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Review

Energy Price Decoupling and the Split Market Issue

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Abstract: Load scheduling and dispatch by merit order on electricity generation networks has used a wholesale market electricity system operator model focused on system marginal pricing, in which the spot price of electricity at any point in time is equal to the system marginal cost given by the higher value of the price, which rations demand to capacity or the operating cost of the most expensive plant on the system, which is usually a fossil fuel price. This idea has come under challenge because renewable technologies such as wind power farms or solar power farms are treated as having close to zero operating costs. The challenges, under the general heading of energy price decoupling, include suggestions for operating split markets possibly overseen by a regulator, and the prediction that marginal cost pricing should be abandoned. This review evaluates these in terms of their economic impact, relating them to the policy debates on electricity market reform.

Keywords: electricity markets; marginal cost pricing; split markets

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1. Introduction

It should not be possible to sell two commodities that are perfect substitutes for each other to the same group of consumers at two different and unrelated prices unless there really are hidden differences in the commodities. Yet, exactly this apparently impossible proposition has become prominent in recent commentary on electricity price structures in Europe, under the name of energy price decoupling. The ideas underlying this proposal are the subject of this review. This is not a full-scale literature review of electricity pricing; it is simply a review of the split market suggestion.

Energy price decoupling is the summary expression for a widely debated issue in electricity prices that has gained additional prominence as a consequence of the war in Ukraine that began in February 2022. The immediate consequence was a massive rise in traded natural gas prices and since many electricity networks, particularly in Europe, use natural gas as a source of electricity generation, there was a surge in the wholesale and retail prices of electricity. This coincided with the ongoing market penetration of renewable generation, particularly wind and solar-powered generation of electricity, for which it is widely known that the operating costs are low. An effect of these changes was to open a public media debate on why there was no separation between the effect of the higher gas price and the effect of the low operating cost of renewables on consumers' bills for electricity. Press discussion and media campaigns grew that argued for the 'decoupling of the price of electricity from renewables from the price of electricity from natural gas fired generation'. This is what is referred to in this review as energy price decoupling. The public and social media online debates oversimplified the issue, as often happens, and largely failed to distinguish between wholesale electricity prices at different hours of the day and night and the typical retail price of electricity averaged through the year for domestic and industrial consumers after taking account of the costs of maintaining and improving the high voltage transmission and low voltage distribution networks. Nevertheless, some of the issues in the energy price decoupling debate have become the focus of public and political attention as well as academic commentary.

The literature on electricity pricing and investment stretches back many years but has coalesced into a set of propositions to generate efficient pricing and investment rules. A key issue in the analysis is the definition of marginal cost. This is completely standard in economics and is available in multiple mainstream textbooks. For example, here is the definition from [1]: "The effect on total cost of producing one additional unit of output". The critical idea is that this is the effect on the total cost of one additional unit of electricity available to consumers in general in a given hour and year. It is a unique value. If the output can be produced from a number of different technological options, there is still only one value for marginal cost since the criterion is the effect on *total* cost. Marginal cost cannot be measured by reference to a single technology type and there cannot be multiple marginal costs that are measurable in any given hour and year for the marginal unit of electricity. Each of a number of different technologies may have a different operating cost, but none of these values can be used to define marginal cost. The concept of different technologies having different marginal costs in the sense of the effect on total cost has no meaning in economics. It is possible to argue that with different technologies each has a different operating cost for the last increment of output from that technology, which could be called marginal operating cost or marginal energy cost, but none of these values defines the unique marginal cost for the generating system as a whole. This is the critical fallacy that underlies the opposition to the marginal pricing model. A second critical idea is that marginal cost is forward-looking [2,3] and this means that it cannot be calculated by referring to the average cost of a plant that is already installed for which the capacity cost is fixed and sunk. The essence of forward-looking marginal cost pricing is to send market signals about investment in new capacity.

This review begins by looking at the standard approach to setting electricity prices on generation systems and how these are translated into prices for final consumers. Then, it evaluates some of the recent propositions in favor of electricity price decoupling in the form of split markets. The conclusion is that the economics of electricity price decoupling can be complex, but it is often confused with non-relevant political and social attitudes, particularly toward the relief of poverty and the redistribution of income. The contribution of this paper is to show that the problems that price decoupling claims to solve are already completely addressed by the current marginal pricing model which has been adopted widely in international electricity markets, and which does not require price decoupling or split markets.

2. The Standard Approach to Electricity Prices and Investment: System Marginal Pricing Model

The analysis can be made formally in terms of a nonlinear programming model of an electricity generating system. This is an electricity system operator (ESO) model, sometimes called an energy-only model, or the traditional model, which can be applied both to a vertically integrated single utility or to a decentralized system of independent generators selling through a wholesale market to an overall ESO.

The key characteristics of well-developed electricity industries with time of use marginal cost pricing have been analyzed in [2–10].

As a convenient simplification, assume all plant installation is undertaken in the first period with no historic inheritance of plant. Extending the model to allow for inherited plant simply adds another superscript to the plant type.

Definitions:

Types of different capacity: s = 1 . . . S

Hours of operation per year: h = 1 . . . H (=8760)

Years of operation: t = 1 . . . T

Q^s: amount installed of plant of type s (megaWatts)

q^s_{ht}: output of plant of type s in hour h of year t (megaWatts)

C^s: installation capacity cost per unit of capacity installed of type *s*, (currency unit/megaWatt)

R^s_{ht} : operating cost per unit of output of plant type s in hour h and year t (currency unit/megaWatthour)

r^s_{ht}: present value of operating cost per unit of output of plant type s in hour h and year t (currency unit/megaWatthour)

$(1+i)^{-t}$: annual discount factor, and $r^s_{ht} = R^s_{ht}(1+i)^{-t}$

Discount rate: i = social discount rate or private cost of capital including risk premium

X_{ht}: demand on the system in hour h and year t (megaWatts)

$m_{ht}, k^s_{ht}, \forall s, h, t$: Kuhn–Tucker multipliers (dual variables or shadow prices):

Types of plant evaluated: s = w, n, g, c, respectively, wind, nuclear, natural gas, and coal.

Analysis

The system cost minimization problem is to choose: Q^s, q^s_{ht} to minimize the present value of total system costs:

$$\min_{\boldsymbol{q},\boldsymbol{Q}} SC = \sum_s \sum_t \sum_h (r^s_{ht} q^s_{ht}) + \sum_s C^s Q^s. \tag{1}$$

Subject to the constraints:

Output is large enough to meet the demand forecast:

$$\begin{gathered} X_{ht} \le \sum_s q^s_{ht}. \\ h = 1 \ldots H, t = 1 \ldots T \end{gathered} \tag{2}$$

Output from each plant cannot exceed the amount of plant available

$$\begin{gathered} 0 \le q^s_{ht} \le Q^s. \\ h = 1 \ldots H, s = 1 \ldots S,\ t = 1 \ldots T \end{gathered} \tag{3}$$

The problem is solved by Kuhn–Tucker nonlinear programming. There are several different formats in which this can be stated and the analysis here uses the formulation in [11], see also [12]. The Lagrangean function for this problem is

$$\mathcal{L}(\boldsymbol{q}, \boldsymbol{Q}, \boldsymbol{m}, \boldsymbol{k}) = -\left(\sum_s \sum_t \sum_h (r^s_{ht} q^s_{ht}) + \sum_s C^s Q^s \right) - \sum_h \sum_t m_{ht} \left(X_{ht} - \sum_s q^s_{ht} \right) - \sum_s \sum_t \sum_h k^s_{ht} (q^s_{ht} - Q^s). \tag{4}$$

We maximize $(-SC)$ and add nonnegative products of Lagrange multipliers or dual variables and the constraints to the objective to ensure nonnegativity of the dual variables [11]. Kuhn–Tucker optimality conditions to locate a saddle point of $\mathcal{L}(\boldsymbol{q}, \boldsymbol{Q}, \boldsymbol{m}, \boldsymbol{k})$ are

$$q^s_{ht} \ge 0;\ \partial\mathcal{L}/\partial q^s_{ht} = -r^s_{ht} - k^s_{ht} + m_{ht} \le 0; (q^s_{ht} \partial\mathcal{L}/\partial q^s_{ht}) = 0.$$

For

$$h = 1 \ldots H, s = 1 \ldots S,\ t = 1 \ldots T \tag{5}$$

$$Q^s \ge 0; \partial\mathcal{L} \big/ \partial Q^s = -C^s + \sum_h \sum_t k^s_{ht} \le 0; (Q^s \partial\mathcal{L}/\partial Q^s) = 0.$$

For

$$s = 1 \ldots S \tag{6}$$

$$m_{ht} \ge 0;\ \partial\mathcal{L}/\partial m_{ht} = -\left(X_{ht} - \sum_s q^s_{ht} \right) \ge 0;\ m_{ht}(\partial\mathcal{L}/\partial m_{ht}) = 0.$$

For

$$h = 1 \ldots H, t = 1 \ldots T \tag{7}$$

$$k^s_{ht} \geq 0;\ \partial\mathcal{L}/\partial k^s_{ht} = -(q^s_{ht} - Q^s) \geq 0;\ k^s_{ht}(\partial\mathcal{L}/\partial k^s_{ht}) = 0.$$

For

$$h = 1\ldots H, s = 1\ldots S,\ t = 1\ldots T \tag{8}$$

The first set of conditions (5) are the short-run hourly marginal system cost definitions and the second set (6) are the investment rules that state that the capacity cost is recovered by the lifetime present value of the hourly capacity payment components of the short-run marginal system cost. These results have been known for many decades, see [6] for a brief history. The critical ideas underlying the marginal pricing model are (a) that there is one and only one measure of marginal cost in any hour, h, and year, t, and this is m_{ht}, and (b) that the pricing rule is also an investment rule that treats the capacity payment on each plant type in any hour, h, and year, t, i.e., k^s_{ht} as the return on investment in that capacity type. To understand the first rule, (a), the key is the duality theorem of nonlinear programming. This gives the interpretation of the Lagrange–Kuhn–Tucker multipliers:

$$m_{ht} = \partial SC/\partial X_{ht}. \tag{9}$$

This states that in any hour and year, there is a unique value of marginal cost, m_{ht}. At the efficient level of system cost, it equals the sum of marginal operating cost and marginal capacity cost or payment: $r^s_{ht} + k^s_{ht}$ on each plant type currently in operation, i.e., under dispatch. The marginal capacity cost is a critical ingredient of the unique marginal cost. This confirms that the focus on operating cost alone and the identification of the operating cost of any particular technology with marginal cost critically misstates the economics. In a generation system with several different types of capacity, it is an error to think of each capacity type as having its own marginal cost. To do so would imply that a generation system has multiple different marginal costs at each moment in time, which would be economically meaningless. The literature which talks of the marginal cost of renewables as being different from the marginal cost of non-renewables confuses operating cost, sometimes called energy cost, with marginal cost. Marginal cost cannot be analyzed without its capacity cost element since the pricing rule is simultaneously an optimal investment rule. To understand this investment rule (b) it can be seen that the negative of (6) expresses the Net Effective Cost of each type of capacity, (NEC^s), i.e.,

$$NEC^s = C^s - \sum_h\sum_t k^s_{ht} = C^s - \sum_h\sum_t (m_{ht} - r^s_{ht}). \tag{10}$$

Therefore, (5) expresses the short-run pricing rule and (10) expresses the long-run optimal investment rule whereby capacity with negative Net Effective Cost should be installed up to the point where the present value of the lifetime cost savings in each period, i.e., the difference between system marginal cost and the operating cost, $\left(m_{ht} - r^s_{ht}\right)$, cover the cost of installing the capacity, C^s, in preference to capacity with higher or positive Net Effective Cost. Suppose the system is in disequilibrium and that there is insufficient output from the current capacity to meet demand X_{ht} in a given period. Then, the unique system marginal cost in that period (short-run marginal cost) is the price that will ration demand to the available output from installed capacity. The investment rule then signals that more capacity can be economically installed because at least one type of capacity must have a negative Net Effective Cost. After optimum installation, the system marginal cost, still including the appropriate marginal capacity cost, will have adjusted to accommodate the availability of additional capacity which has alleviated the demand constraint, and the system marginal cost is now also the long-run marginal cost. This is the classic result shown in [5].

How do renewables fit into this model? Using RES to stand for renewable energy supplier or renewable energy source, consider wind power as an example. As the first perturbation to the model, assume that the operating cost of wind is assumed to be zero with all the maintenance costs being capitalized, $r^w_{ht} = 0$. While the numerical value of the solution may change, the structural properties of the solution do not change in any way. The results are:

$$m_{ht} = r^c_{ht} + k^c_{ht} = r^n_{ht} + k^n_{ht} = r^g_{ht} + k^g_{ht} = k^w_{ht}$$

For

$$h = 1 \ldots H, t = 1 \ldots T \tag{11}$$

Consequently, the fact that renewable wind generation has zero operating cost can be perfectly accommodated in the system marginal pricing model because the critical element of the marginal capacity cost remains an integral part of marginal cost. Therefore, it is not possible to argue that an assumption of zero operating cost for renewable generation invalidates the system marginal pricing model. This does not mean that there is no basis for the split market model because it might be advocated for other reasons than zero operating cost. However, it is not obvious that zero renewable operating cost must necessarily make a major difference to the structure of efficient electricity pricing and investment. There is also an effect on the Net Effective Cost of investment. The result is:

$$NEC^s = C^s - \sum_h \sum_t (m_{ht} - r^s_{ht}) = C^w - \sum_h \sum_t (m_{ht}).$$

For

$$s = 1 \ldots S,\ s \neq w \tag{12}$$

There is no analytical change to the nature of the investment decision, but compared with the initial model, the Net Effective Cost of wind power has fallen relative to the other capacity types so there will be more wind power in the optimal long run system.

Investment in Intermittent Renewable versus Gas Powered Generation

Analysis of intermittent renewables, e.g., wind or solar power, can be performed with this model, and this is the second perturbation to the analysis. This issue applies to both wind- and solar-powered generation, therefore, we use wind as the representative intermittent renewable. Then, for certain hours of each year, there will be a forecast of insufficient wind (s = w) for wind turbines to operate, and some other plant, for example, gas (s = g), will be used as a backup. We amend the problem to allow for the positive probability that wind is intermittent so that $\left(1 - \pi^w_{ht}\right) q^w_{ht}$ is the expected output from wind generation in any given hour and year where $\left(1 > \pi^w_{ht} > 0\right)$, and $(1 + \pi^w_{ht}) q^g_{ht}$ is the consequent expected output from gas generation. This is a forecast based on initial data. The risk may be averaged over long periods. In actual dispatch, it will be known for certain which of the realizations $\pi^w_{ht} \in \{0, 1\}$ applies in reality. The constrained system cost minimization problem becomes:

$$\begin{aligned} \mathcal{L}(\boldsymbol{q}, \boldsymbol{Q}, \boldsymbol{m}, \boldsymbol{k}) = \ & -\left(\sum_{s \neq w,g} \sum_h \sum_t \left(r^s_{ht} q^s_{ht}\right) + \sum_h \sum_t r^w_{ht} q^w_{ht} \left(1 - \pi^w_{ht}\right) + \sum_h \sum_t r^g_{ht} q^g_{ht} \left(1 + \pi^w_{ht}\right) + \sum_s C^s Q^s \right) \\ & - \sum_h \sum_t m_{ht} \left(X_{ht} - \left(\sum_{s \neq w,g} q^s_{ht} \right) - (1 - \pi^w_{ht}) q^w_{ht} - (1 + \pi^w_{ht}) q^g_{ht} \right) - \sum_{s \neq g} \sum_h \sum_t k^s_{ht} \left(q^s_{ht} - Q^s\right) \\ & - \sum_h \sum_t k^g_{ht} \left((1 + \pi^w_{ht}) q^g_{ht} - Q^g \right). \end{aligned} \tag{13}$$

The additional terms in the demand constraints with Kuhn–Tucker multipliers m_{ht}, i.e., $\left(1 - \pi^w_{ht}\right) q^w_{ht} + \left(1 + \pi^w_{ht}\right) q^g_{ht}$, reflect the forecast generation from wind given the probability that zero wind in a given future hour and year will reduce the availability of some wind generation and the forecast generation from gas when it is used as a backup to missing wind generation wind in addition to its scheduled part in the merit order of plant running. In the capacity constraints with Kuhn–Tucker multipliers k^s_{ht}, there is now an additional component. This is the now more restricted capacity constraint on gas arising from its requirement to be available as a backup to wind.

The first-order interior optimum conditions are now:

$$\partial\mathcal{L}/\partial q^{s}_{ht} = -r^{s}_{ht} - k^{s}_{ht} + m_{ht} = 0.$$

For

$$h = 1 \ldots H, s = c, n;\ t = 1 \ldots T \quad (14)$$

Together with, after imposing the assumption zero operating cost for wind, $r^{w}_{ht} = 0$:

$$\partial\mathcal{L}/\partial q^{w}_{ht} = -k^{w}_{ht} + (1 - \pi^{w}_{ht})m_{ht} = 0. \quad (15)$$

And also,

$$\partial\mathcal{L}/\partial q^{g}_{ht} = -(1 + \pi^{w}_{ht})r^{g}_{t} - (1 + \pi^{w}_{ht})k^{g}_{ht} + (1 + \pi^{w}_{ht})m_{ht} = 0. \quad (16)$$

The pricing solution is therefore:

$$m_{ht} = \partial SC/\partial X_{ht} = r^{c}_{ht} + k^{c}_{ht} = r^{n}_{ht} + k^{n}_{ht} = r^{g}_{ht} + k^{g}_{ht} = k^{w}_{ht}/(1 - \pi^{w}_{ht}). \quad (17)$$

Two aspects of the solution can be noted. First, the marginal cost of power is equated to the marginal capacity payment on wind and the marginal operating and marginal capacity payments on other sources. Second, to take account of the risk of insufficient wind the required optimal capacity payment i.e., the marginal capacity cost, on wind is augmented to allow for the availability of gas (or other generation types) as a backup to wind. Intermittency does, therefore, have an effect on the analytical structure of the solution (compare (11) and (17)).

There is also an impact on the least-cost investment program. We see this as follows from the Kuhn–Tucker interior optimum conditions on the capacity decisions. Applying the first-order investment decision rules, the Net Effective Cost results (i.e., negative net benefits) of each plant type are equated:

$$C^{n} - \sum_{h}\sum_{t}(m_{ht} - r^{n}_{t}) = C^{c} - \sum_{h}\sum_{t}(m_{ht} - r^{c}_{t}) = C^{g} - \sum_{h}\sum_{t}\left(m_{ht} - r^{g}_{t}\right) == C^{w} - \sum_{h}\sum_{t}(m_{ht}(1 - \pi^{w}_{ht})). \quad (18)$$

The risk factor applied to wind generation increases the Net Effective Cost of wind capacity investment compared to the situation where there is no risk of intermittency.

Now, add a third perturbation in the form of a subsidy to renewable wind generation. This diminishes the Net Effective Cost of wind generation to offset the intermittency penalty. The net advantage of wind generation over gas when the capacity cost of wind is subsidized by an amount S^{w} is

$$NEC^{g} - NEC^{w} = \left[C^{g} - \sum_{h}\sum_{t}\left(m_{ht} - r^{g}_{t}\right)\right] - \left[(C^{w} - S^{w}) - \sum_{h}\sum_{t}(m_{ht}(1 - \pi^{w}_{ht}))\right]. \quad (19)$$

When $C^{w} > C^{g}$, then the operating costs of gas generation are adjusted for the likelihood of its being available as a backup for wind generation when there is zero wind can be covered sufficiently to favor gas investment. On the other hand, if the capacity cost of wind is sufficiently subsidized by an amount S^{w}, then the adjusted running cost penalty of gas generation may not overcome the difference: $(C^{w} - S^{w}) - C^{g}$.

Alternatively, the subsidy to wind may not be paid in the form of a subsidy to the capacity cost but may come in the form of a *feed-in-tariff* (FIT). This rewards the wind generator with a higher price for the power supplied. Here, we compute the net benefits assuming that each asset type is paid for its power generation at a price equal to the system marginal cost: m_{ht}. Since the benefits of wind are measured by the capacity payments offset to the capacity cost with an assumed operating cost of zero, the comparison of the wind net benefits becomes

$$\sum_h \sum_t \left(\widetilde{m}_{ht}\right) - \sum_h \sum_t (m_{ht}).$$

where $\widetilde{m}_{ht}$ is the FIT price or imputed marginal cost. Then,

$$NEC^g - NEC^w = \left[C^g + \sum_h \sum_t r^g_{ht} - \left(C^w - \left(\sum_h \sum_t \left(\widetilde{m}_{ht}(1-\pi^w_{ht}) - m_{ht}\right)\right)\right)\right]. \quad (20)$$

In this case, a sufficiently large excess of $\widetilde{m}_{ht}$ over m_{ht} will ensure that wind is preferred to gas capacity.

The next perturbation considered is a carbon emissions tax. Replacing the subsidy to wind with a carbon tax produces the solution:

$$m_{ht} = r^c_{ht} + \theta e^c + k^c_{ht} = r^n_{ht} + k^n_{ht} = r^g_{ht} + \theta e^g + k^g_{ht} = k^w_{ht}/(1-\pi^w_{ht}) \quad (21)$$

Here, θ is the rate of carbon tax in £/ton CO_2, and e^c and e^g are, respectively, the ton CO_2 emissions per megaWatthour of electricity generated from coal and gas, respectively. The effect of the carbon tax is to inflate the marginal system cost when computed from fossil fuel sources but to leave the system marginal cost unchanged when computed from nuclear or wind generation. The investment result is that fossil fuel capacity becomes less attractive relative to wind adjusted for intermittency or nuclear since the lifetime operating cost savings for fossil fuel capacity relative to system marginal cost are reduced by the respective carbon taxes:

$$\begin{aligned} C^n - \sum_h \sum_t (m_{ht} - r^n_t) &= C^c - \sum_h \sum_t (m_{ht} - (r^c_t + \theta e^c)) = C^g - \sum_h \sum_t \left(m_{ht} - \left(r^g_t + \theta e^g\right)\right) \\ &= C^w - \sum_h \sum_t (m_{ht}(1-\pi^w_{ht})) \end{aligned} \quad (22)$$

As a final perturbation, consider the impact of a regulatory constraint that mandates a minimal quantity of investment in wind capacity. This adds the constraint $\overline{Q}^w \leq Q^w$ with the associated dual variable $\mu = \partial SC/\partial \overline{Q}^w$. The investment decision becomes:

$$C^n - \sum_h \sum_t (m_{ht} - r^n_t) = C^c - \sum_h \sum_t (m_{ht} - r^c_t) = C^g - \sum_h \sum_t \left(m_{ht} - r^g_t\right) == C^w - \sum_h \sum_t (m_{ht}(1-\pi^w_{ht}) + \mu) \quad (23)$$

The effect is to reduce the Net Effective Cost of wind power as computed in the constrained system relative to the case without the regulatory constraint, compare (18) and (23). The relative changes in NEC^s under a carbon tax and a minimal wind constraint are mirror images of each other, demonstrating that the efficient means of increasing the market penetration of wind power is to use carbon emission pricing [13].

Summarizing, the analysis demonstrates that:

- Zero operating or energy cost for renewable generation from RES does not invalidate the system marginal pricing model in any way and does not mean that marginal cost is zero at any point in the system;
- Intermittency does require that intermittent renewables incur a Net Effective Cost penalty reflecting the risk of zero wind or sun;
- Direct subsidy, FIT pricing, and regulatory constraints to impose market penetration by renewable generation can all be accomplished by imposing a carbon emissions tax and this is likely to be more efficient over the long run since it does not require governments or regulators to pick a politically favored technology.

In the UK and the rest of Europe, there is now a relatively stable set of market arrangements. Most power is generated in a wholesale market based on the ESO or energy-only model. Expanding but still small renewable sources are contracted to supply into the wholesale market usually at a fixed price on a long-term contract. A common basis for these fixed price contracts is the contract for difference or CfD. Under this arrangement, the ESO arranges periodic auctions into which renewable generators submit bids for a 'strike price' (SP) and associated generation capacity which they hope to receive subject to adjustments for general price inflation over the duration of the contract. The settled 'strike price' is at the level of the last bid accepted. When production starts, these generators sell power into the ESO wholesale market and receive revenue based on the market reference price (MRP), i.e., system marginal cost. If the difference between the strike price and the market reference price is positive, $\Delta = SP - MRP > 0$, the generator receives a payment from the ESO, but if it is negative, $\Delta = SP - MRP < 0$, the generator pays the difference back to the ESO. The ESO funds the payments by a levy on the suppliers which is passed onto final consumers, and in the event that $\Delta = SP - MRP < 0$, suppliers are expected and monitored to pass this back to consumers.

Naturally, however, the price signals such as those in Equations (17) or (21) supplemented by CfDs are a long way separated from the retail prices that industrial and residential consumers face. The prices in these equations are signals to independent generators or the generators owned by the electricity system operator and the national or regional grid to enable efficient dispatch of plants on the system. Market suppliers taking power from the grid must then decide how to incorporate these prices into wholesale and retail tariffs for final industrial, commercial, and residential consumers. Typically, in the USA and Europe, the generation prices account for 50–60 percent of the final retail price of electricity. The remainder is accounted for by transmission and distribution network installation and upgrading costs, along with the operating costs of the final suppliers to consumers. The power industry may operate as a vertically integrated single utility or as an unbundled industry with specialized generators, dedicated high-voltage national and regional and low-voltage local grids, and possibly deregulated or liberalized supply firms that engage directly with final consumers [8]. The transmission and distribution networks are usually regulated by national authorities and even the decentralized final supply prices may be regulated and capped. In addition, even with the expansion of smart metering which can identify individual consumer demands at each point in time across every 24 h period, most final consumers will pay a single- or possibly two-rate night/day average price per kWh. There are usually standing charges to cover non-energy costs, but in many European countries, use is instead made of demand charges in kW or kVA, supplemented by household circuit breakers, which require the householder to nominate a maximum power demand and to pay extra to re-energize the circuit if maximum demand is reached. As a consequence of failing to take account of these factors, it will be seen that much of the public media criticism which is directed towards the marginal pricing model is misconceived.

3. The Challenge to the System Marginal Pricing Model

Nevertheless, despite the demonstration that the system marginal pricing model easily accommodates environmental and intermittency issues, criticism of it in principle has been growing in recent years. This review now turns to considering some of these criticisms and their proposed solutions in the form of split markets and decoupling the price of electricity from renewables from the price of electricity from gas. Among the widely known contributions to energy price decoupling are the studies [14,15]. The extension to the split market model is most widely associated with [15] but there are several other studies of the idea as well, e.g., [16–18]. This paper focuses on the policy suggestions for a split market contained in [15,17].

In [14,15], it is claimed that renewable generation has zero short-run marginal cost and that this must undermine the applicability of the system marginal cost pricing model outlined in the previous section. The claim usually amounts to no more than that bald statement and is not given any analytical proof. There is confusion here because, as was demonstrated, zero operating cost does not mean zero marginal cost. We know that this is a misstatement of the analysis because the model easily accommodates zero operating cost plants. There is also an argument that as renewables expand their share of generation, the system becomes dominated by plants that only display a capacity cost that is fixed and sunk. But this should not be relevant to the measurement of marginal cost that must be forward-looking in scope and focus on a plant that is not yet installed. What is the nature of the idea that the marginal cost of generation by RES is zero? The conclusion is assumed from the observation that the operating cost of RES is very low and could be said to be approximately zero. However, this observation ignores the maintenance costs of an RES, which may be considerable over the lifetime of a plant, but could be regarded for convenience as a capitalized component of capacity cost. Therefore, generating one extra kWh unit from an existing RES will incur an operating cost of approximately zero. But in a system of a generating plant, whether these are all RES or a mixture of RES and nonrenewable plants, the relevant measure of marginal cost is the additional total cost to the system as a whole if total kWh demand increases by one unit at a given point in time. In the long run, with a generating system for which the capacity is equal to the demand, this will involve the decision of whether to increase the total capacity by adding a plant (or scrapping a plant if the demand change is negative). Therefore, the marginal capacity cost must be taken into account as well as the marginal operating cost. Since the decision applies to the long run, the fact that an existing RES plant has a fixed and sunk capital cost is irrelevant. It will also be important to determine whether the demand increment is likely to be permanent, as argued in [3]. In the short run, if there is a limited spare capacity margin, the increment in demand must be rationed amongst consumers and the short-run marginal cost is the price that is required to ration the total demand to total capacity. In neither case is the marginal cost of electricity to the system as a whole measured by the operating cost of a typical RES installation. Consequently, the common argument that expanded use of RES generation will drive down the system marginal cost of electricity towards zero is mistaken.

Nevertheless, despite the analytical properties of the ESO model which state that there is a unique marginal cost on the system at any single point in time and that it is the sum of operating cost and capacity cost, $m_{ht} = \partial SC/\partial X_{ht} = r^s_{ht} + k^s_{ht}$, the modern applied economics literature frequently refers casually to operating cost as 'short run marginal cost' [14–17]. This has two effects: it argues as if there are multiple marginal costs on a generating system at a single point in time, and that for some renewable plants, this is close to or at zero. Often, the analysis refers only to non-fossil fuel plants, i.e., solar, wind, wave, hydro, biomass, nuclear, and imported electricity via interconnectors. It also has the consequence of shifting the focus from a plant to be installed or expanded in the future, i.e., the critical element of long-run marginal cost, to the plant that has already been installed and which has a fixed amortization payment arranged through a long-term contract and a zero operating cost. Many commentators, e.g., ref. [14] therefore talk about the shift from a production-based power industry to an asset-based industry providing service on a long-term fixed price contract. It is argued that this will change the nature of the industry structure and lead to the abandonment of the marginal pricing model [14]. However, the analysis of the ESO model demonstrated that it is flexible in accommodating different cost structures. The amortization-only price of intermittent renewable generation is accommodated through the intermittency adjusted term $m_{ht} = k^w_{ht}/\left(1 - \pi^w_{ht}\right)$. The amortization payment can be estimated from the levelized discounted cost of the plant, as suggested in [19], and ref. [20] shows the approximate relationship between levelized discounted cost and the optimal capacity payment in the ESO model. Such a model would have an average cost that is equal to the marginal cost up to a capacity limit. As a consequence of these considerations, it is clear that the zero operating cost property and its apparent but false effect in generating multiple near-zero 'short run marginal costs' does not invalidate the ESO model and is not a solid foundation for energy price decoupling. As the ESO model showed, the split market model cannot be defended on the grounds that renewable generation has zero marginal cost, nor that it is the only way to increase the market penetration of environmentally desirable renewable generation.

However, energy price decoupling and split markets have also been defended on other grounds. A frequent criticism is that electricity markets are 'broken' [14,15], although those who make this claim rarely define what is meant by a broken market. This is a term rarely if ever used in economics because economists prefer to characterize market outcomes as efficient or inefficient. An efficient market outcome is one in which it is not possible to make one person better off without making another one worse off and it is usually achieved when price equals marginal cost. Hence, to understand the criticism that a market is broken or inefficient, it is necessary to understand why the market price may diverge from marginal cost. A number of problems arise in electricity markets, and these include the abuse of market power arising from a dominant firm preventing new entrants to the industry or possessing asymmetric information about the nature of the market. Particularly important in the market described in the previous section, sometimes called an energy-only market, are the problems of 'missing money' and 'missing markets' [21]. The ESO model can be applied to a centralized single-generation system in which the ESO owns the generators or a decentralized system in which the ESO's only task is to make the market and order dispatch for multiple privately owned and competing generators. In the first case, the ESO determines the spare capacity margin and hence directly manages the intermittency issue. In the second case, the individual generators bid into the ESO's market which operates under the assumption that the generator's payments will cover all their capacity costs. If the generators are unsure whether this will succeed there is a 'missing money' problem so a specific capacity market auction mechanism is needed to replace the centralized spare capacity margin. The outcome analyzed in the previous section implied that when the investment rules were applied, investors would have confidence that capacity and operating costs would be covered by prices based on the system marginal cost., i.e., the plant would be installed and remunerated fully up to the point: $NEC^s = C^s - \sum_h \sum_t (m_{ht} - r^s_{ht}) = 0$. If this revenue turns out not to be adequate, there will be a 'missing money' problem and if investors do not have confidence that this revenue will be adequate, there will be a 'missing market' problem, i.e., no opportunity to hedge their risk [20]. Regulators in electricity markets in Europe have instituted systems of capacity payments through auctions to ensure the required payments, but these arrangements mean that regulation and government intervention become critical for the operation of the electricity market. Additional to this, in the wake of political shocks such as the war in Ukraine, governments have introduced price caps to protect consumers and, in response to climate change, have financially supported renewable generation [21]. Developments such as these have led to the claim that the electricity markets in Europe are inefficient in the allocation of scarce resources and that a new structure should be considered. In addition, if the forecasts that electricity supply will come to be dominated by intermittent renewables rather than conventional plants coming to fruition, there may be a case for reevaluating the organization of the industry. It was clear that intermittency does have an analytical impact on the ESO model and therefore that intermittency is a plausible reason for revisiting the structure of the model and explicitly incorporating intermittency into the ESO model as the analysis above demonstrated.

Consequently, the key to split pricing on economic grounds is not zero marginal cost, which is a misconception, but rather it is the issues of market failure, government subsidy of renewables for climate change reasons, and intermittency. The issue of government support for renewables is identified in [15] as critical because the deep support demonstrated both in the EU and in the UK has threatened to undermine the long-term cost recovery of fossil fuel plants and leave them as stranded assets. This is identified as an issue of 'pecuniary externalities' [22], ref. [15], which are not externalities in the sense of market failure but simply a consequence of an innovation which has been subsidized as a political choice, i.e., a consequence of regulatory risk.

The proposal in [15] for split markets is examined first. It has several aims which are described as providing signals for efficient investment and operation for all capacity types, and for providing system optimization based on consumer preferences, in particular, by privatizing the security risk in electricity generation so that consumers become aware that 'reliability has a price while demand flexibility has a value'. The fear expressed in [15] is that consumers believe that power is always available at a constant cost when this is not the case, particularly for intermittent generation. This means that [15] advocates two split markets: one for generation and one for retail supply to residential and industrial consumers. In the generation market, ref. [15] distinguishes 'as available' supply chiefly from intermittent generation and 'on demand' supply from conventional fossil fuel and peaking plants. In the generation split market, there are two price structures. In the 'as available' supply from the intermittent plant, the price is intended to be close to the amortization payment on the renewable plant treated as a fixed price, set in long-term contracts such as CfDs., i.e., $m_{ht} \cong k^{w}_{ht}$. This might be approximated by the levelized discounted cost of the plant established in the initial auction for its installation. In the 'on demand' market, the pricing system from the ESO model would apply. There will be different power flows as well as different expenditure flows. In the generation markets, power will flow from both intermittent renewable generators and conventional plants into a common pool at the transmission grid level to be distributed across the country. Clearly, there will be incentives among generators and purchasers to conflate these two pricing markets for arbitrage reasons since it is not unknown for generators to game the pricing system. One of the most prevalent strategies is to declare the plant as unavailable for maintenance purposes and then declare it as available at short notice for call in the capacity market where prices might have spiked because of the initial declaration of non-availability. Consequently, ref. [15] envisages an important role for government intervention and regulation in order to keep the two distinct markets functioning. The assumption is that electricity supply companies or distribution network operators (DNOs) will be able to sign long-term contracts to purchase renewable power in the 'as available market' using the 'on demand market' as a residual to cope with demand spikes and intermittency. While this will certainly encourage the development of more renewable investment, it is already clear from the ESO model that the most efficient way to encourage renewable investment is through carbon pricing.

However, ref. [15] also suggests a split market for consumers. This clearly cannot function on different power flows since all consumers will be connected to the same network taking power from the grid from intermittent and conventional plants, although they are envisaged as having separate meters. This is the most challenging idea in [15]. The aim would be to present consumers with a simple choice between different sorts of electricity supply contracts, again referred to as 'as available', at a low and stable price, and 'on demand' at a higher and more volatile price. The overall purpose is to encourage consumers to develop their own preferences for reliability of supply instead of the intermittency response being at the grid level. Consumers would be able to access both types of power supply by signing supply contracts for each with the same or different suppliers. The response to intermittency embodied in the dynamic random variable π^{w}_{ht} would be for the individual consumers to determine for themselves. The implication is that this consumer-level split market is, in principle, an offer of an interruptible supply contract and a firm supply contract. Although the consumer level split is given the same name as the split market at the grid wholesale level, there is no intrinsic reason why the prices should be related. It is the hope in [15] that the interruptible supply contract will be able to mirror the average amortization payment on an intermittent capacity at the wholesale grid level, but it is not clear that this will automatically be the case, so the implication is that there will need to be further considerable government or regulatory oversight of the different supply contracts at the consumer level. In summary, the essence of the ideas in [15] is to address the problem of intermittency by devolving the response down to the final consumer by offering extensive interruptible options at this level. However, interruptibility is already an option in many consumer supply contracts, particularly in Europe. For example, in France and Portugal, consumers are used to nominating a level of maximum demand and paying demand charges as well as energy charges for their electricity. Where consumers are able to nominate a maximum demand charge, there is a circuit breaker on their power supply that will interrupt their consumption at the maximum demand level, and this interruptibility can be amended by paying a supplement to raise the nominated maximum demand limit. By contrast, in the UK, standing charges are preferred to the use of demand charges. In the UK, an innovation in 2022 was that supply companies could give their consumers with smart meters the option of signing up to a National Grid scheme to be cut off at short notice at times of severe system maximum demand, with a reward payment that varied with the duration of the cut-off. These are only two of the different possibilities for interruptible demand-side management.

The split market option based on interruptibility is bound to place some planning burden on the individual consumer, who, as well as understanding two supply contracts, must evaluate the distribution of the random variable, π_{ht}^{w}. Here, the individual consumer will not have access to the economies of information search that are available to a well-resourced ESO. In addition, there is an implicit assumption that consumers are rational and skilled in making probability-based judgments. The literature on optimizing failures of behavioral agents emphasizes the prevalence of internalities (the long-term benefits or costs for themselves that agents do not consider when making consumption decisions) and hyperbolic discounting (the failure to make consistent choices about future investment decisions), see [23]. In particular, there is some evidence that while rational consumers can be expected to address uncertainty about investments using the risk aversion approach of expected utility theory, behavioral consumers are more likely to use the loss aversion approach of prospect theory [24]. With behavioral consumers, investments that would be accepted under an expected utility approach would be rejected on a loss aversion criterion. Consequently, devolving the reliability risk to individual consumers could lead to a lower demand for intermittent renewable technologies in the 'as available' market and a stronger demand for reliable fossil fuel technologies in the 'on demand' market. Clearly, this would defeat the purpose of the split market approach. Nevertheless, it is clear that in [15], the major justification for a split market at the consumer level is to decentralize the response to intermittency to consumers as much as possible, even where this might require considerable government 'nudging' or imposed regulation of behavior.

An alternative approach to split markets and energy price decoupling is contained in [16,17]. This is not unlike the model in [15], at least in part, but it proceeds from a different set of motivations. In [16], it is argued that marginal cost pricing, which has long been the key criterion for evaluating the efficiency of microeconomic policy and as a basis for economic cost–benefit analysis, has been pushed far beyond its appropriate limits in electricity systems, and that the short run marginal cost based price is so far from the average cost of electricity that emphasis needs to switch to charging a price closer to average cost. It also supports the case that electricity supply with growing renewables is moving from a commodity-based industry to an asset-based industry. As explained above this simply makes the average and marginal costs very similar to each other. In the case of zero operating cost renewables, the marginal and average cost of a new plant is the fixed price amortization, which can be approximated by the levelized discounted cost [19]. In [16,17], it is argued that the key feature of electricity supply in 2022 is that there is an unstoppable and rapid shift to a state where virtually all electricity will be generated from renewables and that this requires a rethinking of electricity market structures. In particular, attention is focused on the idea of a huge 'cost inversion' in which international gas prices have soared following COVID, supply chain interruptions, and the war in Ukraine, while subsidy support for renewables has rapidly reduced the average cost of electricity from intermittent renewables. Two particular conclusions are offered: firstly, that in Europe, and the UK in particular, attention needs to shift from allowing international fuel prices to set the marginal price of electricity to requiring that average domestically generated and renewable fuel prices are emphasized, and, secondly, that vulnerable agents in society should be first in line to benefit from the support that can be made available through changing the structure of energy markets.

The key proposal in [17] partly reflects a similar idea already made in [18] in the context of the EU response. Ref. [18] addresses a situation in which RES units, which are small independent producers, are not subsidized by FITs or any other income payments and must act independently. It assumes, as a result, that RES units are forced to accept a price for their energy that is equal to their marginal operating cost only. Ref. [18] looks for a software algorithm that will allow RES units to be clustered together in a virtual association that can bid a higher price into the traditional market as a result of their aggregated virtual bargaining power. It treats a pool of RES units as a large independent generator.

Ref. [17] on the other hand argues for the creation of a Green Power Pool (GPP) based on the CfD contracts used to pay for renewable electricity, for example, in the UK. In 2022–2023, the market reference price was a long way above the typical strike price and generators were paying large amounts back to the government agency, and the intention was that these should be returned to consumers via the prices charged by their electricity supplier. This was one of the motivating factors in the proposals in [17] to update the market structure. The GPP suggested in [17] would agglomerate all renewable power supplies into a single power pool separate from the rest of the wholesale market. To alleviate the distress caused to vulnerable groups by the rise in international gas prices, the suggestion is that suppliers could draw on the power available in this pool to offer dedicated supply contracts at prices reflecting the renewables strike price to two groups of consumers, in particular, small to medium enterprises whose international competitiveness was undermined by the rise in international gas prices, and residential consumers in the poorest sections of society, the ‘fuel poor’. This would be a form of split market but one with different aims from the suggestion in [15]. It was seen as the first step in a transition to a power system based on domestic renewable prices corresponding to the CfD prices equal to the average amortization cost in the contracts for renewables (and these by definition are also the marginal cost). Nevertheless, there are well-known reasons for questioning the use of the renewables strike price to target particular groups. Income transfers are more efficient at increasing consumer welfare than subsidizing the price of an individual commodity and there are obvious issues in identifying which consumers are in the fuel-poor group and even greater problems in identifying firms that have had their competitiveness undermined by international fuel prices rather than their general inability to adjust competitively to market shocks. The use of the renewables strike price in this way may simply create zombie firms, as well as being close to protectionism.

Proposals such as these became, in 2022, the subject of a government consultation of the review of electricity markets in the UK [25], and similar consultations are proceeding in other European countries. Among the responses to the consultation request, commentary on the ideas has been made by a major UK research body in the energy field, the UK Energy Research Centre UKERC [26], which is a consortium of academic researchers. The consultation [25] sought views on whether there should be major changes in the current wholesale market arrangements consisting of the ESO model with CfDs for renewable generators. UKERC was not in favor of major step changes, arguing that despite external shocks, the current form of the ESO energy-only model supplemented by the CfDs was working well. The consultation [25] also asked for views on the split market models discussed here [15,17], i.e., the GPP. UKERC felt that the model in [15] was excessively complicated and stated that the shift to devolving all security of supply concerns from ESO to individual consumers would be a fundamental shift in market arrangements. UKERC hypothesized that it would be the poorest consumers who would have to opt for the least reliable supplies and doubted that consumers would be able to cope with the complexity of the idea. UKERC compared it unfavorably with dynamic time-of-use pricing. UKERC was more open to the idea of a GPP and suggested further analysis of it.

4. The Public Media Debates

Social and public media are swamped with comments on energy prices, so it is difficult to obtain a representative selection of well-informed views. However, in February 2023, the Financial Times of London briefly reported on the split market model in [15] and asked for readers' responses [27]. This uniquely provides a small sample of the public debate on the issue in a less extreme context and this sample provides an overview of the well-informed general public's attitudes to the issues considered in this review. There were 40 responses in all (although one-third were from one respondent), and the results are intriguing. Few responses specifically discussed the split market model and it would appear that only a limited number of readers understood what was being suggested. Four responses did support the continued importance of the energy-only ESO model described in this review, and each emphasized the importance of sending efficient market signals for investment decisions (the present author was one of these). One respondent emphasized the need to introduce time-of-use pricing extensively at the consumer level, and one correspondent raised the interesting question of why there was no debate about split markets when nuclear power was first developed since that technology shared the same cost structure as renewables. One of the authors of [17] responded by advocating an end to short-run marginal cost pricing on all supplies, summarizing the case with the query: 'why make all consumers pay based on the cost of what we are trying to phase out'. This response preferred the GPP approach. Interestingly, most of the responses focused on other aspects of electricity markets and ignored the split market idea, suggesting that price decoupling is not central in the minds of well-informed observers. The other aspects that were highlighted by respondents reflected a preoccupation with tariffs and supplier prices to final consumers, suggesting confusion in the public's mind between wholesale and retail prices and a failure to understand the importance of network transmission and distribution costs in setting retail tariffs. Fears were expressed about profiteering by supply companies, although many suppliers have failed in the aftermath of the rise in international gas prices, and there was some distrust of both market outcomes and government intervention. A possible conclusion is that the public is disturbed by the shocks to energy prices over 2022 and is unclear about how to respond, but that market split ideas are not a central preoccupation. However, a factor in this is likely to be the massive targeted income relief to consumers which has characterized the European response to the rise in international gas prices.

5. Conclusions

In this review, the idea of decoupling energy prices has been examined, i.e., the idea that the price of electricity should not be set by the system marginal cost, but instead that the electricity market should be split amongst different types of fuel, particularly differentiating between renewables and fossil fuels. The context is the dominant system for setting electricity prices, which is the ESO or energy-only model of the central wholesale market which establishes for each hour of each year a system marginal cost or price and which simultaneously sends a capacity expansion or contraction investment signal. The review showed that many of the problems identified in the current electricity market can be accommodated in the ESO model. These included low or zero operating costs for renewables, intermittency, which particularly affects solar and wind power, and the support for renewables to combat climate change. The model also demonstrated that carbon pricing was an efficient means of supporting the market penetration of renewables.

The arguments for split markets and the responses to these arguments can be summarized as follows.

1. RES units have zero marginal cost. This is a fallacy and irrelevant. In any case, the ESO model includes the case of zero operating cost.
2. Intermittency, which makes RES a special case. However, the ESO model treats this efficiently and adjusts the pricing and investment signals appropriately. Intermittency is the motivation for the model in [15], which decentralizes the risk and uncertainty in intermittency from the ESO to individual consumers by offering a choice of contracts.

But this model fails to think through the likely consequences of behavioral agents as opposed to rational agents and the consequences of income inequality in pushing poorer customers to opt more for 'as available' supplies than 'on demand' supplies. Partly, it also relies on the argument that the marginal cost is zero for RES and is a preparation for the day when the marginal cost of all or most energy is zero.

3. Subsidies to RES are required to enable market penetration by RES. The ESO model can treat this easily as well. The investment and pricing rules adjust appropriately. This is only a split market proposal in the sense that a special market arrangement is designed to reward an RES for its green credit. In fact, the ESO model rewards the RES with the marginal system cost, which maximizes the incentive to reduce the usage of fossil fuels in generation. The ESO model also treats this issue by using carbon pricing. In this context [28], ref. [29] argue on the basis of German market experience that FIT mechanisms work effectively for intermittent RES units while non-intermittent RES benefit from the marginal pricing model, as was historically the case with nuclear power.
4. The motivation for the green power pool GPP model in [17] is to use low prices based on the marginal operating cost of the GPP RES producers to subsidize the consumption of particular consumer groups. The model fails to analyze the fact that using the price system to redistribute income is welfare-inefficient compared with direct income transfers. It also fails to state how the GPP supply contracts will pass on only the marginal operating costs of RES. It relies on the argument that marginal cost is zero for RES units.

Are there any valid arguments for split markets? Yes, as a form of welfare-enhancing price discrimination, when consumers fall into two or more distinct groups with their own demand characteristics and where there is no possibility of trade or arbitrage between the groups. This is not the case here, where the arguments used to support the split market idea rely entirely on supply characteristics. In all the papers supporting the split market idea, there is the presumption that government or an electricity market regulator will be able to implement the considerable additional institutional requirements that are needed to make the split market work—these include preventing arbitrage and trade across the diverging supply contracts, maintaining the required entry and prevention of entry conditions, assuring the flow of symmetric information to consumers and producers, integrating the generation contracts with the transmission and distribution system, and monitoring the performance and success of the proposed changes. None of the proposals analyzes the regulatory issues involved and none of the proposals recognizes or quantifies any regulatory costs of implementation, which are likely to be considerable.

The review went on to discuss two split market proposals and identified the issues that they addressed and whether they were likely to be successful. Authoritative responses to a UK government consultation suggested that the current ESO model with CfDs for renewables worked well for large electricity networks and that split markets, especially of the type that devolved all responses to intermittency to final consumers, would not be viable. The review ended by looking at a small sample of responses to a newspaper article on the split market proposal in [15] and it appeared not to have favorably engaged the respondents' attention, with most interest being expressed in general being worried about energy prices and efficient market signals.

The practical implications are that the ESO or energy-only model is capable of sending efficient price and investment signals to cope with the issues of low operating cost, renewable intermittency, and the maximization of the market penetration of renewable generation within the context of a single market. There is no likely gain in efficiency or equity from constructing a split between a market for wind- or solar-powered electricity and a separate market for generation from other sources.

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