Real-Time Pricing and Electricity Market Design

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Abstract

This paper considers two related distortions in electricity markets: the lack of real-time retail pricing and the suppression of peak wholesale prices due to Installed Capacity requirements. I lay out a framework for understanding these problems using a two-stage entry model in which producers with multiple technologies set capacity and then sell electricity into wholesale markets as demand varies over time. The model is calibrated to supply and demand conditions in the PJM electricity market. I estimate that moving from 10 percent of consumers on real-time pricing to 20 percent would increase welfare in PJM by $120 million per year. However, the welfare gains from clearer signals of scarcity prices under an Energy Only market design are more than twice as large. Furthermore, equilibrium peak prices in the Energy Only design drop to reasonable levels once a moderate share of retail consumers are on real-time pricing.

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1 Introduction

When a good is scarce, prices rise, suppliers produce more, and consumers substitute away. This process is especially important in electricity markets. Because electricity is economically non-storable, markets constantly cycle from short-run capacity surplus to potential scarcity as demand fluctuates across hours and days. Extreme scarcity can cause blackouts, which are very costly, so it is important to implement a market design that results in adequate production capacity. However, because the industry is highly capital intensive, a design that results in too much capacity can also be extremely wasteful.

This paper considers the effects of two distortions that impede electricity markets from optimally signaling and responding to scarcity. The first is that most retail consumers are charged some average price instead of the real-time wholesale price. It has long been understood that the lack of real-time pricing (RTP) is inefficient in the short run, as consumers demand more than the optimal quantity at peak times and less than the optimum at off-peak times, and in the long-run, as producers enter more than the first-best amount of capacity in order to satisfy higher peak demand.[1] In the past four years, however, this issue has become even more relevant, as millions of additional consumers have been equipped with advanced electricity meters that make RTP immediately technically feasible (Joskow 2012, Joskow and Wolfram 2012). Because RTP can pose problems for the policymakers that regulate electricity retail, such as price volatility and distributional considerations (Borenstein 2007a, 2007b), it is important to realistically quantify the potential efficiency benefits.

The second distortion arises from how consumers pay for reserve capacity. Because supply and demand are stochastic, many system operators impose *planning reserve margins*, which are required amounts of production capacity in excess of equilibrium quantity.[2] At its core, this is a standard peak-load pricing problem, with the addition of an excess capacity constraint. Theoretically, a natural solution is a particular version of what has been called the *Energy Only market design*: the market clears at the intersection of supply and demand unless the reserve margin constraint binds, in which case scarcity rents arise as the market clears along the constraint. Of course, the scarcity rent varies significantly over time: it is zero in off-peak times but can be quite high at peak.

One basic problem with the Energy Only design arises when there are few retail consumers on real-time pricing, as is the case today. When wholesale demand is highly inelastic, the market becomes very sensitive to small perturbations from equilibrium, which has brought concern about whether the planning reserve margin will in practice be satisfied. Furthermore, peak prices can be

[1] The theoretical literature on RTP and peak-load pricing includes Boiteux (1949), Houthakker (1951), Steiner (1957), Williamson (1966), Carlton (1977), Chao (1983), Bergstrom and MacKie-Mason (1991), Borenstein and Holland (2005), and many others.

[2] Reserve margins must be externally imposed on the market because system reliability has public good attributes: a failure in one area can cause a blackout that cascades onto other areas (Joskow and Tirole 2007).

There is an important debate on whether current planning reserve margins are optimal, and many analysts believe that it is too conservative. In this analysis, I leave that issue aside and take the planning reserve margin as exogenous.

very high, which can generate political backlash from consumers. For these and other reasons,[3] many system operators have implemented an alternative to the Energy Only design called the *Installed Capacity (ICAP) market design*. In this design, aside from procuring energy, retailers must also procure credits for peak production capacity sufficient to satisfy their peak demand plus the reserve margin. Unlike in the Energy Only design, the planning reserve margin constraint does not directly affect how wholesale energy prices are set: the energy market always clears at the intersection of supply and demand. Peak energy prices are therefore suppressed relative to their levels in the Energy Only design, and the energy market fails to fully signal scarcity.

When retailers in ICAP markets pass through to consumers the costs of procuring capacity credits, they in practice often do not re-create the time-varying scarcity rent that arises in an Energy Only market. For example, in the worst case, a retailer might recover capacity costs by adding a constant charge to the price of electricity consumed in any hour. In other cases, retailers charge consumers proportionally to their consumption in the system peak hour from the previous year, but when consumption decisions are made, consumers are likely to be imperfectly informed about when system peaks arise. This is the second distortion I study: even when retail consumers pay the real-time wholesale price of *energy*, they often do not face the real-time scarcity rent associated with the cost of *capacity*.

In this paper, I ask the following questions. First, what are the effects of increasing the share of consumers on real-time pricing under the ICAP market design? Second, what are the welfare gains from moving to the Energy Only market design? Third, how do peak prices in an Energy Only market design vary with the number of consumers on RTP?

To answer these questions, I construct a simulation model of the PJM electricity market, which covers more than one-sixth of the United States and is the largest centrally-dispatched electricity system in the world. The basic structure is a two-stage entry model that builds on Turvey (1969), Crew and Kleindorfer (1976), and most directly on Borenstein (2005).[4] In the first stage, potential entrants with different production technologies set capacity subject to zero profit conditions. In the second stage, actual entrants sell electricity in a perfectly-competitive wholesale market as demand varies over time.

This paper departs from other models in two fundamental ways. First, I explicitly compare the two major approaches to implementing a reserve margin, the ICAP and Energy Only market designs. In the ICAP market model, the reserve margin imposes a minimum constraint on the sum of total entering capacity. In equilibrium, the shadow price of this entry constraint is the clearing

[3] Ausubel and Cramton (2010), Batlle and Perez-Arriaga (2008), Bushnell (2005), Chao and Wilson (2004), Cramton and Stoft (2005, 2006), Hogan (2005), Joskow (2006), Joskow and Tirole (2007), Oren (2005), Stoft (2002), Telson (1975), Vazquez, Rivier, and Perez-Arriaga (2002), Wilson (2010a, 2010b), Wolak (2004), and others have discussed the design of reserve capacity requirements and the choice between Energy Only and ICAP market designs.

[4] There are a number of two-stage capacity expansion models in the literature on electricity markets, including Borenstein and Holland (2005), Castro-Rodriguez, Marin, and Siotis (2009), Masse and Gibrat (1957), Murphy and Smeers (2005), and others. Outside of this industry-specific literature, there are of course many configurations of two-stage entry models, such as Gabszewicz and Poddar (1997), Grimm and Zoettl (2008), Kreps and Scheinkman (1983), Mankiw and Whinston (1986), and Sheshinski and Dreze (1976), and many others.

price in the capacity market. The ICAP model assumes that retailers pass through capacity costs as constant adders to electricity prices. Thus, it is important to recognize that what I refer to in shorthand as an "ICAP design" is more precisely an "ICAP design with relatively inefficient pass-through of capacity costs." Because in theory, it might be possible for retailers to re-create the optimal time-varying scarcity rents when they pass through capacity costs, I will sometimes characterize results for the Energy Only design as an "ICAP design with optimal pass-through of capacity costs." In practice, the ways that different retailers currently pass through capacity costs are somewhere between these two extremes, and I will also present results for an example intermediate case.

The second departure from the previous literature is to incorporate an exogenous set of incumbent suppliers, using energy market bidding data from PJM. These incumbents make the model of much more applied interest: when combined with a realistic distribution of demand patterns from historical data, they generate useful predictions of future capacity market prices and the distribution of entrant capacity among the different technologies in PJM. This same model can be calibrated with publicly-available data from other markets.

There is a startling hole in the literature on these issues. Despite the fact that tens of billions of dollars flow through capacity markets across the U.S. each year, there are to my knowledge no models that predict capacity market prices in equilibrium for a real market. Despite significant interest in whether regulated utilities should move more consumers to real-time pricing, none of the simulation models that have guided the policy discussion capture how this would play out in equilibrium in the many markets that employ the ICAP design. For example, Holland and Mansur (2006) model the short-run effects of RTP, which does not capture the fact that welfare gains act primarily through a reduction in power plant capacity, and Borenstein's (2005) long run model does not capture the fact that in most actual markets, the suppression of peak wholesale energy prices in the ICAP design could markedly affect the welfare gains from RTP. Furthermore, despite the substantial literature on electricity market design, there are few quantitative estimates of any aspect of the costs and benefits of the Energy Only vs. ICAP designs.

In answer to the three research questions, there are three basic results. First, the potential gross efficiency gains from RTP in an ICAP market are large. Even when retailers pass through capacity costs as constant adders to marginal prices, the welfare gains from increasing the share of PJM consumers on RTP from 10 to 20 percent would be about $120 million per year. However, this is only about half the welfare gain from RTP when capacity costs are passed through optimally. Furthermore, the channels of welfare gains from RTP under ICAP with constant pass-through are very different than under optimal pass-through. For example, counter to the predictions of short-run models, RTP actually causes peak and near-peak energy prices to *increase*. The consumer surplus gains then flow through a reduction in capacity market prices. This highlights the importance of additional research to more comprehensively model how capacity costs are passed through and to estimate how consumers respond to different capacity pricing structures.

Second, moving from an ICAP to an Energy Only market, or optimally passing through capacity costs in the ICAP design, generates welfare gains that take an inverted-U shape in the number of consumers on RTP. When 20 percent of consumers are on RTP, the welfare gains from moving from ICAP to Energy Only are $473 million per year, or about twice as large the gains from having put that 20 percent of consumers on RTP in the first place. Intuitively, the gains from optimally passing through scarcity rents are so large because of the capital intensity of production: the high peak prices reduce peak quantity demanded, which reduces required capacity and thus the cost of building new power plants. However, with a smaller share of consumers on RTP, there are not enough consumers exposed to wholesale prices for the improvement in pass-through of scarcity rents to have much of an effect. With a larger share of consumers on RTP, peak prices are low enough in the Energy Only design that the suppression of peak prices under the ICAP design is less distortionary.

The third basic result is that while peak prices in the Energy Only design are very high when there are few consumers on RTP, this is eventually moderated with additional RTP consumers. Under the base case assumptions, the maximum hourly price over a five year period in an Energy Only market drops below $10,000 per megawatt-hour once about 30 percent of demand is on RTP. In one sentence, the basic policy implication of these three basic results is that *while real-time pricing is important, optimally passing through time-varying scarcity rents could be even more important, and once enough consumers are on RTP, peak scarcity rents need not be unreasonably high.* The point of this paper is that given the significant research and policy interest in RTP, more attention should be devoted to inefficiencies in how capacity costs are passed through in ICAP markets.

The paper proceeds as follows. Section 2 provides concise background on the PJM market, the Energy Only and Installed Capacity market designs, and retail electricity pricing. Section 3 details the entry model and proves uniqueness. Section 4 details the data on supply and demand in the PJM market which are used to calibrate the model. Section 5 briefly discusses computation, and Section 6 presents results. Section 7 briefly discusses caveats, the most important of which is that we do not have empirical estimates of consumers' elasticity to the high and potentially-unpredictable peak prices that arise in an Energy Only design. Section 8 concludes.

2 Background

In this section, I give a concise overview of the PJM market, the Energy Only and Capacity market designs, and retail electricity pricing. At several points, I will preview assumptions of the model and discuss how well they match actual market conditions.

2.1 PJM Overview

In 1927, three electric utilities in the mid-Atlantic region of the United States recognized the potential gains from trade in electricity supply and joined together to form a "power pool" called PJM. Now the world's oldest and largest power pool, PJM was also on the forefront of electricity market restructuring, becoming the first market certified under the federal restructuring rules of the late 1990s. Figure 1 shows PJM's geographic footprint: as of 2011, electricity flowing through PJM served 58 million people in all or part of 13 states plus the District of Columbia.[5] Because of its size and importance, PJM is an excellent context to study the potential effects of real-time pricing and alternative market designs.

PJM Interconnection, LLC, is a Regional Transmission Organization: a federally-regulated entity that manages and operates the wholesale electricity market. System operators like PJM are responsible for clearing the electricity market auctions, managing the transmission network, ensuring that electricity service is reliable, and designing an economically efficient market. PJM also maintains an independent market monitor, a firm called Monitoring Analytics, that oversees the market, determines whether it is economically efficient, and makes market design recommendations.

There are more than 750 different firms that buy, sell, and trade electricity in PJM. On the supply side are electricity generating companies, which operate power plants with a total of about 179,000 megawatts of capacity. A typical power plant capacity is several hundred megawatts, which equals the average consumption of several hundred thousand American homes. Figure 2 illustrates the short-run supply curve for an example day in August 2011, highlighting three major production technologies. The lowest units on the supply curve are *baseload* coal-fired and nuclear plants. These plants have high fixed and low variable cost and typically run continuously except for scheduled maintenance periods during the spring and fall. The highest units on the curve are *peaker* plants fueled by oil and natural gas, which employ gas turbine or steam turbine technologies that entail lower capital costs but less efficient fuel use and thus higher variable cost. In the middle are smaller coal plants and *combined-cycle* plants that run on natural gas. The model will include entrant firms corresponding to these three italicized technologies. There is also a large amount of wind generation capacity being built in PJM. Because much of this capacity is built to comply with state-level environmental mandates, it is less likely to be affected by real-time pricing or changes in market design, so the model will not endogenize wind capacity construction.

A key feature of electricity markets is the "hockey stick" shape of the short run supply curve. Peak supply is highly convex due to a small number of old, inefficient plants with high marginal costs, and supply becomes fully inelastic at the capacity constraint. The hockey stick shape means that while prices will be relatively low in most hours of the year, they will be significantly higher in a small number of hours. These peak hours are of particular interest because they account for a substantial flow of revenues from consumers to producers. Owners of some peaker plants recover

[5] This and the other basic facts about PJM in this section are from the 2011 State of the Market Report for PJM (Monitoring Analytics 2012).

their fixed construction costs while operating in only a small number of hours each year.

On the demand side of the wholesale market are retailers, which sell electricity to residential, commercial, and industrial customers. In most states, these retailers are regulated natural monopolies that cover a particular geographic region, such as Public Service Electricity and Gas in New Jersey, Baltimore Gas and Electric, and Potomac Electric Power Company in Washington, D.C. Retail prices set by these firms are regulated by state Public Utilities Commissions such that they earn a market rate of return on investment. The model will capture this form of regulation by assuming that these regulated retailers earn zero profits.

A second key feature of electricity markets is the variability in demand. In 2011, the mean quantity demanded in PJM was 82,541 megawatts, but the standard deviation was 16,000 megawatts. Demand is lowest at night and highest on hot summer days when people turn on air conditioners in homes and offices. PJM's maximum quantity demanded in 2011 was 158,016 megawatts, nearly twice the mean.

2.2 The Energy Market

The central element of a wholesale electricity market is the *Energy Market*, a daily uniform-price procurement auction for electricity. The day before supply is to be provided, every generating unit submits a supply function consisting of a maximum of ten segments. Given generators' supply functions, quantities demanded by consumers, and the transmission network, PJM sets the lowest-cost production schedule and computes the Locational Marginal Price at each node of the network. In order to maintain simplicity and ensure uniqueness in the entry game, the model will assume away transmission constraints and losses and instead model one system-wide market-clearing price.[6]

Suppliers have the incentive to exercise market power when setting Energy Market bids. However, at the aggregate market level, PJM is not highly concentrated, with a Herfindahl index of 1203. Transmission constraints can cause more highly concentrated local markets, but this is restrained by "offer capping," under which a unit deemed to have local market power has its bid mitigated and instead receives its reported marginal cost plus ten percent. Monitoring Analytics uses confidentially-reported marginal costs to calculate that the average markup of marginal suppliers in 2011 was only $1.28 per megawatt-hour, which is a small fraction of the average price of $42.84 per megawatt-hour. To capture the fact that these auctions are very close to competitive, the model assumes that suppliers bid their marginal cost functions. Allcott (2012), the working paper version of this analysis, relaxes this assumption and allows profit maximizing bid functions to endogenously change with the expansion of real-time pricing, but because markups are so small, this has little impact on the results. Allcott (2012) shows that most of the efficiency gains from real-time pricing flow through the reduced entry of new power plants, which the model in the

[6] In PJM and other markets, the Energy Market actually comprises two auctions, the Day-Ahead and Real-Time markets. In the model, I will simply assume one market-clearing price.

present paper will indeed capture, not from the improvements in the efficiency of the auctions due to reduced markups.

Aside from the Energy Market, PJM and other market operators also have market-based or non-market approaches to procuring "operating reserve" capacity for each point in time. For example, PJM procures additional capacity equal to one percent of load to serve as regulation reserves, which must be able to respond within seconds to fluctuations in supply or demand. PJM procures further traunches of capacity as synchronized reserves and supplemental reserves, which must be available within 10 and 30 minutes, respectively. In reality, revenues from provision of operating reserves and other ancillary services are insignificant compared to revenues from the sale of electricity, and the model assumes that these profits are exogenous. What is significant, however, is how a reserve requirement can affect how Energy Market prices are set. I turn to this issue presently.

2.3 Energy Only Market Design

By definition, an *Energy Only market design* is one that does not include a Capacity Market.[7] Figure 3 illustrates how in this market design, the reserve margin is enforced by making the red-colored Energy Market supply curve fully inelastic at the reserve margin constraint. In off-peak periods, price is the intersection of demand with aggregate supply, as illustrated by point A. In peak periods, the market will clear along the reserve margin constraint, as exemplified by point B and price P_t.

In this peak period, all producers to the left of point C supply energy. All producers to the right supply reserves. The bid of the marginal supplier of energy is b^e. In the Energy Only design, all suppliers of energy are compensated b^e for supplying energy. The scarcity rent per unit of energy is $P_t - b^e$, and the total scarcity rents over all production in this peak period are the gray rectangle. These total scarcity rents are divided between all suppliers of energy and reserves. This means that each producer available in the market at time t earns a scarcity rent of $\frac{P_t - b^e}{1+m}$ per unit of capacity, where m denotes the percent required reserve margin.[8]

There are other ways of implementing the reserve margin in an Energy Only market. I use this approach because as I will show, it attains the first best in my particular model when all consumers are on real-time pricing. Hogan (2005) outlines another implementation in which demand is inflated by the reserve margin to determine an Operating Reserve Demand Curve, and prices are determined by the intersection of supply with the Operating Reserve Demand Curve. While semantically different, my model and Hogan's implementation generate identical equilibria if the Operating Reserve Demand Curve is in effect only when the reserve margin constraint binds and

[7] The "Energy Only market design" is not to be confused with the "Energy Market." Similarly, the "ICAP market design" is not to be confused with the "Capacity Market."

[8] Notice that this allocation of payments to producers means that no supplier of reserves would prefer to supply energy, and no supplier of energy would prefer to supply reserves. (The marginal producer at point C is indifferent.) This condition would not necessarily hold if scarcity rents were not allocated equally across all units of capacity supplying either energy or reserves.

if prices are determined by the intersection of the Operating Reserve Demand Curve and the total capacity constraint. Several U.S. electricity markets, including the PJM, Midwest, New York, and New England markets, have implemented some limited form of Operating Reserve Demand Curve, while others, such as California, have not. Differences in implementation mean that it is useful to have a stylized representation of this approach that does not conform exactly to any one market's particular rules.

Other market design details may vary, and for the model I will make some particular choices. First, the reserve margin could be characterized as a proportion of load or as an absolute amount of capacity. The model will do the former. Second, the optimal operating reserve requirement is some decreasing function of the market-clearing price (Joskow and Tirole 2007). However, in order to ensure that the Energy Only and ICAP market designs give comparable minimum reliability levels in the simulations despite different maximum market clearing prices, the model will use a constant percentage reserve margin. It would be straightforward to modify the model I develop to make the reserve margin be a constant amount of megawatts instead of a proportion of equilibrium quantity, or to make the reserve margin a function of price. Third, the market operator should optimally institute controlled blackouts for consumers not facing real-time prices when market prices exceed the "value of lost load," or the average marginal willingness to pay for electricity. The value of lost load is difficult to estimate: Cramton and Stoft (2006) report estimates of between $2000 and $267,000 per megawatt-hour. The model will simply assume that controlled blackouts are not implemented in equilibrium because the value of lost load always exceeds the market-clearing price.

2.4 Installed Capacity Market Design

In theory, existing operating reserve markets such as those detailed above for PJM could give the same equilibria as the Energy Only market design. The model will capture three factors that suppress peak prices in the Installed Capacity design. First, all U.S. electricity markets have either bid caps or offer caps: for example, PJM limits bids to $1000 per megawatt-hour. Second, many electricity markets do not have a mechanism like an Operating Reserve Demand Curve, meaning that scarcity rents are suppressed relative to what they would be if the reserve margin were enforced in the Energy Market. Third, even in markets that do have some Operating Reserve Demand Curve, the operating reserve margin used to determine Energy Market prices is typically smaller than the planning reserve margin that determines total desired installed capacity.

These and other factors described by Joskow (2006) and others[9] create what is called the "missing money problem": a reduction in peak prices and thus supplier profitability which reduces entry below the level required by the planning reserve margin. In the long run, this reduction

[9] Joskow (2006) describes other actions that market operators take to prevent blackouts during times of scarcity that also cause missing money, including voltage reductions, "Reliability Must Run" contracts, and other out-of-market contracts. Hogan (2005), Cramton and Stoft (2006), and others also discuss the sources of the missing money problem.

in available capacity would eventually compromise system reliability. To remedy this potential problem, many electricity markets in the U.S. and other countries also require retailers to procure credits for capacity sufficient to satisfy their customers' peak demand plus a reserve margin. This is called the *Installed Capacity (ICAP) market design.*

In PJM, for example, analysts predict the equilibrium quantity in the peak hour three years forward and increase this by a reserve margin to arrive at a total system capacity requirement. All incumbents and potential entrants must bid capacity rights into a uniform price procurement auction called the Capacity Market, which is centrally managed by PJM. Retailers pay to PJM a share of total Capacity Market costs proportional to their share of peak load. PJM then compensates each capacity seller based on the measured proportion of peak hours when the power plant is available.

Sellers in the Capacity Market auctions have the incentive to exercise market power, and this would be exacerbated by fully inelastic demand at the reserve margin constraint. As in the Energy Market, PJM thus makes extensive use of offer capping: capacity owners deemed to have market power have each plant's capacity market bid replaced by an administrative estimate of the annualized difference between the plant's value of exiting and the continuation value. Furthermore, instead of a fully inelastic system capacity constraint, PJM substitutes an administratively-determined downward-sloping demand curve such that the market clearing quantity of capacity is expected to be near the desired system capacity. Although the appropriate way to design a capacity market is under debate, it is currently reasonable to model PJM and similar auctions as perfectly competitive.

As discussed by Pfeifenberger, Spees, and Schumacher (2009), these and other specifics vary by market. For example, California has no centralized capacity auction, so retailers independently procure capacity rights, and the New York and Midwest markets have a centralized auction for capacity available in the current year instead of a forward capacity market. The model in this paper will reflect the equilibrium of a perfectly competitive capacity market.

In recent years, some markets have implemented both a Capacity Market and an Operating Reserve Demand Curve with a smaller reserve margin than the planning reserve margin. While this hybrid design does not fully eliminate the missing money problem, it reduces it, which reduces the shadow price of the planning reserve margin constraint and therefore reduces Capacity Market prices and revenues. The model can easily accommodate a hybrid design, but to keep the results sharp, I will compare only the two extremes.

Figure 3 illustrates the central mechanism of welfare gains from the Energy Only vs. the ICAP designs that I model. The blue line is the ICAP supply curve. In the ICAP model, the reserve margin constraint will not be enforced when determining market-clearing prices in the Energy Market. This means that price is the intersection of aggregate demand with aggregate supply. Therefore, the planning reserve margin must require additional entry until the point where the peak-hour demand clears the market at the bid of the marginal supplier of energy illustrated by point D. By contrast, in the Energy Only market, prices rise along the reserve margin constraint, and that same peak-hour demand curve results in lower quantity demanded because equilibrium price is higher. Therefore, the reserve margin can be satisfied with less capacity in the Energy Only design than under the ICAP design.

2.5 Retail Electricity Pricing

Despite the wide variation in wholesale market prices across hours and days, nearly all electricity consumers in the U.S. and abroad do not pay the real-time market price. Instead, most consumers other than large commercial and industrial facilities pay some constant averaged price called a *flat-rate tariff*. Historically, charging real-time prices was not possible because most smaller consumers had meters that recorded only the sum of consumption over each month, not in each minute or hour, making it impossible to charge different prices for consumption at different times. However, encouraged by about ten billion dollars of recent federal and state incentives, utilities in the United States have now installed eight million advanced electricity meters for residential and small commercial customers that record minute-to-minute consumption and thus make it possible to charge real-time prices (Joskow 2012, Joskow and Wolfram 2012).

Although the new meters make real-time pricing immediately possible from a technical perspective, the extent to which RTP will actually be adopted over the next 10 years is still highly uncertain. Retail utilities and regulators that approve retail prices have historically been concerned that consumers are averse to hourly price variation (Borenstein 2007a), that the customers currently receiving implicit subsidies due to the flat rate tariff would oppose RTP (Borenstein 2007b), that consumers would be confused by real-time pricing, or that some consumers are not sufficiently price elastic to justify any costs. Industry experts surveyed by Faruqui and Mitarotonda (2011) believe that between 7.5 and 20 percent of residential consumers would be on some form of dynamic pricing nationwide in 2020, and between 5 and 15 percent of commercial and industrial consumers. In the PJM specifically, expert opinion suggests even larger uncertainty: 12.5 to 45 percent of residential customers could be on dynamic pricing by 2020, and 20 to 40 percent of commercial and industrial customers. This uncertainty motivates the counterfactual simulations: what would be the efficiency gains if a larger vs. smaller share of consumers were moved from a flat rate tariff to real-time pricing? If the efficiency gains are large, this suggests that policymakers and regulators that oversee electricity retail should push harder for real-time pricing despite the potential concerns.[10]

Retail electricity providers in ICAP markets vary in how they pass through capacity costs to consumers. In most cases, even when a consumer pays the real-time Energy Market price, the pass-

[10] Real-time pricing is only one form of dynamic pricing. Other forms include critical-peak pricing, in which consumers pay especially high prices on a small number of peak days, and various forms of demand response programs that act to change the marginal price that consumers pay at peak times. These other forms of pricing are by definition less efficient than real-time pricing, and if these other forms of dynamic pricing are implemented instead of RTP, the welfare gains would be lower than the model will predict.

through of Capacity Market charges fails to replicate the time-varying scarcity rent that arises under the Energy Only market design (McDonough and Kraus 2009).[11] Some utilities charge RTP consumers a lump sum capacity charge based on the consumer's maximum hourly quantity demanded, which may or may not coincide with system peaks. Others charge a lump sum proportional to the customer's quantity demanded during the previous year's system peak, which is determined only at the end of the year. Consumers cannot perfectly predict when that peak occurs, whereas in the Energy Only design they have real-time signals of the shadow cost of reserves. Other retailers, such as those offering the real-time pricing programs analyzed by Allcott (2011) and Boisvert *et al.* (2007), add a constant amount to the marginal price of electricity consumed on summer afternoons or across all hours of the year. In the ICAP market design, the model will assume that Capacity Market costs are passed as a constant increase to all consumers' marginal prices in all hours.

3 Model

The welfare effects of real-time pricing and of different market designs can be simulated in a simple two-stage entry model. In the first stage, entrants with three different electricity production technologies set capacity. In the second stage, entrants and an exogenous set of incumbents sell electricity in perfectly competitive Energy Market procurement auctions to retailers, who re-sell to consumers with demand that varies over multiple periods of time. In the ICAP market design, the reserve margin is implemented as a constraint on total entry, and the shadow price of the constraint is passed through to consumers via constant adders to marginal prices in all periods.

In equilibrium, entrants and retailers earn zero profits, and the Energy Market auctions clear in every time period. The equilibrium capacity of each technology that enters is unique. The model will allow me to compare the welfare effects of the two market designs, because both satisfy the equilibrium conditions and achieve the same minimum reserve margin in all periods.

It is important to again be clear about the semantics that I am using, as they affect the interpretation of the results. As we have seen, different retailers currently use different approaches to pass through capacity costs. The constant pass-through in my "ICAP" market design is effectively a worst-case scenario. The time-varying scarcity rents in my "Energy Only" market design can in theory be replicated by retailers in an ICAP market through an optimal approach to passing through capacity costs. Thus, there are two ways of interpreting the differences in outcomes that arise under my models of the two market designs. First, the differences could be interpreted as the difference between an ICAP design with poorly-executed pass-through and an Energy Only market design. Second, they could be interpreted as an upper bound estimate of the importance of optimally passing through capacity costs within an ICAP design.

[11] Joskow and Tirole (2007, page 73) also point out this issue in their discussion of capacity obligations. "Another important point is that price-sensitive consumers consume too much . . . unless capacity obligations are imposed on LSEs in a way that reflects the peak demand of all the retail consumers that they serve. The price paid by all retail consumers must also include the price of capacity in order to restore proper incentives on the demand side."

This section details the second stage and then the first stage of the entry model, and finally demonstrates uniqueness. While there are a number of two-stage entry models with multiple production technologies, the model and application build closely on Borenstein (2005), and I follow his notation when possible.

3.1 Second Stage: Energy Market

3.1.1 Consumer Demand

Consumers have constant elasticity of demand $\eta \leq 0$. There is a set of time periods $t = \{1, ...T\}$, each of which has an aggregate demand shifter $\xi_t \geq 0$. For example, in the afternoons of hot days, demand shifters are relatively high, as people want to turn on their air conditioners. Shares α and $1-\alpha$ of consumers are on real-time pricing and the flat rate tariff, respectively. The parameter α is exogenously determined by electricity metering technologies and the regulatory environment. All consumers have the same demand parameters η and ξ, and while the ξ's vary over periods, there is no uncertainty over their distribution.

Real-time pricing (RTP) consumers face the wholesale energy price P_t in each period t. For non-RTP consumers, wholesale energy prices are passed through as a constant "flat rate tariff" $\overline{P}$. In the ICAP market design, the retailer's capacity market costs are passed through as a constant adder to the marginal price denoted P_c, which does not vary between RTP and flat rate consumers. In the Energy Only design, $P_c = 0$. The aggregate demand function for period t is thus:

$$Q_t^d(P_t, \overline{P}, P_c) = \left\{\alpha(P_t + P_c)^\eta + (1-\alpha)(\overline{P} + P_c)^\eta\right\} \cdot \xi_t \tag{1}$$

3.1.2 Retailers

Retailers procure electricity from the wholesale market, as well as capacity credits in the ICAP market design, and sell to consumers. I assume that retailers do not cross-subsidize Energy Market and Capacity Market costs. I also assume that they earn zero profits in equilibrium, either because they are in a state with rate of return regulation, or because they are in a state with free entry into competitive markets for retail supply. This implies that there are two zero profit conditions, one that pins down the flat rate tariff $\overline{P}$ and one that pins down the capacity adder P_c.

The first zero profit condition requires that retailers set the flat rate tariff $\overline{P}$ such that the retail revenues from the flat rate tariff equal the Energy Market procurement costs for the flat rate tariff consumers:

$$\pi_r^{\overline{P}} = \sum_t (\overline{P} - P_t) \cdot (1-\alpha)(\overline{P} + P_c)^\eta \xi_t = 0 \tag{2}$$

Rearranging, this gives an equation for the flat rate tariff $\overline{P}$:

$$\overline{P} = \frac{\sum_t P_t \cdot (\overline{P} + P_c)^\eta \xi_t}{\sum_t (\overline{P} + P_c)^\eta \xi_t} \tag{3}$$

In the ICAP market design, denote the total Capacity Market payments by R. I will later specify how R is determined. The second zero profit condition requires that retailers set the capacity adder P_c such that R equals the total revenues from the capacity adder:

$$\pi_r^{P_c} = \sum_t P_c \cdot Q_t^d(P_t, \overline{P}, P_c) - R = 0 \tag{4}$$

Although there are many separate retailers in PJM, I have modeled only one α and one set of prices P_c and $\overline{P}$. In this model, equilibrium prices would be identical across retailers if demand patterns and wholesale market prices are identical; and to the extent that these factors vary it would likely not affect the basic conclusions to explicitly model separate retailers with different α, P_c, and $\overline{P}$. For simplicity, I do not include any adder to marginal prices to recover retail distribution costs. Taken literally, this means that retail distribution costs would be recovered through lump sum payments, perhaps as monthly fixed charges.

3.1.3 Wholesale Supply

Each power plant submits a step function bid into the Energy Market. The price and length of each segment of this step function are denoted b_{jt} and k_{jt}, where j indexes steps and t indexes time. The aggregate supply function at time t is thus:

$$Q_t^s(P_t) = \sum_j k_{jt} \cdot 1\left(b_{jt} \leq P_t\right) \tag{5}$$

In computing equilibrium quantity, supply from the marginal segment or segments is rationed such that quantity supplied exactly equals quantity demanded. Because the auctions are perfectly competitive, the rationing rule does not affect profits.

As explained earlier, I assume that the auctions are perfectly competitive, meaning that $b_{jt} = c_{jt}$. There are two kinds of suppliers: incumbents and entrants. Because there is very little exit in this industry that is not caused by exogenous environmental regulation, incumbents' Energy Market costs and capacities are modeled as exogenous. Entrants' marginal costs c are exogenous, and their capacity k will be determined endogenously in the first stage.

Denote by b_t^e the bid of the marginal supplier of energy in period t. In the ICAP market design, $b_t^e = P_t$. In the Energy Only design, $b_t^e \leq P_t$, depending on whether the reserve margin constraint binds. In either design, the total profits from the sale of energy earned by segment j are:

$$E_j = \sum_t k_{jt} \cdot 1\left(b_{jt} \leq b_t^e\right)\left(b_t^e - c_{jt}\right) \tag{6}$$

In the Energy Only design, scarcity rents arise when the reserve margin constraint binds. Denote $\overline{Q}_t^s = \sum_j k_{jt}$ as total production capacity available in period t. In period t, the scarcity rent per unit of energy is $P_t - b_t^e$, and the total scarcity rents are $\frac{\overline{Q}_t^s}{1+m} \cdot (P_t - b_t^e)$, where $m > 0$ denotes the percent reserve margin. The total scarcity rents earned by segment j over all periods is:

$$S_j = \sum_t \frac{\overline{Q}_t^s}{1+m} \cdot (P_t - b_t^e) \cdot \frac{k_{jt}}{\overline{Q}_t^s} = \sum_t \frac{k_{jt}}{1+m} \cdot (P_t - b_t^e) \tag{7}$$

The scarcity rent earned by segment j in period t is the scarcity rent per unit of energy deflated by $1+m$, which accounts for the fact that the scarcity rents are shared between all suppliers of energy and reserves.

3.1.4 Equilibrium

In the ICAP market design, equilibrium Energy Market prices $\{P_t^*\}$ are determined by the intersection of demand with the aggregate bid function in each hour. Equilibrium prices are determined by the following equation:

$$Q_t^d(P_t^*, \overline{P}, P_c) = Q_t^s(P_t^*), \forall t \tag{8}$$

In the Energy Only market design, this same equation determines equilibrium prices as long as the reserve constraint does not bind, i.e. when $Q_t^s(P_t) < \frac{\overline{Q}_t^s}{1+m}$. Otherwise, prices are determined by the intersection of demand with the reserve constraint. Thus, equilibrium prices in the Energy Only market design are determined by:

$$Q_t^d(P_t^*, \overline{P}, P_c) = \min\left\{Q_t^s(P_t^*), \frac{\overline{Q}_t^s}{1+m}\right\}, \forall t \tag{9}$$

3.2 First Stage: Entry Decision

There are a large number of homogeneous potential entrant firms. Entrants are of three technology types, peaker, combined cycle, and baseload, which are indexed by $e \in \{p, c, b\}$. Each technology is characterized by a constant marginal cost c_e and fixed cost F_e. Because this is a two-stage static entry game and entrants thus cannot later exit, this fixed cost combines the amortized sunk cost of entry and annualized fixed operating and maintenance costs.

Each potential entrant firm can set any non-negative capacity for any technology. Entrants' decisions result in a vector $K = \{k_p, k_c, k_b\}$ of total entering capacity of each technology. Because capacity within each technology is homogeneous, this vector completely summarizes first stage outcomes; entrant plant size and the number of distinct firms that own these plants are both indeterminate. Entrant capacity and costs do not vary over periods t in the second stage.

Denote entrants' second stage profits per unit of capacity by D_e. In the ICAP design, $D_e = E_e/k_e$. In the Energy Only design, $D_e = (E_e + S_e)/k_e$. Denote by $r \geq 0$ the Capacity Market price: the amount paid to entrants and incumbents per unit of capacity available. In the Energy Only market design, $r = 0$. For firms of each of the three entrant technologies, the profit function per unit of capacity is:

$$\Pi_e = D_e + r - F_e \tag{10}$$

Although I have not made this explicit in order to simplify the notation, notice that D_e depends on K, because entrants' second stage Energy Market profits depend on the amount of entering capacity. As more capacity enters, Energy Market prices, and thus profits, will drop.

3.2.1 Equilibrium

The equilibrium is such that no entrant firm could make higher profits by not entering, and no potential entrant who does not enter could make higher profits from entry. Since profits from non-entry are defined to be zero and the homogeneous entrant firms earn the same profit per unit of entering capacity, all actual entrants must also earn zero profits. An equilibrium vector of entering capacity K^* thus must fulfill the following zero profit conditions:

$$\left\{ \begin{array}{l} \Pi_e(K^*) = 0, k_e^* > 0 \\ \Pi_e(K^*) \leq 0, k_e^* = 0 \end{array} \right\}, \forall e \in \{p, c, b\} \tag{11}$$

The second line of this equation reflects the fact that corner solutions are possible: in equilibrium, there could be zero entry of one or more of the entrant technologies. This will be more likely to occur for a technology if higher fixed costs relative to other entrants are not outweighed by sufficiently low marginal costs, or if relatively high marginal costs are not outweighed by sufficiently low fixed costs. This could also occur if there are already many similar incumbent plants already in the market.

3.2.2 Reserve Margin in the ICAP Design

As with the Energy Only design, the ICAP design requires that the quantity demanded in each period multiplied by $(1+m)$ not exceed total installed capacity. Unlike the Energy Only design, however, this is enforced by a constraint on total system capacity, not through a constraint that affects Energy Market prices. Denoting the total capacity available from incumbent producers at time t as $\sum_i k_{it}$, this constraint is:

$$(1+m)\cdot Q_t^d(P_t,\overline{P},P_c) \leq \sum_i k_{it} + \sum_e k_e, \forall t \tag{12}$$

Denote as $\widehat{t}$ the period in which the constraint binds. Rearranging slightly, we have that the reserve margin implies a scalar constraint k^*_{rm} on the sum of entry across the three technologies:

$$\sum_e k_e = (1+m)\cdot Q_{\widehat{t}}^d(P_{\widehat{t}},\overline{P},P_c) - \sum_i k_{i\widehat{t}} \equiv k^*_{rm} \tag{13}$$

In words, the total required entry k^*_{rm} is such that in period $\widehat{t}$, the demand function intersects the aggregate supply curve at the point where m percent excess capacity remains. Entrants' zero profit conditions pin down their bids at $F_e - D_e$, and this determines the equilibrium Capacity Market price in the ICAP design:

$$r^* = F_e - D_e \tag{14}$$

Consistent with PJM rules, I assume that capacity payments are proportional to capacity available on peak days in the three summer months, June, July, and August. Total capacity payments for an incumbent segment are thus $R_j = \frac{k_{j,June}+k_{j,July}+k_{j,August}}{3}\cdot r$. Because entrants' capacity k_e does not vary over time, total capacity payments to an entrant technology can be written as $R_j = k_e r$. Total Capacity Market payments in the ICAP design are thus $R = \sum_j R_j$.

3.3 Uniqueness

Borenstein (2005) explains why his model, with no incumbent capacity and no reserve margin, has a unique equilibrium. For the same basic reasons, the equilibrium in my extension of his model is unique. More precisely, conditional on entrant cost parameters F_e and c_e, incumbent cost functions, demand parameters η and ξ_t, and the parameters m and α, there is a unique set of energy market prices $\{P_t^*\}$, entrant capacity K^*, and retail prices $\overline{P}^*$ and P_c^* that clear the Energy Market and satisfy entrants' and retailers' zero profit conditions. Below, I demonstrate why this is true.

First, conditional on a value of the vector K and values of $\overline{P}$ and P_c, there is a unique set of equilibrium Energy Market prices P_t in the second stage of the entry model. This is because demand $Q_t^d(P_t, \overline{P}, P_c)$ is strictly monotonically decreasing in P_t and the supply curve is monotonically increasing.

Second, conditional on values of $\overline{P}$ and P_c, there is a unique equilibrium value of K, denoted K^*, that satisfies entrants' zero profit conditions. This results from two lemmas. Lemma 1 is what I call the *Unequal Profit Stealing* condition, which results from the fact that the entrant technologies have a particular order of marginal costs, $c_p > c_c > c_b$. Consider a higher-marginal cost technology h and a lower-marginal cost technology l. Substituting one unit of capacity of technology l for one unit of h does not affect D_h but reduces D_l. This is because in each period where $P_t \geq c_h$, P_t is unaffected by substituting l for h. However, in each period when $c_h > P_t > c_l$, substituting l for h decreases P_t.

Lemma 2 is that there is a unique equilibrium value of $\sum_e k_e^*$. In the ICAP design, there is a unique value of the scalar $k_{rm}^* = \sum_e k_e^*$ determined by Equation (13).[12] In the Energy Only design, there is a unique value of $\sum_e k_e^*$ that satisfies the zero profit condition of the highest marginal cost technology with positive entry, which I denote by $\overline{h}$. Relative to $\sum_e k_e^*$, any reduction in total entrant capacity increases P_t in all hours when $P_t > c_{\overline{h}}$, which increases $D_{\overline{h}}$. Any increase in total entrant capacity reduces reduces P_t in all hours when $P_t > c_{\overline{h}}$, which decreases $D_{\overline{h}}$.

Using lemmas 1 and 2, the uniqueness of K^* can be proved by contradiction. Consider a proposed second equilibrium vector K'. Relative to K^*, the proposed K' must redistribute capacity

[12] Intuitively, this is because as entrants shift out the supply function, there is only one point at which the excess total capacity exactly satisfies the reserve margin. However, this requires an additional regularity condition.

In Equation (13), $Q_t^d(P_t, \overline{P}, P_c)$ increases in $\sum_e k_e$, because the increase in supply reduces prices. Thus, the following regularity condition is required in order to ensure that k_{rm}^* is unique:

$$\frac{\partial Q_t^d(P_t, \overline{P}, P_c)}{\partial \sum_e k_e} < \frac{1}{1+m}, \forall \sum_e k_e \tag{15}$$

In words, the ratio on the left-hand-side of this equation captures how equilibrium quantity increases with an outward shift in supply. When demand is fully elastic, this ratio takes value one: outward shifts in supply cause equal increases in equilibrium quantity. When demand is less than fully elastic, this ratio depends on the relative elasticities of supply and demand: the more inelastic is demand relative to supply, the lower the ratio. The regularity condition ensures that demand is sufficiently inelastic relative to supply such that as entrants enter, additional capacity required to satisfy the reserve margin always decreases. Unless this regularity condition always holds, there could be multiple entering capacities at which the reserve margin holds exactly. In practice, the condition always holds in this market given that m is small and demand is relatively inelastic compared to supply as long as the capacity constraint does not bind.

among the three technologies without changing $\sum_e k_e^*$. When a lower-marginal cost technology is substituted for a higher marginal-cost technology, the Unequal Profit Stealing condition implies that D_l decreases. The Capacity Market price r must increase to maintain $\Pi_l = 0$. However, because D_h is unaffected, now $\Pi_h > 0$. Therefore the proposed equilibrium K' is not an equilibrium.

So far, I have shown that there is a unique K^* and set of $\{P_t^*\}$ conditional on $\overline{P}$ and P_c. What remains is to show that there are unique values of $\overline{P}$ and P_c that satisfy retailers' zero profit conditions. Consider Equation (2), the zero profit condition that determines $\overline{P}$. Total demand by flat rate tariff customers $(1-\alpha)(\overline{P}+P_c)^\eta \xi_t$ is always positive. Furthermore, $\sum_t (\overline{P} - P_t)$ is monotonically increasing in $\overline{P}$, as $\frac{\partial(\overline{P}-P_t)}{\partial \overline{P}} = 1 - \frac{\partial P_t}{\partial \overline{P}}$ and $\frac{\partial P_t}{\partial \overline{P}} < 0$. Thus, there cannot be more than one $\overline{P}$ at which $\pi_r^{\overline{P}} = 0$.

Similarly, consider Equation (4), the zero profit condition that determines P_c. The quantities $\sum_t P_c \cdot Q_t^d(P_t, \overline{P}, P_c)$ and R are increasing and decreasing in P_c, respectively, meaning that there cannot be more than one P_c at which $\pi_r^{P_c} = 0$.

3.4 Social Optimum

The Energy Only market described here attains the social optimum given the reserve margin constraint, if and only if all consumers are on real-time pricing, i.e. $\alpha = 1$. This is for the same basic reasons that the competitive equilibrium in Borenstein and Holland (2005) with $\alpha = 1$, no incumbent capacity, and no reserve margin attains the social optimum: there are no missing markets, and all the conditions of the First Welfare Theorem are satisfied. In the short run, Energy Market prices equal short run marginal cost conditional on the reserve margin constraint. In the long run, entrants enter until fixed costs equal Energy Market profits, which also equal the social value of incremental capacity at the optimum. However, when $\alpha < 1$, the first best will not necessarily be attained in this equilibrium without an appropriately set tax or subsidy to $\overline{P}$, which might be funded through lump sum transfers (Borenstein and Holland 2005).

4 Data for Calibration to PJM

Calibrating the simulation model to PJM or any other market requires three classes of data: entrants' fixed and marginal costs, incumbents' variable costs, and demand parameters.

4.1 Entrants' Fixed and Marginal Costs

Table 1 presents fixed and marginal cost parameters for the three entrant technologies. These parameters are the base case assumptions in the 2011 PJM State of the Market Report (Monitoring Analytics 2012), which are derived from detailed engineering estimates relevant for power plants entering the PJM market. The principal part of fixed cost is the amortized construction costs. From this capital cost, I subtract annual revenues from provision of reactive services, which help maintain grid stability. Reactive service payments for each electricity generation technology are determined by the U.S. Federal Energy Regulatory Commission and are assumed to be exogenous.

The principal part of marginal cost is fuel input. The fuel cost per megawatt-hour of output is the cost of coal or natural gas fuel multiplied by the heat rate, which reflects the technology's efficiency in transforming fuel into electricity. The total marginal cost also includes other variable operation and maintenance expenditures and the cost of permits to emit air pollutants.

Notice that the coal-fired baseload technology has both higher fixed costs and higher marginal costs than the gas-fired combined cycle technology. This is the first time in the past decade that natural gas plants have had lower marginal costs: North American natural gas prices have recently decreased, and environmental costs have increased. Under these assumptions, the combined cycle technology thus strictly dominates the baseload technology in the entry model, and there will be zero entry of baseload capacity in equilibrium. Of course, this may or may not be the case under future assumptions, so I do not remove the baseload technology from the model.

4.2 Incumbents' Marginal Cost Functions

I use the set of observed bids from the PJM Real-Time Energy Market for calendar year 2011 (PJM 2012a). Under the assumption of perfect competition, these bids equal marginal costs. Bids often change from month to month, for example as some units are taken offline for scheduled maintenance during low-demand months. However, there is often little variation in bids from day to day. Thus, to reduce memory requirements, I use the observed bids for the first Wednesday of each month for all non-holiday weekdays of that month. I use the observed bids for the first Saturday of each month for all holidays and weekend days of that month.

4.3 Demand

The choice of demand elasticity η is important because it mechanically drives the results: if retail consumers are more price elastic, the distortions from passing through averaged prices are larger, and thus the allocative gains from real-time pricing and the Energy Only design are larger. Empirical analyses of real-time pricing programs, such as Allcott (2011), Boisvert *et al.* (2007), Herriges *et al.* (1993), Patrick and Wolak (2001), Schwartz *et al.* (2002), and Taylor, Schwarz, and Cochell (2005), have estimated own-hour price elasticities ranging from -0.04 to -0.15. For the base case simulations, I use $\eta = -0.05$. In the Online Appendix, I present results for $\eta = -0.03$ and $\eta = -0.15$.

To generate a distribution of demand shifters ξ_t, I begin with the distribution of ξ_t that reflects PJM market conditions over the five-year period from 2007-2011. To calculate this, I back out the equilibrium quantity supplied $Q_t^s(P_t)$ in each hour t using incumbents' aggregate bid functions discussed above and the hour's market price P_t from the PJM Real-Time Energy Market (PJM 2012b).[13] The 2007-2011 demand shifters ξ_t are calculated by inverting the demand function in Equation (1). For that calculation, I assume for simplicity that $\alpha = 0$ and that $\overline{P} + P_c = \$55.66$, the average cost per megawatt hour for energy plus capacity in PJM in 2011 (Monitoring Analytics 2012). Finally, to simulate future market conditions with entry of new capacity, I increase the 2007-2011 demand shifters by 15 percent.

As in the survey by Faruqui and Mitarotonda (2011) discussed earlier, there is uncertainty over the share α of consumers that will be on real-time pricing in 2020 and beyond. One objective of this analysis is to provide an estimate of the allocative gains if α is higher. As such, I compare scenarios with $\alpha = 0.1$ and $\alpha = 0.2$.

5 Computation

The computation of the equilibrium parallels the proof of uniqueness. First, trial values of the retail prices $\overline{P}$ and P_c are chosen. Second, the total entering capacity $\sum_e k_e^*$ is pinned down. In the ICAP market design, this is determined by the reserve margin constraint in Equation (13). In the Energy Only design, this is determined by the zero profit condition of the highest-marginal cost entrant technology that enters. Third, the equilibrium distribution of entrant capacity K^* conditional on the pair $\overline{P}$ and P_c is determined by backwards induction. The equilibrium pair $\overline{P}^*$ and P_c^* that satisfies the retailers' zero-profit condition is found using secant search, looping over these three steps.

Because the distribution of Energy Market prices P_t is highly skewed, it is important to have precision in simulating the second stage revenues that flow during a small number of peak hours. By contrast, there are many off-peak hours with similar prices. To reduce computational time, the model simulates each of the 1600 highest-price hours from the period 2007-2011 but simulates only a sample of lower-priced hours with sampling probability increasing in observed price. These sampled hours are re-weighted appropriately when calculating averages and annualized profits.

6 Simulation Results

The simulations compare several scenarios that capture potential future market conditions. Scenario 1 is an ICAP market with zero consumers on RTP. While there already is a group of consumers that face real-time prices, this scenario will be a useful benchmark. Scenarios 2 and 3 are ICAP

[13] PJM also reports observed equilibrium quantities for each hour. I choose to back out the equilibrium quantities from the supply curves instead of directly using observed quantities because this allows me to capture unobserved factors that affect equilibrium prices, such as the import and export of electricity from nearby regions and transmission constraints within PJM. These factors are assumed to be exogenous.

markets with $\alpha = 0.1$ and $\alpha = 0.2$, respectively. Scenarios 4 and 5 are Energy Only markets with $\alpha = 0.1$ and $\alpha = 0.2$, respectively.

Comparing Scenarios 2 vs. 3 and 4 vs. 5 will show the effects of moving incremental consumers to RTP. Comparing Scenario 3 to Scenario 1 will show the effects of moving 20% of consumers to RTP with constant pass-through, and Scenario 5 vs. 3 then reflects the incremental effects optimal pass-through for those same consumers. Welfare in each of these scenarios is comparable, as all satisfy the same equilibrium conditions and achieve the same minimum reserve margin m in all hours.

For these simulations, I set the reserve margin to be $m = 0.05$. This is chosen to be halfway between the example reserve margins used in Hogan's (2005) exposition, which are 7% in normal conditions and 3% in conditions of extreme scarcity. Notice that this is a reserve margin above the maximum quantity demanded over a five year period, so it would be equivalent to a larger planning reserve margin based on the more common approach of forecasting maximum quantity for any one year. In Appendix Table A3, I also present results with a reserve margin of $m = 0.1$.

Three fundamental points will arise repeatedly in the results. First, while there are significant welfare gains from RTP in the ICAP market design with constant pass-through, some of the effects of RTP are very different in my ICAP market model compared to an Energy Only market. Second, it is extremely important from a welfare perspective to pass through capacity costs optimally - in fact, at moderate levels of RTP, this is more important than passing through the real-time Energy Market price in an ICAP design. Third, although maximum prices in an Energy Only design can be very high, they are moderated once a sufficient share of retail consumers are on RTP.

6.1 Equilibrium Prices and Quantities

For the scenarios with $\alpha = 0.2$, Figure 4 illustrates the basic difference between the Energy Only and ICAP market designs, which is that the latter does not pass through the time-varying scarcity rent. Against the left vertical axis, the figure plots the marginal energy bids b^e across the hours of an example week in July, when afternoon demand shifters are especially high. Against the right axis, the figure plots scarcity rents $P_t - b^e$ for the Energy Only market, and the capacity adder P_c for the ICAP market. In almost all hours, total quantity demanded plus the reserve margin is strictly less than total capacity, and the scarcity rent is zero in the Energy Only market. In several simulated hours on the right side of the graph, the constraint binds, and market prices have to rise above the bid of the marginal supplier such that equilibrium quantity demanded plus the reserve margin does not exceed total capacity. This implies high scarcity rents - in the hundreds or thousands of dollars per megawatt-hour - in a small number of hours. Obviously, the constant capacity adder in the ICAP model does not reflect this.

Notice also that marginal energy bids are higher in the afternoon hours in the Energy Only market. This is because there is less entry in that market design, so peak and near-peak prices clear higher on the incumbents' supply curve. Both this and the scarcity rents mean that peak Energy Market prices are suppressed in the ICAP design relative to the Energy Only design.

The black line on Figure 5 presents the cumulative distribution function (CDF) of equilibrium wholesale prices P_t under the ICAP market design with $\alpha = 0.1$, with units on the left vertical axis. The vast majority of hours have prices between \$30 and \$80, while the top half of percentile has prices ranging from \$90 to \$231. The dashed blue line illustrates the change in equilibrium price at each point in the CDF when α moves from 0.1 to 0.2 in the ICAP design. This line and other changes in the CDFs have units on the right vertical axis. Remarkably, prices increase slightly at the right of the distribution, especially in the top five percentiles. This violates the conventional wisdom about real-time pricing from short-run models, which is that it reduces peak wholesale prices in equilibrium. Why does the conventional wisdom not hold?

Figure 6 illustrates the mechanism behind this effect. In the ICAP market design, the total entrant capacity is determined by the reserve margin constraint. In the peak period, the market must clear such that m percent capacity is available in reserve. This reserve capacity is entirely high-marginal cost incumbents; all entrant technologies appear in the short run aggregate supply function with much lower bids. Because the reserve margin is a percentage of maximum peak quantity, the required excess capacity is slightly less with more consumers on RTP, because peak equilibrium quantity is lower. In a High RTP scenario, the Energy Market therefore clears at a slightly higher price on the incumbents' supply curve in the maximum peak period. The maximum peak equilibria in these two scenarios are points A and B, respectively.

Why are near-peak prices also higher? The additional wholesale demand elasticity from RTP reduces quantity demanded less in lower-price periods. Therefore, the excess capacity in near-peak periods is lower in the High RTP scenario, and near-peak prices are therefore also higher. This is not simply an artifact of having exogenous incumbent capacity. While endogenous exit would moderate this effect, t the basic result holds until all high-cost incumbent capacity retires. Since higher prices increase Energy Market revenues, entrants' zero profit conditions will require that capacity prices drop when α increases.

Figure 7 is analogous to Figure 5, except that it displays quantities instead of prices. The black line presents the cumulative distribution function of equilibrium quantities under the ICAP market design with $\alpha = 0.1$, with units on the left vertical axis. The dashed blue line illustrates the change in equilibrium quantity at each point in the CDF when α changes from 0.1 to 0.2 in the ICAP design. Because lower capacity prices decrease P_c and because off-peak wholesale prices are less than $\overline{P}$, equilibrium quantities increase slightly in off-peak hours. In peak hours, however, the higher Energy Market prices cause RTP consumers to reduce quantity demanded, and the maximum quantity decreases by just over one gigawatt. This is the average consumption of about one million homes, or about 0.7 percent of total maximum demand. Thus, the conventional result that RTP reduces peak *quantities* does hold.

How do the effects of RTP differ in an Energy Only design compared to an ICAP design?

Returning to Figure 5, the dashed gold line illustrates the change in equilibrium price at each point in the CDF when α moves from 0.1 to 0.2 in the Energy Only design. When more consumers move to RTP in the Energy Only design, the variance of peak and near-peak prices must decrease because the more elastic demand curves intersect the supply curves at more similar prices. Prices in the several peak hours of the year decrease: for example, the maximum price decreases from $220,000 to $62,000 per megawatt-hour. However, to maintain entrants' zero profit conditions, prices below these peak hours must increase. I will later discuss the fact that these maximum prices are very high.

The dashed gold line in Figure 7 illustrates the change in equilibrium quantity at each point in the CDF when α moves from 0.1 to 0.2 in the Energy Only design. Comparing this gold line to the dashed blue line, we see that RTP reduces equilibrium quantities more in almost all percentiles of the distribution under ICAP than Energy Only. However, the reduction in maximum quantity demanded from RTP is significantly larger in the Energy Only design. Thus, we can start to see substantial differences between how RTP affects equilibrium prices and quantities depending on how scarcity rents are passed through to consumers.

Returning for a final time to Figure 5, the red line presents the change in equilibrium wholesale price at each point in the CDF when the share of RTP customers is held constant at $\alpha = 0.2$ but the market design is changed from ICAP to Energy Only. Units for this change in prices are again on the right vertical axis. While off-peak prices do not change much, peak prices change significantly, both because scarcity rents become non-zero and because the reduction in entry means that the market clears higher on the incumbents' supply curve. In the several peak hours over the five year period, prices increase significantly in the Energy Only design. The resulting higher Energy Market revenues are needed to induce entry in the absence of capacity payments.

The solid red line on Figure 7 illustrates the change in equilibrium quantity at each point in the CDF when the market design is changed from ICAP to Energy Only. For most of the distribution until the highest percentiles, quantities increase. This is because although Energy Market prices do not change at the lower percentiles, total retail prices decrease because there the capacity adder P_c is eliminated. In other words, under this ICAP market, total off-peak retail prices are higher than optimal, even for RTP consumers, because of the capacity adder. One channel of welfare gains from the Energy Only design is to reduce off-peak retail prices and thereby increase off-peak consumption.

In the highest percentiles, equilibrium quantities decrease as the RTP consumers respond to the increased peak prices. The maximum quantity in the Energy Only market design is 4.3 gigawatts less than in the ICAP design. This again highlights the central driver of allocative efficiency gains from the Energy Only design: peak demand is much higher under the ICAP design if capacity costs are passed through to retail consumers in ways that do not reflect the high scarcity rents in peak hours. This increased peak demand requires more entry to satisfy the reserve margin, which increases overall costs.

6.2 Effects on Profits and Welfare

Table 2 presents detailed results from four scenarios: $\alpha = 0.1$ and $\alpha = 0.2$ for each of the ICAP and Energy Only designs. Some of the results in Table 2 are already apparent from the graphs discussed above. Average equilibrium quantities are slightly higher in the Energy Only compared to the ICAP design, and the average retail price drops. More RTP slightly increases the maximum price in the ICAP design but significantly reduces maximum price in the Energy Only design. While more RTP increases the mean Energy Market price in the ICAP design, the capacity price is reduced from \$86.20 to \$81.30 per kilowatt of capacity per year.

The first column of results is scenario 2, with $\alpha = 0.1$ in the ICAP design. In this scenario, equilibrium entry is 30.4 gigawatts of combined cycle plants, with zero baseload or peaker capacity. As discussed earlier, baseload entry was assured to be zero given that fixed and marginal costs are higher than for combined cycle plants in the 2011 data used in these simulations. The importance of combined cycle entry is consistent with actual market conditions: as of the end of 2011, 42.2 gigawatts of peaker, combined cycle, and baseload coal plants had filed permits to enter by 2018 (Monitoring Analytics 2012). While much of this capacity will not actually be built in that time frame, the distribution is informative: 82 percent is combined cycle, 7 percent is peaker, and 10 percent is baseload coal.

Reduced equilibrium entry is the main driver of welfare gains from RTP and from optimal pass-through of reserve costs. Under the ICAP design, equilibrium entry drops by 1.3 gigawatts when α moves from 0.1 to 0.2. In comparison, equilibrium entry drops much more under the Energy Only design: 4.5 gigawatts. Furthermore, optimal pass-through of scarcity rents matters a lot: holding $\alpha = 0.2$ constant, equilibrium entry is 8.2 gigawatts lower in the Energy Only design compared to the ICAP design.

Examining total annual electricity costs, we again see that RTP has very different effects depending on the market design. Comparing scenarios 2 and 3, we see that the reduction in costs from RTP is \$400 million in the ICAP design. By contrast, comparing scenarios 4 and 5, we see that this reduction is \$1.6 billion in the Energy Only design. Total costs are between \$51 and \$54 billion in the four scenarios. Dividing by the 58 million people in the PJM area, these figures are on the order of \$900 per capita.

Table 3 presents welfare calculations. The first two columns of results present the welfare effects of increasing RTP from $\alpha = 0.1$ to $\alpha = 0.2$ in the ICAP and Energy Only designs, respectively. In other words, they compare scenario 3 to scenario 2, and scenario 5 to scenario 4, respectively. In the ICAP design, the net welfare gain is \$120 million per year. This is about 0.23 percent of baseline electricity costs, or \$2.10 per person in the PJM region. Put differently, for each person whose per capita demand is moved to real-time pricing, total welfare increases by \$21. This qualitative result of large gross welfare gains is consistent with other work. However, at these levels of RTP, the welfare gains from RTP in the ICAP market at this level of α are half the welfare gains from RTP in the Energy Only market. This highlights the importance of understanding the pass-through of scarcity rents when modeling the effects of RTP.

Not only are the magnitudes of the welfare gains different between the two markets designs, but the channels also differ. Borenstein and Holland (2005) show that in an Energy Only market, increasing the share of consumers on RTP reduces welfare for the consumers that were already on RTP. By contrast, in the ICAP market model, increasing the share of consumers on RTP increases consumer surplus for all three consumer groups: those already on RTP, those that move to RTP, and those that remain on the flat rate tariff. The reason for this difference is that in an ICAP design, substantial consumer surplus gains flow through the reduced capacity adder, which affects all three consumer groups about equally.

The second pair of columns in Table 3 illustrate the relative importance of passing through scarcity rents compared to just the real-time Energy Market prices. The first column of this pair compares ICAP markets with $\alpha = 0$ vs. $\alpha = 0.2$. In other words, it compares scenario 3 to scenario 1. The second column of this pair holds α constant and compares the Energy Only market to the ICAP market. In other words, this pair compares scenario 5 to scenario 3. The former captures the effects of real-time pricing of energy, while the latter captures the effects in equilibrium of passing through the real-time scarcity rents. At these levels of α, the latter is much more important: the welfare gains are \$473 million per year, compared to \$242 million per year for the former. These results highlight the importance of carefully designing wholesale markets or retail pricing structures to induce the optimal reductions in peak quantity demanded.

Although there are a number of published empirical studies of real-time pricing programs in different parts of the country, the elasticity of additional RTP consumers is still highly uncertain. Furthermore, it is very difficult to predict how responsive consumers would be to the higher price variance in the Energy Only market. For this reason, Appendix Tables A1 through A4 replicate Tables 2 and 3 with $\eta = -0.025$ and $\eta = 0.1$. The net welfare gains from changing α from 0.1 to 0.2 in the ICAP design are \$1.10, \$2.10, and \$3.70 per capita, respectively, when $\eta = -0.025$, -0.05, and -0.1.

Appendix Tables A5 and A6 replicate Tables 2 and 3 with reserve margin $m = 0.1$ instead of 0.05. In the Energy Only market design, this increases peak prices, as the shadow cost of the reserve margin constraint in the Energy Market increases. However, in the ICAP market, this decreases peak prices, as the increase in required excess capacity means that peak demand intersects the Energy Market supply curve at a lower price. The capacity price r therefore must increase to keep entrants at zero profits. Thus, the larger the reserve margin, the wider the variance in Energy Only design scarcity rents, and the worse that the ICAP design does at passing through this variance. Thus, a larger reserve margin strengthens the basic conclusions: the welfare gains from RTP in an ICAP market are even lower compared to the welfare gains from RTP in an Energy Only market, and the gains from optimally passing through scarcity rents via the Energy Market even are larger compared to the gains from real-time pricing of energy alone.

Appendix Tables A7 and A8 present true long run results, without including the incumbent suppliers. In this case, the qualitative results are even more stark. In the ICAP market model, there are only two price levels, c_p and c_c, because no baseload capacity enters under these cost assumptions. Price never rises above c_p, and the capacity price equals peakers' fixed cost: $r = F_p$. Because there is so little variation in Energy Market prices and the capacity price is fixed at r, the welfare gains from RTP in the ICAP market are extremely small. By contrast, the welfare gains from RTP in the Energy Only market, and the gains from moving from ICAP to Energy Only, are relatively large.

As I have discussed, retailers have different ways of passing through capacity costs. One alternative approach is to allocate capacity costs for RTP consumers across summer peak hours, instead of across all hours of the year. Of course, targeting the pass-through of capacity costs during peak times when the reserve capacity constraint is more likely to bind should be more efficient than socializing these costs across all hours. Therefore, from an efficiency perspective, this alternative is an intermediate case between the ICAP design considered so far and the Energy Only design. It may also more realistically reflect what more retailers actually do.

Appendix Tables A9 and A10 present the results of simulations in which capacity costs for RTP consumers are passed through as a constant adder applied only between noon and 6PM in June, July, and August. Non-RTP consumers continue to have their adder P_c applied across all hours of the year. In equilibrium, the summer RTP capacity adders are \$198.63 per megawatt-hour in scenario 2 and \$180.52 per megawatt-hour in scenario 3. In other words, this approach adds about 20 cents per kilowatt-hour to RTP consumers' summer peak prices. By comparison, the P_c under constant pass-through adds about 1.7 cents per kilowatt-hour to prices in all hours of the year.

The quantitative and qualitative results of this alternative scenario do not change substantively from the base case: summer peak pass-through still leaves significant welfare gains on the table relative to optimal pass-through. The basic reason is that most of the welfare gains come from reduced entry, and entry is only reduced when maximum quantity demanded is reduced. Thus, most of the welfare gains from optimally passing through capacity costs arise because prices are significantly higher in the several hours of the year when the reserve capacity constraint actually binds. This result is analogous to Borenstein's (2005) finding that Time-of-Use pricing leaves significant welfare gains on the table relative to RTP. The summer peak pass-through is analogous to Time-of-Use pricing in the sense that it applies a somewhat higher retail price across about 500 high-demand hours instead of a much higher retail price across a small handful of maximum-demand hours.

Of course, this result that summer peak pass-through is significantly suboptimal depends on consumers actually responding to significantly higher retail prices in a small number of hours. This highlights two issues. First, new technologies to help consumers quickly reduce demand are especially valuable. Beginning to pass through optimal prices could hasten the development and installation of such technologies. Second, if one needed to determine precisely how inferior summer peak pass-through is, it would be necessary to better measure elasticities to high and volatile prices.

This would likely happen through a combination of randomized control trials plus an assessment of how future technologies might change the econometrically estimated elasticities over time.

6.3 Effects of Varying the Share of Consumers on RTP

In the Energy Only market with $\alpha = 0.2$, the simulated prices in the three peak hours of the five year period are approximately \$62,000, \$42,000, and \$10,000 per megawatt-hour. Because these prices are far out of the sample of any empirical estimates of demand elasticities, it is not clear whether the assumed elasticity is correct. Furthermore, infrequent large price spikes may be politically undesirable (Hogan 2005), and these prices may be above non-RTP consumers' value of lost load, suggesting that controlled rationing might be optimal. It would be possible to modify simulations like these to curtail supply to non-RTP consumers above some price, perhaps \$20,000 per megawatt-hour. Within this model, however, it is useful to understand how maximum prices and welfare effects vary with the share of consumers on RTP.

The dot-dashed orange line on Figure 8 graphs the Energy Only market peak hour price as a function of α, the share of consumers on RTP. This is displayed against the left vertical axis in units of log base 10. With $\alpha = 0.05$, the maximum hourly price over the five year period is larger than 10^5: it is \$341,000 per megawatt-hour. At this price, running a standard air conditioner for one hour would cost a consumer \$341 in electricity. This is 341 times the current PJM bid cap and above even the highest estimates of the value of lost load (Cramton and Stoft 2006). Furthermore, because demand is so inelastic, shocks to demand or supply relative to the equilibrium could significantly affect the peak price, which could in turn dramatically increase or decrease entrants' profits. For example, if total entrant capacity is artificially increased by 50 megawatts relative to the equilibrium, which might be one-tenth the size of a new power plant, the peak hour price drops by half and entrant combined cycle profits drop by \$30,000 per megawatt, or about one fifth of the fixed costs. A market design that results in such a sensitive equilibrium seems undesirable.

As the share α of consumers on RTP increases and wholesale demand becomes more elastic, the peak hour price decreases and also becomes less sensitive to deviations from the equilibrium. Once α reaches about 0.3, the maximum price observed over the five year period is less than 4 on the log scale, i.e. less than \$10,000 per megawatt-hour. With $\alpha = 0.5$, the maximum price is just over \$1500. Having more consumers on RTP is therefore a complement to the Energy Only design in the specific sense of reducing the level and sensitivity of peak prices. Holding η constant, larger demand elasticity η would also reduce these peak prices, highlighting the importance of information technologies that enable peak demand reductions.

Figure 8 also re-simulates other results from Tables 2 and 3 under the wider set of α parameters. The dashed black and solid red lines in Figure 8, respectively, show the change in total entry and welfare when the market design is changed from ICAP to Energy Only given each particular α. The change in entry is graphed against the left vertical axis, while the change in welfare is graphed against the right vertical axis. Both take an inverted-U shape.

To see why this is the case, notice that there are two mechanisms through which a change in α influences the efficiency gains from the Energy Only design. The first is that when α is larger, more consumers face the time-varying scarcity rents that are passed through under the Energy Only design, and the reduction in entry and the welfare gains are both larger. Second, however, when α is larger, peak prices in the Energy Only design are lower, which moderates the reduction in entry and the welfare gains from moving to the Energy Only design. The inverted U shape reflects the fact that as α increases, the second effect eventually outweighs the first. Under the other assumptions of the model, the peak of the inverted U is at approximately $\alpha = 0.2$. The policy implication is that it is especially important to properly pass through the shadow cost of the reserve margin at the moderate levels of α comparable to the RTP shares that industry analysts expect to see over the next decade. Once a large share of consumers are on RTP, however, the variance in the scarcity rents becomes low enough that simply passing through real-time Energy Market prices captures the majority of the welfare gains.

The solid blue line, which is plotted against the right vertical axis, represents the welfare gains from moving from $\alpha = 0$ to the given α under the ICAP design. The gains are close to linear in α. For example, moving from $\alpha = 0$ to $\alpha = 0.05$ and $\alpha = 0.10$ under the ICAP design generate \$63 million and \$122 million in welfare gains, respectively. By contrast, Borenstein's (2005) results, which does not include a Capacity Market, had suggested that these welfare gains would be concave in α, i.e. that much of the welfare gains are achieved by moving an initial group of customers to RTP. In Borenstein's model, an important effect of RTP is to reduce the variance in Energy Market prices, and much of this variance reduction can be achieved with a relatively small α. In an actual ICAP market, however, RTP does not have much effect on the variance of Energy Market prices, as these prices are restrained by the reserve margin. Instead, much of the welfare gain flows through the reduction in capacity prices, which move close to linearly in entry, which itself drops close to linearly in the share α of consumers on RTP.

This underscores the importance of understanding the effects of RTP in a model that reflects market designs currently in use. These results could have different implications for policymakers and regulators, who must decide whether it is beneficial to move additional consumers to RTP after some initial group is on that pricing structure. Of course, the actual effects of an increase in RTP are likely in between the effects in my stylized ICAP and Energy Only models, given that the pass-through of scarcity rents is in practice somewhere between constant pass-through and the optimum.

7 Additional Considerations

The model rests on a series of assumptions that maintain simplicity and guarantee uniqueness. This section highlights several of the most important issues not discussed elsewhere in the paper.

The model abstracts away from some basic features of electricity supply and demand. On the supply side, I assume away transmission constraints, ramping constraints, start-up costs, and lumpiness in investment. On the demand side, I assume away substitution across hours: cross-hour price elasticities are assumed to be zero. Borenstein (2005) discusses each of these issues and argues that they cause models to understate the gains from real-time pricing.

For simplicity, the model does not include any notion of short-term or long-term elasticities. In reality, consumers can respond more when price fluctuations are predictable instead of sudden. For example, consumers can invest in energy efficient air conditioners or get in the habit of turning off existing equipment when they know that they will face predictably higher summer afternoon prices. By contrast, many consumers may not be aware if prices spike when demand shifts out slightly against inelastic supply on an unusually hot summer afternoon. This distinction between short-term and long-term elasticities is therefore crucial to the evaluation of the Energy Only market design, where most of the allocative gains flow through consumers' responses to large variation in peak prices that may be difficult to predict. On the other hand, the allocative gains from moving consumers from the flat rate tariff to RTP under the ICAP market design depend more on elasticity to predictable variation at lower price levels. Abstracting away from this distinction may cause the model to overstate welfare gains from the Energy Only design.

The model assumes that entrants do not exit. In practice, this is not unrealistic. An analysis of the 2008 PJM Capacity Market shows that nearly all of incumbents' bids were below entrants' projected equilibrium bids (Pfeifenberger *et al.* 2008). Furthermore, between 1997 and 2007, for every megawatt of new capacity constructed in the U.S., 0.11 megawatts were retired (US Energy Information Administration 2008). Over the next few years, however, it is forecasted that a large number of coal plants will exit due to the cost of compliance with environmental regulations. As long as this exit is exogenous to RTP and the Energy Only market, the model could accommodate this. It is not clear how to endogenize exit of discrete plants while guaranteeing a unique equilibrium, so the model is best suited to analyzing counterfactuals that do not differentially cause exit. As we have seen in the alternative simulations in Appendix Tables A7 and A8, entirely removing incumbents from the model strengthens the qualitative results.

8 Conclusion

Two of the most important current regulatory policy issues in the electric power industry are how much to encourage retail real-time pricing and whether or not to de-emphasize Capacity Markets as mechanisms for ensuring reliability. The discussion of real-time pricing has been hindered by the fact that the models of RTP do not actually reflect the ICAP market designs currently in place. The discussion of the ICAP design has been hindered by the fact that there have been few quantitative estimates of any aspect of the tradeoffs between ICAP and the alternative Energy Only design. In this paper, I present a two-stage entry model of an electricity market with a reserve margin requirement and calibrate it to supply and demand conditions in PJM. This presents a useful framework for understanding how Capacity Market equilibria are determined and a way to predict the capacity prices that might arise in an actual market.

I have emphasized three basic takeaways for regulatory policy. First, in PJM under the ICAP market design, the gains from real-time pricing are large in absolute terms: simulations suggest that moving from 10 to 20 percent of the market on real-time pricing would increase welfare by $120 million per year. However, these predicted gains are lower than the gains from RTP under optimal pass-through of capacity costs, and the channels of the gains are different than under an Energy Only market design. This highlights the importance of using models that capture the ICAP market design.

Second, at moderate levels of RTP like those expected over the next 10-20 years, simply passing through real-time Energy Market prices misses the majority of the welfare gains: simulations suggest that with moderate shares of consumers on RTP, it is twice as important to pass through the high peak scarcity rents, which bring down peak demand and thus required entry. This could be done either by moving to an Energy Only market design or by improving the way that retailers pass through Capacity Market costs to consumers. One benefit of the former approach is that the Energy Only design gives immediate, clear, and location-specific signals of scarcity to both consumers and producers, while the ICAP market design requires various schemes to re-create those incentives (Joskow 2006).

Third, RTP and the Energy Only design are complements in the specific sense that more consumers on RTP moderates the volatility in peak Energy Market prices. Simulations suggest that maximum prices drop below $10,000 per megawatt-hour once about 30 percent of the market is on real-time pricing with a price elasticity of -0.05.

Of course, the model has relied on out-of-sample assumptions about demand elasticities, and one might suggest a variety of different assumptions about how capacity costs are passed through to consumers and how well consumers predict the peak hours when retailers might assign capacity charges. The objective of this paper is simply to point out quantitatively that the pass-through of scarcity rents can be very important. This means that given the rise of the ICAP market design in the past ten years, measuring how consumers respond to different pass-through mechanisms and designing them optimally is a critical area of future research.

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Tables

Table 1: Entrant Technologies

Technology Type	Peaker	Combined Cycle	Baseload
Fixed Costs			
Annualized Capital Cost ($/MW-year)	110,589	153,682	474,692
Reactive Services Revenue ($/MW-year)	2,384	3,198	1,783
F_e: Total Fixed Cost ($/MW-year)	108,205	150,484	472,909
Marginal Costs			
Heat Rate (Btu/kWh)	10,241	6,914	9,240
Variable Operation & Maintenance ($/MWh)	7.59	1.25	3.22
c_e: Total Marginal Cost ($/MWh)	53.20	32.75	36.79

Source: Monitoring Analytics (2012).

Table 2: Simulation Results

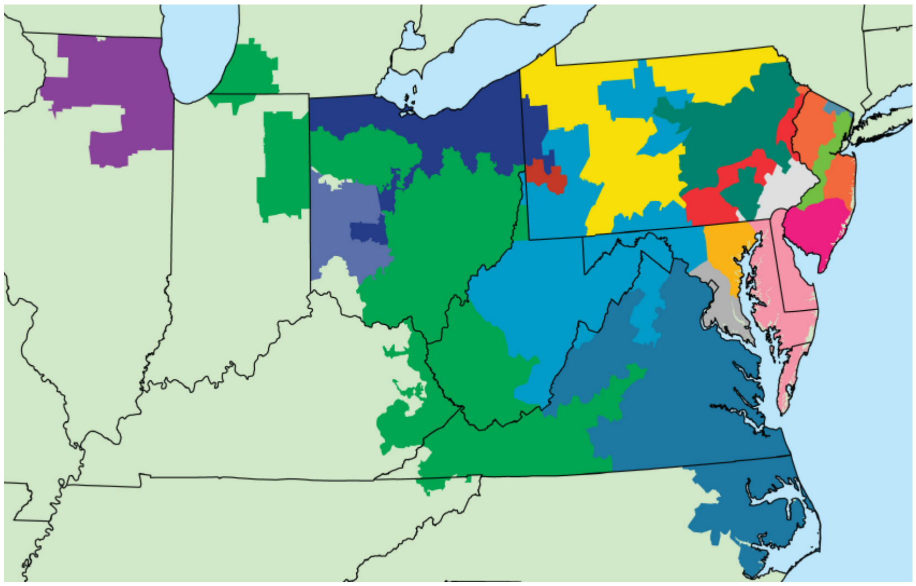
Scenario	2	3	4	5
Market Design	ICAP (Constant P_c)	ICAP (Constant P_c)	Energy Only	Energy Only
Share of Consumers on RTP (α)	0.1	0.2	0.1	0.2
Equilibrium Quantities				
Mean (gigawatts)	101.4	101.4	101.6	101.8
Maximum (gigawatts)	179.6	178.4	174.9	170.6
Equilibrium Prices				
Mean Energy Price P_t (\$/megawatt-hour)	38.8	39.4	49.0	48.8
Maximum Energy Price P_t (\$/megawatt-hour)	230.7	239.8	220,490	61,977
Flat Rate Tariff $\overline{P}$ (\$/megawatt-hour)	42.5	43.3	59.5	57.6
Capacity Adder P_c (\$/megawatt-hour)	17.9	16.8		
Non-RTP Retail Price $\overline{P} + P_c$ (\$/megawatt-hour)	60.4	60.0	59.5	57.6
Capacity Price r (\$/kilowatt-year)	86.2	81.3		
Entry				
Peaker (gigawatts)	0	0	0	0
Combined Cycle (gigawatts)	30.4	29.1	25.4	20.9
Baseload (gigawatts)	0	0	0	0
Total (gigawatts)	30.4	29.1	25.4	20.9
Annual Wholesale Electricity Costs				
Energy Market Costs (\$billions)	37.7	38.4	52.6	51.0
Capacity Payments (\$billions)	15.9	14.9		
Total Electricity Costs (\$billions)	53.7	53.3	52.6	51.0
Total Electricity Costs (\$/capita)	925	919	906	879
Scarcity Rents (\$billions)	0	0	11.3	4.8
Annual Profits				
Incumbents' Profits (\$billions)	28.8	28.5	28.0	26.5

Table 3: Welfare Results

Scenario	3	5	3	5
Market Design	ICAP (Constant P_c)	Energy Only	ICAP (Constant P_c)	Energy Only
Share of Consumers on RTP (α)	0.2	0.2	0.2	0.2
Counterfactual Scenario	2	4	1	3
Market Design	ICAP (Constant P_c)	Energy Only	ICAP (Constant P_c)	ICAP (Constant P_c)
Share of Consumers on RTP (α)	0.1	0.1	0	0.2
Annual Consumer Surplus Change				
Average Consumer ($/capita)	6.0	29.1	11.6	42.8
Always-RTP Consumers ($/capita)	6.1	-7.5		61.5
Movers to RTP ($/capita)	7.2	55.0	12.7	
Never-RTP Consumers ($/capita)	5.9	30.4	11.4	38.1
Total Annual Welfare Effects				
Total Consumer Surplus Change ($millions)	349	1685	676	2483
Incumbent Profit Change ($millions)	-229	-1435	-433	-2010
Net Welfare Gain ($millions)	120	250	242	473
Net Welfare Gain ($/capita)	2.1	4.3	4.2	8.1
Net Welfare Gain/Baseline Electricity Costs	0.0023	0.0049	0.0045	0.0093

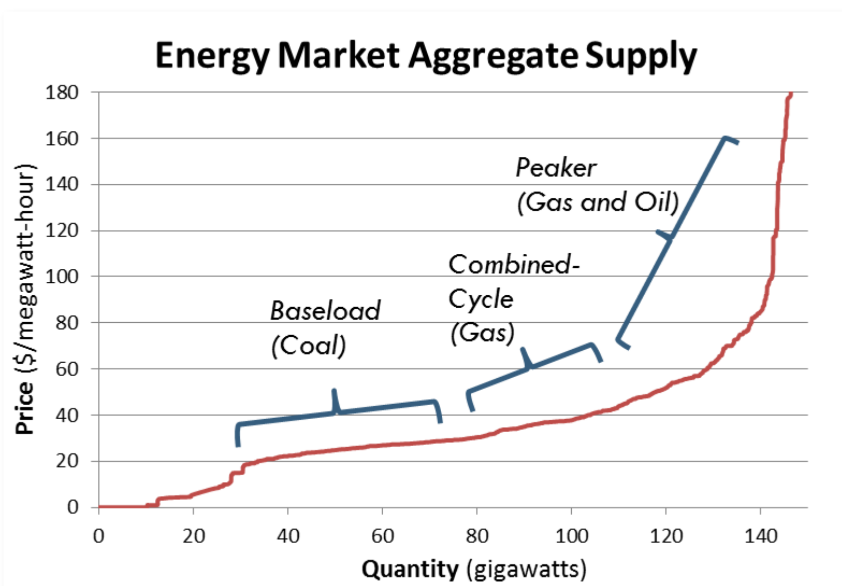
Figures

Figure 1: PJM Geographic Footprint



Source: Monitoring Analytics (2012).

Figure 2: Energy Market Supply Curve



Notes: This is the PJM aggregate supply curve for August 3rd, 2011.

Figure 3: Energy Only and ICAP Market Designs

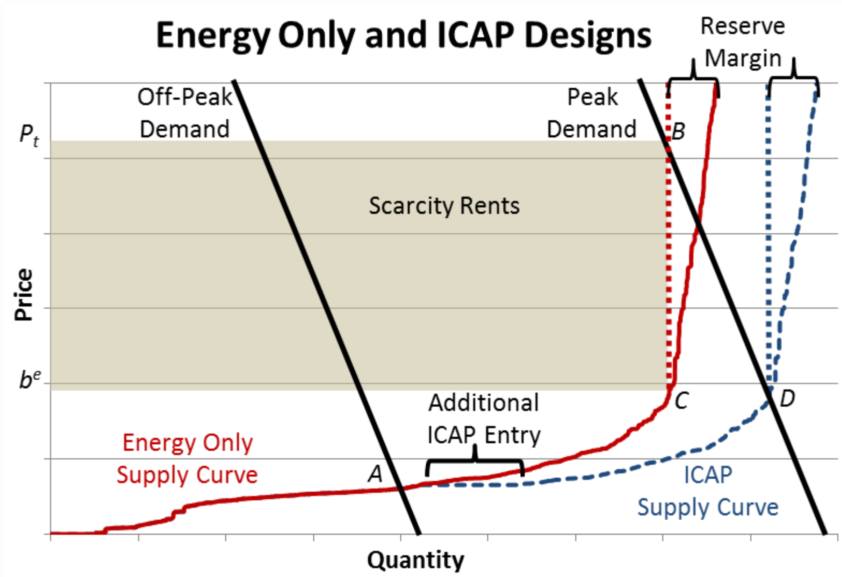
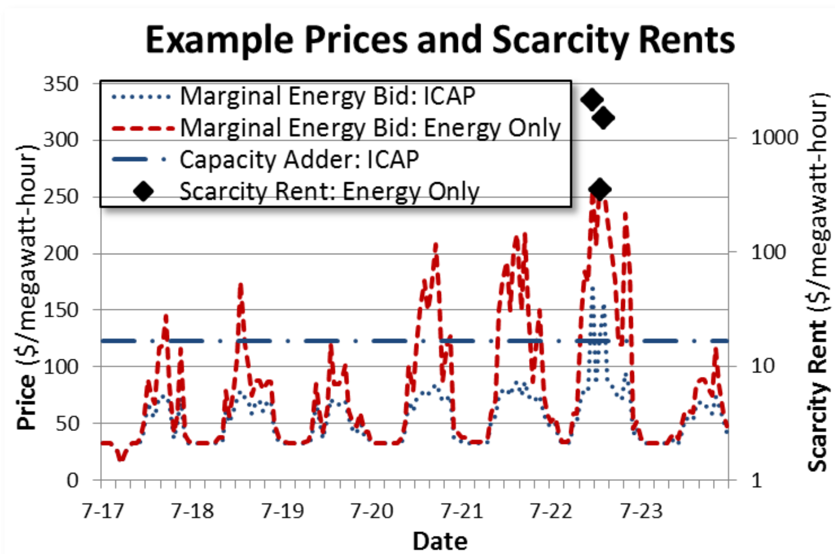
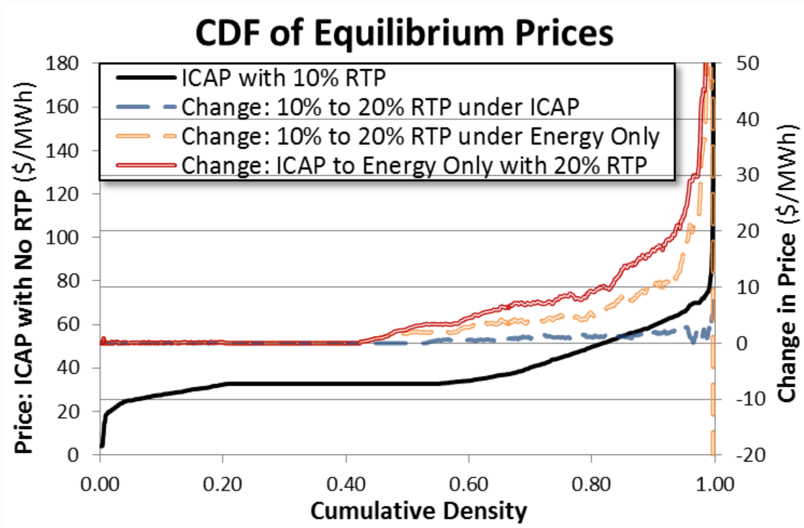


Figure 4: Prices and Scarcity Rents for an Example Week



Notes: This shows the simulated equilibrium Energy Market-clearing bids and scarcity rents for the Energy Only and ICAP market designs with $\alpha = 0.2$ for the supply and demand functions corresponding to an example week in July.

Figure 5: Distribution of Equilibrium Prices



Notes: This shows the CDF of equilibrium wholesale prices P_t for the ICAP market with 10% RTP, the change at each point in the CDF from moving from 10% to 20% RTP under each of the ICAP and Energy Only designs, and the change from moving to the Energy Only market design with 20% RTP.

Figure 6: Peak Prices in the Installed Capacity Market Design

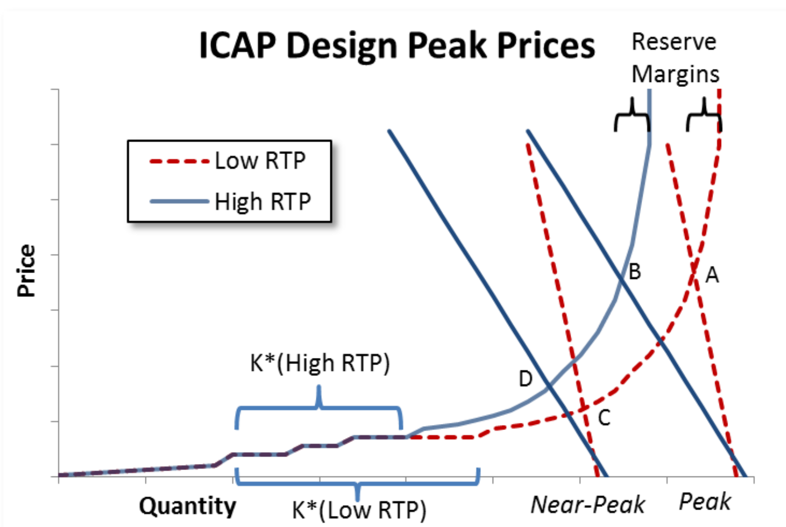
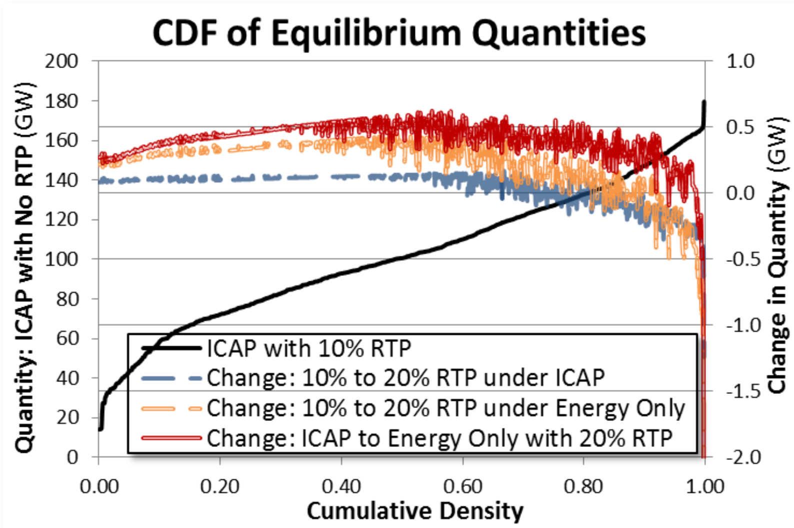
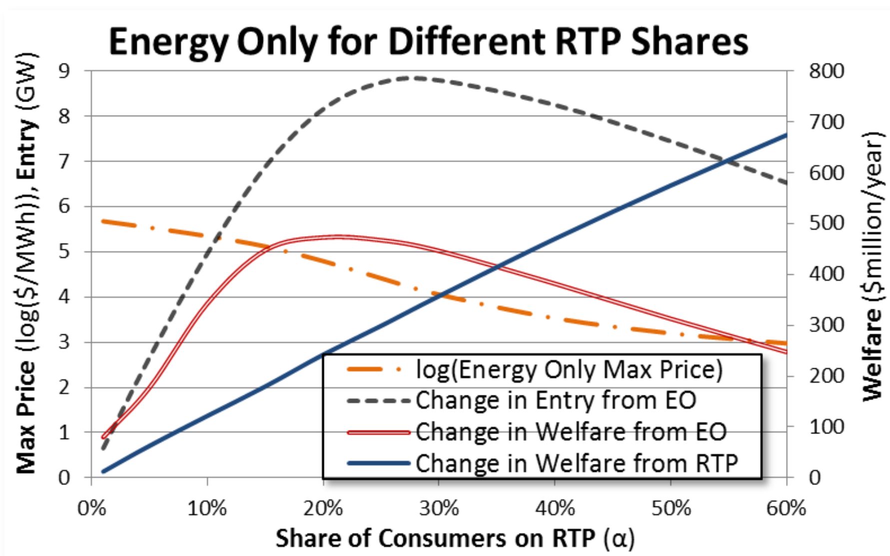


Figure 7: Distribution of Equilibrium Quantities



Notes: This shows the CDF of equilibrium quantities for the ICAP market with 10% RTP, the change at each point in the CDF from moving from 10% to 20% RTP under each of the ICAP and Energy Only designs, and the change from moving to the Energy Only market design with 20% RTP.

Figure 8: Effects of Energy Only Market Design for Different RTP Shares



Notes: This figure shows the maximum price in the Energy Only Market, the change in entry and welfare from moving from ICAP to Energy Only at a given α, and the change in welfare from moving from $\alpha = 0$ to the given α under the ICAP design.

Online Appendix: Not For Publication

Real-Time Pricing and Electricity Market Design
Hunt Allcott

Appendix Table A1: Simulation Results With Lower Elasticity

Scenario	7	8	9	10
Market Design	ICAP (Constant P_c)	ICAP (Constant P_c)	Energy Only	Energy Only
Share of Consumers on RTP (α)	0.1	0.2	0.1	0.2
Equilibrium Quantities				
Mean (gigawatts)	101.6	101.6	101.7	101.8
Maximum (gigawatts)	180.6	180.0	177.7	174.7
Equilibrium Prices				
Mean Energy Price P_t (\$/megawatt-hour)	38.5	38.8	49.1	49.0
Maximum Energy Price P_t (\$/megawatt-hour)	229.4	230.0	319,720	196,890
Flat Rate Tariff $\overline{P}$ (\$/megawatt-hour)	42.1	42.5	60.4	59.4
Capacity Adder P_c (\$/megawatt-hour)	18.5	18.0		
Non-RTP Retail Price $\overline{P} + P_c$ (\$/megawatt-hour)	60.6	60.5	60.4	59.4
Capacity Price r (\$/kilowatt-year)	88.7	86.5		
Entry				
Peaker (gigawatts)	0	0	0	0
Combined Cycle (gigawatts)	31.4	30.8	28.4	25.2
Baseload (gigawatts)	0	0	0	0
Total (gigawatts)	31.4	30.8	28.4	25.2
Annual Wholesale Electricity Costs				
Energy Market Costs (\$billions)	37.5	37.8	53.5	52.5
Capacity Payments (\$billions)	16.5	16.0		
Total Electricity Costs (\$billions)	53.9	53.8	53.5	52.5
Total Electricity Costs (\$/capita)	930	927	923	905
Scarcity Rents (\$billions)	0	0	14.2	10.7
Annual Profits				
Incumbents' Profits (\$billions)	28.9	28.8	28.7	27.9

Notes: This re-creates Table 2 except with $\eta = -0.025$ instead of $\eta = -0.05$.

Appendix Table A2: Welfare Results With Lower Elasticity

Scenario	8	10	8	10
Market Design	ICAP (Constant P_c)	Energy Only	ICAP (Constant P_c)	Energy Only
Share of Consumers on RTP (α)	0.2	0.2	0.2	0.2
Counterfactual Scenario	7	9	6	8
Market Design	ICAP (Constant P_c)	Energy Only	ICAP (Constant P_c)	ICAP (Constant P_c)
Share of Consumers on RTP (α)	0.1	0.1	0	0.2
Annual Consumer Surplus Change				
Average Consumer ($/capita)	2.9	18.2	5.8	22.9
Always-RTP Consumers ($/capita)	2.9	4.3		47.9
Movers to RTP ($/capita)	3.4	48.0	6.2	
Never-RTP Consumers ($/capita)	2.8	16.2	5.6	16.6
Total Annual Welfare Effects				
Total Consumer Surplus Change ($millions)	168	1056	334	1327
Incumbent Profit Change ($millions)	-106	-829	-210	-947
Net Welfare Gain ($millions)	62	227	125	380
Net Welfare Gain ($/capita)	1.1	3.9	2.1	6.5
Net Welfare Gain/Baseline Electricity Costs	0.0012	0.0043	0.0023	0.0072

Notes: This re-creates Table 3 except with $\eta = -0.025$ instead of $\eta = -0.05$.

Appendix Table A3: Simulation Results With Higher Elasticity

Scenario	12	13	14	15
Market Design	ICAP (Constant P_c)	ICAP (Constant P_c)	Energy Only	Energy Only
Share of Consumers on RTP (α)	0.1	0.2	0.1	0.2
Equilibrium Quantities				
Mean (gigawatts)	101.1	101.2	101.6	102.0
Maximum (gigawatts)	177.8	175.6	171.3	168.1
Equilibrium Prices				
Mean Energy Price P_t (\$/megawatt-hour)	39.4	40.6	48.9	48.7
Maximum Energy Price P_t (\$/megawatt-hour)	239.8	242.2	108,860	5,379
Flat Rate Tariff $\overline{P}$ (\$/megawatt-hour)	43.3	44.9	58.1	56.3
Capacity Adder P_c (\$/megawatt-hour)	16.7	14.4		
Non-RTP Retail Price $\overline{P}+P_c$ (\$/megawatt-hour)	60.0	59.3	58.1	56.3
Capacity Price r (\$/kilowatt-year)	80.9	70.9		
Entry				
Peaker (gigawatts)	0	0	0	0
Combined Cycle (gigawatts)	28.5	26.1	21.6	18.3
Baseload (gigawatts)	0	0	0	0
Total (gigawatts)	28.5	26.1	21.6	18.3
Annual Wholesale Electricity Costs				
Energy Market Costs (\$billions)	38.3	39.7	51.3	50.0
Capacity Payments (\$billions)	14.8	12.8		
Total Electricity Costs (\$billions)	53.1	52.5	51.3	50.0
Total Electricity Costs (\$/capita)	915	905	884	862
Scarcity Rents (\$billions)	0	0	6.6	0.7
Annual Profits				
Incumbents' Profits (\$billions)	28.5	28.1	26.9	25.7

Notes: This re-creates Table 2 except with $\eta = -0.1$ instead of $\eta = -0.05$.

Appendix Table A4: Welfare Results With Higher Elasticity

Scenario	13	15	13	15
Market Design	ICAP (Constant P_c)	Energy Only	ICAP (Constant P_c)	Energy Only
Share of Consumers on RTP (α)	0.2	0.2	0.2	0.2
Counterfactual Scenario	12	14	11	13
Market Design	ICAP (Constant P_c)	Energy Only	ICAP (Constant P_c)	ICAP (Constant P_c)
Share of Consumers on RTP (α)	0.1	0.1	0	0.2
Annual Consumer Surplus Change				
Average Consumer ($/capita)	11.6	23.5	22.8	47.2
Always-RTP Consumers ($/capita)	11.9	-20.7		56.1
Movers to RTP ($/capita)	14.5	41.3	25.5	
Never-RTP Consumers ($/capita)	11.2	26.8	22.2	45.0
Total Annual Welfare Effects				
Total Consumer Surplus Change ($millions)	673	1363	1324	2737
Incumbent Profit Change ($millions)	-457	-1206	-871	-2352
Net Welfare Gain ($millions)	216	157	452	386
Net Welfare Gain ($/capita)	3.7	2.7	7.8	6.6
Net Welfare Gain/Baseline Electricity Costs	0.0041	0.0031	0.0086	0.0077

Notes: This re-creates Table 3 except with $\eta = -0.1$ instead of $\eta = -0.05$.

Appendix Table A5: Simulation Results With Higher Reserve Margin

Scenario	17	18	19	20
Market Design	ICAP (Constant P_c)	ICAP (Constant P_c)	Energy Only	Energy Only
Share of Consumers on RTP (α)	0.1	0.2	0.1	0.2
Equilibrium Quantities				
Mean (gigawatts)	101.2	101.2	101.4	101.7
Maximum (gigawatts)	180.1	179.6	174.2	169.6
Equilibrium Prices				
Mean Energy Price P_t (\$/megawatt-hour)	36.5	36.6	49.8	49.5
Maximum Energy Price P_t (\$/megawatt-hour)	144.0	142.5	367,620	186,500
Flat Rate Tariff $\overline{P}$ (\$/megawatt-hour)	39.3	39.3	62.6	60.7
Capacity Adder P_c (\$/megawatt-hour)	23.2	23.1		
Non-RTP Retail Price $\overline{P} + P_c$ (\$/megawatt-hour)	62.5	62.5	62.6	60.7
Capacity Price r (\$/kilowatt-year)	106.2	106.0		
Entry				
Peaker (gigawatts)	5	5	0	0
Combined Cycle (gigawatts)	34.6	34.5	33.4	27.5
Baseload (gigawatts)	0	0	0	0
Total (gigawatts)	39.8	39.3	33.4	27.5
Annual Wholesale Electricity Costs				
Energy Market Costs (\$billions)	34.8	34.9	54.9	53.1
Capacity Payments (\$billions)	20.6	20.5		
Total Electricity Costs (\$billions)	55.4	55.4	54.9	53.1
Total Electricity Costs (\$/capita)	956	955	946	916
Scarcity Rents (\$billions)	0	0	18.6	13.6
Annual Profits				
Incumbents' Profits (\$billions)	29.7	29.7	29.7	28.4

Notes: This re-creates Table 2 except with a 10 percent instead of a 5 percent reserve margin.

Appendix Table A6: Welfare Results With Higher Reserve Margin

Scenario	18	20	18	20
Market Design	ICAP (Constant P_c)	Energy Only	ICAP (Constant P_c)	Energy Only
Share of Consumers on RTP (α)	0.2	0.2	0.2	0.2
Counterfactual Scenario	17	19	16	18
Market Design	ICAP (Constant P_c)	Energy Only	ICAP (Constant P_c)	ICAP (Constant P_c)
Share of Consumers on RTP (α)	0.1	0.1	0	0.2
Annual Consumer Surplus Change				
Average Consumer ($/capita)	1.1	31.4	2.3	40.7
Always-RTP Consumers ($/capita)	1.0	-8.7		96.1
Movers to RTP ($/capita)	1.6	97.9	2.7	
Never-RTP Consumers ($/capita)	1.1	28.1	2.2	26.8
Total Annual Welfare Effects				
Total Consumer Surplus Change ($millions)	67	1821	134	2360
Incumbent Profit Change ($millions)	-7	-1303	-13	-1279
Net Welfare Gain ($millions)	59	518	121	1081
Net Welfare Gain ($/capita)	1.0	8.9	2.1	18.6
Net Welfare Gain/Baseline Electricity Costs	0.0011	0.0098	0.0022	0.0203

Notes: This re-creates Table 3 except with a 10 percent instead of a 5 percent reserve margin.

Appendix Table A7: Simulation Results With No Incumbent Suppliers

Scenario	22	23	24	25
Market Design	ICAP (Constant P_c)	ICAP (Constant P_c)	Energy Only	Energy Only
Share of Consumers on RTP (α)	0.1	0.2	0.1	0.2
Equilibrium Quantities				
Mean (gigawatts)	101.2	101.2	101.4	101.7
Maximum (gigawatts)	180.4	180.2	174.1	168.1
Equilibrium Prices				
Mean Energy Price P_t (\$/megawatt-hour)	37.6	37.6	50.5	50.5
Maximum Energy Price P_t (\$/megawatt-hour)	53.2	53.2	391,860	294,720
Flat Rate Tariff $\overline{P}$ (\$/megawatt-hour)	39.7	39.7	62.8	62.7
Capacity Adder P_c (\$/megawatt-hour)	23.1	23.1		
Non-RTP Retail Price $\overline{P} + P_c$ (\$/megawatt-hour)	62.8	62.8	62.8	62.7
Capacity Price r (\$/kilowatt-year)	108.2	108.2		
Entry				
Peaker (gigawatts)	61	61	54	48
Combined Cycle (gigawatts)	128.3	128.3	128.7	128.8
Baseload (gigawatts)	0	0	0	0
Total (gigawatts)	189.4	189.2	182.8	176.5
Annual Wholesale Electricity Costs				
Energy Market Costs (\$billions)	35.2	35.1	55.0	54.4
Capacity Payments (\$billions)	20.5	20.5		
Total Electricity Costs (\$billions)	55.6	55.6	55.0	54.4
Total Electricity Costs (\$/capita)	959	959	949	938
Scarcity Rents (\$billions)	0	0	19.8	19.1
Annual Profits				
Incumbents' Profits (\$billions)				

Notes: This re-creates Table 2 except with no incumbent suppliers.

Appendix Table A8: Welfare Results With No Incumbent Suppliers

Scenario	23	25	23	25
Market Design	ICAP (Constant P_c)	Energy Only	ICAP (Constant P_c)	Energy Only
Share of Consumers on RTP (α)	0.2	0.2	0.2	0.2
Counterfactual Scenario	22	24	21	23
Market Design	ICAP (Constant P_c)	Energy Only	ICAP (Constant P_c)	ICAP (Constant P_c)
Share of Consumers on RTP (α)	0.1	0.1	0	0.2
Annual Consumer Surplus Change				
Average Consumer ($/capita)	0.5	11.2	1.0	21.8
Always-RTP Consumers ($/capita)	0.4	-5.7		107.0
Movers to RTP ($/capita)	1.0	108.2	1.4	
Never-RTP Consumers ($/capita)	0.4	1.2	0.9	0.6
Total Annual Welfare Effects				
Total Consumer Surplus Change ($millions)	28	651	59	1267
Incumbent Profit Change ($millions)				
Net Welfare Gain ($millions)	28	641	56	1268
Net Welfare Gain ($/capita)	0.5	11.1	1.0	21.9
Net Welfare Gain/Baseline Electricity Costs	0.0005	0.0118	0.0010	0.0233

Notes: This re-creates Table 3 except with no incumbent suppliers.

Appendix Table A9: Simulation Results With Summer Peak Pass-Through

Scenario	27	28	29	30
Market Design	ICAP (Constant P_c)	ICAP (Constant P_c)	Energy Only	Energy Only
Share of Consumers on RTP (α)	0.1	0.2	0.1	0.2
Equilibrium Quantities				
Mean (gigawatts)	101.5	101.7	101.6	101.8
Maximum (gigawatts)	179.2	177.6	174.9	170.6
Equilibrium Prices				
Mean Energy Price P_t (\$/megawatt-hour)	39.1	39.8	49.0	48.8
Maximum Energy Price P_t (\$/megawatt-hour)	235.0	240.0	220,490	61,977
Flat Rate Tariff $\overline{P}$ (\$/megawatt-hour)	42.8	43.8	59.5	57.6
Capacity Adder P_c (\$/megawatt-hour)	17.4	15.9		
Non-RTP Retail Price $\overline{P}+P_c$ (\$/megawatt-hour)	60.3	59.7	59.5	57.6
Capacity Price r (\$/kilowatt-year)	84.2	77.6		
Entry				
Peaker (gigawatts)	0	0	0	0
Combined Cycle (gigawatts)	29.9	28.3	25.4	20.9
Baseload (gigawatts)	0	0	0	0
Total (gigawatts)	29.9	28.3	25.4	20.9
Annual Wholesale Electricity Costs				
Energy Market Costs (\$billions)	38.1	39.0	52.6	51.0
Capacity Payments (\$billions)	15.5	14.2		
Total Electricity Costs (\$billions)	53.6	53.1	52.6	51.0
Total Electricity Costs (\$/capita)	923	916	906	879
Scarcity Rents (\$billions)	0	0	11.3	4.8
Annual Profits				
Incumbents' Profits (\$billions)	28.7	28.4	28.0	26.5

Notes: This re-creates Table 2 except with capacity costs for RTP consumers recovered as constant adders to prices between noon and 6PM in June, July, and August. This adder is \$198.63 per megawatt-hour in scenario 2 and \$180.52 in scenario 3. Capacity costs for flat rate consumers are still recovered as constant adders to retail price in all hours.

Appendix Table A10: Welfare Results With Summer Peak Pass-Through

Scenario	28	30	28	30
Market Design	ICAP (Constant P_c)	Energy Only	ICAP (Constant P_c)	Energy Only
Share of Consumers on RTP (α)	0.2	0.2	0.2	0.2
Counterfactual Scenario	27	29	26	28
Market Design	ICAP (Constant P_c)	Energy Only	ICAP (Constant P_c)	ICAP (Constant P_c)
Share of Consumers on RTP (α)	0.1	0.1	0	0.2
Annual Consumer Surplus Change				
Average Consumer ($/capita)	7.6	29.1	15.0	39.5
Always-RTP Consumers ($/capita)	9.4	-7.5		64.1
Movers to RTP ($/capita)	1.9	55.0	10.1	
Never-RTP Consumers ($/capita)	8.0	30.4	16.2	33.3
Total Annual Welfare Effects				
Total Consumer Surplus Change ($millions)	439	1685	869	2290
Incumbent Profit Change ($millions)	-311	-1435	-614	-1829
Net Welfare Gain ($millions)	127	250	254	460
Net Welfare Gain ($/capita)	2.2	4.3	4.4	7.9
Net Welfare Gain/Baseline Electricity Costs	0.0024	0.0049	0.0048	0.0090

Notes: This re-creates Table 3 except with capacity costs for RTP consumers recovered as constant adders to prices between noon and 6PM in June, July, and August. This adder is $198.63 per megawatt-hour in scenario 2 and $180.52 in scenario 3. Capacity costs for flat rate consumers are still recovered as constant adders to retail price in all hours.