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Should Electricity Market Designs Be Improved to Drive Decarbonization?

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Abstract

Wholesale electricity spot markets of different variants have been operating in most developed countries and around 20 percent of their developing counterparts. Although these markets have by and large stood the test of time, their ability to decarbonize power systems in tandem with carbon, renewable, and other policy drivers raises questions about the efficacy of the existing market designs. Expert opinions in the academic and industry literature are divided on this issue, ranging from very few changes to sweeping changes. This review of the literature suggests that in the short term, there is prima facie no reason to believe that the existing market designs are inadequate. At least, there are robust mechanisms in the current markets for energy, capacity, and ancillary services that can be mixed and matched to accommodate renewable energy and storage, and indeed substantial utility-scale renewable energy additions have taken place in several developed countries that are traded through wholesale markets. In the medium term, there may be a need for additional mechanisms. Opinions begin to diverge on this issue for high–variable renewable energy systems and places where markets, especially voluntary net pool markets, have tended to be illiquid due to the presence of legacy fuel supply and generation contracts. Markets like those in India and South Africa, with liquidity in the day-ahead market below 10 percent after more than a decade since they started, are clearly not working, regardless of their decarbonization roles. There is no reason to rethink yet about a complete overhaul of the market design, at least not until there is more evidence that the current systems are not working and empirical evidence in support of a new mechanism. A fuller quantitative examination of the market design options building on the insights derived in this review is a critical task. Future research efforts should construct country case studies to assess the performance of alternative market design proposals.

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Should Electricity Market Designs Be Improved to Drive Decarbonization?

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INTRODUCTION

Wholesale electricity markets over the past three decades have become more sophisticated with near real-time (e.g., 5 minute) bid-based security constrained nodal pricing together with co-optimized ancillary services (or balancing) markets in several systems. However, electricity market designs differ significantly across jurisdictions – most notably across the Atlantic in the United States and Europe. It is fair to say both forms of market, and their many variants within these regions as well as in other parts of the world, have stood the test of time in terms of their robustness. Electricity markets around the world in recent years have gone through massive volatility in fuel prices, financial crises, increasing frequency of extreme weather events, as well as a technological shift towards variable renewable energy (VRE) generation, and yet they have proved to be mainly successful and resilient, driven in large part through policy initiatives including subsidies.

A major test that remains ahead of markets is their ability to support decarbonization policies to retire inefficient coal (and gas) and bring in clean energy sources and storage. It has been argued that the market designs may need to be adjusted to cope with high shares of renewables, and to play an active role in providing adequate investment signals for technologies desired from the decarbonization perspective. This is a particularly daunting task in the developing world that accounts for more than 80% of coal consumption and also hosts more than 80% of the existing stock of coal plants. These systems are not only heavily reliant on fossil fuels capacity but suffer from a lack of supply security, driven by inadequate, unreliable, and inflexible generation capacity, an underdeveloped or nonexistent grid infrastructure, a lack of reliable monitoring and control equipment, and a lack of skilled human resources and maintenance (ESMAP, 2020). Yet only one in five of these countries has a functioning wholesale electricity market (Foster & Rana, 2019). Even if there is a wholesale market in place (e.g., in India, South Africa, Vietnam, Türkiye, or Mexico), the inability to deal with legacy coal supply, disturbing generation contracts and shortcomings in the market design have often led to poor liquidity with muted or inefficient price signals.

Consequently, electricity market designs need to be critically assessed to unlock their potential so that they aid to bring in cost-effective, cleaner forms of generation *and* retire inefficient fossil fuel units in line with the emission reduction policies. In the short term, these market reforms serve as the first step towards deeper decarbonization and reliable operation of a renewable-heavy system in the long run. This is a critical need not just for decarbonization of the sector but also to decarbonize heating, transport and industry including production of hydrogen that may be an integral part of the solution for the sector as a whole in the long term. Large-scale retirement of coal coupled with a much larger entry of solar, wind, storage, and other new forms of generation would further test the efficacy of the markets in place. Markets must provide the correct locational signals to attract new entries and produce prices that are not unmanageably volatile or prone to excessive market power. To the best of our knowledge, the behavior of market prices and levels of investment under alternative market designs and without the support of out-of-market subsidies and a Renewable Portfolio Standard or RE target (RPS/RET) or other policy mechanisms have not been studied sufficiently. In particular, the central hypothesis to check is the following: ***Can an incumbent electricity market under a deep decarbonization scenario produce a price outcome that is revenue adequate, ensures security of supply, and will not lead to excessive room for exercise of market power or volatility that cannot be managed through existing stock of risk products? Or does it need enhancements and new mechanisms to deal with these issues? Or is there a need for a substantially new design of electricity markets to support deep decarbonization?***

An issue that is closely linked to markets and prices is that of planning and physical capacity addition plans. The link exists in theory because liberalized markets were fundamentally designed to deliver the least cost plan (in the long term) and dispatch (in the short term). As far as clean energy transition goes, however, this link has been tenuous in reality at best. Least-cost plans routinely predicted a volume of competitive entry of renewables that did not eventuate or at least required a policy vehicle, often with subsidies, and hence cannot be termed as 'market led'. Plans have been meticulously prepared for the next 20-30 years that show systems could be decarbonized at reasonable costs while ensuring resource adequacy and system security. Markets, in reality, even with a healthy allowance for the difference between theory and practice, have not yielded these plans. Several systems, including advanced systems in the United States, Europe, and Australia, encountered system security and inadequacy issues even with far lower realization of variable renewables than planned. The situation is far worse in developing countries, where a wholesale market's absence or poor functioning has made it difficult for renewables to enter the market, even if there is a clear economic case. Although countries like China and India are bright exceptions, with 600 GW and 100 GW of variable RE additions over the past decade, respectively – there are two significant issues, namely: (a) almost all of this capacity has come about through dedicated policy initiatives rather than a market-driven competitive entry; and (b) the presence of legacy coal supply and generation contracts, and the absence of a (liquid) market has led to the continuation of inefficient coal units even if their utilization in both countries has steadily declined over the years. This, in turn, has led to less than the optimal level of RE entry. India, for instance, fell well short of its 175 GW RE target in 2022.[2] There is also inefficient overuse of coal coupled with underutilization of RE, including significant rejection of solar and wind in China (Zhang et al., 2016).

It is fair to say that the interface between least-cost planning and market outcomes for alternative market design is not very clear. At the very least, very few decarbonization studies have been accompanied by a credible market analysis to suggest *the* plan can be delivered through a market. As long-term planning exercises have typically been carried out using commonly utilized optimization models, there is a potential for increased exploitation of similar types of decision-support tools designed specifically for the assessment of wholesale markets. Such tools, if appropriately calibrated and parameterized, could provide a robust and quick evaluation of proposed market designs, including price formations, dispatches, and strategic investment decisions. In fact, a wide range of market models have been proposed over the last 20 years, but these have not been utilized well for long-term planning and policy analysis . This is an area where significantly more work is needed to bring planning and market outcomes in alignment to better understand why these outcomes often diverge and design market mechanism to reduce the gap. As (Conejo & Ruiz, 2020) discusses that the appropriate representation of the decisions of all market agents, which is beyond the purview of conventional optimization approach and is most appropriately represented through equilibrium models – an issue we discuss at length in a later section of this paper. As many developing countries embark on wholesale market developments together with renewable policies, analytical exploration of these markets is a critical need to ensure markets can deliver the desired clean generation portfolio and lower cost. It is worth recollecting that RE portfolio standards have often been met at a substantially higher impact on tariffs than was envisaged in least-cost plans. Worse – even if only a fraction of the "least cost" renewable energy is added to the system – retail prices faced by customers have increased. Indeed some of the cleanest generation systems in the world,

[2] As of July 2022, "*only around 57% of the 100GW solar target and 67% of the wind target has been met. This means India is projected to miss its 2022 solar and wind capacity targets by about 27% and 18%, respectively.*" Please refer to: https://www.weforum.org/agenda/2022/07/india-investment-renewables-green-energy/.

including several in Europe and the United Kingdom, have the highest retail prices[3] and the conundrum also exists within the states in the United States.[4]

The key research questions, therefore, that we address in this paper are as follows:

1. Is the design of the existing wholesale electricity market robust enough and compatible with carbon reduction policies, i.e., is the status quo good enough to deliver a decarbonized power system;[5] or

2. Are there adjustments needed in some of the existing features of a market or to augment the market with some mechanism (e.g., a heavier reliance on bilateral contracts, mandatory mechanisms like must-run contracts, administered prices for part of the generation and vested contracts or some other form of cost-of-service regulation to maintain resource adequacy); [6] or

3. Is there, in fact, a need to rethink market design quite differently, e.g., an organized long term market (OLTM)?[7]

In order to address these questions, we present a summary of the critical literature that supports each of the three propositions to form our own views on the need for changes to the market design in the short, medium, and long term. We follow this up with a discussion on the available modeling methodologies and an analytical framework that may be used to empirically test these alternative market design constructs. A quantitative analysis will eventually be needed to arrive at a definitive answer which is likely to differ for each country's context. However, this is a significant ask and is not covered in this paper.

[3] Please refer to: https://www.globalpetrolprices.com/electricity_prices/

[4] Please refer to: https://www.forbes.com/sites/brianmurray1/2019/06/17/the-paradox-of-declining-renewable-costs-and-rising-electricity-prices/?sh=79547bd561d5

[5] Frank Wolak noted that "*The basic features of an efficient short-term wholesale market design do not need to change to accommodate a significantly larger share of zero marginal cost intermittent renewable energy from wind and solar resources. A large share of controllable zero marginal cost generation does not create any additional market design challenge relative to a market with a large share of controllable positive marginal cost generation. In both instances, generation unit owners must recover their fixed costs from sales of energy, ancillary services, and long-term resource adequacy products.*" (Wolak, 2021)

[6] Some of the ISOs in the US are already doing this and there are several ad-hoc mechanisms elsewhere too to manage resource adequacy that are outside markets, e.g., maintaining semi-retired coal plants in a mothballed state for a side payment, "reserve generators" that kick in based on physical or market-based signals, cross-border trade agreements that sit outside the market, special provisions for ancillary services, etc.

[7](P. L. Joskow, 2019) and also the RFF workshop material in December 2020 available online: ttps://www.rff.org/events/workshops/market-design-for-the-clean-energy-transition-advancing-long-term-approaches/.

A REVIEW OF KEY ISSUES IN WHOLESALE ELECTRICITY MARKET DESIGN

In this section, we first review some of the critical issues that are central to the design of wholesale markets. Opinions were, and still are, divided on critical issues like the role of the spot vs. contract market, cost vs bid based markets, means of ensuring capacity adequacy, providing short-term reliability and balancing services, or impacts of out-of-market emission reduction mechanisms. The questions we pose in the preceding section around the efficacy of existing market designs to drive decarbonization require revisiting these fundamental issues. The transition from fossil fuel-based power systems into emission-free ones in many ways exacerbates especially the challenges around resource adequacy, as coal/gas plants need to give way to cleaner forms of generation, including solar, wind, and storage. The efficacy of the market to send appropriate signals to close coal/gas plants down *and* bring substantially more solar, wind, and storage, among other forms of generation, renews and reopens some of the long-standing debates in existing markets, as we discuss further below in the following two sub-sections.

CRITICAL ISSUES IN MARKET DESIGN

It has been more than three decades since the first wave of liberalization of electricity markets took place in Chile, followed by the UK, led by some influential seminal works in this area (e.g., P. L. Joskow & Schmalensee, 1988). The electricity market design evolved from a simplistic cost-based pool conceived originally in Chile in the 1980s to bid-based markets in the UK, followed by the US, New Zealand/Australia in the 1990s. Opinions on market design diverged around the role of a wholesale spot market vis-à-vis contracts, most notably in the UK during the late 1990s as the mandatory pool was dismantled – a phenomenon that had since become mainstream in Europe. The US states that had adopted a market reform by and large retained a dominant role of the pool, although contracts in all markets continued to play a significant role outside the market but were influenced by the spot price outcomes. The debate on which of these two forms performs better in terms of the right kind of new entry and management of market power continues to date. In practice, the combination of two models has been adopted in different ways by various countries to meet the specific objectives they have identified for their particular market.

There is also significant debate on the design of the spot market, namely, whether it should be 'Energy Only' wherein the generator bids reflect all costs including capacity costs, or whether there should be a separate capacity remuneration mechanism (CRM). One of the issues that has plagued wholesale spot markets, especially for energy-only markets where participation is mandatory, is the potential for dominant generation companies to exercise market power to set spot prices above the competitive level. While this causes significant financial stress for customers/retailers who are exposed to spot prices for part of their purchase, at the other extreme is the problem of spot prices being too low for the generators to earn adequate revenue. The latter in turn may mean a resource adequacy issue for the system if spot and associated contract prices are too benign to attract sufficient entry needed to meet peak as well as the minimum reserve margin. As the process of liberalization progressed, policy makers, regulators, and system operators have increasingly faced the issue of resource adequacy (RA) , with the market not necessarily providing the desired level and type of capacity. The RA issue stems from the so-called ''missing money'' problem and the associated lack of appropriate price signals provided by the energy-only markets to ensure the optimal level of investments (Cramton & Stoft, 2006; P. L. Joskow, 2006a). In theory, a few hours of high prices, rising well above the marginal costs of the most expensive unit, are required to provide an adequate return on investment. It is particularly relevant for peaking plants, usually the price-setting units when dispatched, but this problem also extends to other types of generation, including generators that are expected to operate only occasionally and contribute to the reserve margin in the system. Nevertheless, in practice, the prospects for revenue adequacy are substantially reduced due to a series of market imperfections or constraining regulations, including the potential exercise of market power (e.g., entry deterrent pricing), low price caps, difficulty in estimating a proper price cap (e.g., the value of lost load or VOLL value), or bias by the out-of-market supply of ancillary services (Finon & Pignon, 2008). According to (Cramton & Stoft, 2006), the root cause of the RA problem lies in flaws on the demand side, which renders it impossible for the market to evaluate reliability from the consumer's perspective.

These market imperfections have long been known but fixing these is not straightforward because of the trade-offs involved. While a high price cap may cure the RA problem, it also opens up a substantial risk of exercise of market power even in moderately concentrated electricity markets. In general, two schools of thought arose in dealing with these issues. First, the "energy-only" approach states that fundamental market design centered around energy products can deal with resource adequacy problems by only marginal adjustments within the ancillary service segment or new contract types. More specifically, (Hogan, 2005) proposed the energy-only market concept that should tackle resource adequacy using a joint energy-reserve demand curve and a substantial increase in the offer-cap, albeit this was also recognized as a recipe for excessive market power. The proposed call-option obligation approach (Oren, 2005) suggests that the load entities be obligated to purchase options with various strike prices. Finally, (Wolak, 2004) argued that the adequacy and least-cost supply could be achieved through the purchase of financial forward contracts, hedging against the spot price risk at the locations in the network.

The second school of thought is based on various CRMs that pay for generators to make their capacity available as a separate payment stream from generating energy. (Cramton & Stoft, 2006) were the prominent advocates of this approach, arguing that investments should be guided by capacity targets and forward markets for capacity should be deployed to restore adequacy and performance incentives. In fact, since the beginning of the liberalization process, the notion that energy markets are not mature enough to provide the desired level of adequacy was shared by many regulators. Consequently, multiple markets have long relied on some supporting mechanism to ensure adequate generation capacity (Wen et al., 2004).

Although this fundamental market design debate is already two decades old, as we have alluded to, it has not been resolved. Markets worldwide adopted a wide range of mechanisms, including different nuances within the energy-only and capacity market designs, indicating the importance of tailoring a solution to fit each specific country/system context. Substantial differences emerged across the North American markets and their European counterparts. The former placed a greater emphasis on the spot market's role, keeping it close to the physical realities of the power system, including real-time security-constrained market clearing processes, co-optimized ancillary services, and mandated participation in real-time that produced highly granular spot prices. Market power concerns have been raised but there are also elaborate market surveillance practices in place to ensure unexpected price behaviors are closely examined. In contrast, the European power exchanges or "net pools" use the spot market for settling shortfalls and excesses relative to the contract positions of buyers and sellers on a voluntary basis. Although the liquidity in these markets has generally been good in Europe, these power exchanges do not resemble the physical system, including zonal or even single price for the whole country in some cases. Market power practices are generally less stringent as the contracts take a more predominant role for buyers and sellers. If the power exchange markets have *not* been sufficiently liquid as has been the case in the developing world (e.g., India, Southern African Power Pool, parts of Eastern Europe) – there is a serious problem as the wholesale market with say less than 10% liquidity hardly serves any purpose.

Long-term contract prices are often not in sync with illiquid spot prices. These contracts and the lack of an effective price signal may delay the retirement of coal/gas as well as stall the entry of renewables.

Barring the illiquid power exchanges in the developing world, by and large, both categories of markets have stood the test of time over the last two decades. That said, the questions on optimal entry have been raised in both jurisdictions from time to time. The grid failures in UK/Europe and Texas in recent years due to extreme weather events (namely, heat waves, winter storms, and cyclones) have shown the importance of sufficient firm reserve capacity to withstand these events (Littlechild & Kiesling, 2021). The extremely high spot prices in the energy-only Texas market during its winter storm also exhibited the risk of arguably excessive volatility that many customers were exposed to. Germany (Jahns et al., 2022) and UK's (Shankleman, 2022) policy to shut down its coal plants also eventually requires backtracking to some extent to reinstate some of its coal capacity. These events highlighted the potential vulnerability of the power systems as well as policies that may prove to be too aggressive in exposing these risks and, to some extent, interfere with the market to force thermal capacity out too quickly, leading to supply disruptions and excessive price volatility.

Mature North American and European markets offer valuable insights into the performance of each regime, but the documentation of wholesale competition in developing countries is far less common. According to (Rudnick & Velasquez, 2018), a significant share of developing countries do not meet the preconditions for the introduction of wholesale power markets, including financial sustainability, technical state of the power system, institutional suitability, and adequate political and economic environment. Many countries that initiated power system reform efforts have not implemented competitive wholesale markets, and if they did, they often struggled with the low liquidity or the presence of inflexible contracts (e.g., 20-30 year long Power Purchase Agreements) that may slow down the pace of decarbonization. Consequently, countries like Mexico, Türkiye, and Vietnam transitioned to the wholesale power markets through a simpler and more centralized Single Buyer Model. Despite the economic, technical, and political struggles discussed above, guiding principles for the design of markets remain highly relevant for developing countries. As the transition stage from the old vertically integrated (or Single Buyer) regime to the new electricity market is a vulnerable period, developing countries need a workable framework for market implementation. Since supply adequacy, in countries with rapidly growing demand with inadequate/unreliable generation is a critical measure of success of the market, the design must be tested for its robustness to bring in sufficient capacity.

As we face the added steep transition challenges involving the exit of coal/gas and entry of renewables/storage, these issues remain relevant if not reinforced, as discussed in the following subsection.

MARKET-DRIVEN DECARBONIZATION ISSUES

Markets can and did in some cases, most notably in England and Wales over the last 25 years, deliver significant emissions relief if the cheaper form of generation also happens to be cleaner (e.g., gas over coal in the UK and renewables over gas/coal more recently in other systems). On the other hand, despite the cost rapidly falling, solar, wind, and now storage have not yet radically changed the generation mix, with solar and wind accounting for around 10% of the generation mix globally in 2021.[8] Even when renewables are clearly cheaper, their share in generation through wholesale markets has remained

[8] Enerdata yearbook: https://yearbook.enerdata.net/renewables/wind-solar-share-electricity-production.html

limited. In 2020, the global share of solar and wind in a generation was 5.3% and 2.7%, respectively. Countries like China and India– two power systems with as much as ~1,000 GW and ~200 GW coal – have not yet seen the (wholesale) market-led entry of renewables. The wholesale market in India, in fact, explicitly excluded participation of VRE in its power exchanges because of the variability of these resources and the lack of a mechanism to manage them.

Policy interventions, including subsidies in some shape or form to renewables and mandatory RE targets, have been the major vehicle to promote renewables in most jurisdictions in the initial phases of their deployment. There is a visible cost of such interventions, including significant RE integration costs with investments needed in transmission and distribution, as retail prices have inevitably risen in countries where aggressive policies have been pursued, most notably in Germany, Denmark, the US, and Australia. The implied/imputed cost of carbon reduction has, therefore, arguably been quite high. Although reliance on market-based mechanisms like capacity auctions to bring in renewables has been very successful in some quarters in keeping the cost of such intervention lower than non-market mechanisms like feed-in-tariffs, the efficacy of a policy standard remains a moot point. Subsidies like the Feed-in Tariff (FIT), not only pass levies and charges to consumers, which bears an increasing burden for the societal goal of affordable electricity but may lead to distorted wholesale electricity market prices. Consequently, there is a demand to design and implement alternative intervention-based or market-based approaches incentivizing RE deployment and meeting emission reduction targets.

Empirical and simulation studies suggest that the traditional electricity market designs that do not explicitly consider flexibility issues through an ancillary services market may be inadequate to sustain RE deployment without out-of-market incentive mechanisms. A wholesale electricity market's role in providing a granular, accurate, transparent, and dynamic signal for entry is, in theory, superior, as it seems to create more efficient outcomes. This is why there is an increasing notion that REs should be more extensively integrated into competitive markets and associated risks. However, in practice, this approach has demonstrably been less effective. This is a paradox that is not easy to resolve and has not been resolved. Imperfections in the design, as well as the implementation of wholesale markets, are both reasons. Citing the Indian example, the lack of an adequate ancillary services mechanism has been one of the reasons why the main power exchanges could not see the participation of renewables, although there was significant enthusiasm from the DISCOMs to buy green power. The power exchanges have also been collectively illiquid, with less than 10% of the power generated going through exchanges. Allowing renewables to participate in these exchanges would have helped liquidity as well as the entry of renewables. However, there was a separate Green Day Ahead Market (GDAM) that was introduced in India instead of addressing these problems. A more general problem that has also dented the success of wholesale markets is the exercise of market power – an issue that can potentially be exercised if large-scale VRE is introduced.

A more fundamental concern that has been raised around the suitability of wholesale spot markets to deliver green power is that these markets are not equipped to deal with a high share of zero marginal cost generation or ensure the security of the system. Electricity generated by renewable energy sources is not only characterized by low-end marginal costs but its dispatch is also prioritized in the merit order, with curtailment only happening when the physical limits of the system are reached. Subsequently, depending on the specific market design, either more expensive base and peak conventional generators are pushed down the merit order, or the remaining demand/load that has to be purchased on the electricity markets is reduced correspondingly. The final result is similar, and as long as the supply curve has a positive slope, this leads to lower than the original prices. As the significant expansion of VREs in many systems entered its third decade, this effect has been analyzed and quantified for a number of markets (see, for example (Antweiler & Muesgens, 2021), (Sensfuß et al., 2008) or (Hirth, 2018)). Furthermore, replacing conventional supply in the market also reduces the average price (market capture price) that VRE operators receive on the market, an effect referred to as *market cannibalization* (Halttunen et al., n.d.). Thus, spot prices will be low most of the time, set by RE variable costs, and high only during periods of VRE scarcity. That said, the missing money syndrome is purely an artifact of a price cap in wholesale markets – particularly in energy-only markets – that is almost routinely put in place with few exceptions to curb market power and unmanageable price volatility concerns, among other issues. A high share of renewables would require a higher price cap as there will be a greater proportion of thermal generation that would need to recover its capital costs during fewer low-VRE hours. If the price cap cannot be raised sufficiently to balance some of the other objectives of the market, the missing money problem may become more acute and potentially lead to a resource inadequacy concern.

It should also be recognized that bringing RE through markets on their own may or may not necessarily reduce emissions. As an example, flexibility through storage needed to support VRE may entail leasing a longer life to baseload coal/gas generators as the additional load to charge batteries or pump water for a pumped storage hydro would require running these coal/gas units more during off-peak (or surplus VRE) hours. Market-based policies (e.g., carbon pricing) and non-market-based policies (e.g., direct action to accelerate shutting down coal) will be needed to meet the emissions reduction goals. It is, however, critically important that the design of the market and its implementation are aligned with the accompanying carbon reduction policies. For instance, any administered carbon price needs to be appropriately set to achieve the desired emissions reductions, and the wholesale electricity market must be implemented in a way to pass through the carbon price to the electricity price properly. A carbon price set too low will simply boost the profitability of carbon-intensive generation because they may remain cheaper relative to their cleaner counterparts even after adding the carbon costs.[9] In addition, wholesale electricity prices may rise disproportionately high if there are market power issues with incumbent fossil fuel generators, further extending their profitability. In a similar vein, it is also not advisable to shut down coal too quickly through 'direct action' without having the mechanisms built in the market to attract new entry, especially if these are mostly zero marginal cost renewables. Even if capacity *per se* is not the problem, system security may be jeopardized if there is no way to incentivize generators and the demand side to provide the requisite ancillary services that are critical in the new paradigm with highly variable wind and solar generation.

It is a common utility practice to enter into long-term power purchase agreements (PPAs) with fossil fuel producers that poses the most fundamental obstacle to achieving deep decarbonization goals, especially within developing countries.[10] Upon signing such a contract, utilities or other parties are obligated to purchase electricity from units which can often be highly emissive. It is possible that these kinds of agreements can have a maturity period of up to 30 years, which effectively prevents decarbonization by locking in carbon for a specific portion of the energy supply. Nerveless, there are similar risks associated with entering into long-term contracts. For example, due to a lack of sufficient competition, or the rising prices of fossil fuels, electricity from such contracts might become more expensive than procured from

[9] This was precisely one of the issues in the Australian carbon pricing regime. See for example (Chattopadhyay, 2013).

[10] A recent analysis for the Indian power sector shows that the Power Purchase Agreements in India lead to 26% higher costs and up to 24% higher emissions that could be avoided through an optimal dispatch of the system. Please refer to (Kumar et al., 2022).

other producers or wholesale markets, especially given the declining price of renewables.[11] High costs of such inefficient contracts are passed through to consumers, which not only bear the financial costs of these agreements but also the environmental and health costs for coal/gas contracts. As the DISCOMS/retailers are locked heavily into fossil fuel contracts either through PPAs, or some other mechanism like quotas allocated to them – there is limited room for them to procure RE even when their costs are lower. This is the reality in the vast majority of developing countries, especially India and China.

The process described above, not only in the context of long-term fossil fuel power contracts, is often referred to as carbon lock-in. Generally, carbon lock-in is the result of the inertia of technologies, institutions, and behaviors that limit the rate of decarbonization through a path-dependent process (Seto et al., 2016). Based on the discussion above, lock-in relates to a long-term contractual obligation from conventional units, which locks in future global warming emissions. Few regions in the world are as exposed to the potential carbon lock-in through long-term contracts as South-East Asia (Brown & Hauber, 2021). The fossil fuel generation fleets of Vietnam, Indonesia, and the Philippines are particularly young, with many of their assets being covered by long-term power purchase agreements. Consequently, this reliance on long-term contracts, combined with other barriers, has made it difficult to accelerate the energy transition, restricting regional governments' ability to shed high-emissions coal assets without severe financial damage and providing inadequate investment incentives for renewables (Isaad, 2020).

A combination of a (more acute) missing money syndrome in a high VRE system driven by policies/subsidies together with legacy thermal PPAs can be fatal for a market. The former may leave little incentive for thermal peakers or storage to enter the market as they cannot earn a decent return on their investments. The legacy thermal PPAs, on the other hand, may be cost-inefficient, and the buyer distribution companies/retailers are obligated to buy, increasing their supply cost. The underlying dispatch is inefficient and may lead to significant renewable curtailment to accommodate the PPA minimum running conditions and take-or-pay obligations. Apart from locking in carbon, the combined impact is also to discourage new investments in both firm peaking capacity as well as renewables and an inefficient dispatch. It may also perpetuate the practice of long-term inflexible contracts that are not linked to market prices simply because the market is illiquid, not representative of the overall system, and prices do not yield adequate returns.[12]

There are viable ways to orient long-term PPAs to be compatible with the market. In fact, every country/system that initiated a wholesale market had to deal with pre-existing contracts in some shape and form, albeit the power exchange structure where participation is typically voluntary had more freedom to preserve these contracts. The options have ranged from mandating part of the generation to bid at cost, including must-run contracts, and the introduction of vesting contracts as a transition mechanism (Kee, 2001) that sets the volume and prices for part of the generation typically for a few initial years from the market start, and financial instruments such as contracts for differences (CfD) and cap contracts. The basic idea is to bring a good share (e.g., at least 50%) of the generation of the system to the wholesale market so that prices are a meaningful representation of the system and a market-led optimization of dispatch can be ensured. The latter is critical for decarbonization as baseload coal and gas almost routinely tend to be under long-term PPA with onerous take-or-pay contracts that would be

[11] As per the estimates of IEEFA, Cleveland Public Power spent at least $106 million more on electricity from two projects (the Prairie State and the hydro plants) between 2012 and 2019 than it would have paid if it had purchased the same amounts of capacity and energy in the wholesale PJM (regional) market. (Schlissel, 2020)

[12] See for instance the discussion on wholesale market case studies in (Foster & Rana, 2019).

dispatched even if they are more expensive. Market orientation of legacy contracts, therefore, can be among the top priorities in systems where such contracts are prevalent. The broader market design must consider bringing these legacy contracts under the fold of the market, albeit giving due consideration to the financial health of the utilities and honoring the contractual conditions. It is, for instance, possible to bring the incumbent holders of legacy contract generators in the wholesale market for these to be dispatched based on merit order but keep them financially whole relative to the original terms of the PPA.[13]

13 Please refer to the following report for a summary of the international experience on market orientation of contracts and capacity mechanisms: (Chattopadhyay, 2012).

KEY MARKET DESIGN PROPOSITIONS

The technical challenges associated with developing a stable, near-zero carbon grid have recently received considerable attention. There have been myriad 'net-zero' transition proposals around carbon markets, coal phase-out, and aggressive RE/storage targets. There have, however, been limited discussions on whether or how these policies and mechanisms align with incumbent electricity market design. As a result of the climate change focus, a resource transition imperative has been created, although there is a great deal of disagreement as to how electricity markets should be managed (Borenstein & Kellogg, 2021).

There are two key points to consider in decarbonization strategies. First, it is important to determine a wholesale market design that will ensure a secure, reliable, and least-cost supply, along with a high proportion of VREs. This relates to a number of long and short-term features to deal with a high share of zero marginal cost generation, such as resource adequacy, incentive compatibility, revenue sufficiency, supply-demand balancing, energy and reserves pricing, or valuing flexibility. Several of these issues are similar to those raised during the debate surrounding resource adequacy at the beginning of the millennium, as discussed before. The second is to determine how wholesale electricity markets should play a role in reducing emissions, allowing for appropriate investments in clean energy, as well as enabling the achievement of climate goals. We discuss next how these two issues can be addressed within the ambit of specific market designs.

ENERGY-ONLY MARKETS

There are a number of regions such as erstwhile England and Wales NETA/BETTA,[14] Texas ERCOT system, New Zealand, Singapore, Alberta, Australia, a large part of Europe, India, Philippines, and to some extent California that have relied on an energy-only approach to ensure resource sufficiency. Nevertheless, there have always been debates on the sustainability of energy-only structures to attract an adequate amount of entry.[15] As the frequency of extreme weather events has been on the rise, including heatwaves in Europe and winter storms in Texas, these debates are intensified, and some countries like France have adopted a capacity reserve mechanism. One of the key reasons was the ultimate concept of scarcity pricing, wherein prices can shoot up very high for a few hours in a year to enable generators, especially peaking generators, to recover their fixed costs, including capacity costs. This is, however, a grey area and a constant source of discomfort for energy-only market proponents as such high prices may also be construed as cases of exercise of market power by dominant generators of market power on the market (Cramton, 2017; P. Joskow & Tirole, 2007). There have been cases, including the California summer of 2000, wherein market power allegations have been leveled against some of the generation companies. (Chattopadhyay & Alpcan, 2014) also demonstrated that the South Australian zone in the Australian energy-only market was prone to exercise of market power during summer peak

[14] The NETA/BETTA design replaced the original pool in 2000 and was in place for 16 years before a capacity market was reinstated in 2016.

[15] Soon after the launch of NETA, 2001 the significant excess of reserve margins was diminished, due to extensively mothballed capacities following the dramatic drop in energy prices (Pfeifenberger et al., 2009). Three years after launch, (F. A. Roques et al., 2005) expressed concerns weather NETA's original design can provide appropriate investment signals. Similar concerns were expressed by stakeholders in other energy-only markets (California, Texas, Ontario or Alberta) (P. L. Joskow, 2006b, 2008; Sioshansi, 2006).

when the wind generation drops and the dominant generator in the state can withhold capacity to increase both energy and ancillary services prices.

The ability of energy-only markets to bring in sufficient reserve capacity to meet resource adequacy requirements has been an intense area of debate. Discussion as to whether a market design based solely on energy could meet resource adequacy objectives as well as other key goals, including reliability, security, and affordability (P. L. Joskow, 2006a) continues to this day. Recent developments have intensified this debate following the rapid integration of zero-marginal VREs into grids around the world and ambitious climate targets calling for the complete decarbonization of the power sector. Some of the other crucial topics related to this include pricing volatility, missing markets, missing money, or interactions with environmental policies.

There are contrasting opinions on the ability of energy-only markets to recover investment costs in a generation. It is argued in detail by (Wolak, 2021), that wholesale market design does not need to be altered to accommodate a significantly larger share of zero-marginal-cost sources of income. There is, however, a need to rethink how the long-term resource adequacy mechanisms are designed and how they are coordinated with short-term market forces. Wolak (2021) proposes a standardized fixed-price forward contract (SFPFC) approach as the crucial resource adequacy instrument, which principally requires all buyers to hold contracts for fractions of realized system demand at various horizons to delivery. Furthermore, the proposal suggests increasing the offer cap on the short-term market to incentivize all suppliers to produce as much energy as possible during stressed system conditions.

Nevertheless, as firms in energy-only markets are allowed to bid at prices above short-run marginal cost (SRMC) to cover the capital costs, there is a risk of market power exercise by dominant generators. The price caps (either on the wholesale spot price and/or offer prices from individual generators) were established to limit the excessive bidding above the level needed to generate sufficient returns to peaking units. Offer/price caps are periodically reviewed in light of cost escalations and new entry-level.[16] Raising the offer/price caps, combined with the merit order effect of VREs and further suppressed revenues, might incentivize strategic behavior.[17] (Wolak, 2021) recognizes this issue and proposes automatic local market power mitigation (LMPM) mechanism as prevention. The challenge of maintaining market power in energy-only markets with raised offer/price caps has been indicated and broadly discussed by several system operators, including Alberta (AESO, 2019) and Australia (Kemp et al., 2018).

The views expressed by Wolak are echoed in (Leslie et al., 2020), who state that shifting from fossil fuels to a renewable heavy supply mix will not change the fundamental economic principles underlying market design. There is an argument to be made about the difficulties in pricing scarcity, network constraints, ancillary services, and mandating long-term hedges to provide adequate resources, which is presented

[16] The Australian price cap (termed as VoLL) has increased from AUD 5,000/MWh at the start of the market to $10,000/MWh, $12,500/MWh, etc. and currently stands at $15,100/MWh. There is also a Cumulative Price Threshold (CPT) that puts a limit on the sum of prices over a 7-day period which if breached may lead to a market suspension. Please refer to the AEMC website for further details: https://www.aemc.gov.au/rule-changes/nem-reliability-settings-voll%2C-cpt-and-future-reli

[17] In the context of a system with a growing renewable share, this effect was evaluated by (Browne et al., 2015). Increasing wind penetration results in more market power in some periods, but it allowed to receive satisfaction rates of return on investment. However, it came at costs of occasional dispatch inefficiencies, which grow as wind capacity increases.

in The National Electricity Market (NEM) of Australia. These findings were consistent with an analysis conducted by (Rai & Nunn, 2020), where it was concluded that with case-specific advancements and enhancements (like increased interconnection, increased storage integration, active demand participation, or consistent contract cover) energy-only markets could operate sustainably under high and increasing VRE penetration. Similarly, (Simshauser, 2020) has taken the case of Australia for the analytical valuation assessment of merchant gas turbines, merchant wind generators, and an integrated portfolio. There is, again, nothing in their analysis that suggests that energy-only markets are incompatible with attaining environmental objectives and meeting adequate resource needs. In fact, the analysis indicated that resource adequacy could be maintained in different forms of portfolio integration, making renewable and flexible assets more bankable. In another work (Simshauser, 2019) investigates government-initiated Contract for Differences (CfDs), as a measure to adapt energy-only markets to the changing environment and to achieve deeper penetration of VREs and lower CO_2 emissions. It is discussed that if applied prudently, such CfDs can overcome a series of market failures, which are usually used as an argument to introduce various capacity mechanisms, including those associated with missing or incomplete markets. The risk of these measures is to, in some way, reduce the role of the spot market as participants who are locked into a CfD may have a perverse incentive to bid low to deliver its contracted volume or not participate in the forward market at all.

Theoretically, the merit order effect of zero-marginal cost renewables integration in the energy-only market should lead to more volatile and extreme prices during peak (and hence a regulatory push to increase price caps to contain reliability and adequacy), but may also depress prices during off-peak, including increased incidences of negative prices. The literature reveals quite distinct outcomes. (Rai & Nunn, 2020) challenged these statements with evidence of the South Australian market. It was found that the simultaneous natural evolution of the market towards more interconnection and storage, broader contract coverage, more responsive demand, and revenues from the FCAS market caused lower than expected rise in volatility and no compromise in reliability. On the other hand, (Gholami et al., 2021) evaluated the energy-only market of New Zealand and concluded that the current design is unsuitable for approaching a 100% renewable share system, with inadequate revenues and highly depressed prices.

Similar to Australia's NEM, the Electric Reliability Council of Texas (ERCOT) is another prominent large-scale market committed to energy-only procurement. (Hogan & Pope, 2017) investigated high-level issues that have affected ERCOT's operation in recent years and recommended a series of design improvements, keeping the fundamental structure of the energy-only market. They indicate that while the implementation of the Operating Reserve Demand Curve (ORDC) was an essential step in the evolution of the market, some enhancements might be needed to cope with it. In (Botterud & Auer, 2020), after a careful comparison of energy-only markets and capacity mechanisms in the US and Europe, it was concluded that it is first necessary to achieve better integration of VRE into current electricity markets to improve the energy-only market. The use of capacity mechanisms should be viewed as a backup solution, which is to be implemented only when long-term price formation is insufficient to ensure investment incentives. (Thomaßen et al., 2022) have extensively explored the suitability of an energy-only market for a decarbonization process, examining whether such a market will allow investors in generation assets to accommodate sufficient margins for the recovery of their original investment in such assets. Based on the combination of theoretical and analytical discussion, they established that current markets could align low carbon goals and scenarios with the outcomes of a competitive market. Two key ingredients were (1) selecting an appropriate carbon pricing mechanism, which will incentivize new carbon-free investments, and (2) allowing for involuntary load shedding, which will set scarcity price whenever it occurs, providing an adequate level of supply security.

CAPACITY REMUNERATION MECHANISMS

If resource adequacy and price volatility issues are paramount, and decision-makers are reluctant to use instruments of scarcity pricing and energy-only constructs, alternative market mechanisms are needed to promote resource adequacy, which in most cases take the form of some type of capacity payment. This has been the primary mechanism in several prominent markets, including the forward capacity market in PJM and administered capacity payment mechanisms in some of the cost-based pools in Latin America and the Republic of Korea.

There is significant support in the literature on the need for some form of capacity mechanism to overcome the limitations of the energy-only market. For example, (Cramton & Stoft, 2006) criticized the suitability of the "pure" energy-only approach for driving incentives for investment and operations appropriately. They argue that introducing the missing money must be restored without reintroducing the market power problems currently controlled by price suppression. With a stable functioning capacity market, adequate reliability would be ensured, market power would be reduced, and the risk premium associated with the industry would be minimal. Similar argumentation is provided by (P. L. Joskow, 2006a), where it is stated that according to data from the US and some other countries, wholesale electricity markets and operating reserves do not provide sufficient incentive to stimulate generating capacity in accordance with reliability requirements. A claim is made that the solution to this problem may be the introduction of well-designed forward capacity markets, which should enhance the efficiency of spot wholesale markets and provides incentives for investing in generating capacity in a manner consistent with operating reliability criteria applied by system operators. The authors echoed the same argument during the *Symposium on 'Capacity Markets'* (P. L. Joskow, 2013). (Cramton & Ockenfels, 2011) describe the forward procurement of reliability options, which refers to physical capacity bundled with the option to supply energy at a spot price above a strike price. This approach aimed to suppress risk and market power, not interfering with real-time price signals, yet providing adequate investment levels.

(Newbery, 2016) argues that although that energy-only markets can potentially provide adequate new investments, hardly any of the necessary pre-conditions hold (at least for the European market case). As in the case of Great Britain, appropriately designed capacity auctions can address the missing money and missing market problem, yet the significant risks of over procurement are still in place. Similar criticism has also been raised for PJM and other US markets with a capacity mechanism as the observed reserve margin has been well in excess of the resource adequacy norms as we discuss later.

(Henriot & Glachant, 2013) suggest that while VREs may participate in various capacity remuneration mechanisms (CRM), a single regulatory tool may be applied to promote investments in renewable energy sources and ensure adequate levels of capacity. However, the challenge remains with appropriate valuation VREs capacity factor, as being unavailable at the time would produce severe penalties. The issue of cost and distortion due to inconsistent capacity credits for renewables has been analyzed by (Bothwell & Hobbs, 2017). They found that when a producer is compensated based on their marginal contribution to the adequacy and the timing of peak loads is considered, this can lead to optimal utilization of capacity. Finally, (Bhagwat et al., 2017) argue that although energy-only is optimal in theory, capacity mechanisms can be a solution to the situation when imperfect competition conditions prevail, such as imperfect information, uncertainty, a demand shock, or out-of-market interventions.

Although the precise form of the capacity market is not universally agreed upon, different types of CRMs were implemented worldwide to incentivize new entry, revenue, and resource adequacy. Strategic reserve refers to the mechanism of contracting selected dispatchable and flexible power plants that do not participate in the electricity market to be used in extreme situations of system stress and when the market price is close to the defined cap. Strategic reserves have been a relatively popular option in European markets, already deployed in Belgium, Sweden, Finland, and Poland (Keles et al., 2016). A centralized capacity market is another type of mechanism, where the regulator determines the capacity to procure, and the level of payments is based on auctions in which the operator clears the market in the order of the offers. These kinds of capacity markets have been introduced in, for example, PJM, ISO-NE, Colombia, and Ireland (Bhagwat, de Vries, et al., 2016). MISO and NYISO introduced voluntary capacity markets but with the possibility of bilateral capacity contracts or self-supply (Byers et al., 2018). It is also worth noting that energy-only markets also use non-market-based reserve procurement mechanisms to address any low reserve concern. The Australian National Electricity Market, for instance, introduced a 'Reserve Trader' mechanism at the start of the market in 1998 as a temporary/transition measure to guard against any potential lack of new entry. Although the market attracted sufficient new entry over the last 25 years since its start, the mechanism has however been retained to date as an emergency protocol.[18]

CRMs still cause a series of controversies, also due to potential negative impacts and inefficiencies within the market. (Bublitz et al., 2019), provides an excellent review of CRMs experiences, including an evaluation of potential inefficiencies. PJM is a prominent example of the myriad of capacity market failures. As recently outlined by (McCullough et al., 2020), recent reforms of the capacity market increased market concentration over the past decade by removing the majority of PJM's capacity from the competition, allowing for the extensive exercise of market power by individual suppliers to the point that capacity margin could reach 70% in 2040. (Bhagwat, Richstein, et al., 2016) mentions that due to future uncertainty, a market with strategic reserves may become unstable, causing high volatility with exercise price spikes.

NEW PARADIGMS

Finally, we turn to the last group of proposals that call for disruptive changes in the electricity market design. This has been primarily led by Professor Paul Joskow from MIT, who, inspired by Oliver Williamson's concepts of institutional adaptation, proposed the concept of hybrid markets based on the principles of 'competition for the market' that relies on market-based procurement for long-term PPAs (P. L. Joskow, 2022). (WRI & Resources for the Future, 2020) summarize the options for shifting towards hybrid markets. These include competitive procurement for long-term contracts grounded on resource planning, supplemental capacity remuneration support mechanisms, as well as short-term markets. These mark a more significant departure from the conventional wholesale spot market. The premise for such a significant change is that as energy prices may become more uncertain in the future, investors will find it more challenging to make substantial investments in VRE, which comprises almost entirely upfront capital costs. To achieve ambitious decarbonization goals, the volume and type of renewable energy investments required could be better supported by hybrid markets, which could provide more

[18] Refer to the Australian Reliability and Emergency Reserve Trader mechanism page: https://aemo.com.au/en/energy-systems/electricity/emergency-management/reliability-and-emergency-reserve-trader-rert

consistent earnings over the long term. (Gimon, 2020) outlined the principles of new market design and implementation for long-term procurement and resource adequacy, using the concept of Organized Long-Term Markets (OLTM). The OLTM proposal essentially extends the current procurement horizon, and facilitates the least-cost entry of new resources, in line with resource adequacy and other sustainability goals.

(Keppler et al., 2021) argue that hybrid markets are needed to provide a sustainable reach of low-carbon goals. The proposal broadly reflects the European experience and its energy-only design to combine the long-term investment procurement process with the administrated capacity choices and a module for short-term dispatches based on competitive procurement. (F. Roques & Finon, 2017) proposed a hybrid regime based on the convergence of the various changes in market designs. The approach included procurement divided into two stages where the first one involves auctioning long-term contracts to support investment ("competition for the market") followed by a typical energy-only competition ("competition in the market") for the existing units. Conclusions from these two papers were recently supported by modeling results of (Lebeau et al., 2021), who concluded that in order to reach decarbonization targets, a paradigm shift toward hybrid markets is necessary. The same was argued by (Joseph, 2022), that to achieve the required level of decarbonization, competitive wholesale energy markets require moving away from the idea of exclusively price-driven transition.

ANALYTICAL FRAMEWORK FOR MARKETS

As the discussion above alludes to – market design choices for decarbonization seems to be wide open with views ranging from relatively minor changes to existing market design to practically abandoning market and resorting to planning and long-term contract. The academic and industry literature to date is relatively low on empirical evidence to support one proposal over another. While there is a significant and growing list of planning studies on decarbonization pathways, a market-led realization of these plans under each of the three broad alternatives and multiple variants therein, even for a single system, is indeed a significant task. In fact, not only is this topic extensive in scope, but also it is dependent on a series of market-specific contexts, including systems size, current energy mix, political dynamics, or state of market regulation. The answer is unlikely to be the same across vastly different systems. The purpose of market design is not to select from existing models but to devise mechanisms that are best suited to the particular context of that country (Chattopadhyay & Klein, 2021). However, the broad selection of available designs and their combinations complicate the decision process, especially when facing contradictory opinions on the efficacy or distorting effect of various market structures (Holt, 2020). There is a clear need to develop robust and practical analytical tools to evaluate the scope of market design proposals. In this section, we present a discussion on the modeling constructs for each of the three options, including an overview of the relevant literature.

There are two key components of an analytical framework for markets: the bidding behavior by generators, typically determined at the level of the portfolio of generators by owners; and the market clearing process at the system level, typically handled by a market/system operator. The physical realities of the system, namely, capacity limits on generation and transmission, ancillary services, etc. will need to be incorporated in both components, e.g., a generation company, in preparing its bids, may consider any locational advantage they may possess due to transmission constraints and how the offers should be structured for both energy and ancillary services for its available capacity.

Computational models of electricity markets, including strategic behavior of generators and market price simulations, have steadily emerged as a tool of choice to assess different market design proposals and their impact on investments, prices, revenue, welfare, and performance under stress. Following the scheme (Ventosa et al., 2005) and complemented by (Cretì & Fontini, 2019), electricity market models can be divided into three main groups: optimization, simulation, and equilibrium models. The optimization models are formulated as the profit maximization problems for each player (typically, a generation company with a portfolio of generation assets) competing in the market, subject to economic and technical constraints. In these models, the price is treated as an exogenous input to the model, allowing this model to represent only simple quasi-perfect competition situations in which the incumbent player is a 'price taker' with no influence on prices. In simulation models, the agents' or firms' strategic decisions are represented by interconnected rules describing the players' behavior. This genre of model offers a wide range of flexibility to the modeler in defining the market behaviors and generally offers good computational performance. However, the approach may be atheoretical that requires substantial work in constructing the mentioned rules, while those assumptions embedded in the simulation are based loosely on the available theory and the knowledge of the specific market (which often may be scarce or misleading). Finally, the equilibrium models represent a group that explicitly consider market equilibria within a traditional mathematical programming framework (Gabriel et al., 2010). These models jointly consider a set of interrelated optimization problems of all the market participants, allowing for strategic interactions among the market participants.

The equilibrium models over the years have become the mainstream tool for evaluating different design options for electricity markets, analysis of electricity bids by market monitoring agencies, and also preparation of bids by traders. Equilibrium models have been successfully calibrated against actual market price outcomes.[19] These models have also been used for merger analysis and a number of litigation cases around market power since the late 1990s.[20] Equilibrium models internally account for profit-maximizing decisions of each company, assuring that the modeled bidding reflects real-life behavior. Thus, it allows us to evaluate, and gain some insights into, the impact of strategic behavior on the market outcomes and the impact of various market designs on the players' behavior (in both production and investment stages). In the remainder of this section, we discuss the possible modeling constructs for each of the market design proposals focusing on the ability of the modeling framework to deal with energy transition issues, including modeling of bidding behavior by generators, representation of physical realities transmission, RE, storage, ancillary services, etc. as well as specific market design constructs including representation of physical and financial contracts they may entail.

ENERGY-ONLY MARKETS

Significant works in this area paving the way for the most recent developments and applications were presented between 1994 and 2005. In 1994 (Scott & Read, 1996) used the Cournot duopoly model to represent the hydro reservoir operation in wholesale markets and the impact of contracts. In 1995, (Borenstein et al., 1995) suggested using the Cournot oligopoly equilibrium to analyze the Californian energy industry while undergoing restructuring. The authors suspected market power abuse and concluded that the Cournot model would be a suitable methodology. In 1997, (Borenstein et al., 1997) deployed the Nash-Cournot model to evaluate the New Jersey electricity market. The model was used to assess the impact of the line congestion and the amount of time congestion is likely to be a problem. In 1999, (Jing-yuan & Smeers, 1999) presented a similar model with Cournot players and regulated transmission prices. A variational inequality (VI) approach was used to compute the equilibrium solution. In 2001, (Hobbs, 2001) presented two Cournot models of imperfect competition among electricity producers formulated as MCP.

An equilibrium model based on Cournot competition has been used for over twenty years to describe energy-only markets. Using these basic principles, we may represent the basic principles of this model by utilizing individual optimization problems for producers, as shown in Eq. (1). Assuming that the set i represents players participating in the market, each player simultaneously chooses their profit-maximizing production (revenues obtained through market price λ minus costs C_i), assuming the output of other competitors as constant.

$$\max_{Q_i} \pi(Q_i) = Q_i\lambda(Q) - C_i(Q_i) \tag{1}$$

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[19] See for example, J. Bushnell, E. Mansur, and C. Saravia, Vertical Arrangements, Market Structure, and Competition: An Analysis of Restructured U.S. Electricity Markets. CSEM WP 126, University of California Energy Institute, 2005. And also, E. G. Read, J. Tipping, and D. Chattopadhyay, "Incorporating bottom-up structure into top-down electricity market models," in Proc. Int. Assoc. Energy Economics, IAEE Int. Conf., Wellington, New Zealand, 2007 present a calibration outcome for the New Zealand electricity market.

[20] Please refer to the FERC document on Inquiry Concerning the Commission's Policy on the Use of Computer Models in Merger Analysis: https://www.govinfo.gov/content/pkg/FR-1998-04-24/html/98-10687.htm

As discussed earlier, the energy-only markets can co-optimize additional products like different classes of ancillary services. The 'second generation' electricity markets that were commissioned around mid to late 1990s, including New Zealand and Australia (Alvey & Goodwin, 1998) included multiple classes of frequency control ancillary service (FCAS) products co-optimized in an energy-only setting. These markets, by and large, coped well with the penetration of VRE. Australia also saw the successful integration of a 100 MW/ 129 MWh Tesla battery in 2017, the world's largest battery project at the time. Demand for ancillary services and payment for it in a real-time (5-minute) market made it possible to deal with the additional variability in net demand arising from solar/wind. A significant increase in such variability will manifest into a higher price of ancillary services, primarily as a result of higher balancing requirements resulting from renewable energy's variability (Strbac et al., 2021). (Chattopadhyay, 2004) extended the traditional Cournot-based production game by modeling a joint market, which means that the players make offers for energy and ancillary services markets simultaneously, considering the technical limitations of the products (both separately and jointly). The new profit maximizing objective function is presented in Eq. (2), where production decisions, prices, and costs are not dependent on the set of products p, which may include energy but also various categories of FCAS. The modeling framework also accounts for transmission constraints and allows for a range of other constraints, including intertemporal ramping constraints for generators and demand response from the customer side.

$$\max_{Q_{i,p}} \pi(Q_{i,p}) = \sum_{p} Q_{i,p}\lambda_p(Q_p) - C_{i,p}(Q_{i,p}) \tag{2}$$

The dynamic nature of the electricity market, including the inclusion of new categories of products, new pricing methods, and new technologies, poses additional challenges to the modeling process. Consequently, the simplified representation from Eq. (2) may need to be expanded or modified to appropriately test new designs. In addition to the core features of an energy-only market including energy bids, nodal prices and transmission constraints and ancillary services, the presence of forward contracts may influence the market outcomes. For instance, (Shanbhag et al., 2011) showed how to incorporate forward contracting under uncertainty to the regular production game. (Ruiz et al., 2012) presented how two-settlement equilibrium, originally formulated as EPEC, can be recast as a single-stage MCP. The two-settlement models have also been explored by (Kamat & Oren, 2002, 2004; Yao et al., 2008).

Other analytical works focused on interactions between different products within energy-only designs. (Martin et al., 2015) developed a stochastic two-settlement equilibrium model of the short-term market to investigate the impact of wind operation under different incentive mechanisms. (Smeers et al., 2022) continued this topic, presenting an equilibrium model co-optimizing energy and reserve, accounting for incentives for wind generation. (Papavasiliou & Smeers, 2017) presented the equilibrium energy-only market model with an operating reserve demand curve (ORDC) mechanism. (Zou et al., 2017), deployed a multi-period Nash-Cournot equilibrium model with the representation of energy, reserves, and regulation markets to investigate the market perspective of the decarbonizing Chinese power sector. It was shown that with increasing renewable supply, the energy prices decrease while the regulation and reserve prices significantly increase, providing adequate profits for conventional producers. (Xiao et al., 2022) developed the equilibrium model of joint electricity and ancillary services market with strategically acting CSP operator with thermal storage. To understand the impact of new electricity market participants, an illustrative case study revealed that with increased capacity of CSP units, the equilibrium price continuously decreases, despite strategic operation. In (Rayati et al., 2020) novel equilibrium formulation of the frequency-constrained electricity market model was proposed. The new dispatch based on generalized Bayesian Nash equilibrium (OGBNE) is developed and compared with other traditional dispatch approaches to improve system dynamics and disincentivize strategic bidding.

Several works, apart from advancing energy-only equilibrium formulations, included investment decisions internally within the same model. (Masoumzadeh et al., 2020) presented the equilibrium model with capacity expansion to investigate different tax and subsidy incentives to reach emission reduction and resource adequacy within Australia's electricity market. (Milstein & Tishler, 2011) examine the impact of intermittent renewable energy, specifically PV technology, on the mix of generation capacity and prices in deregulated electricity markets. (Brøndbo et al., 2020) presents an imperfectly competitive electricity market model with a real options approach as a means of expanding generation capacity, with strategically acting producers, various technologies, and long-term demand uncertainty. (Oderinwale & Weijde, 2017) used the equilibrium model to analyze strategic capacity expansion decisions under carbon emission tax and/or feed-in tariffs. In two related articles, (Ehrenmann & Smeers, 2010, 2011) introduce stochasticity and scarcity pricing to evaluate investment decisions under various market designs (including energy-only scheme).

In addition to detailed representation of VRE and demand variability, Cournot models have also been extended to include representation of storage.(Zou et al., 2016) evaluated the contribution of energy storage to support renewable energy integration in an oligopolistic market based on the Nash-Cournot theory. (Virasjoki et al., 2020) built a market model with the Cournot competitive players to investigate the storage impact on the Western Europe wholesale electricity prices. (W.-P. Schill & Kemfert, 2011) introduced the game-theoretic market model to evaluate the effect of market power on electricity storage utilization in Germany. (Masoumzadeh et al., 2018) presented a stochastic bi-level optimization model to find the optimal storage capacities in the energy-only market with Cournot players.

In summary, there is a rich modeling literature that allows all physical, market and financial aspects associated with energy transition allowing a full examination of energy transition options in a decarbonized scenario.

CAPACITY REMUNERATION MECHANISMS

Equilibrium models have also been developed for capacity markets. Consistent with Eq. (1) and Eq. (2), (Chattopadhyay & Alpcan, 2016) provide a straightforward extension of the traditional production energy-only game in Eq. (3). The profit function of the producers is expanded with capacity payments λ^C revenues and costs associated with the new capacity C_i^C.

$$\max_{Q_i^E, Q_i^C} \pi\left(Q_i^E, Q_i^C\right) = Q_i^E \lambda^E(Q^E) - C_i^E\left(Q_i^E\right) + Q_i^C \lambda^C(Q^C) - C_i^C\left(Q_i^C\right) \tag{3}$$

In reality, there are alternative forms of compensation for availability that may range from an exogenous/administered capacity payment to an auction for capacity on a periodic basis. Designing a CRM is a complex challenge in which the right solution depends on the particular circumstances of the market, for instance, the existing capacity mix as well as the characteristics of the demand for the particular mechanisms. Consequently, a large number of studies find the use of models as highly suitable for investigating optimal capacity payments. (Kwon et al., 2020) presented a market equilibrium model to analyze resource adequacy under various generations' portfolio, with co-optimization of energy and reserves. A case study was conducted on the ERCOT market, comparing the outcomes from the equilibrium framework with the ones resulting from a traditional centralized least-cost planning model. (Aryani et al., 2021) developed a bi-level robust regulatory model to analyze generation companies' investment response to various regulatory decisions or players' behaviors, including capacity markets, subsidies or uncertainty. A similar model was used in (Aryani et al., 2020), to investigate capacity and energy payments for conventional and renewable generations, necessary to achieve targets for adequacy and emission reduction. (Mcrae & Wolak, 2019) developed the equilibrium model to analyze reliability payment instruments in the Colombian electricity market, demonstrating the shortfalls of this design to minimize the cost of meeting electricity demand and reduce market power exercise. (Lynch & Devine, 2017) analyze capacity remuneration mechanisms using a stochastic mixed complementarity problem, focusing on the impact on electricity prices and generation investment.

There is again a range of modeling options to analyze joint capacity and energy markets to complement energy-only market analysis.

NEW PARADIGMS

Recent discussions around the need for substantially new mechanisms entail the development of a new methodology. The construct of organized long-term markets, proposed by (P. L. Joskow, 2022), as a substantial alteration of market design, would, for instance, need an extension to the existing models. As these are relatively new propositions, only a handful of studies picked it up in terms of modeling methodology. (Abate et al., 2022) formulated a game-theoretic equilibrium model that represented the interactions between oligopolistic generators in a two-stage electricity market with a high share of renewable energy sources. Their methodology focused on the contract design by introducing physical and financial contracts to investigate their impact on the wholesale market and evaluate their overall performance under various levels of RE penetration. (Lebeau et al., 2022) analyzed hybrid markets through a quantitative methodology based on linkages between optimization and dynamic simulations models. The dynamic combination of models allowed to complement energy-only market representation with long-term auction modules for contract-for-difference (CfD) and closure compensations, which closely aligns to the theoretical hybrid market proposal.

The studies above indicate a few challenges associated with representing long-term contracts in a traditional modeling construct. First, there needs to be a methodology developed to assess the technology mix, volume and price of the long-term contracts. In line with the OLTM methodology, this would require running the least-cost planning model and determining the required contract volumes and types. Furthermore, the challenge also lies in the appropriate representation of competitive auctions, different contracts, and resulting compensations. Finally, outcomes of the long-term contract auctions are directly and dynamically connected with the results of the spot market. Theoretically, it is a two-stage game that may be represented either through multi-level equilibrium constructs, which may be difficult to solve or through the dynamic linkage between two separate models and achieving the equilibrium iteratively. All these challenges must be addressed to produce an effective decision-support tool that is not only accurate but also computationally tractable and robust in terms of temporal and spatial resolution or technology representation.

ADDITIONAL MODELING ISSUES

NEW TECHNOLOGIES

A modeling framework must represent market mechanisms appropriately, but newly emerging and innovative market participants may also present a challenge to the modeler. Considering that these new competitors may have a decisive impact on a decarbonization process and on how the markets will operate in the future (for example, by providing reliability services), their representation is necessary for constructive assessments. Most prominently, storage facilities are perceived as technologies offsetting the intermittency of RE technologies and providing reliability with high shares of VRE supply. They were comprehensively modeled in a single-stage equilibrium MCP framework under strategic operation by (Ekholm & Virasjoki, 2020; Virasjoki et al., 2016). Furthermore, there has been increasing interest in prosumers in recent years, who have the capacity to act both as suppliers and consumers in a power market, which in a strategic equilibrium setting was analyzed by (Ramyar et al., 2020). (Devine & Bertsch, 2018) focused on the increasingly active participation of consumers and the value of demand response in mitigating unilateral market power. (W. P. Schill, 2011) used a game-theoretic equilibrium model to evaluate the impacts of a large-scale electric vehicle fleet on the imperfectly competitive electricity market. Finally, green hydrogen is increasingly being discussed as part of the decarbonization solution, which can be, in the first instance, a significant increase in clean generation requirement to produce hydrogen but also present a long-term storage and peaking generation option. For instance, (Hasankhani & Hakimi, 2021) and (Michalski, 2017)introduced the hydrogen storage and electrolyzers operators into the regular Cournot game in the electricity market.

INCORPORATING CAPACITY EXPANSION AND LINKAGE WITH OTHER MODELS

As resource adequacy, revenue compatibility, and investment incentives are at the center of the current market design discussion, an appropriate representation of the capacity expansion decisions is critical in the modeling framework. In terms of incorporating capacity expansion within the equilibrium models, there are two essential available approaches. The first one represents the investment decisions directly as a part of the equilibrium problem. This can be either done through multi-stage (also called multi-level) representation or within the simpler single-stage problem (Wogrin, Hobbs, et al., 2013). While the former allows for representing complex relationships among market participants as well as game stages, it usually ends up being represented as a nonconvex Mathematica/Equilibrium Program with Equilibrium Constraints (MPEC/EPEC) and requires nonlinear algorithms or linearization to reach the equilibrium (Gabriel et al., 2010). The latter might be represented as a single-stage MCP problem (or even a centralized optimization problem) (Wogrin, Centeno, et al., 2013), it is unable to represent all the desired market dynamics within the model without violating equilibrium properties.

The second group of approaches creates soft links between traditional centralized capacity expansion long-term planning models and bidding or market clearing models. In such structures, the capacity expansion is conducted as a system wide optimization, and the specific outcomes of this model (primarily capacity levels) are transferred to the production game for individual players. Using this methodology, it is possible to focus on the detailed representation of the short-term market dynamics, including market power or different market stages, and keep the expansion decisions outside traditional production games. This approach resembles linkages within the different stages of agent-based modeling structures

(Tao et al., 2021). In terms of equilibrium models, such linkages were presented by (Tipping, 2007) or (Suski & Chattopadhyay, 2022).

REPRESENTING MARKET POWER

It is worth reinstating the fact that the market power issues will need to be carefully managed in a decarbonized world. As substantial Giga Watt scale renewable projects have started materializing under common ownership often with peaking thermals, the possibility of a concentrated market in future cannot be ruled out. The variability in zero SRMC generation may leave room for substantial opportunities to withhold firm capacity. As VRE generation similar to hydro may also exhibit prolonged periods of low availability (e.g., "wind drought"), special care needs to be taken to understand the ramification of a high-VRE generation system from a market power perspective. These imperfect competitions (Biggar & Hesamzadeh, 2014) may need to be modeled together with the capacity expansion and new technology representations under the three broad market design alternatives. Cournot competition is one of the simplest yet most popular and versatile approaches to explaining and modeling the strategic behavior of the players (Chattopadhyay, 2004) and as discussed before, there are proven modeling options to test energy-only and capacity markets. Nevertheless, representing market power and bidding behavior bring additional complexities to the modeling framework when we combine it with some of the other facets including market design options like OLTM. This has not been explored so far.[21]

[21] For instance, (Gurkan et al., 2013) show a comprehensive evaluation of various market designs but, due to equilibrium properties, focusing only on perfectly competitive settings. To the best of our knowledge, there has not been an integrated methodology that considers alternative market design proposals taking into consideration decarbonization objectives.

CONCLUDING REMARKS

Although recent years have seen intense discussions and planning analyses on the decarbonization of power systems, there has been surprisingly little evidence-based analysis on whether/how such a massive transformation in generation can be delivered through the wholesale electricity markets. There are some market design proposals emerging in recent years but unfortunately with highly divergent opinions that range from little or no changes to the existing market design to sweeping changes. As far as we are aware, none of these proposals has been supported through empirical studies. On a more positive note, the electricity market modeling literature has advanced to the point that such an empirical investigation of the core proposals can begin starting with an exploration of the incumbent 'energy-only' and 'capacity and energy' market design avenues. The Cournot equilibrium model presents a versatile and computationally reliable option to test the efficacy of these two designs to cope with a net zero or, more generally, a deep decarbonization target. We can test, for instance, if some of the criticisms that have been leveled against the energy-only market design over the years in terms of its inability to ensure resource adequacy or contain price volatility, including excessively high prices, are true and if the performance of such a market is likely to worsen under a decarbonized scenario. The capacity and energy market design has more support in the literature to ensure resource adequacy but also have the potential downside to build excessive reserve margin through the exercise of market power in the capacity market. As the fundamental cost composition in the electricity market changes from a high OPEX to low/zero OPEX and high CAPEX – the underlying strategic interactions among generators during the transition is a highly complex phenomenon that needs to be studied for both market design options. There are also important nuances around ancillary services that are critical for flexibility in a market that may be dominated by solar and wind in the future, with some support from expensive storage and hydrogen options. It is possible in fact that an energy-only market with a substantially larger FCAS might hold the key to the transition with or without the aid of a capacity market. The third category of market design proposals that calls for a sweeping change includes the introduction of the OLTM– essentially a long-term contract akin to the incumbent Power Purchase Agreements for renewables. It is less clear how these contracts, including the underlying generation mix, volume, and prices, will be determined and to what extent this leaves room for the incumbent players to compete. Some of the methodology innovations – possibly as an extension to the Cournot model as an iterative process – will need to be crafted to examine this proposal.

While the answers to the questions we had set out at the beginning remain inconclusive, let us summarize the discussion to reflect our views on these:

1. *Is the design of existing wholesale electricity market robust enough and compatible with carbon reduction policies, i.e., is the status quo good enough to deliver a decarbonized power system?*

   In the short term, there is *prima facie* no reason to believe that the existing market designs are inadequate. At least, there are components therein for energy, capacity and ancillary services that can be mixed and matched to accommodate RE and storage, among others, and indeed substantial utility-scale RE additions have taken place in several developed countries that are traded through wholesale markets. The old debates around the efficacy of energy-only markets continue, although countries like Australia with the aid of a sophisticated FCAS market that was put in place in 1998 have managed to integrate significant RE. Energy-only markets with FCAS readily offer a business model for battery storage and have not exposed the system to generation shortage risk to date. It remains to be seen if these markets also eventually need a forward capacity market but even so – this will be within the realm of known market mechanisms.

2. *Are there adjustments needed in some of the existing features of a market or to augment the market with some mechanism (e.g., a heavier reliance on bilateral contracts, mandatory mechanisms like must-run contracts, administered prices for part of the generation and vested contracts or some other form of cost-of-service regulation to maintain resource adequacy)?*

   In the medium term, there *may be* a need for additional mechanisms. Opinions begin to diverge on this issue for high-VRE systems and places where markets, especially voluntary net pool markets, have tended to be illiquid due to the presence of legacy fuel supply and generation contracts. Markets like India and South Africa, with liquidity in the day-ahead market below 10% after more than a decade since they started, are clearly not working anyway, regardless of their decarbonization roles. These cases obviously need to be looked at and a reform of the legacy PPAs should be an essential component to allow inefficient coal/gas/oil generation to exit the market. Adjustments like an introduction of contract for differences (CfD) and/or vesting contracts, retaining part of the thermal generation for security reasons through a must-run contract, or forcing part of the generation to be offered in the market at the administered price, etc. should be done with great care for these to be aligned with the fundamental principles of the market rather than interfere with it and choke the price signal. If, for instance, a low reserve trigger is set and the system operator needs to procure capacity, the boundaries between market and non-market mechanisms need to be clearly defined. Australia has, for instance, relied on a non-market reliability and emergency reserve trader mechanism for more than two decades that has worked well without interfering with the core energy and FCAS market.

3. *Is there, in fact, a need to rethink market design quite differently, e.g., an organized long-term market (OLTM)?*

   As the previous two points suggest, there is no reason to rethink yet a complete overhaul of the market design at least not until there is more evidence that the current systems are not working *and* empirical evidence in support of a new mechanism like the proposed OLTM. Electricity markets have been through rapid and significant change in generation, interconnections with other markets and substantially new technologies supported through wholesale markets. Indeed, we are looking at a future transformation that is likely to be far more significant if decarbonization goals are to be achieved. Nevertheless, great attention should be paid for introducing any mechanism like OLTM that may risk imposing contracts that restrict the technology-neutrality or even operation of the market. **This may be a long-term option but one that needs substantial research and development before it can be considered for adoption in a real-life market.**

Our review of the analytical studies also helped us to form views on how some of the empirical analysis may be conducted:

4. *What are the available methods to evaluate various market designs from the perspective of efficacy and alignment with decarbonization goals?*

   Equilibrium models of electricity markets have emerged as a tool of choice to assess different market design proposals. These are more complex but rigorous models with a solid economic foundation that can fully account for power system realities of co-optimization of energy, ancillary services, and CRMs, and investment decisions. While new innovations will continue to be needed to deal with new technologies, these models are flexible enough to be likely candidates for evaluating the impact of decarbonization policies.

5. *Are these methodologies robust enough to be applied to diverse case studies and, at the same time, detailed enough to provide reliable decision support?*

   Equilibrium models have been **successfully calibrated against actual market price outcomes and utilized to evaluate different design options** for electricity markets, analyze electricity bids by market monitoring agencies, and prepare bids by traders. In particular, models based on Cournot competition have been robust in aligning the historical and simulated outcomes, representing various market regimes, market power exercise, or disruptive technologies.

6. *What are the potential modeling challenges in appropriately representing constructs of wholesale electricity markets?*

   New technologies, alignment with planning models, representation of market power, and accounting for decarbonization policies pose additional challenges for the model representation of the modern electricity markets. Although many of these aspects have been individually assessed within the equilibrium models, so far, no comprehensive decision-support tool has been introduced to account for all of them collectively.

WAY FORWARD

A fuller quantitative examination of the market design options building on the insights derived in this review is a critical task. As a way forward, we propose to develop a stylized Cournot model by way of a 'market design laboratory' wherein design options such as energy-only, energy-only with FCAS, capacity and energy, capacity-energy-FCAS, capacity energy-OLTM, etc. can be simulated. This model can then be applied for a realistic country case study to tailor specific design options. It is envisaged that such exercises will need to be conducted in the first instance for every fossil fuel-dominated country with an electricity market, including but not limited to China, India, South Africa, Türkiye and Mexico. Such a model will also be very useful for examining market design options for other countries that are embarking on introducing a wholesale market.

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