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The Future of Power Markets in a Low Marginal Cost World

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Abstract

A major contribution from the economics of regulatory practice in electricity markets is the usefulness of marginal cost pricing. In recent years, expanded supply of low cost natural gas, increased energy efficiency, growing market penetration of renewable electricity sources, and substantial reserve margins have contributed to low prices reflecting low marginal costs in wholesale energy and capacity markets. These low prices have placed some existing generation assets at financial risk and altered incentives for new investment. While low prices should indicate ample generation capacity, some observers fear they fail to represent the long run scarcity value of electricity and thereby undermine resource adequacy. This paper explores four paradigms for the future of the electricity sector in a low marginal cost world, including traditional cost of service, energy-only power markets, energy plus capacity payment mechanisms, and new relationships between providers and consumers on an energy platform. These paradigms are evaluated for their ability to achieve efficient long-run outcomes in the industry and other criteria.

Key Words: electricity markets, wholesale, retail, regulation, cost of service, platform, market design

JEL Classification Numbers: D47, L51, L94

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1. Introduction

The electricity sector is undergoing a rapid transformation. Generation from coal is being displaced by generation from existing and new natural gas capacity and utility-scale and distributed renewable capacity (largely wind and solar), and demand-side resources are increasingly entering the market (Hibbard et al. 2017). In addition, the organization of the sector is changing as the geographic footprints of several organized regional wholesale markets have expanded. A consequence of the transformation has been historically low clearing prices in organized energy and capacity markets. While this outcome can be good for consumers if low wholesale prices are passed through to retail rates, it raises concerns that under a future with continued growth in low-marginal cost generation, sustained periods of consistently low prices might not reflect the long-run scarcity value of energy services. This could lead to improper incentives for the investment in new or maintenance of existing resources necessary to reliably meet demand for electricity services. This paper provides an overview of these issues and options for addressing them in the power sector.

Throughout most of the last century, the familiar functions of the electricity sector—generation, transmitting and delivering electricity, resource adequacy and operational reliability, and retail sales—were carried out by integrated monopoly firms subject to cost of service regulation, and this regulated monopoly structure remains in place in the majority of states (Brennan et al. 2002; Flores-Espino et al. 2016). Meanwhile, as a consequence of industry restructuring, which started in the 1990s, several states have implemented functional and sometimes structural separation of generation from transmission and delivery. In those states and

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in some that retain a regulated structure for cost recovery, organized wholesale power markets play the primary role in facilitating the provision of electricity generation and resource adequacy.

Recent and on-going changes in technology mix and fuel prices pose challenges in both restructured and regulated markets. In states where separation of generation from delivery of energy services has been implemented, and for independent power producers in cost of service regions, revenues received by owners of power plants are predominantly from energy payments. Wholesale energy prices have been declining primarily due to the expanded availability of low cost natural gas and, to a lesser degree, increasing availability of near-zero marginal cost renewable energy generation. As natural gas and renewable generation shares continue to grow, and/or if nuclear capacity is added to the grid in substantial quantities, energy prices could fall to very low values, and, under very high penetrations of renewable resources, energy prices could be near zero in almost all hours of the year.

Another factor contributing to low prices in both energy and capacity markets is the slowing rate of growth in electricity load, particularly relative to predictions that have been used to inform capacity requirements to meet reliability standards (DOE 2017). Slow load growth is a function of changes in the overall pace of economic growth, changes in the composition of economic activity with shifts away from energy intensive industries, and improvements in energy efficiency that have resulted in part from efficiency standards and utility efficiency programs. This limited load growth relative to forecasts led to greater investment in new capacity than was needed. This new capacity, predominantly natural gas combined-cycle (NGCC), wind, and solar, often has lower marginal costs than the previously existing capacity and has contributed to a reduction in energy and capacity prices.

Low wholesale energy prices can have substantial benefits. For one, they should translate into low electricity prices for consumers, although sometimes they may be slow to do so (DOE 2017). Moreover, low variable cost generation technologies are typically low emitting, and thus greater supply from these sources will enable states to achieve air quality and other emissions goals.

At the same time, low energy prices also create challenges for both existing infrastructure and future investment, especially in states with competitive electricity markets. They make cost recovery difficult for incumbent generators with high variable costs, such as older coal or gas steam generators or older NGCC units, even if they offer the lowest fully loaded cost of generation, accounting for both capital and all operation and maintenance costs, because they experience reduced utilization in lieu of resources with lower variable costs. Low energy prices also pose a problem for incumbent generators with low variable costs but high fixed costs because the reduction in revenue can limit a generator's ability to service the debt on capital or to undertake periodic sizable investments necessary to remain operable. Low energy prices also mute incentives for investment in new capacity, even if the new capacity has zero marginal energy cost.[1] While abundant capacity may suggest that new investment is unnecessary, it may be that the composition of capacity does not match the evolving needs of the electricity system.

Firms in states that have not separated generation from delivery services, as well as regulated wires companies everywhere, face a different sort of challenge stemming from new opportunities for customers to disassociate from their utilities (i.e., customer flight). Large industrial and commercial customers may be enticed to procure independent resources directly for self-generation or indirectly through bilateral contracts for energy where retail rate design has not responded to the changing cost structure. These incentives may also exist where the utility has not kept up with changing customer service demands such as preferences for environmental attributes or long-term price certainty.[2] This system bypass allows these customers to avoid the fixed costs of the electricity network, and enables them to market to their own customers based on the idiosyncratic environmental attributes of their electricity supply. The capital cost-intensive nature of renewable resources also encourages fixed price power purchase agreements that allow customers to reduce price volatility, further increasing the appeal to customers of procuring electricity from independent generators.

While beneficial to some customers, these trends also may create social costs. For example, if proper scarcity signals cannot be conveyed and investments rewarded, system reliability might be threatened. Also, the economic impacts on owners of existing facilities and the communities of workers at those plants raise sharp distributional concerns. In competitive or regulated regions, if large energy consumers respond to the availability of new generation options with lower variable or total costs by departing from the market and self-generating, this may create a burden on the smaller customers who do not have that option.

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[1] This may or may not be true for investments that occur within an integrated resource planning process or are otherwise mandated by policy.

[2] As an example, MGM Resorts International and Wynn Resorts, two Las Vegas casino resort chains that are responsible for over five percent of electricity sales for the local utility, have paid an initial exit fee to disassociate with the utility and now procure their electricity in part from solar arrays owned and operated by third parties.

Addressing these challenges in an uncertain environment will likely require more than one solution, as regions have different starting points and social preferences. The resulting questions at hand include:

- What are the market or regulatory solutions that will elicit all necessary energy services required (including energy, capacity, operating reserves, frequency regulation, ramping and voltage stability) to meet consumer demand for electricity reliability under alternative electricity futures with high penetrations of low variable cost generation and expanded demand-side technologies?
- How are those market structures and regulatory solutions likely to impact the future technologies and service options that emerge?

In this paper, we characterize four broad regulatory and market structure paradigms evident across the electricity sector, propose criteria for evaluating these different approaches to organizing and governing electricity transactions and system operations, and evaluate the different paradigms relative to the criteria, including a discussion of proposed reforms to improve performance. These paradigms include:

(1) cost of service regulation and associated reforms to incorporate potential expansion of performance regulation and greater customer choice;
(2) energy only markets that integrate ancillary services and demand-side resources;
(3) the addition of capacity payment mechanisms (CPMs) to the energy only market framework, including explicit integration of resources such as grid-side and customer-side storage; and
(4) a new vision for retail electricity markets as a platform, which could involve an open franchise in the provision of energy services where both the demand- and supply-sides could be compensated.

Throughout the paper, our discussion is oriented around the resilience of each paradigm in the face of a potential future with consistently high levels of low marginal cost electricity. We note that these paradigms are not necessarily exclusive; for example, firms operating under cost of service regulation sometimes participate in organized markets.

Each of the forms of organizing electricity transactions has its strengths and weaknesses. Cost of service regulation mitigates risk for investors, but some argue that it provides muted incentives and transparency for efficient operation and investment and for innovation. Moving toward more incentive-based regulatory designs could improve the efficiency of outcomes under regulation. Energy-only markets have strong efficiency properties and tend to work better when the demand-side is at least partially responsive to spatial and temporal price fluctuations. In theory and in practice, these markets are easily augmented to include market approaches to pricing operating reserves, but price caps put in place to limit market power may also limit valuable signals regarding scarcity and the need for new investment. CPMs provide another way to compensate existing and potentially new generators for fixed costs, but designs to more accurately award capacity value from variable generators and storage merit further consideration.[3] In the future a wholly different model may emerge as part of an industrial evolution that could resemble the experience of the telecommunications industry. This business model would offer a way to compensate both low marginal cost and distributed resources, as well as a platform for customers to engage with the electricity system through a fee-based service.

The remainder of this paper is organized as follows. In the next section, we describe criteria that we will use to evaluate each paradigm. In the subsequent sections, we characterize the different paradigms. We close with a brief consideration of the broader implications of the choice of a regulatory or market structure paradigm for transmission and distribution system planning, introduction of new technologies on both the demand and supply-sides of the market, opportunities for electrification of energy end uses such as transportation and heating, and how to deal with transitions as states change market and regulatory structures.[4]

2. Clarifying the Potential Challenge and Criteria for Understanding Electricity Sector Paradigms

As outlined in the introduction, an overarching challenge facing states, regional grid operators, and federal regulators is how to structure electricity markets—be they regulated or restructured—to ensure the efficient operation of the power grid under a suite of alternative futures, particularly ones in which low marginal cost resources comprise a dominant portion of generation. This overarching concern takes shape in the form of specific challenges and objectives within each of the major regulatory and market structure paradigms identified in the introduction. This section aims to establish a coherent framework for assessing how these

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[3] Capacity value refers to the contribution of a power plant to reliably meeting demand, measured in terms of physical capacity (e.g., megawatts).

[4] One area that has received significant attention recently is how to preserve the cost-saving and efficiency benefits of regional markets while still respecting state policies, some of which include out-of-market subsidies to specific technologies. Substantial attention was paid to this issue at the FERC Technical Conference held on May 1-2, 2017 (FERC 2017). We do not separately address those issues here, except as they contribute to the overall theme of a future power system with low marginal costs.

challenges apply within each of these four paradigms, while subsequent sections discuss how each paradigm performs with respect to our criteria.

The six criteria used to evaluate each paradigm are listed and described below.[5] Ultimately, the criteria that were chosen reflect goals that, if achieved, would ensure a well-functioning power sector that can accommodate alternative future technological and policy pathways. In addition, the goals reflected in our criteria are intended to have global appeal, meaning that their desirability does not depend on context- or institution-specific details.

1. *Promotes efficient investment and operation*

At a fundamental level, any market structure paradigm should create efficient incentives for cost-effective operation of the grid in the short run and investment in the long run. Moreover, these incentives should apply to all infrastructure and grid services required to serve load. Specifically, any paradigm that meets this criterion needs to provide proper incentives for: maintaining incumbent facilities based on the value of the services they provide, provide proper incentives for investment in and avoid undue barriers to entry for new capacity resources (both supply- and demand-side) to promote an efficient level of reliability, and avoid cross-subsidies among generators or consumers to the extent that is administratively practical or otherwise intentional to achieve distributional goals or network economies.

2. *Allows for market power mitigation*

A successful market structure paradigm should have mechanisms available to it to minimize exercise of market power. Market power concerns are particularly acute in the context of electricity for a variety of interrelated reasons. First, electricity is largely non-storable, meaning that sharp spikes in demand must be met instantaneously rather than by excess capacity at other points in time. Second, the current configuration of most US power systems provide customers with limited incentives or capability to respond to temporal price fluctuations; indeed, most customers do not receive timely information about price fluctuations in the wholesale power market. Third, due to the capital-intensive nature of the electricity sector, significant barriers to entry exist, at least in the short-run. Together, these factors create an environment in which the exercise of market power can undermine the stability of the market.

[5] Several other possibilities were considered but not chosen, including some that undoubtedly influence decision-making. These criteria include ease with which externalities can be internalized by market participants and promotion of local economic development.

3. Enables efficient assumption of risk across market participants

Another key consideration for market structure paradigms is how they distribute financial risk across market participants. The power sector is fraught with uncertainties: uncertainty over the prices of input fuels for fossil generators, meteorological uncertainty that affects both demand for electricity and the output of variable renewable generation resources, and policy uncertainty that reflects ever-shifting changes in political objectives at all levels of government. With uncertainty comes risk, and markets and regulation should provide equitable treatment with respect to risk across producers and consumers, including consumers who lack the resources needed to by-pass the grid entirely. Ideally, financial risk would be assumed by those market participants best positioned to mitigate it.

4. Promotes innovation

In the current climate of rapid technological change, the ability of the various market structure paradigms to not only accommodate, but promote, innovation serves as an important basis for comparison. One prominent near-term example of innovation in the power sector is the re-casting of electricity markets as markets for energy services, in which traditional demand-side participants shift from a passive to an active role in the market. This shift in thinking will need to be accompanied by concrete technological developments, and market structure paradigms should be adapted to facilitate their implementation.

5. Robust to alternative futures

Another prominent feature of the current energy landscape is how much it has evolved over the past decade, which has underscored the need for a regulatory and market structure paradigm that can perform well under a diverse set of possible future electricity sector configurations. In recent years, natural gas and variable renewable resources have increasingly displaced traditional baseload resources such as coal and nuclear. Going forward, the electricity sector will continue to evolve in response to new technological advances and policy objectives, but the nature of those advances and objectives is difficult to anticipate.

6. Transparent

A practical consideration for regulatory and market structure paradigms is the extent to which the rules they create are transparent. These traits are valuable to regulators responsible for designing and implementing those rules, as well as to market participants making significant financial decisions subject to them. A particular paradigm might be desirable for its theoretical properties, but if it cannot be administered in such a way as to provide clear signals for operation and investment for all market participants, then its usefulness is diminished. Additionally, if the costs associated with implementing rules on the part of the regulator are excessive, the usefulness of the design suffers. In most cases, simplicity will enhance transparency.

In the following four sections, we evaluate each of the regulatory and market structure paradigms identified in the introduction relative to these six criteria, and we highlight some options that have been posited to improve performance relative to the criteria.

3. Cost of Service Regulation

While the 1990s and early 2000s saw much enthusiasm for greater competition in wholesale electricity markets and even in retail sales, with policy proposals at both the state and national levels, most states did not choose to allow retail customer choice or require the structural separation between the provision of generation services and delivery services. Thus, in most of the country the electricity sector is regulated much the way it has been for many decades. In these states, electricity is typically supplied by a vertically integrated investor-owned utility that is responsible for generation, transmission and distribution of electricity to its customers. Publicly-owned utilities and cooperatives are similar in that they operate under a structure that resembles regulation, but incentives may be quite different.[6] The regulated utility has an obligation to serve all customers within its franchise service territory and, in exchange for that obligation, can charge prices that cover its cost of serving those customers inclusive of a rate of return on capital. In some cases, however, these regulated firms operate within geographically broad wholesale power markets.[7]

Cost of service regulation creates an environment that is focused on planning and is relatively friendly to specific types of new investment by regulated utilities. State regulators

[6] Twenty-seven percent of electricity sales are by municipally owned utilities that are owned and operated by cities and towns, or by rural electric cooperatives that are owned by their customers. These entities may or may not be vertically integrated including the provision of generation, but when they are not they typically purchase most of the power needed to serve their customers through long-term contracts with generators and transmission owners. These entities set rates to recover costs, but rates may be adjusted for in-kind services such as the provision of street lighting to a jurisdiction and sometimes there are cross subsidies.

[7] In many states that retain cost of service regulation, the utility operates in organized power markets where multiple investor owned utilities in the same state or neighboring states interact, along with independent (unregulated) energy providers, to supply electricity. See Hartman (2016) for a discussion of these situations. Companies in this mixed market environment face a unique set of challenges that we discuss in later sections. In this section, we focus on states where generation and operation of the system is dominated by regulated investor-owned utilities.

typically require the utilities they regulate to engage in regular integrated planning exercises that consider both generation and transmission investments necessary to meet expected new demand in the future. The pre-determined rate of return on investment lowers risk for the owners of generation and transmission assets and is typically associated with a lower weighted average cost of capital than available to investors in unregulated sectors. Low capital costs and system-level resource planning also enhance a utility's ability to finance the construction of new large central station generators or pursue large-scale innovative technologies.

Evaluating cost of service regulation with our criteria reveals strengths and weaknesses as well as areas where the paradigm could be modified for potential improvements in performance, which we discuss below.

3.1. Efficient Investment and Operation

Perhaps the primary concern with cost of service regulation is the lack of incentive that it provides for efficient operation and investment. In the absence of competition, these incentives are muted, given the inability of regulators to fully observe and therefore reward the effort the regulated firms put into improving efficiency (Laffont and Tirole 1993).[8] The time lag between rate setting hearings provides a window in which the firm has an incentive to reduce operational costs (Joskow 1974; Joskow and Schmalensee 1986). The ability to earn a regulated rate of return on capital investment can also bias these firms toward capital and contributes to a strong incentive to protect existing assets and complete unfinished projects even when they face cost overruns (Averch and Johnson 1962; Hayashi and Trapani 1976). The potential bias toward capital is less relevant for publicly-owned utilities, although they do have low costs of capital compared to even to investor-owned utilities. Barriers to entry of potential competitors on the generation side remain an issue despite requirements to purchase from qualified independent power producers under the Public Utility Regulatory Policies Act. These barriers also affect providers of new distributed energy services or demand-side resources that might be poised to enter the market in the future.

[8] In an empirical study of the impacts of deregulation on power plants, Fabrizio et al. (2007) found modest medium-term efficiency benefits associated with moving to a market-based industry structure.

Regulatory processes also typically include some explicit consideration of fairness in the cost recovery to guard against unintentional cross-subsidies, while also potentially introducing cross-subsidies to provide minimal levels of service to low income customers.[9]

3.2. Market Power Mitigation

Cost of service regulation, by its nature, affords little opportunity for the exercise of market power. Indeed, the regulation is designed to limit prices that regulated utilities can charge to those that can be justified by cost recovery plus a reasonable rate of return on capital. However, the possibility for regulatory capture by regulated firms could limit the regulator's incentives for effective market power mitigation (Stigler 1971; Peltzman 1976).

3.3. Efficient Assumption of Risk across Market Participants

Most of the risk associated with investment is passed onto consumers, as is fuel cost risk due to the widespread use of fuel adjustment cost mechanisms that allow variations in fuel price to flow through to regulated rates between rate cases. The potential for cost disallowances ostensibly provides some incentive for firms to minimize cost overruns on new plants and other investment projects, but it is rarely exercised (Lyon 1991). Regulation and regulatory oversight play an important role in assuring reliability under this model. The level of resource adequacy that firms must achieve is defined by the regulator and not by the market and thus opportunities to vary wholesale energy prices with different levels of service quality are very limited.

3.4. Promotes Innovation

Incentives for innovation are also thought to be weak under cost of service regulation. The set rate of return on investment and the inherent caution among elected or appointed officials on public service commissions limit potential earnings on the upside, and the possibility of ex-post prudency review and possible disallowance of expenditures that deviate from standard operating procedure further constrain incentives to innovate. However, regulated firms have a potential advantage in the present context of rapidly changing technology, especially as those changes might directly affect customers. Increasing attention is being given to demand-side ("behind the meter") technologies that might be used to balance supply and demand in power markets, and especially to accommodate the potential integration of intermittent renewable

[9] It is noteworthy that expanding service at discounted rates to low income customers may not impose additional costs if it allows the achievement of network externalities or if it does not incur an expansion of fixed cost investments.

resources (FERC 2016). Implementing technologies that, for example, cycle air conditioners and refrigerators or schedule the charging of electric vehicles requires customer education and approval, and the incumbent investor-owned utility may have an advantage in this regard. Further, the investor-owned utility has access to data about the pattern of electricity use in households, which could give them a substantial advantage in designing programs. In many industries, the value of data about customer behavior is as important as the value of services provided.

3.5. Robust to Alternative Futures

The robustness of cost of service to different potential futures for the electricity sector is an emerging issue that may increase in importance as technology continues to evolve. A growing number of large electricity customers, including technology companies like Google and Amazon, are interested in buying exclusively clean energy and are looking to contract with suppliers other than their local utility, and, in some cases, opt for self-generation, thereby taking their business off the grid, but often still relying on the grid for specific services such as backup reliability (Darrow 2016; Moodie 2016). Given that much of the largely fixed costs of electricity delivery are currently recovered through volumetric charges per kilowatt-hour (kWh) of energy sold, loss of energy revenue from these sources can challenge the regulatory model if the embedded cost challenge is not addressed through a restructuring of fees. Customer flight may leave other customers bearing a greater share of the fixed costs that accelerates the possibility of further customer flight and loss of revenue from even more customers.

3.6. Transparent

The regulatory setting can be transparent, but it also can be difficult to access. Uniform and well-known accounting rules govern how costs are reflected in rate determination, and several states have a role for a public advocate in the rate-setting process. Conceptually, cost-of-service regulation is simple to explain as a system where prices are based on the ratio of costs, inclusive of a rate of return on capital, to sales. The rate setting process gets more complicated when prices are adjusted ex post to reflect changes in fuel costs that are outside of the utility's control. In practice, the determination of allowed costs and what is included and not included in the rate base can be complicated. At both the federal and state levels, the underlying reasoning for regulatory decisions is well-documented and typically governed by a requirement for regulated rates to be just and reasonable. Regulatory decisions are subject to legal review and challenges, and the checks and balances on this process contribute to its transparency.

Nonetheless, the transparency to the public depends on the disclosure of information, and integrated resource planning exercises may be kept confidential or may be only partially shared with the public.

3.7. Potential Reforms

To remain robust to a future with near-zero marginal costs, cost of service regulation could be modified to improve the incentives provided to regulated entities and the opportunities for consumers. Performance-based regulation is a mechanism that helps to overcome the disincentive to reduce costs that is inherent in full cost recovery. Under current approaches to cost of service regulation, electricity retail rates (prices) are set to cover average cost in periodic rate cases, and during the time between these rate cases utilities may face an incentive to lower costs especially if they can keep at least some of the difference as profits for shareholders. Performance-based regulation in the form of price caps can be structured to grow at the rate of inflation, including some adjustment for expected productivity improvements.[10] This approach would formalize the process of performance-based regulation and perhaps extend the time period between reconciliations of revenues and costs (Sappington and Weisman 2010; Joskow 2014). Performance based regulation has been used primarily in the telecommunications sector but there has been some experimentation in the states with performance based regulation of electric utilities (Sappington et al. 2001) and increasing interest in doing so (Littell et al. 2017).

Another type of innovation involves hybrid models. Regulation of truly monopoly services like low voltage distribution can be coupled with customer choice at a more aggregate level such as has been happening in California, where community choice aggregators now serve a total of 915,000 customers across the state, and several other counties and cities with populations over 15 million are actively considering implementing such a program (CPUC 2017). Regulated utilities, sometimes at the behest of regulators and always with their permission, are also seeking to improve the efficiency of customer incentives to use and conserve electricity over time by adopting more granular pricing including critical peak pricing and time-varying rates.

[10] In Britain, this is referred to as RPI – X, where RPI is the retail price index and X is the expected productivity growth of the regulated firms, benchmarked to performance of similar firms in other electricity markets and intended to simulate the effects of competition.

4. Energy-Only Markets

In this section we present an approach that substitutes markets for the role of regulation in determining wholesale electricity prices and the revenues that generators receive. The idea of relying on a short-term energy-only market design for not only electricity market operation but also long-term investments occupies the intellectual center of the theoretical literature on electricity market design. Proponents assert that short run price signals, coupled with the proper financial instruments and some guiding regulations, can provide a robust basis on which to make long term investment decisions. An anticipated virtue of this approach is that it would avoid prescriptive regulations and other rules that provide less efficient incentives for investments, and that are potentially open to manipulation.

In the abstract, the theory builds on the expectation that instantaneous scarcity pricing should lead to the most efficient use of resources at a point in time. In theory, market actors can anticipate future scarcity and will have the incentive to make investments to capture profits where scarcity values are high, thereby reducing scarcity values to marginal costs. In theory, the energy-only market approach positions actors who are best able to assume risk to do so, effectively absorbing risk from the market environment, with the cost of doing so reflected in risk-adjusted scarcity prices in the energy market. Prices would reflect scarcity with temporal and geographically differentiated scale. It would also allow for price-based approaches to address associated regulatory issues such as the provision of ancillary services (including frequency regulation and voltage stability) and environmental protection.

Implementation of an energy-only market, without a cap on prices, would allow prices to rise sharply during hours of scarce capacity. Market-clearing prices during these hours presumably would be sufficiently high to cover long-run marginal costs, including capital costs for the most expensive resource. In most hours of the year, energy offers would determine the prices earned by winning bidders, with relatively few super-peak episodes of very high prices that could be anticipated by investors. Consumers could be protected from price fluctuations through price hedging or smoothing actions taken by their retail providers, but the efficient functioning of this approach requires freely equilibrating supply-side prices in the energy market. Ideally energy markets would be complete with both demand and supply-sides responding to prices, with at least some portion of customers voluntarily reducing demand during high price hours or shifting demand to lower price hours.

The label “energy-only market” is often interpreted to imply that there would be no compensation for the availability of capacity that does not generate. However, in the theoretical framework, payment for operating reserves is envisioned as intrinsic to the energy market (Hogan 2005). The market clearing price is received by units that generate as well as additional units in the supply schedule up to a quantity of megawatts in a given hour that is sufficient to meet operating reserve requirements. However, the payments to those that do not generate are adjusted to equal the market clearing price minus what their energy costs would have been if they had generated. For example, the electricity system operator in Texas, ERCOT, has an energy-only market design, which emphasizes the role of real-time prices, but also has an operating reserve demand curve to represent price sensitivity in the provision of reserve services (Hogan and Pope 2017).

Further, in an energy-only market framework, transactions are not all short-term in nature. This market design would facilitate and encourage long-term contracting as a mechanism for risk sharing. In principle, only a small portion of total supply would need to trade at prices determined in the centralized energy market, but those trades would be the source of information about scarcity value that informed a variety of other transactions. This approach, if fully realized, would give incentives to actors on the supply and demand-sides of the electricity market to take actions to reduce costs and harvest value in the near-term and the long-term.

In practice, the advent of price-responsive demand has been slow to materialize. In several states, generation assets were divested by utilities, but local distribution companies had an obligation to serve customers at regulated prices, and customers did not have the technology to be able to recognize or respond to instantaneous scarcity in power markets. Concern that very high prices might persist for some time if there were high and unresponsive demand and limited generation capacity precipitated the imposition of price caps in energy markets. Without the caps, an unbridled energy market might be expected to lead to very high revenues (at least in the short run) and the appearance of windfall profits in the newly restructured industry, which would pose a substantial political challenge. The additional possibility that newly deregulated generators might exercise market power by withholding capacity from the market to drive up energy costs could also amplify concern about windfall profits in newly restructured markets, even in the face of contestability through new investment.

The reliance on price caps to address very high energy prices and to guard against the possibility of strategic behavior undermines the basic energy-only model because the caps reduce the incentive for investors by limiting the upside potential rewards to investment. The so-called “missing money” problem described the difference between true scarcity value and regulated (capped) prices, and would thereby lead to inadequate investment. Supplemental regulations such as installed capacity requirements were introduced to provide assurance for resource adequacy (capacity), further inhibiting the ability of energy prices to reflect scarcity value and to provide signals to investors, and further undermining the energy-only model. The introduction of a CPM in some regions is a manifestation of this outcome, and is the subject of the next section of this paper.

In an attempt to evaluate the energy-only market design in the context of criteria described above, we discuss both the theoretical construct and the experience.

4.1. Efficient Investment and Operation

As described in theory, an energy-only market is efficient in virtually every dimension. Practical operation of an energy-only market has shown the possibility of occasional sharp price variations that are consistent with the theory but pose political challenges. These price variations might be expected to be reduced over time, but only in ERCOT has something resembling an energy-only market been given the chance to develop without the imposition of CPMs. The experience of the ERCOT market has been widely studied and is viewed by many as successful, although it is characterized by excess capacity, which may suppress price volatility that might otherwise be observed (Hogan and Pope 2017).

4.2. Market Power Mitigation

Open entry to new supply-side investors provides an expectation that the contestability of a market to entrants will discipline it against the exercise of market power, although long project development timelines might mute that contestability a bit. However, observed price spikes and variability has fueled concern about market power, leading to the introduction of price caps, even in ERCOT, which conflicts with the fundamental idea that market prices provide efficient incentives.[11] Proponents of energy-only markets have advocated for other mechanisms, such as a requirement to bid in to prevent strategic withholding of generation, as an alternative way to mitigate market power in an energy-only market.[12]

[11] In ERCOT they have set the price cap equal to the current estimate of the value of lost load in an effort to reflect what users are willing to pay for reliability.

[12] All existing ISO energy markets have local market power mitigation of bids that is applied to generators identified as having the potential to influence local energy prices as a result of local transmission constraints. Mitigation usually consists of a limit on energy bids for those units bringing them close to marginal cost.

4.3. Efficient Assumption of Risk across Market Participants

The risk of excess investment falls on producers and the risk of insufficient investment falls on consumers. Furthermore, in the absence of any capacity payment, owners of peaking plants must recover their capital costs during the peak hours of the year in which short-term prices are extremely high. Given the uncertainty in prices during these times, risk of investment in these units could be quite high. This uncertainty, coupled with general uncertainty about future demand and other market factors, is thought to raise risks for investors, raise the hurdle rate for new investment and cause the energy-only market to provide inefficient incentives for investments, raising costs for the entire system that fall primarily on consumers (de Sisternes and Parsons 2016). Further, without real-time pricing, the level of reliability is uniform across customers, imposing costs in excess of value for many customers, but this phenomenon occurs in other market approaches that we discuss as well. Also, without real-time pricing, customers may be exposed to price fluctuations in their monthly tariff and total bill that are not contingent on an individual customer's actual time of use. The energy-only market would benefit substantially from reforms in retail markets that allow the introduction of real-time, or at least time of use, pricing.

4.4. Promotes Innovation

An energy-only market provides incentives for innovation in general, but whether that incentive is realized depends on other important reforms such as time of use or real-time prices and payment for demand-side services. If those reforms were fully realized, then the energy-only market might evolve toward something like the platform model that we describe in a later section.

A characteristic of the energy-only market, compared to other market and regulatory approaches, is the cost of capital for financing of new generation will be relatively high because there are fewer regulatory guarantees to ensure cost recovery. This high cost would be most evident for financing of large central station power plants, because the hurdle rate for large investments is increased by the value of waiting (option value). Hurdle rates increase with the energy market transformation currently underway and with the length of the construction period associated with large investments. Hence, innovation may evolve toward smaller scale investments in an energy-only market. While not proof of a causal linkage, one observes that the energy-only market in ERCOT has witnessed substantial investments in smaller-scale generation assets.

4.5. Robust to Alternative Futures

The signal for investments is driven by prices in the short-term energy market, without explicit ties to a planning process that embodies the preferences of policymakers and an integrated assessment of the needs of the market in the long term. Hence, there might be a possibility that the market would not be robust to alternative futures if, for example, high penetration of zero and low marginal cost generation fails to signal future scarcity and thus misrepresents the returns and level of risk associated with new investment. On the other hand, the cost of capital and inherent preference for smaller projects with shorter construction periods suggests the energy-only market might be more robust to alternative futures than one that locked in large scale investments.

4.6. Transparent

The theoretical construct of an energy-only market is the most transparent and simple of the designs that we evaluate. The ideal energy market provides a single source of information to guide the actions of investors and other actors. The energy market is not presumed to operate in a vacuum. Just as in other markets, there is a presumed requirement for ancillary services and capacity requirements; however, in an energy-only market these services would be provided on a market basis to a greater extent than is likely in a more regulated setting. The energy-only market becomes more complicated when one recognizes the locational differences in energy prices, but this complication accompanies the operation of any market relying on locational marginal pricing.

4.7. Potential Reforms

There are two major concerns about the energy only approach to the electricity market design. First is the possibility of price variability with occasional sharp price spikes that might mask or reflect the exercise of market power. Second is a concern that short-run prices may not reflect the long-run needs of an electricity market and therefore may be an inadequate guide to investment and innovation. These concerns might be overcome with greater experience that may impart more comfort with the operation of the market. However, it is crucial that retail customers have access to information about price movements and the ability, either individually or through their retail company or an aggregator, to respond to short-run price fluctuations. Automatic technology may be essential to ensuring this outcome, and energy markets might be advanced by efforts to promote the dispersion of such technology.

5. Capacity Payment Mechanisms

In this section, we discuss the addition of an explicit capacity payment mechanism (CPM) to the energy-only paradigm of the previous section. For our purposes, the term *CPM* encompasses all regimes through which generators can earn revenues by supplying an explicit capacity product.[13] In the United States, this construct includes regimes in which capacity requirements are met by individual load serving entities (LSEs) through direct bilateral contracts with suppliers and both mandatory and voluntary centralized capacity markets operated by an ISO/RTO.[14] Outside of the United States, this also includes fixed capacity payment schemes in which the regulator determines the price to be paid for qualified capacity but does not establish the overall quantity of capacity eligible for payment.

The purpose of CPMs is to compensate electricity generators for their expected capacity contributions to ensuring resource adequacy, thereby providing incentives for new investments and the maintenance of existing capacity. Resource adequacy in this case refers to administratively-set targets for reliability aimed at keeping the probability, or expected number of hours, of unserved load at or below an acceptable threshold. As such, CPMs are intended to address "extreme and rare events" by ensuring that adequate capacity is available to meet the hours with the highest loss of load probabilities, which have historically coincided with peak load conditions (de Sisternes and Parsons 2016). Implicit in the inclusion of an explicit CPM is the belief that the energy-only market construct is insufficient to ensure efficient or adequate capacity investment (Joskow 2008; de Sisternes and Parsons 2016), or fails to deliver politically palatable solutions (Besser et al. 2002).

To date, all deregulated electricity markets in the United States, except for ERCOT, have adopted a form of CPM, though the implementation varies across ISOs/RTOs (Bushnell et al. 2017). CAISO and SPP establish capacity requirements for individual LSEs, which they meet through bilateral contracting or self-supply. MISO, ISO-NE, NYISO, and PJM administer centralized capacity markets through which LSEs can procure capacity, though the timeframes

[13] This differs conceptually from the operating reserve demand curve approach used in ERCOT, which does not create markets for separate energy and capacity products, but rather includes pricing for operating reserves through the energy market that is intended to provide adequate financial incentives for investors to provide resource adequacy.

[14] In practice, operationalized capacity markets often include a blend of both approaches, in which LSEs procure a portion of their capacity through bilateral contracting and the reminder through a centralized auction. In addition, there have been proposals for shifting the obligation to purchase capacity to distribution utilities (Hamal 2013).

over which those markets are administered vary widely. For instance, ISO-NE and PJM hold their base auctions for capacity three years in advance, while MISO holds its auction immediately prior to the delivery year.[15] Longer lead times (three years or more) allow new investments to participate but increase the challenge of accurately assessing the need for and value of capacity at the time of delivery.[16]

Over time, some experts believe that the demand-side of the electricity market could be transformed in such a way as to make CPMs obsolete (Cramton and Ockenfels 2012; Keppler 2014), which is a perspective we explore in our discussion of a platform model. In the meantime, well-constructed CPMs may provide insurance against potential pitfalls associated with an energy-only approach, particularly during the current transition towards low marginal cost generation sources. Next, we assess the performance of CPMs relative to the criteria enumerated previously.

5.1. Efficient Investment and Operation

Support for CPMs focuses primarily on their presumed benefits for providing efficient long-term investment signals.[17] A primary concern with the energy-only market construct is that energy markets fail to provide clear and efficient signals for investment, particularly in the presence of price caps, or when demand plays a limited role in the market and potentially exacerbated by transitions to low marginal cost systems. Considerable uncertainty accompanies capacity investments, and real-option theory predicts such uncertainty will lead to under-investment in capacity (Cramton and Ockenfels 2012; de Sisternes and Parsons 2016), which has the potential to threaten reliability. One of the salient features of current CPMs is that the reliability targets are administratively-set, since load cannot signal its preferences for reliability due to a lack of real-time metering, billing, and ability of the regulator to provide customer-

[15] In addition to the base auctions, several ISOs hold additional, incremental capacity auctions as the time to delivery approaches to allow LSEs to procure additional capacity (or to allow generators to cover any capacity obligations they can no longer meet) in response to updated information on electricity load.

[16] The three-year forward market construct appears to be gaining momentum, as MISO is currently reviewing a proposal for such as market.

[17] In general, arguments for de-regulation focused less on improvements in operational efficiency and more on the potential for cost savings associated with better incentives for capacity investment (Joskow 1997). For electricity markets that have been deregulated, (Joskow 2008) argues that most wholesale energy markets include the basic design features that lead to good short-run performance.

specific reliability (Stoft 2002).[18] Assuming that the payment mechanism is designed so that all generators are properly compensated on a nondiscriminatory basis for their contributions to achieving the reliability standard, then efficient investment, entry, and exit can be expected to occur.

Critics of CPMs question the outcome in practice, however (Morrison 2016). Concerns about the performance of CPMs include the possibility that capacity payments may provide windfall profits to generators and extend the life of existing assets such that the transformation to a more efficient energy system is delayed. In general, critics of CPMs point out that the performance of the market depends heavily on key design parameters and rules chosen by the system operator. For example, PJM has been revising its CPM design over the past several years, moving away from a Base Capacity product that awards capacity credit according to resources' ability to contribute to expected peak load (summer afternoons) toward a Capacity Performance product that awards credit based on a resource's ability to contribute to emergency conditions throughout the year. More recently, PJM has revised its auction process to clear offsetting quantities of summer- and winter-only resources in order to better accommodate variable renewable generation and demand-side resources under the Capacity Performance product structure (PJM 2017). These changes in design have had important implications for all capacity resources, and only time will tell if they, and other changes in CPM design in recent years, have improved or reduced market efficiency.

5.2. Market Power Mitigation

Like the energy-only market framework, CPMs can be designed to mitigate market power, but doing so may require sacrificing efficiency of entry and exit. The promise of good CPM design is that it provides a revenue stream through which generators can recover their fixed costs, thereby encouraging true marginal cost bidding behavior in the energy market even during

[18] As outlined in the previous section, in the future, these "demand-side flaws" could be addressed by changes in the retail market, by applying real-time pricing to customers and/or by allowing customers to express their preferences through retail choice. Currently, however, the capacity mechanism procures a uniform level of reliability that has been deemed acceptable, and directly monetizes the capacity requirement.

times of peak demand. If market power concerns remain, regulators can still institute price caps in the energy market. Compared to the energy-only construct, however, these energy price caps are less likely to interfere with fixed cost recovery.[19]

Even if market power can be mitigated effectively in the energy market, the regulator still has to prevent the exercise of market power in the CPM, both on the part of suppliers and buyers. Supplier-side market power has been addressed in some ISOs by installing a forward capacity mechanism with a base auction many years in advance of the first delivery year, which allows new entrants an opportunity to compete in the market and lessens the ability of existing generators to bid well above their fixed costs (plus a reasonable rate of return). However, there is still a concern that companies with existing generation assets could withhold capacity from the auction and drive the price up. Due to this possibility, Cramton and Ockenfels (2012) suggest that only new generators be eligible to set the CPM clearing price. The authors also suggest that the regulator employ a downward-sloping demand curve (also called a “variable resource requirement” curve) to reflect a declining marginal value of reliability as more is provided, and allow for demand-side participation in the CPM as market power mitigation measures. To address the possibility of buyer-side market power, many ISOs/RTOs have recently adopted minimum offer price rules (MOPRs) to support CPM clearing prices and guard against the exercise of market power. However, Morrison (2016) argues that these rules have had adverse consequences on investment efficiency.

5.3. Efficient Assumption of Risk across Market Participants

Compared to an energy-only market design, consumers subject to a CPM framework trade off the reliability risk of insufficient capacity in favor of monetary risk associated with

[19] Cramton and Stoft (2006) suggest that, instead of instituting energy market price caps, system operators should hedge all load with call options tied to the capacity market. This feature is embedded in ISO-NE’s forward capacity market, which calculates “peak energy rents” (PER) for a hypothetical peaking unit operating in the spot and operating reserve markets. The PER are then deducted from the capacity payments that generators receive. This approach is intended to provide the dual benefits of mitigating the exercise of market power in the spot market, since load is hedged, and providing performance incentives to generators, who will lose revenues from the capacity market if they are unable to perform when called upon. However, the effectiveness of the P ER mechanism in practice has been called into question and it is scheduled to be eliminated in 2019 (McDonough 2015).

payments for capacity. Financial risk is reallocated from investors to consumers,[20] as CPMs don't guarantee profitable investment, but they can provide more stable revenue streams to generators and can even guarantee revenue before assets are operational (contingent on good performance).[21] By ensuring payment in advance to generators, consumers may pay to keep incumbent capacity in service that ends up not being needed or is inefficient. In addition, payments may be made to incumbent generators that do not need capacity payments to remain open, resulting in perceived windfall profits to these units, but these payments also could be characterized as rewards for the risks associated with previous investments.[22] On the other hand, establishing a CPM means that the consumer risk of lost load is diminished. The risk faced by consumers is that the market procures a level of reliability beyond what is reasonably required, and that such procurement is costly.

5.4. Promotes Innovation

Like the energy-only market construct, a CPM framework can be designed to promote innovation, but certainly some designs lend themselves to innovation better than others. On the supply-side, the combination of energy, capacity, and ancillary service markets generally provides payments for the provision of new technologies and improvements in existing technologies, but those payments do not necessarily provide the correct incentives for the types of technologies and operational characteristics that are needed. Specific market design considerations, such as those discussed previously for PJM, can significantly impact the viability of less mature technologies. The CPM framework can also promote innovation on the demand-side, though there might be additional challenges, and it may require innovation in market regulations. Both Joskow (2008) and Cramton and Ockenfels (2012) suggest that demand-side resources should be treated symmetrically to supply-side resources, though the latter acknowledges that demand-side resources might not supply the grid flexibility and reliability that CPMs are intended to provide. Ultimately, successfully integrating demand-side and storage

[20] From a financial risk perspective, a market with a CPM lies between a regulated market, which places virtually all of the risk on the consumer by ensuring a certain return on investment for the utility, and an energy-only market, which places the majority of the risk on investors by requiring them to recover both variable and fixed costs through a market environment subject to price volatility. It also bears mentioning that producers operating in CPM frameworks may be exposed to even more regulatory risk than those in energy-only or cost-of-service frameworks, as the rules of capacity mechanisms have been, to date, rapidly evolving and are subject to further change.

[21] As noted by Bushnell et al. (2017), early capacity markets failed to appropriately incentivize capacity resources to perform during periods of scarcity (p.20).

[22] This situation will be more likely to occur under a fixed capacity payment approach, but it could result from an auction framework as well, depending on the rules.

resources within a CPM structure might eventually make the CPM obsolete, as argued by Keppler (2014).

5.5. Robust to Alternative Futures

A potential relative strength of the CPM framework is its robustness to alternative future configurations of the power system. While the energy-only market approach is theoretically ideal under a fairly specific set of conditions, mostly notably that there exists an active demand-side, there are important discrepancies between these ideal conditions and the current state of electricity markets both in the United States and abroad (Keppler 2014).[23] In the absence of a demand-side transition, CPMs appear to have the ability to handle a variety of possible technology futures on the supply-side. For example, a well-designed CPM will ensure that if baseload plants and other more flexible resources have adequate value to the system, they will be compensated for it and resource adequacy and operational reliability will be maintained, even if energy market revenues decrease due to an unexpected shock to fuel prices or advances in new technology. By similar logic, the CPM framework can in principle also accommodate high future penetrations of variable renewable generation, but the associated challenge is to assign proper capacity values to the portfolio of resources that enable that transformation. Careful design considerations will need to be made to ensure that other resources such as demand-side resources and storage are also appropriately valued.

5.6. Transparent

A properly conducted CPM would be expected to be transparent, but simplicity is a concern, both from the perspective of the regulator and market participants. On a basic level, generators need to co-optimize their participation across energy, ancillary service, and capacity markets, which adds an additional layer of complexity beyond the energy-only paradigm. Also, as alluded to throughout this section, there are a variety of design rules and parameter values that the regulator must decide on, including the shape of the variable resource requirement curve (which, in addition to the load curve and conventional generator outage probability distributions, contains information on the acceptable loss of load expectation (LOLE)), the treatment of non-conventional resources, the number of years in advance to hold the base capacity auction and the

[23] While momentum towards an active demand-side in the market for energy services is undeniable, the length of time needed to produce adequate demand response, and the exact nature of that transition, are unknown.

length of time to guarantee that payment for,[24] etc. These and other design parameters, such as the MOPRs described above, are constantly being reviewed and revised, which can complicate participation on the part of investors.

5.7. Potential Reforms

Going forward, there are useful CPM design reforms that either have not been adopted, or have not received widespread adoption. For example, a major challenge associated with a transition towards a future power sector with high levels of variable renewable generation and associated low marginal costs is to accurately value the contribution of those resources towards reliability. To this end, Milligan et al. (2016) suggest that system operators base capacity value for variable renewable resources on probabilistic measures such as the effective load-carrying capacity (ELCC), which accounts for uncertainty in load and variable generation levels.[25] Currently, most ISOs use historical performance during predefined peak load windows to assign capacity credit, which ignores higher order moments of the joint load/variable generation distribution.[26] System operators could increase the granularity of CPMs to reflect important correlations between variable generation and load in the revenues available to generators. CPM designs that are too temporally aggregated could encourage an inefficient, and potentially overbuilt, generation mix.

Other proposed reforms that ISOs/RTOs with CPMs could take to address the transitioning electricity sector include the integration of all supply and demand-side resources, and the creation of more sophisticated markets for ancillary services. As levels of variable generation increase and battery costs decrease, CPMs will likely need to be adapted to properly value the contributions of both utility-scale and customer-sited storage. By providing efficient participation signals to demand-side and energy storage resources, CPMs can help the electricity sector transition toward a theoretical ideal. As part of the transition, it may be necessary to develop additional markets that identify and compensate generators for providing ancillary

[24] In most US markets commitment periods are for one year, though ISO-NE allows new resources to choose to lock in their payment for up to seven years.

[25] One downside to using ELCC is that it requires the ISO to conduct a probabilistic analysis, such as a Monte Carlo study, after auction bids are submitted in order to determine capacity credit for variable renewable resources. As a result, investors in those resources face uncertainty over both the price and quantity components of capacity market revenue, making investment more risky.

[26] See Table 2 in Bushnell et al. (2017) for a description for of how each ISO assigns capacity credit to variable renewable resources. Currently, only wind resources in MISO are credited based on ELCC, though ERCOT performs an ELCC study to assess reliability.

services such as frequency regulation, voltage stability, contingency reserves, and ramping. An example is CAISO's flexible ramping product, which compensates generators for their ability to rapidly increase or decrease production. At least in theory, this product helps to maintain reliability through significant fluctuations in variable generation.

6. Re-Envisioning Electricity Markets as a Platform Model

In this section, we give shape to a potential market design of the future, often referred to as the platform model. This approach is similar to, and in practice might be operationally equivalent to, an integrated energy services utility (Fox-Penner 2014). One promise of the platform model is that it might be able to leverage technological advances and promote innovation more easily than the conventional models we have discussed thus far, which could be particularly useful given the rapid transition currently underway in the electric sector.

Despite the extensive experience and expertise that has been brought to bear on electricity market and regulatory design, none of the previous paradigms we discuss fully satisfies in practice all of our evaluation criteria. Many critics argue that CPMs and regulated companies share an apparent bias toward providing more reliability than is desired by consumers (as opposed to less reliability at a lower cost) and focusing on the wrong kind of reliability by emphasizing the adequacy of generation capacity. For example, over the last decade, the vast majority of the billions of hours of disruptions in energy supply for retail customers were due to disruptions in distribution and transmission systems, not generation services. The 20 largest disruptions, which interrupted 5.7 billion customer hours on the electricity grid and accounted for 49 percent of the total interrupted customer hours, were due to distribution and transmission problems rather than inadequate generation.[27] In the same vein, Newell et al. (2012) find that distribution outages cause customers to lose power 100 times more often than do generation resource shortages.

So why do reliability measures seem to focus on generation as opposed to transmission and distribution? One possibility is that investment in generation assets earn a return on invested capital, either in a market setting or cost of service regulation. In contrast, there may be

[27] In 2016 alone, the top 20 disruptions caused 237 million customer hours of interrupted electricity service, accounting for 93 percent of total interrupted customer hours in 2016. Fifteen of these 20 disruptions were due to distribution and transmission issues. All calculations were performed by the authors using data from EIA Form OE-417.

inadequate incentives for maintenance of distribution systems because related costs would be recovered as an expense and not incorporated into the rate base upon which investors earn profits. If reliability criteria were to place greater emphasis on the performance of transmission and distribution systems, more focus on these functions would naturally arise.[28,29] The Brooklyn-Queens Demand Management project demonstrates the potential cost effectiveness of this approach (Walton 2017).[30] This shift in focus toward an emphasis on the transmission and distribution network is one possible pathway to the development of what is described as a platform model.

The platform model departs from the conventional paradigm of power plants as service providers and customers as service demanders, and instead it enables the potential for power plants and customers to both provide and purchase services through a hub, which could either take the form of a regulated distribution utility or an independent company. The platform would remove the exclusive franchise in the provision of some or all of the various functions performed by firms in the electricity sector, enabling various aggregators of supply- and demand-side services to be compensated through the network of platform users. There are many variants of a platform model, but Apple's App Store is a particularly salient example. There, app developers and buyers interact, while the company at the hub is neither a seller nor buyer, instead earning revenue by providing a market that enables and facilitates the network economy (Zarakas 2017).

One factor promoting an evolution in market design and the potential rise of a platform model is the rapid technological transformation occurring in the power sector and related communication industries. These changes increasingly enable nontraditional energy service providers to bring new service options to consumers. Increased bundling of electricity services with information services, potentially using parallel communication pathways, could be a step

[28] Importantly, these issues reach across federal and state jurisdictions, introducing potentially costly legal ramifications.

[29] Increased emphasis on distribution system reliability might be a natural consequence of the BiCap approach presented in Hamal (2013).

[30] The project by Consolidated Edison Company of New York addresses expected inadequacy of sub-transmission feeders using customer-side and utility-side solutions to avoid major capital investments (Elcock 2017).

toward the platform model. Under that scenario, the ability to control access to data becomes an especially potent barrier to entry, as data access is effectively the gateway for profitable participation in the platform market.[31]

An important aspect of a platform model is that payments for services may move away from volumetric charges and toward periodic subscription fees, as has occurred in telecommunications markets. The traditional roles of suppliers and consumers may be disrupted in this model, especially with the proliferation of zero marginal cost technologies. For instance, customers might: (1) pay a monthly fee for services provided by the platform and also for energy, transmission and distribution services, (2) pay more for additional reliability, and (3) receive credit for demand-side management services and for the data they are willing to share with other service providers. Volumetric energy services might be sold at marginal cost, which might be zero, as occurs in telecommunications today. Under this market structure, cross subsidies among classes of customers, and payments from suppliers to demanders may be economically justified in order for each side of the market to each be compensated for the services it provides and value it creates (Weiller and Pollitt 2013). In Apple's App store, for example, customers may acquire applications for free because their presence brings value to the network and making it possible for service providers (i.e., app developers) to advertise or collect data. By analogy, customers on the electricity grid might receive services at a price that is below embedded cost or marginal cost if that form of pricing enables greater network economies or broader recovery of fixed network costs. Alternatively, customers might see prices below marginal costs if they provide valuable services such as scheduling electricity consumption for buildings and electric vehicle charging, or if they provide localized, short-term reliability services through vehicle-to-grid energy supply.

While there is concern that the grid may be fractured by the emergence of new, small-scale, low marginal cost technologies, the platform model might provide an antidote. On the supply-side, a platform promises to accommodate intermittent, low and no variable cost resources that are distributed across the grid, sometimes farther from and sometimes closer to load, each with different value and payment. On the demand-side, it may provide a revenue model that facilitates payment for a variety of services, providing economic incentives to large industrial and commercial customers, and soon even residential customers, to remain in the network.

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[31] Whether or not a platform market emerges, policies regarding access to data are likely to be an essential part of market design in the future.

A feature of this seemingly futuristic but potentially near-term market structure is that it implies a reorganization of firms, much the way firms in the telecommunications industry have changed since the 1980s. Reliability of service nonetheless is expected to remain a primary concern. Therefore, one potential scenario is that regulated local distribution companies could emerge as the hub of a platform and assume part of the responsibility for reliability that rests currently with organized markets or vertically-integrated investor-owned utilities. This model may accommodate the advent of community-based renewable supply-side resources (typically solar) in many states. On the demand-side, this model may accommodate the growth of community choice aggregators in California, where currently roughly 25 percent of load is served by nonutility retail companies and rooftop solar installations. Together these arrangements could deliver a mix of energy service and environmental attributes and encourage investments that increasingly bring consumers into a platform model (CPUC 2017).

Evaluation of a platform model with respect to the criteria enumerated above is challenging because, beyond the vision expressed in various venues and summarized above, there is no mature model and only a limited theoretical literature pertaining to its application to the electricity sector. Nonetheless, this notion of a platform market structure is gaining interest. Some incumbent utility companies already have positioned personnel to anticipate and perhaps foster development of the platform model.

6.1. Efficient Investment and Operation

The platform model begins with a different premise with respect to technological possibilities and associated efficiency than the existing sector models. Platform advocates point to rapidly emerging technologies and social changes to suggest efficient investments in the future may be less centralized, smaller scale or modular, and have shorter asset lives than investments that characterize the electricity sector today. The platform model arguably is well-suited to this circumstance, but as it is an untested model, it is unclear if it is as well-suited to induce other potential future power sector investments, such as long-distance transmission.

Operation of a platform model could preserve a substantial role for the owner of distribution and transmission wires, presumably in a regulated setting for recovery of costs and planning of investments. Hence, in a platform setting system operation would probably look a lot like an energy-only market model, with grid-connected generation and demand-side resources being utilized according to instantaneous availability and locational marginal cost. The difference is the open access to the network.

6.2. Market Power Mitigation

The platform provides the broadest conceivable private market organizational structure to mitigate the possible exercise of market power, but does not entirely preclude it. A key feature will be access to data for service providers, which is the gateway to the market. Barriers to entry could be maintained in the form of exclusive franchise relationships between the utility and the consumer or with respect to management of the electricity grid and clearance of the real-time energy market.

A conventional remedy to market power might be the ability of consumers to leave the grid and identify separate electricity supply options. Paradoxically, however, this strategy imposes inefficiency for the network and potential inequities in the recovery of the legacy cost of existing resources. The platform does not prevent customer flight, but, as mentioned above, it might incent customers to remain on the grid ("in the network") in order to realize the full value of their role as consumers. The platform might be an antidote to the dilemma facing all of the existing systems with respect to the emergence of new low cost generation technologies.

6.3. Efficient Assumption of Risk across Market Participants

Community choice supply companies and demand aggregators emerging today might be viewed as the tip of an iceberg that that could increasingly leave remaining ratepayers and shareholders behind in a legacy system. Community choice aggregators enable matching of supply-side resources to consumer preferences and, to varying degrees, divorce customers from obligations to pay for embedded costs. This option might appear inequitable, at least from the perspective of those left behind, particularly if the legacy system retains the obligation to provide backup reliability. This outcome imposes risk on those least able to avoid it, not those who benefit the most. However, the platform model, if fully realized, may provide its own solution by creating an incentive for all customers to remain on the grid in order to realize the value of the services each can provide.

As new forms of value take shape, traditional measures of reliability and cost may be affected, just as the quality of telephone service has deteriorated with the loss of land lines.[32] Whether this is an inefficient outcome, however, is an empirical question, especially given the very high and uniform levels of reliability required in the system currently.

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[32] See Malykhina (2015) for a discussion of the low quality of cell phone call quality.

6.4. Promotes Innovation

The platform model purports enhanced opportunities for innovation and integration of the electricity sector with other parts of the economy. A tradeoff may exist in realizing that potential. New entrants might have the expertise and risk-taking culture to pursue radical innovation; however, incumbents in the industry have a deep infrastructure of expertise within the industry as it is currently configured, as well as access to customers. A potential conflict emerges if rules favor the insurgents versus the incumbents; the goal should be to enable both to be more innovative.

6.5. Robust to Alternative Futures

The platform model embodies an alternative future, one that is envisioned to be able to accommodate rapid technological change. Further, a platform model appears well-positioned to enable a substantial expansion of the electricity sector into building and transportation energy services, which many technology analysts see as the dominant pathway for the 21^{st} century economy and helpful for integrating increasing amounts of variable renewable generation into electricity supply. But whether this untried market structure can accommodate alternative futures is uncertain, as is the very shape of the model itself.

6.6. Transparent

To the electricity consumer, the platform model might be as transparent as their current interactions with electronic media; that is to say, not very. To the electricity supplier, especially the incumbent in the industry today, the transition to a platform introduces tremendous uncertainties, and, because the rules are yet to be written, the transformation to a platform is not likely to be simple. But if electricity follows the experience of telecommunications, the transformation may be rapid.

6.7. Potential Reforms

The platform model, whatever shape it might take, would bring a new market structure to the electricity sector, and so while it does not invite a discussion of potential reforms to the platform, it does invite a discussion of reforms that might enable the platform to emerge. Crucial among these is access to data about customer electricity usage. For practical purposes that information is in the hands of the retail utility company, and sharing the information poses privacy challenges. However, entrepreneurs argue that efforts to bring new services into the market require access to that data, for example for new firms to be able to aggregate customers into more substantial load blocks based on their usage characteristics and preferences. Moreover, customers themselves may not know how to access their historic data use. More generally, efforts to facilitate the integration of demand-side services, including mechanisms to pay for those services, appear fundamental to the introduction of a platform model.

7. Broader Implications

The various approaches to organizing electricity transactions identified above raise issues for the electricity sector that go beyond wholesale electricity markets and that may be increasingly apparent over time. In the United States and abroad, many suggest that the potential expansion in the role of electricity in the broader energy landscape could bring environmental benefits that would have associated economic benefits over the next several decades.[33] Energy service demands such as car transportation and space- and water-heating, which are often satisfied through on-site combustion of fossil fuels, may increasingly be supplied by electric vehicles, electric water heaters, and greater reliance on electric heat pumps; electrification enables the integration of various information technologies in all these functions. This potential transformation in the use of electricity provides one lens through which to view the different approaches to organizing electricity transactions described above.

Over time, electrification, particularly for transport, could increase the size of the sector substantially, which in turn could increase prices or would require substantial investments. The structure and performance of electricity transactions within organized markets or outside of them is clearly dependent on the availability of transmission and distribution capacity to move electricity from points of generation to points of consumption. To the extent that low cost distributed generation plays a greater role in future energy markets and predicting the locations of future generation investment becomes more of a challenge, efforts to plan future expansion of both the transmission and distribution grids could become more complicated and investments could become riskier. How that risk is shared among the different electricity market participants is an important question; if that risk falls on consumers, it would amplify the incentive for customer flight. Transmission capacity can be a strategic asset, as investment in particular locations can help to address market power in energy markets by facilitating regional expansion and integration. But in order for such investments to take place, incentives must be aligned, and those incentives will depend on ownership structures and how transmission is priced. They will also depend on how easy and profitable it is for parties to block siting of new transmission lines.

[33] See for example, Dennis et al. (2016) and Bradsher (2017).

Changes in market structures and regulatory frameworks will also raise transition issues for companies and customers that should be anticipated and may need to be addressed before those changes can be implemented. These transition issues have already played an important role in halting the introduction of electricity sector restructuring and the move away from energy-only markets in many parts of the country.

While the transition toward greater electrification of the economy may take some time to unfold, there are likely to be nearer term transition issues associated with the move toward greater reliance on low cost generation and any associated modifications in structures that could occur in response. Retail electricity market restructuring in the 1990s produced expectations of lower electricity prices and the stranding of existing generating capacity. At that time, much of the conversation focused on stranded cost recovery and how to compensate owners of generators who made investments in good faith under a regulatory regime that was being undone in favor of markets and anticipated lower prices. Similar concerns arise in the context of how best to organize future electricity transactions, although this time around potentially affected entities are not necessarily regulated generators but also include independent power producers. The extent to which market structure outcomes will address or potentially exacerbate stranded cost recovery in this case remains to be seen.

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