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Wholesale Electricity Market Design for Decarbonization

Research Opportunities

Christopher Holt

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Wholesale Electricity Market Design for Decarbonization: Research Opportunities

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Abstract

I review several prominent wholesale electricity market design challenges presently facing policy makers, explain their importance with respect to decarbonization of the energy system, and identify a number of areas where economic research can inform policy to facilitate decarbonization. I draw from the experience of the deregulated electricity markets in the U.S. and a large economics literature to illustrate these challenges. Market designs that incentivize price-responsive demand have the potential to improve efficiency and help accommodate intermittent renewable generation resources. Utility-scale storage technologies promise to dramatically change how supply and demand are balanced in the short run. Designs promoting efficient long-run investment, such as capacity markets and scarcity pricing, must contemplate technological complementarities and other generator attributes if they are to achieve reliability standards and decarbonization at lowest cost. Long-run contracts mitigate risk and market power, and are instrumental in deploying renewable energy, yet their role in future market designs is not clearly defined. Internalizing the social cost of carbon is crucial to both short- and long-run market design objectives.

Keywords

Energy, environmental economics, market structure, market pricing, industrial policy

JEL classification numbers

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1. Introduction

Decarbonization of the U.S. economy to meet climate policy goals will require fundamental changes in the electricity sector, which is responsible for approximately 32% of energy-related carbon emissions and 37% of primary energy use (EIA 2020b). Large-scale electrification of energy use in transportation, industry, and commercial and residential buildings will significantly increase electricity consumption, adding to the importance of reducing carbon emissions from electricity generation. Fortunately, the economics of a transition to low and zero-carbon electricity production are favorable in several ways. Renewable energy sources such as wind and solar are cost competitive with fossil-based generation. Utility-scale and distributed storage technologies are developing apace and promise to play an important role in balancing electricity supply and demand. Cheap natural gas, while presenting its own set of challenges for continued decarbonization of the energy system, has hastened the exit of coal plants, the worst polluters among power generators. Original electricity market designs coordinated one-way power flows from generators (mostly fossil based) to consumers, whose demand was treated as perfectly inelastic. These designs did not internalize the social costs from greenhouse gas emissions. New market designs require accommodating the unique characteristics of renewable energy and storage technologies, facilitating price-responsive demand, enabling two-way power flows for consumers with distributed energy resources and internalizing the social cost of carbon.

In this paper, I define an economic research agenda for facilitating decarbonization through wholesale electricity market design, drawing from the experience of deregulated markets in the U.S. — those administered by independent system operators or regional transmission organizations. Because this topic is very broad in scope, I limit my discussion to several prominent areas of study, focusing on topics where conversation among policy makers and economists is the most animated. Several recent overview papers outline emerging issues in electricity market design, including Cramton (2017), Peterson and Ros (2018), Helm and Hepburn (2019), Joskow (2019), Wellinghoff (2019) and Wolak (2019). This article is intended to complement these works by offering a series of specific research questions for economists to address through future academic study or policy analysis. Accordingly, I refer the reader to these and other works where appropriate for more thorough explanations of institutional details and underlying economic theory.

2. Short-run efficiency

Short-run efficiency means balancing supply and demand optimally using available resources. In a perfectly competitive market, this typically results in a price that is equal to marginal cost. In electricity markets, the marginal cost of production varies continually, but consumers are usually exposed to retail prices that are time invariant and based on average costs. Economists have long posited that economic efficiency would be improved if downstream (retail) prices were more reflective of marginal cost (Borenstein and Holland 2005; Joskow and Wolfram 2012). This assertion is based on the reasoning that price variation will allow consumers to respond at times when marginal cost exceeds their willingness to pay.

These potential efficiency gains are intimately connected to decarbonization. Time-variant electricity pricing can help encourage consumption during times when electricity is abundant, cheap and clean, rather than scarce, expensive and polluting. It can also help smooth out price volatility induced by intermittent supply from renewables. In addition, reducing the number of peak-pricing events can defer the need to invest in new generation capacity at a time when much of this capacity derives from burning fossil fuels.

Electricity markets are indeed already evolving toward enabling price-responsive demand. In this section, I describe the current state of electricity market design with respect to efforts to engage demand-side participation in wholesale markets. I suggest that retail-side (downstream) questions of consumer behavior, technology adoption and rate design must be complementary, with research addressing how wholesale-side (upstream) market design changes can stimulate price-responsive demand. To illustrate this, I use the policy experience of so-called “demand response” programs, which are a mechanism for enabling demand-side participation in wholesale electricity markets. I conclude with a list of research questions pertaining to large-scale battery storage, which also has great potential to help balance supply and demand more efficiently. Battery storage is both a demand- and supply-side resource, and therefore has profound implications for wholesale electricity market design.

3. Unlocking price-responsive demand

3.1 Finding the Holy Grail

For economists, liberating the price-responsive portion of the demand curve is analogous to searching for the Holy Grail (see, e.g., Puller and West 2013). Although elusive, the social welfare gains from price-responsive demand are potentially large (Borensten and Holland 2005). Electricity generators sell through three channels: self-supply arrangements, bilateral contracting and spot markets. Spot markets (which I also refer to here as “energy markets”) are cleared via auction on a day-ahead and real-time basis, and the clearing price reflects the cost of the marginal generator — the most expensive unit to be called upon for dispatch. As such, an incremental reduction in demand by even a small price-sensitive contingent can obviate the need to dispatch generation from an expensive price-setting unit, and therefore has the potential to reduce costs for *all* spot market consumers.

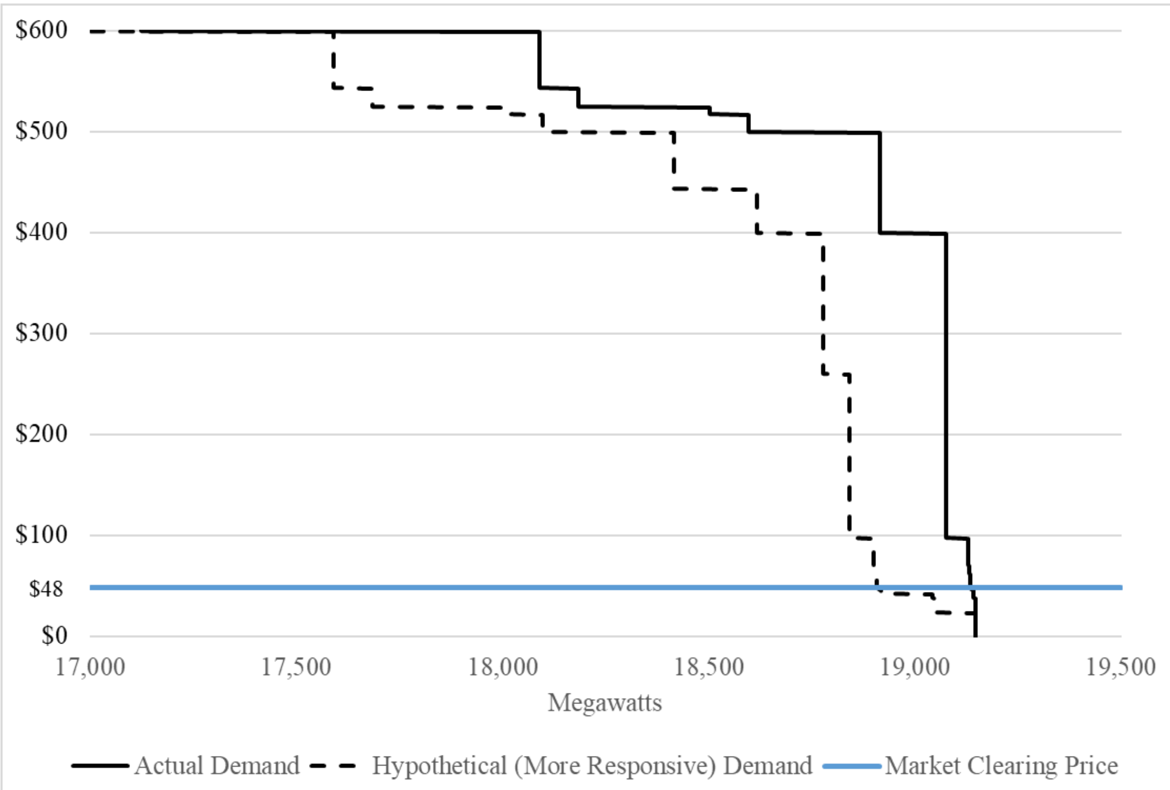
The demand side of electricity markets is brokered through load serving entities (LSEs), which buy electricity on the wholesale market and sell it to residential, commercial and industrial customers. LSEs include competitive electricity supply companies (ESCOs) in retail-deregulated markets, and regulated or not-for-profit entities, including utilities and cooperatives. How marginal cost-based variations in the wholesale price of electricity are passed along to consumers depends on how prices are set at the LSE level — either competitively or through a regulatory process.

In addition to introducing demand response programs, system operators have taken other administrative steps to enable price-responsive demand in wholesale electricity markets. (I refer to consumers’ shifting their consumption of electricity according to price signals as “price-responsive demand.” I use the phrase “demand response” to refer to a specific type of program administered by system operators, explained in greater detail below. These programs are one of many ways to facilitate price-responsive demand through wholesale electricity market design.) LSEs can, for example, bid into spot markets using a demand schedule that specifies a quantity they are willing to purchase at a given price. This schedule could thus be used to reflect the price responsiveness of end-use customers facing time-variant prices.

Figure 1 illustrates demand in the day-ahead spot market in ISO-NE (the independent system operator for New England) in the 17th hour of July 23, 2018. The solid black line shows the actual aggregate demand bid into the market by LSEs. These bids reveal some degree of price sensitivity, mostly at higher price levels that are well above the market clearing price of $48. At this price, indicated by the blue line in the figure, demand remains extremely inelastic. Presumably, this aggregate demand curve — submitted by LSEs on behalf of consumers — is not fully reflective of the price sensitivity of some consumers. For example, only 4.5% of residential consumers used time-variant pricing in 2017 (EIA 2020a). This group most likely represents only a small portion of all price-sensitive demand. As more price-sensitive demand is “unlocked” through market design and technological advances, one would expect a shift to a more elastic demand curve, represented hypothetically by the dotted line in the figure.

FIGURE 1

Demand bids in day-ahead market, ISO-NE, hour ending 5 p.m., July 23, 2018



Source: ISO-NE.

3.2 Impediments to price-responsive demand

Achieving welfare gains from price-responsive demand has been impeded by a variety of factors (Wolak 2013). One commonly cited barrier has been the lack of advanced meter infrastructure (AMI) — so-called "smart meters" and other technologies that enable detailed measurement of electricity consumption and two-way communication between the customer and the utility. Indeed, an LSE cannot charge time-variant prices without information on customers' time-variant consumption. Due largely to state and federal initiatives, however, AMI penetration is now greater than 50% in the U.S. (FERC 2018). In ERCOT (the independent system operator in Texas), virtually all load (demand) is cleared using smart meter infrastructure that measures consumption by end users in 15-minute intervals. ERCOT's deregulated retail market allows ESCOs to charge the real-time price, if they are so inclined.

Such developments raise questions about whether innovations in retail price offerings have followed from AMI deployment, the extent to which they have made retail rates more reflective of marginal cost, and what the attendant social welfare gains have been. There is a vast literature examining retail rate design and consumer behavior that is outside of the scope of this paper.[1] This research must be complemented by an understanding of how well the wholesale market is designed to accommodate, or indeed encourage, price-responsive demand. In other industries, retailers compete for market share by lowering prices vis-à-vis their rivals. Presumably, time-variant pricing can be used to offer price discounts to some customers, thus offering a competitive dimension that allows retailers to capture rents (Borenstein and Holland 2005). Such a competitive edge need not require a behavioral response to be elicited directly from the consumer. Rather, customers can agree to participate in programs passively, where a third party adjusts their consumption for them (say, by cycling programmable appliances on and off in response to price signals).[2]

Even with the promise of programmable technologies and customer aggregation, ESCOs have evidently been unable to use time-variant pricing competitively. This raises the question of why retailer incentives to implement time-variant pricing remain weak while the gains to consumer welfare are large. Below, I explore whether wholesale market design can yet encourage retail competition along this dimension.

3.3 One evolving wholesale design solution

The evolution of "demand response" programs offers some insight into how wholesale market design can facilitate price-responsive demand. Demand response is a term of art referring to programs administered by system operators, where a market participant agrees to curtail load relative to a baseline in return for compensation from the system operator. Depending on the market, participants may include approved individual load resources (such as large industrial

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[1] Hortaçsu et al. (2017), for example, examine consumer inertia in the Texas retail electricity market, which has encouraged retail competition since 2002. The authors posit that search frictions and a behavioral bias toward the incumbent provider inhibit retailers from effectively competing for market share using price discounts. Schneider and Sunstein (2017) lay out an elegant framework for future behavioral research by developing an analytical model demonstrating that, contrary to the classical literature, the most reflective rates may not be the most efficient due to behavioral consumer biases. Ito 2014 suggests that consumers are responsive to average, rather than marginal, prices, providing empirical evidence from consumer response to nonlinear pricing in California.

[2] Wolak 2019 discusses automated technologies and retail pricing.

customers) or aggregated load. While demand response programs have existed in some markets roughly since deregulation, they continue to evolve and grow.[3]

The fundamental design of demand response programs presents interesting challenges for economists. Most demand response programs are administered through capacity markets rather than energy markets.[4] In this setting, firms are called upon an independent system operator (ISO) to reduce load in anticipation of a capacity-constrained emergency. Demand response programs can also take the form of negative supply bids in energy markets. Both types of program require estimating a necessarily imperfect baseline — a counterfactual consumption profile based on historical load patterns. Participants may be rewarded for demand reductions they would have undertaken in the absence of a policy; others may intentionally inflate their baseline to be rewarded an artificially high level of compensation.[5] Despite these challenges, demand response programs are gaining traction. In the PJM ISO interconnection, for example, demand response resources totaled 6.5% of peak load in 2017 (FERC 2018).

One reason for the success of demand response programs may be that the market design allows something that cannot be achieved through retail rate design: a wholesale incentive to keep prices low. Through retail rate design, the individual consumer can accrue cost savings by buying less electricity when prices are high. For any number of reasons, individual response to this incentive may be limited, thus constraining a retailer's ability to capture rents by offering time-variant pricing. In contrast, demand response programs allow participants direct compensation for reducing marginal demand that would otherwise have raised prices for all consumers in the energy market. Demand response payments to participants are ultimately borne by consumers, but if implemented properly this cost burden is small relative to savings.[6]

Consider a market where 20,000 MW are being consumed in an hour. In a situation where a small increase in demand leads to an increase in the wholesale price of $5 in that hour, avoiding the small demand increases saves $100,000 in consumer surplus. What demand response programs do is effectively channel a portion of the $100,000 in savings to the demand response participants. This incentive exists only by market design and, importantly, is only loosely tied to the individual customer savings. Indeed, a consumer may be indifferent to the amount of cost

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[3] Some programs were delayed by a period of legal and regulatory uncertainty. ISO-NE implemented a new demand response program only recently, on June 1, 2018. ERCOT's demand response program expanded by approximately 19% between 2016 and 2017 (FERC 2018).
[4] See Blumsack (2018) and Gagne et al. (2018) for useful overviews and case studies.
[5] See Bushnell et al. (2009) for an overview.
[6] Walawaker et al. (2008) find empirically that social welfare gains were larger than the losses from payments to participants in PJM.

savings they achieve from responding to price signals, but a third-party aggregator will be able to capture rents if they can shift the demand of a large enough contingent of consumers. As long as the aggregator can induce enough participation, demand response programs enable both consumers and aggregators to be better off.

3.4 Research opportunities related to price-responsive demand

What are the potential social welfare gains from price-responsive demand?

Before examining how to design markets to stimulate price-responsive demand, it is important to understand how much of a difference this will make. Imelda et al. (2018 extend) a strand of literature that addresses this question. They employ a sophisticated linear programming model to estimate potential social welfare gains from dynamic pricing in Hawaii. While this analysis is limited to the experience of Hawaii and its unique energy profile, the open source model, known as Switch 2.0, is "widely adaptable to other settings," offering a promising avenue of research. Future applications may explore, for example, how efficiency gains vary across electricity settings with different characteristics such as storage and generation portfolios, or demand profiles. Future analyses may consider both short- and long-run effects (Borenstein 2005). Mass electrification, which promises to bring increased demand and the potential for coordinated response, is an important consideration for future research that uses models like Switch 2.0. Examining social costs of pollution as a component of time-variant pricing also represents an ongoing area for new research. Borenstein and Bushnell (2018), for instance, compare electricity prices to social marginal costs (which account for pollution externalities) to understand deadweight losses from time-invariant pricing.

Do wholesale market structures impede retail competition and price-responsive demand? What wholesale market design reforms could help stimulate price-responsive demand?

The most commonly cited impediments to price-responsive demand focus on retail rate design, behavioral responses and the market rules that dictate retail competition. For any combination of these reasons, LSE incentives to stimulate price-responsive demand — to find the "Holy Grail" portion of the demand curve — are evidently weak. Can wholesale market design also be an impediment? Although they are perhaps not as obvious as retail-side issues, wholesale-side impediments can arise in a number of ways. Hogan (2013) observed that the existing price caps on generator supply offers dampen the price signal to LSEs. Bilateral contracting may also play a role — LSEs with predetermined load and price commitments may not have an incentive to stimulate an active demand side.

Technological advances that facilitate automated load management, coordination and aggregation may yet provide a tipping point for enabling price-responsive demand. If consumers remain indifferent to small changes in their electricity costs, third parties may still be incentivized to offer demand management services (without requiring active participation on behalf of the contracting customer) if certain technological capabilities — such as programmable appliances — are available to them (Wolak 2019). Policy interventions that spurred the build-out of AMI may provide a framework for the deployment of programmable devices.

How well are demand response programs performing?

Demand response programs are one way in which LSEs or other third parties are incentivized through market design to capture efficiencies from price-responsive demand. Walawakar et al. (2010) examine the early experiences of system operators PJM and NYISO. These programs preceded Federal Energy Regulatory Commission (FERC) Order 745, which required that demand response participants be compensated at the locational marginal price. The matter of compensation was the subject of a long debate (King et al. 2015).[7] Against this backdrop, new empirical work may examine how programs have played out in practice.

An empirical analysis of wholesale bidding by LSEs may be informative to the extent that time-variant pricing programs are reflected in energy market bids. Similarly, data on LSE electricity sales and prices can be used to measure elasticities (Miller and Alberini 2016).

4. Storage

In general, the economics literature underpinning electricity markets is premised on the unique feature that electricity is not storable. A gap in this literature emerges once storage technologies become a reality — how might the foundational literature be amended to account for this change? The literature dealing with pumped hydro storage provides a starting point for extensions dealing with battery technologies (see, e.g., Anderson 1972). For brevity, I discuss here only a few of many relevant economic issues that may be promising areas of future research. While the discussion pertains mostly to large-scale battery storage directly participating in the wholesale markets, many questions are relevant to storage deployment in other segments of the market (such as behind-the-meter storage).

[7] See also Brief of Stanford Economics Professor Charles D. Kolstad as *amicus curiae* in support of petitioners, Federal Energy Regulatory Commission v. Electric Power Supply Association, 577 U.S. __ (2016).

What are the social welfare gains from energy arbitrage? How much will storage technologies reduce emissions?

Energy arbitrage refers to the opportunity for market participants to profit from buying and selling electricity based on price fluctuations. While this is not the only service storage technologies can provide, it has the unique potential to smooth price variation, with significant implications for how intermittent supply can be accommodated and how marginal generation costs are passed through to consumers. The Switch 2.0 model presented by Imelda et al. (2018) may prove useful in modeling these effects. Sioshansi (2010) offers an overview of storage technological developments in the U.S. and outlines a research agenda.

Bringing storage onto the grid may not lead to unequivocal reductions in carbon emissions from displaced generation, especially in the absence of a sufficiently high carbon price. Indeed, energy arbitrage facilitated through storage may amplify the effects of carbon pricing policies by increasing system responsiveness to price signals. Linn and Shih (2019) present a model that illustrates how the amount of emissions reductions achieved from storage depends on the responsive generation mix and the price imposed on carbon emissions.

How do pricing and investment incentives change when storage is considered? How can classical models be extended?

Joskow (2019) notes that energy arbitrage will encourage entry of storage capacity to an extent, although incentivizing efficient investment in storage for other purposes (such as deferring transmission and distribution investments) will be complicated and require significant regulatory design changes. In a working paper, Schmalensee (2019) extends a classical Boiteux-Turvey model to include competitive provision of storage. Early results are supportive of the notion that existing markets may generate efficient long-run equilibria with the introduction of competitive storage supply, although this work is preliminary and invites further extensions. Karaduman (2020) uses a dynamic model to explore price effects and investment incentives for storage technology. He finds, among other results, that private incentives alone will not induce optimal storage given current capital costs, but significant welfare gains may be achieved through their deployment, perhaps through a capacity market mechanism.

How will storage affect spot markets? What implications do storage resources have for market power monitoring?

FERC Order 841[8] is intended to facilitate the participation of storage technologies in dispatchable energy markets (as well as capacity and ancillary services markets) as both buyers and sellers. Participation of storage resources at a large scale has the potential to alter spot markets significantly. Price-sensitive demand bids, for example, may become detached from consumer demand and depend instead on the storage participant's ability to shift load or supply temporally. Market power concerns may arise if vertical arrangements are not carefully monitored.[9]

What lessons have we learned from wind and solar subsidies and procurement processes that can be applied to nascent storage technologies?

It is not widely reported that wind and solar power, on a levelized cost of energy basis, are cost competitive with fossil-based generation (Lazard 2018; EIA 2019). Policy makers have a decades-long history of subsidizing these technologies in a variety of ways, which has helped to advance them along a declining cost curve. Some of these policies have been more successful than others (Murray et al. 2014). While economists tend to favor an externality tax or cap-and-trade emissions policy over subsidies, they have suggested that some subsidies may be efficient when a technology is in early research and development stages.[10] Economic research examining learning-by-doing and spillover effects, and perhaps drawing from the experience of wind and solar subsidy programs, can help ensure that policy makers guide the deployment of storage technology efficiently. Similarly, auction procurement processes for renewables may offer useful lessons for storage deployment (Lackner et al. 2019).

8 162 FERC ¶ 61,127 (2018).
9 Vertical arrangements in electricity markets, in contrast to other industries, tend to mitigate market power because firms with retail purchase commitments will have an interest in keeping wholesale prices low (Mansur 2007; Bushnell et al. 2008). A vertically integrated firm with storage capabilities may be able to offset its exposure to wholesale price shocks, thus diminishing the mitigating effect of a vertical arrangement.
10 Baumol et al. (1988) outlines the economics of subsidies in an industry with pollution externalities. Cramton (2017) notes that "[s]ubsidies should be limited to research and the early deployment of emerging technologies where learning-by-doing cost reductions are best thought of as public goods." Acemoglu et al. (2016) build an abstract model of a transition to a clean energy economy; results suggest optimal subsidies are implemented in early stages of technological development and phased out over time. Fischer and Newell (2008) find that an optimal carbon mitigation policy involves a portfolio of instruments designed to address the carbon externality, as well as learning and research and development externalities.

5. Long-run efficiency

Classical models suggest that when capacity is constrained, the market price of electricity should reflect the shadow price of the capacity constraint — doing so will induce efficient long-run investment. However, to protect against the exercise of market power, most restructured electricity markets in the U.S. impose price caps that prevent energy market prices from properly reflecting capacity constraints. The revenue shortfall that results has been referred to as the "missing money" problem (Hogan 2005; Cramton and Stoft 2006). Joskow (2019) argues that growth in renewables will exacerbate this problem (if traditional spot markets are to remain in place) as they tend to depress wholesale prices.

In addition to addressing the missing money problem, long-run efficiency involves ensuring an optimal generation portfolio. That is, an efficient design will not only ensure that investors can recover their costs, but also that the right kinds of technologies are making up the system-level energy mix. This objective requires particular consideration of the characteristics of intermittent sources such as wind and solar resources, whose availability varies with location and weather conditions. In light of this variation, an optimal portfolio would consider the complementarities among resources for ensuring resource adequacy. Achieving long-run efficiency through a decentralized wholesale market design is further complicated by the unique financing structure of renewables, which exhibit high capital costs and therefore often require long-term contracts if they are to be viable.

Market designs that seek to ensure long-run efficiency are varied and evolving. I describe three important areas below: capacity markets, scarcity pricing, and the changing role of forward energy and capacity contracts.

6. Capacity markets

The economic purpose of a capacity market is to ensure resource adequacy, thereby separating the long-run efficiency problem from short-run market operations.[11] Different system operators have arrived at varied market designs for achieving resource adequacy. While system operators ERCOT and SPP run "energy-only" markets that do not rely on capacity markets at all, PJM, NYISO, ISO-NE and MISO conduct auctions to ensure capacity provision, and California mandates bilateral capacity agreements between generators and LSEs.

11 For an overview of the economics of capacity markets and discussion of various designs, see Cramton and Stoft (2006) and Bushnell et al. (2017).

Capacity markets, where they exist, are large and represent an important source of revenue for many generators. In 2008, ISO-NE cleared $3.6 billion in its capacity auction, representing 30% of total annual market revenue (ISO-NE 2019). Capacity market design considerations are increasingly important with respect to decarbonization. Zero marginal cost renewables depress energy market prices, which makes cost recovery more difficult for other generators. Moreover, the design of capacity markets directly determines the entry and exit of generation based on firm attributes such as capital and operating costs: inadequate market design might delay the exit of inefficient resources or prevent the most efficient resources from entering. Capacity market design is affected by carbon mitigation policies (most acutely, state renewable and zero-carbon energy mandates).

6.1 Design implications for new generation

To illuminate various design issues, it is useful to explain briefly how capacity markets work. I use ISO-NE as an example. In ISO-NE's annual auction, a megawatt capacity target is set for the obligation period of one year, three years in advance. Firms then bid on provision of capacity. The lowest cost bidders are awarded monthly capacity payments according to the clearing price. These payments are made by the ISO, which then distributes the costs to electricity consumers according to a formula. Firms receiving capacity payments are still able to participate in energy and ancillary services markets, but they must offer their awarded capacity amount when called upon by the ISO — in particular, during peak demand events when the energy market price cap is binding (ISO-NE 2020).

Since the target is defined in terms of *quantity*, by construction the design favors resources with the lowest capital costs. This is particularly relevant for the marginal bidder, which usually determines the build-out of new capacity rather than the maintenance of existing capacity. Moreover, capacity markets mitigate risk for firms that would otherwise have to rely on unpredictable scarcity rents to recover revenue. Mays et al. (2019) explain how, through capacity markets, natural gas generators are therefore fully hedged against market risk: capacity payments ensure investment costs are predictably recovered (without reliance on scarcity rents), and spot market design ensures that shocks to fuel prices do not cause significant profit losses. Renewable generators, in contrast, do not rely on scarcity rents to recover revenue. In addition, they face supply uncertainty through the intermittency problem (wind and sunlight are subject to random disruption), a supply risk that is not mitigated by capacity markets. As the authors suggest, financial tools for trading risk may help to ameliorate these problems.

The intermittent supply risk issue amounts to a means by which the market design places implicit value on dispatchability (how readily a resource can be called upon for power). Natural gas units are fairly easily dispatchable, given sufficient ramping time and fuel availability.[12] This and other attributes, such as flexibility (ramping speed, range of power, frequency response), play a crucial role in resource adequacy but are often not explicitly valued in capacity markets, although some are valued in ancillary service markets. Ensuring the optimal mix of resources that provide the necessary reliability attributes, beyond a simple quantity standard, has been referred to as the "quality problem" (Cramton and Stoft 2006). This has become urgent in some cases due to the growth in renewables; CAISO, the California system operator, for example, has specific capacity rules for ensuring reliability during the hours of the day when solar generation is quickly diminishing.

6.2 Complementary generation

Bialek and Unel (2019) offer a detailed look at another way in which market designs fail to address the quality problem: capacity markets do not fully account for temporal load and generation patterns. Generation from solar and wind power exhibits seasonal and diurnal patterns, while capacity market auctions often require provision throughout a calendar year. This incongruence limits renewable generators to bidding less than they can potentially offer. Generators can also have spatial and technological complementarities that are important for optimizing a portfolio of resources. Heal (2016) explores the relationship between intermittent renewables and storage, considering how covariances across geographically dispersed wind and solar generators, in addition to storage, can smooth the supply volatility of total output.

Present auction designs do not fully allow for efficiencies from complementary generation attributes, although system operators have taken steps in this direction by holding seasonal capacity auctions and allowing joint bids from generators with complementary assets. If resource adequacy were to be approached as an optimization problem — satisfying a reliability criterion at the lowest possible cost — the solution would involve a mix of generation that reflects complementarities across technologies, space and time. As Bialek and Unel (2019) point out, "[p]erfect aggregation rules would fully incorporate the seasonal character of a resource" and "create no barriers to matching between the resources."

12 Fuel availability may be a significant concern. See, e.g., ISO-NE (2018).

6.3 Research questions: Capacity markets

How do current capacity market designs impact long-run investment decisions for renewables, as compared with fossil fuels?

Mays et al. (2019) and Bialek and Unel (2019) offer two examples of how capacity market designs may be more conducive to the entry of fossil-based, rather than renewable, generation. Levin and Botterud (2015) simulate the build-out of capacity under various resource adequacy designs (an operating reserve demand curve, fixed reserve prices and monthly capacity payments), with an emphasis on wind power. Allcott (2012) presents a static entry model that includes a capacity market with three types of generation technologies (baseload, combined cycle and peaker) but does not address generation from renewables. Further theoretical and empirical assessments of how capacity markets have affected investment decisions would make valuable contributions to the literature.

Do current designs properly encourage efficiency gains from generation technology complementarities?

Lawson (2019) shows that wind and solar power in the U.S. complement each other seasonally: wind blows stronger, on average, in the winter, and the sun shines longer in the summer. Energy companies are increasingly consolidating wind, solar and storage assets to take advantage of synergies. An optimal generation portfolio mix reflects such complementarities and is likely to vary geographically depending on available resources. The extent to which market forces, market design and energy policy have induced, and will continue to induce, a portfolio mix that resembles an efficient outcome is an unanswered question.

How can capacity market design solve the quality problem?

Capacity markets failing to take complementary generation attributes into account is one form of the quality problem. Perhaps more urgently, the quality problem also arises when market designs do not ensure sufficient investment in certain resource attributes such as dispatchability and flexibility. This is not necessarily a capacity market design problem — Cramton and Stoft (2006) observe that the root of this and other resource adequacy problems is a lack of proper scarcity pricing. But redesigning capacity markets may nevertheless offer a next best solution if scarcity pricing is not feasible. Fang et al. (2018) present a capacity market model that explicitly addresses flexibility. ISO-NE and PJM have adopted “pay-for-performance” solutions to encourage reliability and incentivize availability during scarcity events. Whether that reform will help address the quality problem is an open question.

7. Scarcity pricing

Administrative scarcity pricing is a means for allowing the shadow price of capacity constraints to be reflected in the wholesale market price. Wholesale prices during unconstrained times reflect marginal generation costs, allowing efficient balancing of supply and demand. In contrast, scarcity prices reflect the value that is lost in an event where supply cannot meet demand due to short-run capacity constraints. Scarcity pricing therefore represents a signal to generation investors. Economists have long suggested that scarcity pricing in energy markets would solve the resource adequacy problem by allowing generators "quasi-rents" that act as compensation for capital investments. In practice, system operators now use explicit scarcity pricing designs intended to reflect these economic principles. Joskow (2019) maintains that, as renewables depress wholesale electricity prices, scarcity pricing will play an increasingly important role in spot markets.

7.1 Research questions: Scarcity pricing

Has scarcity pricing helped alleviate the quality problem?

The operating reserve demand curve (ORDC) is designed not only to recover the "missing money" that results from price caps in energy markets, but also to address the quality problem (Hogan 2005; Cramton and Stoft 2006). Several markets now use ORDCs in combination with capacity markets, but ensuring flexibility and reliability remains a concern. Understanding how generation asset investors have responded to scarcity pricing signals, and whether scarcity pricing has induced efficient investment in flexible generation, would be valuable contributions to the economic literature.

How should scarcity pricing interact with price-responsive demand?

There is a tension between an active demand side that is designed to respond to high prices — thus making their occurrence less frequent — and scarcity prices, which are designed to be triggered frequently enough that they offer sufficient returns on capacity investment. A fruitful line of research would examine how these features can both ensure cost recovery (long-run efficiency) while activating price-responsive demand (short-run efficiency).

Moreover, offer price caps designed to mitigate market power can dampen price signals that are necessary for allowing demand-side participants to engage in the market. Hogan (2013) describes a chicken-and-egg problem: poorly designed scarcity pricing rules discourage demand bidding, and price-insensitive demand bidding leads to imprecise invocation of scarcity pricing. As demand becomes more responsive (through demand response and other programs), more precise scarcity pricing — most likely in the form of higher price caps — may become feasible, and the chicken-and-egg problem may begin to be resolved.[13]

ERCOT has had an energy-only market since its inception in 1999, and thus provides an empirical testing ground for many of the economic principles in question. Policy changes such as steady increases in offer price caps (from $1,000/MWh in 2002 to $9,000/MWh in 2015), a unique retail competition model, subsidies for renewables and the rollout of smart meters are just a few potential areas of focus for researchers. ERCOT's market designs are being tested — slim reserve margins and heightened demand in the summer of 2019 led to emergency calls for conservation (Walton 2019).

8. The changing role of forward energy and capacity contracts

Forward energy and capacity contracts, whether financial or physical in nature, are a powerful tool in many facets of electricity market design, and are integral to numerous market design proposals.[14] They can be used to prevent generators from exercising market power in spot markets (Wolack 2000), or to mitigate buyer exposure to high scarcity prices (Hogan 2005; Cramton and Stoft 2006). They can ensure resource adequacy, as in the case of CAISO. For renewables in particular, long-term energy contracts are used to mitigate market risk over the lifetime of the capital investment. Bartlett (2019) explains how investors in renewables face a trade-off between selling into wholesale spot markets (complemented by financial hedges) or entering long-term physical contracts in the form of power purchase agreements (PPAs). PPAs are common among LSEs as a means for meeting renewable portfolio standards, which often require LSEs to purchase a certain percentage of power from renewable sources.

Despite their importance, a robust voluntary market for long-term energy contracts has not emerged; most fossil fuel-based bilateral contracts span two to three years (Joskow 2019). PPAs, while common, tend not to arise voluntarily, but rather as a result of state mandates. Given the long lifetime of solar and wind assets (15–25 years), and the crucial role that long-term contracts play in mitigating risk, it is important for researchers to explore how long-term energy contracts will fit into wholesale market design.

[13] Papavasiliou and Smeers (2015) discuss the interaction between scarcity pricing and demand response.
[14] Energy Innovation, a think tank, published a series of design proposals to which long-term contracting is central (Energy Innovation 2019).

8.1 Research questions: Long-term contracts for renewable energy

How does long-term contracting affect retail competition? Does it discourage price-responsive demand? How should long-term contracts coexist with spot markets?

As Vickrey (1971) states, "A change in price occurring after a substantial commitment has been made is of little use insofar as efficient uses of resources is concerned, in that it will have little or no influence on decisions." A long-term contract between an LSE and a generator, by construction, commits the LSE to a set of prices and quantities reflecting the forecasted demand of its customers. While retailers can compete for the most favorable contract terms, bilateral arrangements may inhibit price-responsive demand if they prevent retailers from competing in real time. In contrast, Green (2004) posits that retail competition may serve to raise wholesale prices to the extent that it discourages long-term contracting. This occurs because a weak long-term contracting market enables generators to exercise market power by withholding supply in the spot market. Indeed, an oft-cited cause of the California energy crisis of 2000–01 was that utilities were not allowed to buy forward contracts. Further research may shed light on how long-term contracting, in a future where financing investment in renewable generation is increasingly important, should coexist with spot markets to mitigate market power while still facilitating price-responsive demand.

9. Carbon emissions mitigation policies

For decades, economists have studied various policy instruments for reducing carbon emissions. While the "first-best" policy of a price on carbon, designed to internalize the social harm caused by carbon emissions, has remained elusive politically, an increasing portion of global emissions are now subject to some form of regulatory policy. There is a vast literature on carbon mitigation policies, which is beyond the scope of this report. Here, I briefly discuss some issues that are directly tied to wholesale electricity market design.

In June 2018, FERC issued an order claiming that the "integrity and effectiveness" of PJM's tariff (and in particular its capacity procurement process) "have become untenably threatened by out-of-market payments."[15] There was significant dissent within the commission;

[15] Calpine Corp. v. PJM Interconnection, LLC, 163 FERC ¶ 61,236 (2018).

Commissioner Cheryl LeFleur referred to the decision as "regulatory hubris."[16] PJM's capacity auction was subsequently suspended and the matter is unresolved as at the time of writing.[17]

Such is the fever pitch of regulatory squabbles that have arisen as a result of state-level subsidies for renewables and nuclear power. Simple economics underlie this fractious debate: states, by implementing policies such as renewable portfolio standards, have put an implicit price on carbon (Greenstone and Nath 2019). The dollar value of this price will depend on a variety of factors and will vary by state. The resulting patchwork of different implicit carbon prices will indeed affect entry and exit decisions of generators. The issue has come to a head for involved parties — not only are some fossil generators claiming an unfair playing field, but there is also concern that existing clean resources that are unsubsidized may be arbitrarily disadvantaged (Newell et al. 2017).

These complications are motivating discussions of how ISOs should accommodate, through market design, different carbon pricing policies brought about by state regulators. For example, New York State and NYISO issued a proposal for incorporating a carbon adder (a charge to generators based on carbon intensity) into energy markets. The adder would be set at the social cost of carbon, netting out the price paid for carbon permits under the Regional Greenhouse Gas Initiative (RGGI), the existing cap-and-trade program (NYISO 2018).[18] In PJM, the varied positions of states on subsidizing renewables, as well as leakage issues associated with RGGI, inspired an analysis of a subregional carbon pricing policy (see, e.g., PJM 2017).

An important role for economists in these conversations is to clarify the fundamental objective of a carbon price (to internalize the social cost of emissions) and how this objective may interact with state-level policies. The first-best solution may indeed be to replace all subsidies and mandates with a uniform carbon price set equal to the social cost of carbon. Doing so could efficiently internalize the harm from carbon emissions, putting generators on a level playing field competitively, in the sense that they would each face the same penalty per unit of carbon dioxide emitted. Economists involved in environmental policy debates have acknowledged, however, that carbon pricing policies, including cap-and-trade programs, have proven politically unpopular. Other renewable policies (such as renewable portfolio standards) have instead gained traction.

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16 *Id.*
17 Calpine Corp. v. PJM Interconnection, L.L.C., 168 FERC ¶ 61,051 (2019).
18 Shawhan et al. (2019) provide an analysis of the effects of this proposal on the New York electricity sector.

How much efficiency is lost in accepting this compromise? Economists are increasingly addressing this question. In a working paper, Greenstone and Nath (2019) use a panel regression model to estimate the cost of reducing carbon emissions implied by state-level policies, arriving at a cost that significantly exceeds estimates of the social cost of carbon. A general equilibrium analysis of a more uniform policy — a federal clean energy standard — suggests that such a policy would be nearly as efficient as a carbon tax (Goulder et al. 2016). An analysis of a particular proposal recently introduced by members of Congress echoes this conclusion (Picciano et al. 2019).

9.1 Research questions: Carbon mitigation policies in the context of wholesale electricity markets

Can subregional carbon pricing be effective?

PJM's market area touches 13 states and the District of Columbia. In its review of carbon pricing frameworks, PJM staff were quick to note that a uniform, system-wide policy would be the most efficient.[19] In the case of a subregional policy, dealing with varied renewable portfolio standards represents only one of many design challenges. Several of these states are heavily reliant on coal and politically averse to a carbon tax; others already face a legally binding price on carbon through RGGI. PJM therefore represents a complex arena for a carbon pricing design — solutions must ultimately mitigate leakage (perhaps through carbon border adjustments) and reconcile the coexistence of a carbon tax with a cap-and-trade program.

Fell and Maniloff (2018) perform an *ex post* assessment of leakage from RGGI, finding that some emissions reductions achieved in RGGI states were offset by increases in non-RGGI states, but noting that the effects of future adjustments to the emissions cap are unclear. Fischer and Newell (2008) and Fischer et al. (2017) address optimal policy portfolios for addressing both negative pollution externalities and positive externalities from spillovers and research and development. The experience of California, which has implemented a carbon border adjustment for electricity imports, may serve to provide lessons for other U.S. markets; Pauer (2018) provides an overview of the policy experience. Fischer and Fox (2012) compare various border adjustment policies for addressing leakage across energy-intensive sectors (including electricity), which may provide a useful foundation for further work specific to electricity markets.

How do carbon mitigation policies affect entry and exit of electricity generators?

[19] "Application of a uniform carbon price across all states in the PJM footprint is the most efficient and cost-effective implementation, as this framework would continue to capitalize on the economies of scale created by the size and diversity of resources within the PJM footprint" (PJM, 2017, p. 2).

The aforementioned debate at PJM is evidence that state-level subsidies and renewable portfolio mandates have significantly influenced which generation technologies are chosen for new capacity and which are being retired. This issue is certainly not unique to capacity markets; Hogan and Pope (2017) describe the impact of subsidies for renewables on pricing in ERCOT, which in turn affects generation entry and exit. A price on carbon will also affect entry and exit decisions by changing the position of a fossil-burning generator in the merit order and therefore the revenue received from sales in energy markets. Understanding the long-run investment impacts of carbon policies is increasingly critical in light of policy goals that aim to fully decarbonize the electricity sector. New York, for example, passed a law that aims for zero emissions from electricity generation by 2040; economic research may examine, say, whether a carbon price set at the social cost of carbon will be suffiicient to achieve this target or whether it will fall short.

10. Conclusions

In this paper I have discussed several evolving areas of wholesale electricity market design, described their importance with respect to decarbonization, and identified a number of research questions that, if addressed, will facilitate the transition to a clean electricity sector. Electricity policy in the U.S. has long been guided by economic principles, and this guidance is ever more critical as the electricity sector continues its transformation to low-carbon technologies. I highlight six suggestions for futher research that flow from the above discussion:

1. **Internalizing the social cost of carbon.** This is of paramount importance across all aspects of market design if decarbonization is to be achieved at low cost. Current patchworks of renewable energy policies may be inefficient relative to a first-best price on carbon, but political constraints have prevented such an approach. Consideration of next best approaches may reveal workable solutions that come at little cost in terms of relative efficiency. Further extensions of research on subregional concerns such as leakage will be useful, as will understanding the implications of carbon pricing on firm investment decisions.
2. **Improving wholesale incentives can facilitate price-responsive demand.** Price-responsive demand can improve overall efficiency of the market, reducing the need to invest in and call on carbon-intensive generation using fossil fuels. While much emphasis is (appropriately) placed on retail rate design when it comes to price response, more research that seeks to understand how wholesale market designs can help to

effectuate an active demand side would be valuable to policy makers. Demand response programs, which compensate wholesale market players for averting system-wide price spikes, offer a meaningful example.

3. **Accommodating utility-scale storage.** This will require reconsideration of both short- and long-run market design features. Market disruption may be forthcoming as the costs of large-scale storage assets decline and investors seek to exploit energy arbitrage opportunities. These technologies promise to complement renewables by mitigating supply intermittency and smoothing demand. Futher research is needed on integrating storage into spot markets as firm bids and offers reflect the capability of intertemporally shifting resources. Researchers may also draw on the experience of policies to encourage early-stage renewable energy technologies as a guide for the deployment of storage assets.
4. **Ensuring scarcity pricing is compatible with an active demand side.** This will pose a challenge as price-responsive demand becomes more commonplace. These two market features are endogenous, each one encouraging and enabling the effectiveness of the other. Research that seeks to understand how increasing demand-side participation affects cost-recovery incentives guaranteed through scarcity pricing will be essential to ensuring successful implementation of both features.
5. **Reflecting the complementary nature of different generation technologies (including storage) in capacity market designs.** This is essential if the designs are to ensure that an efficient mix of technology investment is being fostered. More research is needed on how to incentivize quality attributes, such as dispatchability during periods of peak demand, into capacity markets if they are not properly incentivized through energy or ancillary services pricing.
6. **Clarifying the role of long-run contracting between LSEs and generators.** This may have significant benefits toward achieving decarbonization. Most renewable energy contracts are long term in nature, while generators relying on fossil fuels tend to enter shorter-term contracts, thus creating disparate exposure to spot market prices with significant implications for investment incentives. These incentives are further complicated in the presence of a separate capacity market. Retail competition may also be affected by the structure of contracts, and less competition among LSEs is likely to hinder progress toward a more active demand side. More research on the role of long-

term contracts such as PPAs, as well as the effects of contracting on competition among LSEs, would be valuable in meeting climate policy objectives.

This article leaves out many important issues and avenues of research. Research on the political economy of electricity markets and their unique governance structure is limited and may be useful in the context of the current patchwork of subregional carbon mitigation policies. Market power dynamics, while a favorite topic among economists, are shifting with market structure and design and the emergence of new technologies. Price-responsive demand, for example, may play a mitigating role, while storage technology will present new challenges for market monitoring. Ancillary services markets are not discussed in depth here but make up a large portion of electricity markets and will continue to be critical in future market designs; the same can be said for the regulation of electric transmission investment. This paper is limited to wholesale segment market concerns; economic questions abound on the retail side, as do questions pertaining to the market structure and regulation of distribution systems and distributed energy resources (DERs).[20]

20 Burger et al. (2019a) and Burger et al. (2019b) give a careful look at market structure of distribution and transmission.

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