_i^* + PTC_i] \cdot CF_i^* \cdot x_i \cdot \gamma^i}{m \cdot \sum_{i=1}^{T} CF_i^* \cdot x_i \cdot \gamma^i}. \tag{8}$$

In direct analogy to the interpretation of the LCOE, an investor would exactly break even in terms of discounted cash flows if hypothetically all electricity generated over the useful life of the facility could be procured at the constant cost of \$LROE per kWh. We note in passing that in the special case where the entire lifetime energy generated by the power plant attains a constant unit revenue per kWh, possibly because of a power purchasing agreement between the investor and an off-taker, the LROE reduces to this unit revenue because the co-variation coefficients are equal to one.

2.3. Levelized profit margin

Investment in a particular energy generation technology is said to be economically profitable if it generates a positive net present value. Our main analytical result states that economic profitability is aligned with the criterion that the LROE exceeds the LCOE.

Proposition 1. *Given a trajectory of future annual revenue distributions $(p_1(\cdot), \dots, p_T(\cdot))$, unit variable costs $(w_1, \dots, w_T)$ and optimized annual capacity factors $\vec{CF}^* \equiv (CF_1^*, \dots, CF_T^*)$, investment in a particular power generation technology is economically profitable if and only if $LROE(\vec{CF}^*) \geq LCOE(\vec{CF}^*)$.*

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

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

where PTC_i^o denotes the nominal production tax credit in year i. 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:

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

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:

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

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

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

where the last term on the right-hand side reflects that the production tax credits are not subject to corporate income taxation. The capacity factor at time t in year i will be chosen so as to maximize:

$$\left[p_i^o(t) + q_i \cdot I_i(t) + \frac{PTC_i^o}{(1-\alpha)} - w_i\right] \cdot CF_i(t).$$

To consolidate the components of revenue, we define $PTC_i \equiv \frac{PTC_i^o}{(1-\alpha)}$ and $p_i(t) \equiv p_i^o(t) + q_i \cdot I_i(t)$. Thus, $CF_i^*(t) = b(t)$ if $p_i(t) + PTC_i > w_i$ and $CF_i^*(t) = 0$ if $p_i(t) + PTC_i < w_i$. 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 (3), 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:

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

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

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

Dividing by the levelization factor, $L(\vec{CF}^*)$, in (1) and recalling the definitions of w, f, and c in (2), the right-hand side of (12) reduces to $LCOE(\vec{CF}^*)$, as defined in (4). Correspondingly, the left-hand side of (12) reduces to $LROE(\vec{CF}^*)$, as defined in (8). Thus, the project net present value is non-negative if and only if:

$$LROE(\vec{CF}^*) - LCOE(\vec{CF}^*) \geq 0. \quad \square$$

The finding reported in the above Proposition builds on and unifies earlier findings that have captured the revenue potential of intermittent renewable power sources [20–23,27]. In order to accommodate both intermittent and dispatchable power technologies, both the LROE and the LCOE metric of a generation technology must be based on the same optimized and endogenous capacity factors. Both metrics further depend on the anticipated sequence of future cost and revenue distributions. Finally, in the calculation of the LROE, annual average unit revenue must be adjusted by the annual co-variation coefficients in order to capture the covariance between fluctuations in electricity prices and optimized capacity factors [20]. Accordingly, these coefficients are technology-specific.

We define the *Levelized Profit Margin* (LPM) as the difference between LROE and LCOE. In our baseline formulation the LPM is stated in terms of a given trajectory of future revenue distributions and variable costs. Yet, these future parameters will generally be uncertain at the time of investment. We note that holding the optimized capacity factors fixed (as they effectively are for wind and solar power), the expected net present value of an investment, relative to any given beliefs, is positive if and only if the expected LPM is positive. In that sense, risk-neutral investors would judge investments by the difference between their expected LROE and LCOE.

A common assumption invoked in earlier studies [21,24,27] is that the cost and revenue distributions observed in the first year of operation will prevail over the entire lifetime of a facility. In such a "stationary environment," where both the distribution of unit revenues $p_i(t)$ and the unit variable costs w_i are constant across the years, the aggregate LPM reduces to:

$$LPM^o = \Gamma^* \cdot p - LCOE(CF^*).$$

For stationary environments, one thus obtains a concise condition for a competitive long-run equilibrium in which installations earn zero LPMs: the ratios $\frac{LCOE(CF^*)}{\Gamma^*}$ must be the same for all active generation technologies and equal to the average market price, p. For the reasons described in Section 1, we do not expect the zero economic profit condition to hold in our numerical analysis of either of the two market settings we examine. Nonetheless, we find that the LPMs of the generation sources considered in this paper generally approach the benchmark value of zero by the year 2019.

3. Market dynamics in California and Texas

We calibrate our model framework for natural gas combined-cycle (NGCC) turbines, utility-scale solar PV plants, and onshore wind power installations. Our calculations rely on the day-ahead electricity wholesale markets in California and Texas. Both states have deregulated their power markets and traditionally obtained a large share of their electricity from natural gas. Furthermore, California's investments in renewable energy have focused on solar PV, while wind power has become the dominant renewable source in Texas [36]. As detailed in Supplementary Note 2, our calculations rely on data collected from multiple sources including industry databases, technical reports, and journal articles. The requisite information became available in its entirety in the year 2012.

Fig. 1 shows the trajectory of the main cost and revenue parameters underlying the LPMs for the years 2012–2019 (details in Supplementary Tables 1–6). The average revenue per kWh fluctuated in both states across the years. Differences in the unit revenues between California and Texas partly result from the capacity premium that is offered in California.

The decline in unit variable costs for NGCC plants in Texas (Fig. 1e) reflects the impact of hydraulic fracking on the price of natural gas [37]. While NGCC plants in California also experienced falling fuel costs, their variable cost trajectory reflects rising charges for CO_2 emission allowances under California's cap-and-trade system [38]. NGCC plants in Texas experienced slightly increasing capacity factors (Fig. 1g) and co-variation coefficients (Fig. 1h) that were consistently above one, as these plants began to substitute for coal-fired power generation [5]. In contrast, NGCC plants in California experienced a relegation effect, as evidenced by the drop in capacity factors due to renewables expanding their market share [6,16]. Yet, this drop was counterbalanced by a rising price premium which is reflected in co-variation coefficients that rose from about 1.1 to above 1.2.

For wind and solar PV, Fig. 1 shows that system prices fell rapidly, while the capacity factors increased over the past decade. This is consistent with the widely reported learning-by-doing effects driven by cumulative deployments of each technology [39]. The increased capacity factors for solar PV are largely due to the introduction of axis trackers [40], while the higher utilization rates for wind turbines stem from larger rotors and turbine towers [41].

Fig. 1 further shows that for the two dominant renewable sources, that is, solar PV in California and wind energy in Texas, the co-variation coefficients fell to about 0.70 and 0.75, respectively, by 2019. While in 2012 wind power in Texas already faced a penalty of about 10% for primary generation at night, solar PV in California still exhibited synergies of about 35% with market prices that were above average during the day [27]. The significant decline in the coefficients in California illustrates the cannibalization effect [9–11,21]. 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 local heat waves led to strong electricity demand from air conditioning [42].

4. Estimates of the levelized profit margins

This section reports estimates of the LPMs for NGCC, solar PV, and onshore wind installations in California and Texas over the years 2012–2019. These profitability estimates must specify what investors anticipated at particular points in time regarding the trajectory of future electricity price distributions and variable costs of production. To check our estimates for robustness, our calculations are based on three alternative scenarios, with each one specifying investors' beliefs regarding future revenues and costs.

In the first scenario, investors are assumed to have anticipated the distributions of unit revenues and variable costs with perfect foresight up to the year 2019. Beyond that, they are assumed to have partly relied on forecasts by the US Energy Information Administration [36]. These forecasts project the price for natural gas to increase moderately over the coming years. Furthermore, wholesale power prices are expected to fall slightly on average due to the growing share of low-cost renewables. For the hourly distributions of electricity prices in a particular year, investors are assumed to have extrapolated from the observed price dynamics in recent years (details in Supplementary Note 2). These extrapolations effectively magnify the growing volatility in daily and seasonal wholesale electricity prices [43].

The dashed colored lines in Fig. 2 show the trajectories of the LCOE for the three technologies we consider in both Texas and California. These LCOE estimates are generally within the range reported in journal articles and by industry analysts [40,41,44,45].[2] As one might expect, the LCOE estimates for renewables exhibited fast declines on account of falling system prices. Since 2018 all generation technologies have 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 Supplementary Tables 1–6). The pattern of relatively constant LCOEs for NGCC plants in both jurisdictions is the aggregate effect of three factors pointing in opposite directions: lower prices for natural gas and, in the case of California, higher CO_2 emission charges as well as the relegation effect corresponding to lower capacity utilization at NGCC facilities.

One conclusion emerging from Fig. 2 is that 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 beliefs about the future than assumed in our calculations, factors beyond economic profitability must have motivated new capacity additions. One potential explanation for this is that Californian utilities were subject to a renewable portfolio standard. We also note that there were relatively few capacity additions for NGCC plants in California during the past decade [46]. Furthermore, many new renewable power facilities built in both states were arguably justified as "impact investments." Technology firms, in particular, have long made voluntary decarbonization pledges. Carbon-free energy delivered by renewables is then counted as an offset for the CO_2 emissions associated with grid electricity [25,26].

[2] For instance, [41] estimates the average LCOE of wind power plants in Texas to have declined from about ¢7.0/kWh in 2012 to about ¢3.0/kWh in 2019 in terms of 2019 $US. Similarly, the average LCOE of solar PV in California has fallen from about ¢11.5/kWh in 2012 to around ¢4.0/kWh [40].

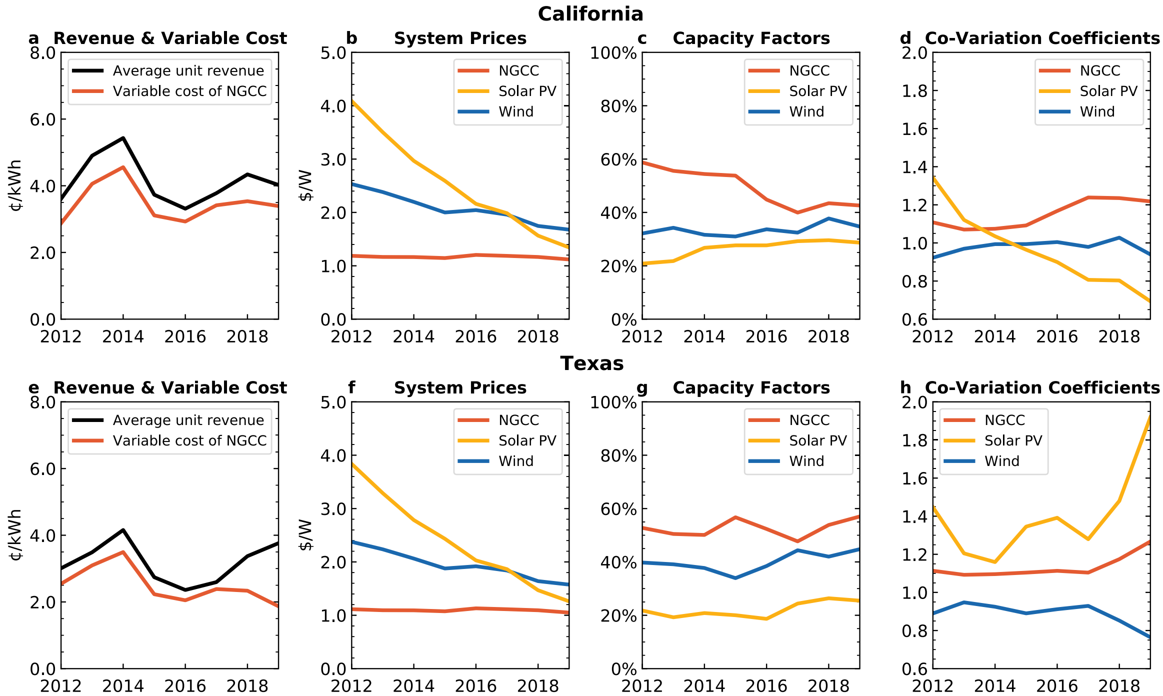

Fig. 1. Dynamics of key cost and revenue parameters. a, b, c, d, e, f, g, h, This figure shows the trajectory of average unit revenue and variable operating cost (a and e), system prices (b and f), optimized capacity factors (c and g), and co-variation coefficients (d and h) for NGCC turbines, solar PV, and onshore wind in California and Texas between the years 2012–2019. $-values are in 2019 $US.

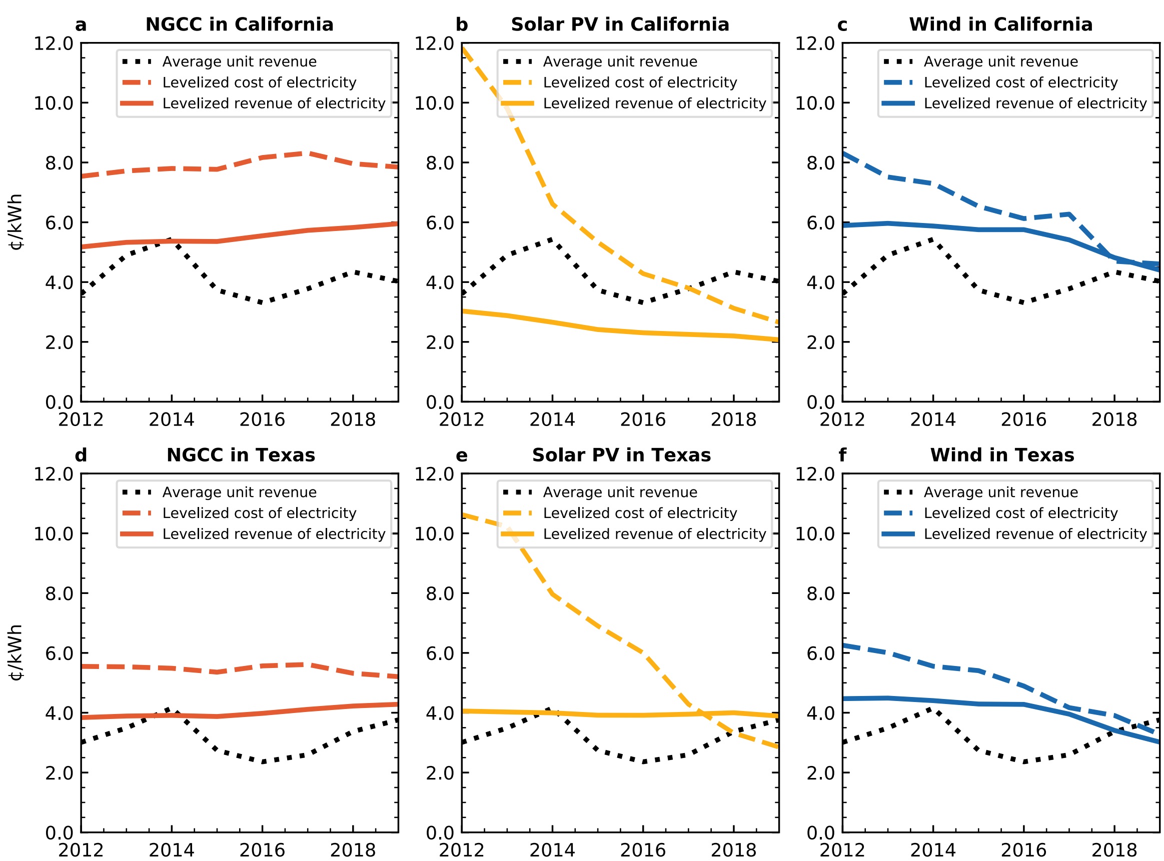

Fig. 2. Trajectory of levelized profit margins (Scenario 1). a, b, c, d, e, f, This figure shows the trajectory of levelized profit margins for NGCC turbines in California (a), solar PV in California (b), onshore wind in California (c), NGCC turbines in Texas (d), solar PV in Texas (e), and onshore wind in Texas (f) as the difference between the weighted average of adjusted unit revenues (colored solid lines) and LCOE (colored dashed lines).

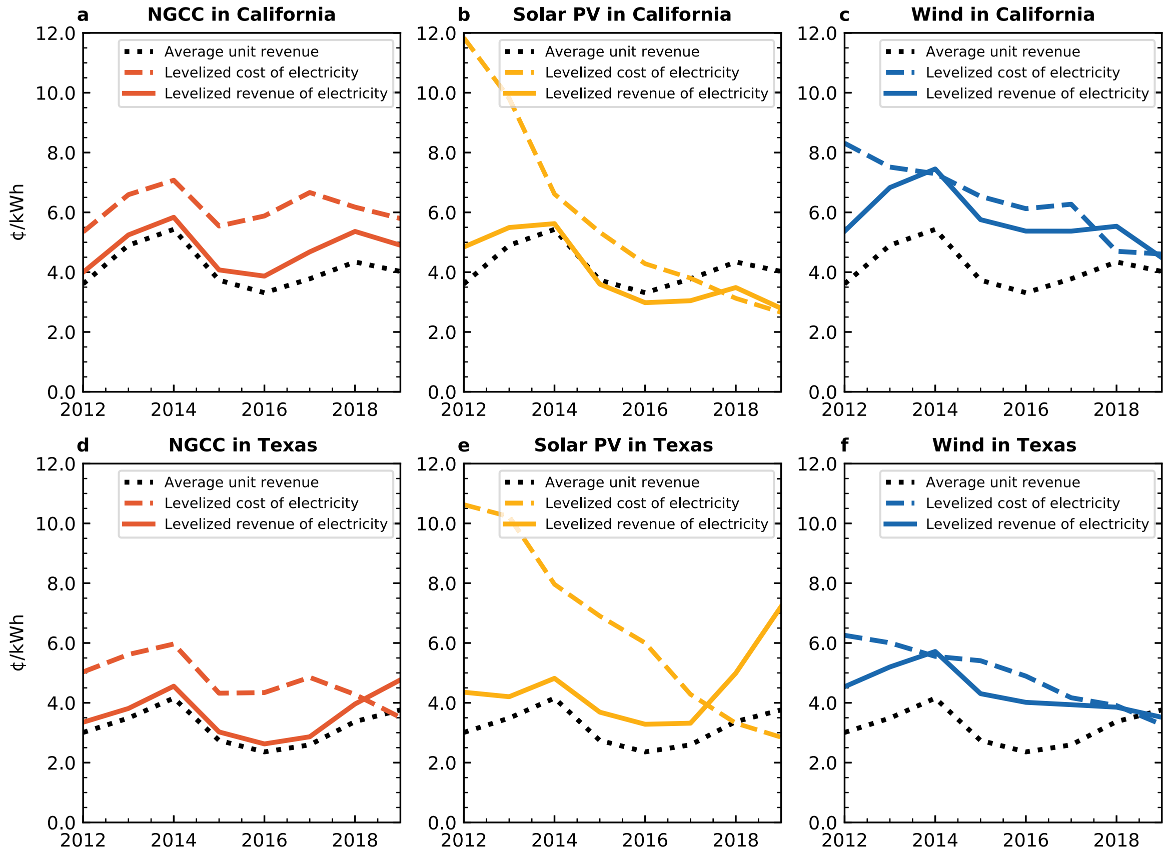

Fig. 3. Trajectory of levelized profit margins (Scenario 2). a, b, c, d, e, f, This figure shows the trajectory of levelized profit margins for NGCC turbines in California (a), solar PV in California (b), onshore wind in California (c), NGCC turbines in Texas (d), solar PV in Texas (e), and onshore wind in Texas (f) as the difference between the weighted average of adjusted unit revenues (colored solid lines) and LCOE (colored dashed lines).

Another pattern emerging from Fig. 2 is that the LPMs have been consistently improving. 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 renewable power sources, we find that the LCOE reductions were much more consequential than any cannibalization effects, despite the tangible effect of a lower co-variation factor for solar PV in California. The cost declines for wind energy have also aligned with the scheduled phase-out of the production tax credit beginning in 2017. In contrast, Fig. 2e shows that solar PV in Texas achieved positive LPMs due to the relatively high co-variation coefficients (Fig. 1). 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 [47].

In the second scenario, we calculate the LPMs that would emerge if investors had assumed in each year that revenues and costs in the first operating year would remain unchanged from thereon (see Supplementary Note 2 for further detail). Such stationary environments have been implicitly assumed in earlier studies on the revenue potential of intermittent renewables [11,21,27,36]. The general patterns emerging from Fig. 3 are consistent with those in Fig. 2. By construction, the LCOE estimates of renewables remain unchanged in this scenario. Yet, NGCC plants fare much better because of the implicit assumption that the contemporary optimized capacity factors will be sustained in the future. Similarly, the recent LPM estimates for solar PV are much more favorable, because the LROE now ignores the potential of a growing cannibalization effect going forward.

The final scenario examines a belief scenario that is in-between the first two scenarios. Investors are assumed to again have had perfect foresight until 2019. Beyond that date, they are assumed to have anticipated a steady state in which the revenue distributions and variable costs remain constant at values given by their average across the last three years, that is, 2017–2019 (further details in Supplementary Note 2). Accordingly, the third scenario incorporates the cost and revenue dynamics observed across the past decade but excludes those anticipated over the remaining lifetime of a facility. As one might expect, Fig. 4 shows that, for each technology and jurisdiction, the trajectory of LPMs lies between those in Figs. 2 and 3. In summary, we note that all three hypothetical belief scenarios in our calculations deliver a consistent assessment regarding the magnitudes of and trends in profitability.

5. Concluding remarks

It is widely understood that investment in a power facility may not be economically profitable even though the average price for electricity in each future year exceeds the LCOE [19]. The levelized profit margin introduced in this paper captures the changing unit economics of both intermittent and dispatchable power sources that compete in markets with time-of-use pricing. For solar PV and wind power in both 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.

Going forward, our LPM framework lends itself to projecting the mix of power generation sources that might emerge in equilibrium for alternative scenarios of how real-time electricity demand evolves in different jurisdictions. Correspondingly, an LPM analysis can guide policymakers in identifying supportive policies needed to justify additions in renewable generation capacity. Such analysis could, for instance,

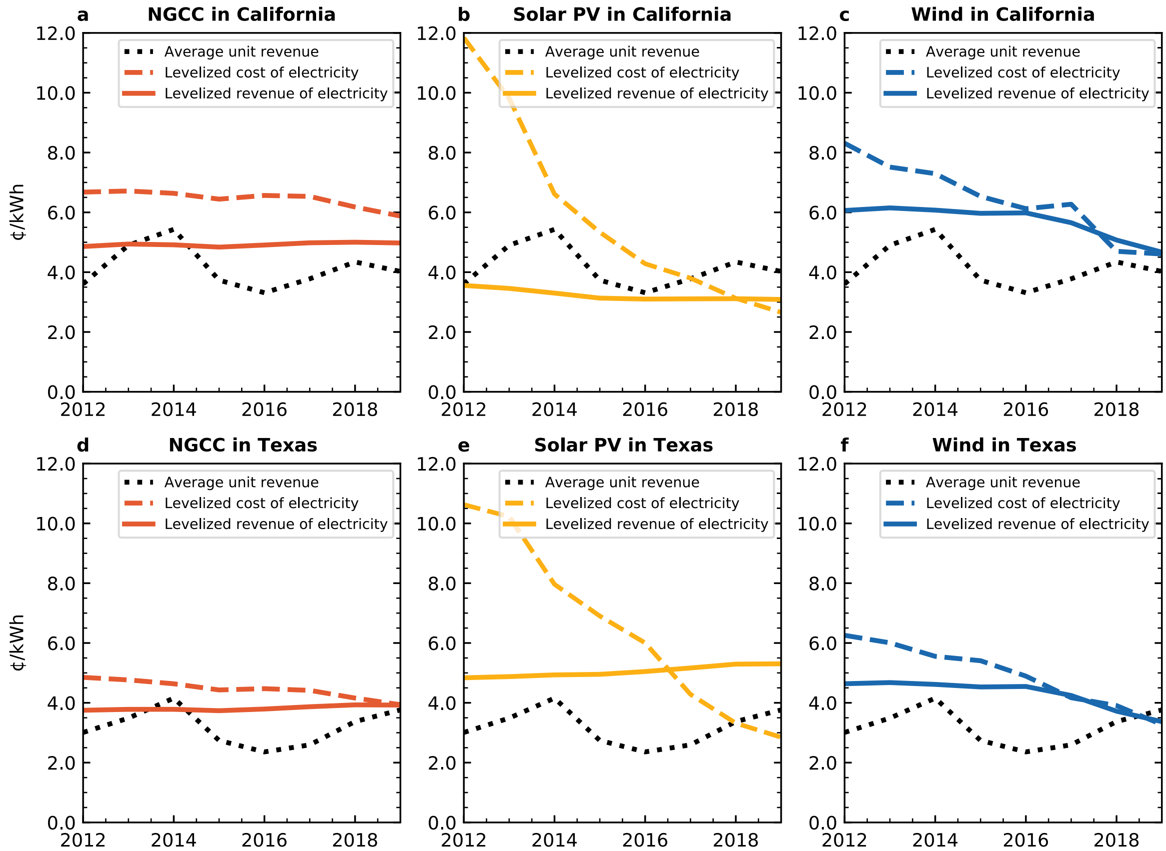

Fig. 4. Trajectory of levelized profit margins (Scenario 3). a, b, c, d, e, f, This figure shows the trajectory of levelized profit margins for NGCC turbines in California (a), solar PV in California (b), onshore wind in California (c), NGCC turbines in Texas (d), solar PV in Texas (e), and onshore wind in Texas (f) as the difference between the weighted average of adjusted unit revenues (colored solid lines) and LCOE (colored dashed lines).

extend earlier studies that sought to solve for a scheduled phase-out of federal tax credits so as to leave the LCOE of wind and solar power unchanged over time [48].

Our analysis has ignored the possibility of making intermittent renewable sources partly dispatchable by adding energy storage capabilities [49–51]. Combined solar PV and battery storage projects have become increasingly attractive due to recent advances in battery technology. At the same time, the US federal tax code has designated stationary batteries as solar equipment and thereby made them eligible for the same investment tax credit as solar power installations [52,53]. We expect further analysis that includes the possibility of 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.

CRediT authorship contribution statement

Gunther Glenk: Conceptualization, Methodology, Software, Resources, Data curation, Writing, Visualization, Project administration, Funding acquisition. **Stefan Reichelstein:** Conceptualization, Methodology, Writing, Funding acquisition.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

Data availability

Data will be made available on request.

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Appendix A. Supplementary data

Supplementary material related to this article can be found online at https://doi.org/10.1016/j.rser.2022.112758.

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