Essays on Restructured Electricity Markets

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Emma Leah Nicholson, M.A.

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Emma Leah Nicholson, M.A.

Thesis Advisor: Ian Gale, Ph.D.

Abstract

This dissertation focuses on the performance of restructured electricity markets in the United States. In chapter 1, I study bidder-specific offer caps ("BSOCs") which are used to mitigate market power in three wholesale electricity markets. The price of electricity is determined through multi-unit uniform price auctions and BSOCs impose an upper limit, which is increasing in marginal cost, on each generator's bid. I apply BSOCs in both the uniform and discriminatory price auctions and characterize the equilibria in a two firm model with stochastic demand. BSOCs unambiguously increase expected production efficiency in the uniform price auction and they can increase the expected profit of the generator with the lower cap.

Chapter 2, coauthored with Ramteen Sioshansi, Ph.D., compares two types of uniform price auction formats used in wholesale electricity markets, centrally committed markets and self committed markets. In centrally committed markets, generators submit two-part bids consisting of a fixed startup cost and a variable (per MWh) energy cost, and the auctioneer ensures that no generator operates at a loss. Generators in self committed markets must incorporate their startup costs

into their one part energy bids. We derive Nash equilibria for both the centrally and self committed electricity markets in a model with two symmetric generators with nonconvex costs and deterministic demand. Using a numerical example, we demonstrate that if the caps on the bid elements are chosen appropriately, the two market designs are equivalent in terms of generator revenues and settlement costs.

Regulators and prominent academic experts believe that electric restructuring polices have stifled investment in new generation capacity. In chapter 3 I seek to determine whether these fears are supported by empirical evidence. I examine both total investment in megawatts and the number of new investments across regions that adopted different electric restructuring policies to determine whether electric restructuring is associated with lower levels of investment in new generation capacity. The estimation results do not prove that total investment levels are lower in regions with restructured electric systems, but I cannot rule the possibility out.

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Introduction

Electric restructuring policies in the United States drastically changed the electric systems of the states that pursued them. These policies were expected to increase the production efficiency of existing electric generation capacity and lower the costs of new investments in generation by introducing competition into the generation sector. Since their implementation in the late 1990s, two problems emerged in restructured electric systems: a lack of competition in wholesale electricity market auctions; and concerns of underinvestment in new generation capacity. I investigate competition in wholesale electricity markets in two theoretical chapters. In chapter 1, I analyze a rule used to mitigate generator market power in wholesale electricity auctions. Chapter 2 compares bidding behavior and expected profits in two auction formats; auctions with a one part energy bid; and auctions with two-part bids consisting of both a startup and energy bid. I study investment in new generation capacity in chapter 3 and compare investment in regions and states in the U.S. that restructured their electric systems with those that did not.

Chapter 1 models the effects of bidder-specific offer caps ("BSOCs") which are used to mitigate market power in three wholesale electricity markets in the U.S. Generator market power is virtually inevitable in wholesale electricity markets, which can lead to high electricity prices and the inefficient use of generation capacity. The price of electricity in these markets is determined through multi-unit uniform price auctions. BSOCs impose an upper limit, which is increasing in marginal cost, on the bid each generator can submit. If marginal cost varies across generators, generators bidding in the same auction can face different BSOCs. This chapter, the first to theoretically analyze BSOCs, finds a unique equilibrium in a two firm, multi-unit uniform price auction with BSOCs and stochastic demand. BSOCs are also applied to a discriminatory price auction and the results are compared to the uniform price auction. The model is used to investigate the effect that BSOCs have on equilibrium bidding strategies, expected production efficiency, and expected profit. BSOCs unambiguously increase expected efficiency in the uniform price auction and in some cases they increase the expected profit of the more efficient firm.

Chapter 2, coauthored with Ramteen Sioshansi, Ph.D., compares two types of uniform price auction formats used in wholesale electricity markets; centrally committed markets and self committed markets. Auctions in both markets are conducted by an independent system operator that collects generator bids and determines which generators will operate and how much electricity each will produce. In centrally committed markets, generators submit two-part bids consisting of a one time startup cost and a variable energy cost. Self committed systems force generators to incorporate their startup costs into a one part bid that consists of an energy cost. The system operator in a centrally committed system ensures that each generator recovers the startup and energy costs stated in its two-part bid, while system operators in self committed systems offer generators no such guarantee. The energy cost ranking and incentive properties of centralized and self unit commitment remains an open question. While with a centralized commitment the system operator can determine the most efficient dispatch, the auction mechanism used to solicit generator data may compel generators to overstate startup and variable operating costs. Self commitment might involve less efficient dispatch but have better incentive properties. We derive Nash equilibria for both the centrally and self committed electricity markets in a model where two symmetric generators with nonconvex costs compete to serve a deterministic electric demand. Using a numerical example, we demonstrate that if the price caps are chosen appropriately, the two market designs have equivalent total costs.

Chapter 3 contains an empirical study of generation investment in the U.S. Despite its intentions to lower investment costs and improve the performance of generation assets, many regulators and prominent academic experts believe that the policies associated with electric restructuring have stifled investment in new generation capacity. I seek to determine whether these fears are supported by empirical evidence. The states can be divided into three groups: states that unbundled vertically integrated regulated public utilities and joined wholesale electricity markets; states that joined wholesale electricity markets without unbundling; and states that pursued neither policy. I examine the total investment from large-scale investments in generation capacity across the three groups between 1992 and 2007. I analyze regional investment levels to account for trade within wholesale electricity markets. I also examine the number of investments in new generation capacity in each region. I investigate whether electric restructuring is associated with lower levels of investment in new generation capacity. Given concerns about the Northeast in particular, I investigate whether investment is lower in this region as compared to the rest of the U.S. The estimation results do not prove conclusively, as many have claimed, that total investment levels are lower in regions that restructured their electric systems. The coefficients of the variables associated with electric restructuring policies are insignificant in virtually all of the total investment specifications. Although they are insignificant, some of the magnitudes associated with the estimates are nontrivial. As such, I cannot rule out the possibility that total investment is lower in states and regions that pursued electric restructuring policies.

Chapter 1: Bidder-Specific Offer Caps in Wholesale Electricity Auctions

1 Introduction

Wholesale electricity markets were developed to foster competition in electric energy generation. The price of electricity in all organized wholesale electricity markets in the United States is based on the outcome of uniform price auctions.[1] In these power auctions, generators offer capacity to the system operator by submitting a bid equal to the minimum price they will accept to produce a particular amount of electricity. Electric transmission constraints often result in a small number of generators (e.g. power plants) competing to supply electric demand that is essentially captive and inelastic. To combat the effects of generator market power in such cases, the entities that operate wholesale electricity markets employ various methods to mitigate generator market power.

This chapter examines the effect of bidder-specific offer caps, which are used to mitigate generator market power in three of the largest wholesale electricity markets in the U.S.: PJM Interconnection ("PJM"), ISO New England ("ISO NE"), and the New York ISO ("NYISO").[2] Bidder-specific offer caps ("BSOCs") im-

[1] Uniform price auctions are held continuously throughout the day. Bilateral contracts also play a significant role on wholesale electricity transactions.

[2] PJM is technically considered a Regional Transmission Organization, but for the purposes of this chapter, RTOs are synonymous with ISOs. All three entities are regulated by the Federal

pose an upper limit on the level of each generator's bid, and that upper limit, or cap, is increasing in marginal cost. As such, if marginal costs differ across firms, generators bidding in the same auction can face different offer caps.

This chapter is the first to theoretically analyze BSOCs. I find a unique Nash Equilibrium to a uniform price auction ("UPA") where two firms with fixed capacity compete to satisfy stochastic demand. I then compare the expected profits and production efficiency under BSOCs to a UPA with a system-wide offer cap, which was solved by Fabra et al. (2006). I also find that relative to a system-wide cap, BSOCs unambiguously increase expected production efficiency in the UPA, which means that the imposition of BSOCs increases the probability that the more efficient firm bids below the less efficient firm. BSOCs can also increase the expected profit of the more efficient firm in some cases in the UPA. This counterintuitive result is consistent with empirical evidence in the PJM. I also apply BSOCs to the discriminatory price auction ("DPA") and make comparisons between DPAs with and without BSOCs. BSOCs increase expected production efficiency in most cases in the DPA, but rarely result in an increase in expected profit.

The outcomes of the UPAs in PJM, ISONE, and NYISO determine wholesale electricity prices that are rolled into the retail electricity rates of over 84.2 million retail electricity customers in the Northeastern U.S.[3] Furthermore, the wholesale

Energy Regulatory Commission and the various Public Utility Commissions of the states they operate in.

[3]PJM serves 51 million retail electricity customers in the mid-Atlantic, ISONE serves 14 million in New England, and NYISO serves 19.2 million in New York state.

electricity rates determined in these markets impact the price of long-term forward contracts and hence influence investment decisions for new generation capacity. These sums can amount to hundreds of millions of dollars, and as such, wholesale electricity markets have important consequences. The effects of BSOCs are also interesting because PJM officials claimed in the 2004 State of the Market Report that BSOCs can actually increase the profits of firms that have lower BSOCs than their rivals (PJM Interconnection, 2005).

Extensive research has been conducted on wholesale electricity markets in recent years, particularly in the aftermath of electric restructuring. The research most relevant to this chapter was conducted by Fabra, von der Fehr, and Harbord (2006) ("FFH" hereafter), which found a unique mixed-strategy equilibrium to a two firm UPA with stochastic demand and a system-wide offer cap. FFH also characterized equilibrium behavior and profits in the DPA. Prior to this work, von der Fehr and Harbord (1993) characterized mixed-strategy equilibrium to a multi-unit UPA with two bidders and stochastic demand. Crampes and Creti (2001) used mixed-strategies to solve a two firm UPA with a capacity commitment game in the first stage and found that adding a capacity commitment stage led to strategic withholding of capacity.

Supply Function Equilibrium ("SFE") models, developed by Klemperer and Meyer (1989), are often used to analyze generator bidding in wholesale electricity auctions. SFE models characterize bidding behavior when firms submit supply functions, which are common in practice, rather than a single price for their capacity. In their study of the British electricity system, Green and Newbery (1992) were the first to apply SFE to electricity markets. Many followed and applied SFE to other electricity markets, such as Sioshansi and Oren (2007) and Baldick et al. (2004). von der Fehr and Harbord (1993) found, however, that when capacity is bid in discrete units, SFE do not exist.

Neither the FFH nor SFE model is wholly adequate for modeling generator bidding in wholesale electricity markets. One shortcoming of the FFH model is that it only allows bidders to submit a single price for their capacity rather than a step-supply function, which is common in practice. Generalizing the FFH model to study BSOCs, however, provides useful insights about the effects of the rule. The next section contains a brief summary of market activity in PJM, ISONE, and NYISO.

Wholesale Electricity Markets

Wholesale electricity market participants include entities that own generation capacity, wholesale electricity customers (e.g. regulated public utilities and large industrial consumers) and power marketers. The PJM, ISONE, and NYISO auctions are operated by three different ISOs. Each ISO manages its respective electric transmission system to satisfy the demand of wholesale electricity customers given generation capacity and electric transmission constraints. Unfortunately, the transmission grid was built by vertically integrated monopolies and thus not designed to support a competitive wholesale power market. As a result, some regions are transmission constrained, making it possible for generators in that region to exercise market power. To combat the negative effects of generator market power, PJM, ISONE and NYISO have independent market monitoring units that oversee market participants and employ market power mitigation measures, such as BSOCs, in an effort to curb generator market power.[4]

UPAs are used to allocate the demand for electricity to generators based on generator supply functions and the constraints of the electric power grid.[5] The supply bids submitted by generators (e.g. electric power plants) are essentially step-supply functions, and each step indicates a generator's willingness to supply a specific amount of energy at a given time (e.g. 10 MW from 9:00 am-10:00 am) and a reserve price (e.g. $30/MW).[6] Supply bids contain other components, such as start-up costs, economic minimum and maximum operating levels, and costs associated with producing no electricity.

The demand and supply of electricity must be kept in balance at all times to avoid blackouts and other service disruptions. Demand varies unpredictably throughout the day, so the ISOs clear the real-time electricity market every five minutes. The demand of virtually all wholesale electricity customers, composed mostly of electric utilities and large industrials, is price inelastic in the short run.[7] Given the

[4]The market monitoring rules are explicitly outlined in the Open Access Transmission Tariffs of each market.

[5]Constraints include transmission constraints, voltage constraints, and reserve requirements.

[6]The reserve price is the minimum price the generator is willing to accept for its capacity. The unit of sale in wholesale electricity markets is a Megawatt hour ("MWh"), which means producing a flow of electricity equal to one megawatt for 1 hour.

[7]PJM, NYISO, and ISONE have demand response programs that allow customers to submit

demand for electricity and transmission constraints, the ISOs use the UPA bids and optimization software to determine the least costly way to satisfy demand, and dispatch generators accordingly.

Electric transmission constraints often divide the wholesale market (which is based on the electric transmission grid) into submarkets or zones. Market power is inherent to electricity markets that clear on UPAs because the zones created by the electric transmission constraints can have a small number of generators bidding to serve demand that is essentially captive.[8] Generator market power is exacerbated by the inelasticity of the majority of electricity demand.

The exercise of market power by a generator in a UPA has two effects: higher wholesale electricity prices and inefficient generator dispatch.[9] With inelastic demand, increased electricity prices are not a concern in terms of total surplus because they constitute a transfer from electricity consumers to electricity generators. Inefficient dispatch, wherein high cost generators produce electricity instead of lower cost generators, is a concern because it increases the cost of producing a given amount of electricity. BSOCs strive to reduce some of the inefficiencies that result from generator market power.

BSOCs are imposed directly in PJM, and indirectly in ISONE and NYISO.[10]

price sensitive demand bids but participation is low and constitutes a small fraction of total demand.

[8]The demand is captive because when transmission constraints bind, no electricity can be imported into the zone.

[9]I thank David Mead of the Federal Energy Regulatory Commission for this insight.

[10]PJM imposes BSOCs when contingencies force generators to dispatch out of merit order or

The key feature of BSOCs is the same in all three markets, however, because generators bidding in the same auction are capped at levels that are based on generator marginal cost, which can vary across generators. BSOCs are also used to encourage investment in new generation capacity. For example, the NYISO gives new entrants a higher BSOC, which are referred to as a reference level in the NYISO, in their first three years of operation.[11] The next section presents a model where two firms with BSOCs compete to serve stochastic demand in a UPA.

2 Uniform Price Auction

Binding constraints in the electric transmission grid create independent submarkets, often referred to as zones. PJM, ISONE, and NYISO use UPAs to allocate electricity demand between generators and determine the price of electricity within each zone. Generators ("bidders") participating in UPAs have the ability to set a high uniform price if their capacity is essential to serve demand (e.g. the generator has a large share of available zone capacity). In an effort to minimize the negative effects of generator market power, PJM, ISONE, and NYISO impose BSOCs under

fail the Three Pivotal Supplier Test. See PJM Manual 11, Scheduling Operations, Revision 24, Effective Date May 9, 2005. ISONE and NYISO use the Conduct and Impact Test, which caps bidders at a bidder-specific level (reference level) if certain conduct and impact thresholds are met. See: ISONE: FERC Electric Tariff No. 3, §III.A.5-III.A.5.; and NYISO: FERC Electric Tariff, Attachment H

[11] NYISO Tariff, Original Volume No. 2, Attachment H, §3.1.4 (c) (effective February 11, 2004)

specific operating conditions.[12] The BSOCs are increasing in generator marginal cost, hence generators with higher marginal costs have higher BSOCs.

BSOCs give firms interesting incentives in the UPA because they cap the *level* of a firm's bid but not the level of the firm's *payment.* BSOCs are *bid caps* and not *price caps* because when BSOCs are imposed, firms that are dispatched receive the *maximum* of their bid and the uniform price of electricity.[13] Therefore, a bidder with a BSOC that is lower than its rival's receives a price in excess of its BSOC if it is dispatched and the uniform price exceeds its BSOC. This model can be used to examine the impact that BSOCs have on equilibrium bidding strategies, efficiency, and equilibrium profits, and to provide a theoretical foundation for the PJM claim that a firm with a lower BSOC than its rivals can experience an increase in profit.

The BSOC model primitives below capture the essential features of a UPA in a zone with a small number of firms that face different BSOCs. Suppose, without loss of generality, that firm 1 has a lower marginal cost than firm 2, and hence a lower BSOC. Demand, represented by θ, is unknown when the firms submit their bids but its distribution is common knowledge. For low realizations of demand, a single firm can satisfy demand by itself, but for high realizations, both firms are needed to satisfy demand.[14] The model primitives are as follows:

[12] The specific conditions that trigger BSOCs are delineated in the Open Access Transmission Tariff of each market. Each tariff is approved by the Federal Energy Regulatory Commission.

[13] The firm with the highest BSOC in the auction cannot receive a payment in excess of its BSOC.

[14] The demand assumptions resemble "peak" and "off peak" demand periods, a feature of all wholesale electricity markets.

Model primitives

Firm 1 has capacity k_1 and constant marginal cost $c_1 > 0$

Firm 2 has capacity k_2 and constant marginal cost $c_2 > c_1$

Firm 1 has BSOC $P_1 > c_2$, hence $b_1 \leq P_1$

Firm 2 has BSOC $P_2 > P_1$, hence $b_2 \leq P_2$

Demand, represented by θ, is inelastic and continuously distributed on the compact support $[\underline{\theta}, \bar{\theta}]$ according to $G(\theta)$

$\underline{\theta} < \min\{k_1, k_2\} \leq \max\{k_1, k_2\} < \bar{\theta} \leq k_1 + k_2.$

The model primitives are common knowledge. The $P_1 > c_2$ assumption rules out the trivial pure-strategy equilibrium where each firm bids its BSOC: $(b_1 = P_1, b_2 = P_2)$. A UPA is used to allocate demand, θ, between the firms and determine the uniform price that the consumers pay. The firm with the lower of the two bids is dispatched first, and the firm with the higher bid is only dispatched if demand exceeds the capacity of the low bidder. The quantity sold by firm i in the UPA, based on $\mathbf{b} = (b_i, b_j)$ and θ, is:

$$q_i(\theta; \mathbf{b}) = \begin{cases} \min\{\theta, k_i\} & if\ b_i < b_j \\ \rho_i \min\{\theta, k_i\} + (1 - \rho_i)\max\{\theta - k_j, 0\} & if\ b_i = b_j \\ \max\{\theta - k_j, 0\} & if\ b_i > b_j \end{cases} \quad (1)$$

where ρ_i represents the tie-breaking rule. If $c_i > c_j$, $\rho_i = 0$ and $\rho_j = 1$; and if $c_i = c_j$, $\rho_i = \rho_j = \frac{1}{2}$.

The ISO accepts any positive bid less than or equal to P_1 and P_2 from firms 1 and 2, respectively. Suppose firms i and j submit bids $b = (b_i, b_j)$. If $b_i < b_j$, the uniform price equals b_i if $\theta \leq k_i$ and it equals b_j if $\theta > k_i$. Given firm 1's BSOC, P_1, firm 1's bid cannot exceed P_1 but firm 1 can receive a payment in excess of P_1 if both firms are dispatched ($\theta > k_1$) and $b_2 > P_1$. This feature has a significant impact on the BSOC equilibrium.

Table 1 gives three numerical examples of how the BSOCs work in the UPA. In example 1, firm 1 is the low bidder so it is dispatched first. Because demand (0.5) is less than the low bidder's capacity, firm 1 serves all of the demand and the uniform price is $b_1 = 2$. Firm 2 is the low bidder and gets dispatched first in example 2, but since both firms are needed to satisfy demand, firm 1 serves the excess demand left by firm 2 ($\theta - k_2$) and the uniform price is $b_1 = 5$. Example 3 best illustrates how the BSOCs work. If firm 2 bids above firm 1's BSOC and demand exceeds k_1, firm 1 receives 8 dollars for its output, despite the fact that its BSOC is 5, because both firms were dispatched. Hence, the firm with the lower BSOC in the UPA can receive a payment in excess of its BSOC. This chapter will show that outcomes similar to example 3 make it possible for BSOCs to increase the expected profit of firm 1 (the firm with the lower BSOC).

Timing of the Uniform Price Auction:

Table 1: Examples of BSOCs in the UPA

Parameters: $c_1 = 1$, $P_1 = 5$, $c_2 = 2$, $P_2 = 8$, and $k_1 = k_2 = 0.6$

	b_1	b_2	θ	uniform price	output of firm 1	output of firm 2
Ex. 1	2	3	0.5	2	0.5	0
Ex. 2	5	4	0.7	5	0.1	0.6
Ex. 3	3	8	0.8	8	0.6	0.2

1. Firms offer a minimum price for their entire capacity

2. θ is realized

3. The auctioneer uses a UPA to allocate θ between the firms and set the uniform price for electricity

When BSOCs are imposed, the equilibrium is unique and three types of equilibria are possible; a pure-strategy equilibrium, and two types of mixed-strategy equilibria: Case 1 and Case 2. In Case 1, firm 1 bids more aggressively than firm 2, while in Case 2, firm 2 is the more aggressive bidder.[15] This section will show that the BSOC equilibrium is in mixed-strategies if a specific condition holds. Lemmas 1 and 2 show that if a pure-strategy equilibrium exists, it has the strategy profile $(b_1 = P_1, b_2 = P_2)$. Lemma 3 presents the (MSE) condition, which determines whether the BSOC equilibrium is in pure or mixed-strategies.

Lemma 1. *The strategy profile $(b_1 \in [c_2, P_1), b_2 = P_2)$ does not constitute an equilibrium.*

[15] Firm i bids more aggressively than firm j if $F_i(b) > F_j(b)$ for $\underline{b} < b < \bar{b}$.

Proof. If $b_2 = P_2$, firm 1 will bid P_1 because firm 1's profits are strictly increasing in b_1 when $b_2 = P_2 > P_1$.

Lemma 2. *The strategy profile $(b_1 = \gamma, b_2 = \alpha)$, $\alpha, \gamma \in [c_2, P_1]$ is not possible in equilibrium*

Proof. If $\alpha = \gamma$, firm 2 only sells electricity if $\theta > k_1$. Firm 2 can strictly increase its expected profit by moving all mass to just below α, hence $\gamma = \alpha$ is not an equilibrium. If $\alpha \neq \gamma$, the firm with the lower bid would optimally bid just below the higher bid. Finally, consider the pure-strategy profile $(b_1 = c_2, b_2 = c_2)$. Given the tie-breaking rule, firm 1 is dispatched first so firm 2's best response is to bid P_2, where its expected profit is strictly positive (as opposed to zero if it bids c_2).[16]

Lemma 3. *If (MSE) holds, no pure-strategy equilibrium exists.*

Proof. Given Lemmas 1 and 2, the only possible pure-strategy equilibrium profile is $(b_1 = P_1, b_2 = P_2)$. If firm 1 bids P_1, a bid of P_2 is a best response for firm 2 if and only if it is not profitable to undercut firm 1 by bidding just below P_1. Firm 2 has no profitable deviation to a firm 1 bid of P_1 if and only if, for $\varepsilon > 0$, small:

$$\begin{aligned} \lim_{\epsilon \to 0}\{\pi_2(P_1 - \varepsilon - c_2)\} &< \pi_2(P_2) \\ \Leftrightarrow (P_1 - \lim_{\epsilon \to 0}\{\epsilon\} - c_2) \int_{\underline{\theta}}^{\overline{\theta}} \min\{\theta, k_2\}\, dG(\theta) &< (P_2 - c_2) \int_{k_1}^{\overline{\theta}} [\theta - k_1]\, dG(\theta) \end{aligned} \tag{2}$$

Clearly, if (2) holds, the pure-strategy profile $(b_1 = P_1, b_2 = P_2)$ constitutes an equilibrium.[17] *To prove the only if part, suppose (2) doesn't hold and take the*

[16]If ties were broken by a fair coin, firm 1 would have the incentive to deviate from the pure-strategy profile $(b_1 = P_1, b_2 = P_2)$ because decreasing b_1 by an arbitrarily small amount would discretely increase firm 1's quantity sold while only continuously decreasing the price it receives.

[17]If the two sides of (2) are equal, then firm 2 is indifferent between bidding P_1 and being

limit as $\varepsilon \downarrow 0$. Equivalently, assume the (MSE) condition below holds:

$$\frac{\int_{k_1}^{\overline{\theta}} [\theta - k_1] \, dG(\theta)}{\int_{\underline{\theta}}^{\overline{\theta}} \min\{\theta, k_2\} \, dG(\theta)} < \frac{(P_1 - c_2)}{(P_2 - c_2)} \qquad (MSE)$$

If the (MSE) condition holds (or (2) *doesn't hold), firm 2 can profitably deviate from the pure-strategy profile* $(b_1 = P_1, b_2 = P_2)$ *by bidding just below* P_1*, hence no pure-strategy equilibrium exists.*

If the (MSE) condition holds, demand and supply conditions are such that firm 2 will compete with firm 1 to be dispatched first. Hereafter, assume that the (MSE) condition holds. Given that the (MSE) condition rules out a pure-strategy equilibrium, mixed-strategy equilibria must be considered. There are two types of mixed-strategy equilibria, one where firm 1 bids more aggressively than firm 2 (Case 1) and another where firm 2 bids more aggressively than firm 1 (Case 2). Lemma 4 characterizes the equilibrium CDFs $F_1(b)$ and $F_2(b)$ of the mixed-strategy equilibrium.

Lemma 4. *The Case 1 and Case 2 equilibrium CDFs in the UPA have the following properties:*

1. *Firm 2 will not place density in the interval* (P_1, P_2)

dispatched first and bidding P_2 and being dispatched second. However, if firm 2 bids P_1, P_2, or mixes between the two, firm 1's optimal response is to bid P_1 since it gets dispatched first if firm 2 bids P_1. However, if firm 1 bids P_1 with certainty, firm 2 serves firm 1's excess demand when it bids P_1 (i.e. firm 2 will not receive a profit equal to $(P_1 - c_2) \int_{\underline{\theta}}^{\overline{\theta}} \min\{\theta, k_2\} \, dG(\theta)$ and will instead receive $(P_1 - c_2) \int_{k_1}^{\overline{\theta}})[\theta - k_1] \, dG(\theta)$. Hence, firm 2 will optimally respond by bidding P_2.

2. $F_1(b)$ *and* $F_2(b)$ *have a common infimum bid* $\underline{b}$

3. $F_1(b)$ *and* $F_2(b)$ *have a common and fully connected support for* $b \in [\underline{b}, P_1]$

4. *Neither firm places mass at the common infimum* $\underline{b}$

Lemma 4 contains the familiar properties of mixed-strategy equilibria with continuous CDFs defined over a compact support. Lemma 4 characterizes the Case 2 BSOC equilibrium, where firm 2 bids more aggressively than firm 1. In the Case 2 equilibrium firm 1 has a mass point at P_1 and firm 2 bids below P_1 with probability one.[18] Firm 1 bids more aggressively than firm 2 in Case 1 BSOC equilibrium. Lemmas 4 and 5 characterize the BSOC Case 1 equilibrium CDFs. Proofs of Lemmas 4 and 5 are provided in the Appendix.

Lemma 5. *The Case 1 equilibrium has the following properties:*

1. *Firm 2 has zero density at* P_1
2. *Firm 2 places nonzero mass at* P_2
3. *Firm 1 places nonzero mass at* P_1
4. *The common infimum* $\underline{b} > c_2$

In Case 1, both firms have mass points at the suprema of their respective CDFs. Neither firm places mass at the common infimum $\underline{b} > c_2$, firm 1 alone places positive mass at P_1, and firm 2 places positive mass at P_2.

[18] This case is analogous to the FFH equilibrium Case 2^s with a system-wide offer cap of P_1.

2.1 Case 1 BSOC Uniform Price Auction Equilibrium

The next step in finding the BSOC equilibrium CDFs is solving for α, the probability that firm 1 bids its BSOC P_1 in Case 1. Firm 2 is employing a mixed-strategy, so all bids in the support of $F_2(b)$, $(\underline{b}, P_1) \bigcup \{P_2\}$, must yield the same profits in expectation given $F_1(b)$. In the limit, when firm 2 bids just below P_1, it is the high bidder with probability $(1-\alpha) = Pr(b_1 < P_1)$ and it is the low bidder with probability $\alpha = Pr(b_1 = P_1)$. Bids arbitrarily close to P_1 yield expected profit $\lim\limits_{b \to P_1} \pi_2(b)$, which must equal $\pi_2(P_2)$, the expected profit firm 2 earns from bidding P_2.

$$\begin{aligned}
\lim_{b \to P_1} \pi_2(b) \quad &= (1-\alpha)(b-c_2) \int_{k_1}^{\bar{\theta}} [\theta - k_1]\, dG(\theta) \\
&+ \ \alpha \left\{ (b-c_2) \int_{\underline{\theta}}^{k_2} \theta \, dG(\theta) + (P_1 - c_2) k_2 [1 - P_2(k_2)] \right\} \\
&= \pi_2(P_2) \\
&= (P_2 - c_2) \int_{k_1}^{\bar{\theta}} [\theta - k_1]\, dG(\theta)
\end{aligned} \tag{3}$$

Talking limits and solving (3) for α yields:

$$\alpha = \frac{\left(\frac{P_2 - P_1}{P_1 - c_2}\right) \int_{k_1}^{\bar{\theta}} [\theta - k_1]\, dG(\theta)}{\int_{\underline{\theta}}^{\bar{\theta}} \theta \, dG(\theta) - \int_{k_1}^{\bar{\theta}} [\theta - k_1]\, dG(\theta) - \int_{k_2}^{\bar{\theta}} [\theta - k_2]\, dG(\theta)} \tag{4}$$

The α parameter makes firm 2 indifferent between bidding in $(\underline{b}, P_1)$ and bidding P_2. The comparative statics of α, given in the Appendix, are as expected. When the difference between the BSOCs increases (an increase in P_2 or decrease in P_1) α increases. Increasing the capacity of either firm, all else equal, decreases alpha and hence makes firm 1 bid more aggressively. The mass at P_1, α, is an artifact of the unequal BSOCs. When the BOSCs are equal (a system-wide offer cap), α equals zero and the equilibria coincide with those found by FFH.

Standard methods are used to find the Case 1 and Case 2 BSOC equilibrium CDFs for firms 1 and 2. The expected profit of firm i, given that its rival employs mixed-strategy $F_j(b)$ for all bids $b \in (\underline{b}, P_1)$ is:

$$\begin{aligned}\pi_i(b) = F_j(b)(b-c_i)\int_{k_j}^{\bar{\theta}}[\theta-k_j]\,dG(\theta) + [1-F_j(b)](b-c_i)\int_{\underline{\theta}}^{k_i}\theta\,dG(\theta)\\ +[1-F_j(b)]k_i[1-G(k_i)]\int_b^{P_1}\tfrac{[\tau-c_i]}{[1-F_j(b)]}\,dF_j(\tau)\end{aligned} \tag{5}$$

The first-order conditions of the profit functions yield differential equations that the BSOC CDFs must satisfy for all $b \in (\underline{b}, P_1)$.[19] The terminal condition, $\lim_{b\to P_1} F_1(b) = 1-\alpha$, is used to pin down the Case 1 infimum bid because firm 1 bids P_1 with probability α. Proposition 1 summarizes the BSOC equilibria in the UPA and a proof is provided in the Appendix.

Proposition 1. *The Case 1 BSOC uniform price auction equilibrium CDFs of the uniform price auction are:*

$$F_1(b) = \begin{cases} (1-\alpha)+\beta_1\ln\left(\frac{b-c_2}{P_1-c_2}\right) & for\ b\in(\underline{b},P_1),\ \lambda_1=\lambda_2=0\\ \frac{\beta_1}{\lambda_1}\left[\frac{\beta_1+(1-\alpha)\lambda_1}{\beta_1}\left(\frac{b-c_2}{P_1-c_2}\right)^{\lambda_1}-1\right] & for\ b\in(\underline{b},P_1),\ \lambda_1,\lambda_2\neq 0\end{cases} \tag{6}$$

[19] These techniques were used by FFH.

and $Pr(b_1 = P_1) = 1 - \lim_{b \to P_1} F_1(b) = \alpha$.

$$F_2(b) = \begin{cases} \beta_2 \ln \left(\frac{b-c_1}{(P_1-c_2)e^{\frac{-(1-\alpha)}{\beta_1}}+c_2-c_1} \right) & for\ b \in (\underline{b}, P_1),\ \lambda_1 = \lambda_2 = 0 \\ \frac{\beta_2}{\lambda_2} \left[\left(\frac{b-c_1}{(P_1-c_2)\left(\frac{\beta_1}{(1-\alpha)\lambda_1+\beta_1}\right)^{\frac{1}{\lambda_1}}+c_2-c_1} \right)^{\lambda_2} - 1 \right] & for\ b \in (\underline{b}, P_1),\ \lambda_1, \lambda_2 \neq 0 \end{cases} \tag{7}$$

and $Pr(b_2 = P_2) = 1 - \lim_{b \to P_1} F_2(b)$.

The infimum bid is $\underline{b} = \begin{cases} = c_2 + e^{\frac{-(1-\alpha)}{\beta_1}}(P_1 - c_2) & if \lambda_1 = \lambda_2 = 0 \\ = c_2 + \left(\frac{\beta_1}{(1-\alpha)\lambda_1+\beta_1}\right)^{\frac{1}{\lambda_1}}(P_1 - c_2) & if \lambda_1, \lambda_2 \neq 0 \end{cases}$

□

Equilibrium profits in Case 1 are:

$$\begin{aligned} \pi_1 = &\ (P_1 - c_1)Pr(b_2 < P_1) \int_{k_2}^{\bar{\theta}} [\theta - k_2]\, dG(\theta) + (P_1 - c_1)Pr(b_2 = P_2) \int_{\underline{\theta}}^{k_1} \theta\, dG(\theta) \\ &+(P_2 - c_1)Pr(b_2 = P_2)k_1[1 - G(k_1)] \\ \pi_2 = &\ (P_2 - c_2) \int_{k_1}^{\bar{\theta}} [\theta - k_1]\, dG(\theta) \end{aligned} \tag{8}$$

where $Pr(b_2 < P_1) = \lim_{b \to P_1} F_2(b)$ and $Pr(b_2 = P_2) = 1 - Pr(b_2 < P_1)$. Firm 1's profits are increasing in the probability that firm 2 bids P_2 because $Pr(b_1 < b_2)$ increases with $Pr(b_2 = P_2)$, and firm 1 receives a price of P_2 for its capacity when $b_2 = P_2$ and $\theta > k_1$. This important fact makes it possible for the BSOCs to increase firm 1's expected profit. Firm 2's expected profit is equal to the expected profit of bidding P_2 and serving the excess demand of firm 1.

2.2 Case 2 BSOC Uniform Price Auction Equilibrium

The other possible BSOC equilibrium when the (MSE) condition holds is Case 2, where firm 2 bids more aggressively than firm 1. The Case 2 equilibrium CDFs are characterized in Lemma 4. The common support of the Case 2 CDFs is $(\underline{b}, P_1)$ and firm 1 has a mass point at its BSOC, P_1. Firm 2 bids below P_1 with probability one. Case 2 is identical to Case 2^s of the FFH model with a system-wide offer cap of P_1. Given that firm 2 can bid P_2 but doesn't do so in Case 2, the following incentive compatibility ("IC") constraint must be satisfied:

$$\pi_2^n \geq (P_2 - c_2) \int_{k_1}^{\bar{\theta}} [\theta - k_1] \, dG(\theta) \tag{9}$$

where π_2^n represents firm 2's expected profit in the Case 2 equilibrium. Let $F_1^n(b)$ and $F_2^n(b)$ denote the Case 2 equilibrium CDFs. The same techniques employed in section 2.1 can be used to find the Case 2 equilibrium CDFs, but the boundary condition used to find the infimum $\underline{b}^n$ is $Pr(b_2 < P_1) = 1$ or $\lim_{b \to P_1} F_2^n(b) = 1$ because firm 2 always bids below P_1.

Proposition 2. *The Case 2 BSOC uniform price auction equilibrium CDFs are:*

$$F_1^n(b) = \begin{cases} \beta_1 \ln\left(\frac{b-c_2}{(P_1-c_1)e^{\frac{-1}{\beta_2}}+c_1-c_2}\right) & for\ b \in (\underline{b}, P_1),\ \lambda_1 = \lambda_2 = 0 \\ \frac{\beta_1}{\lambda_1}\left[\left(\frac{b-c_2}{(P_1-c_1)\left(\frac{\beta_2}{\lambda_2+\beta_2}\right)^{\frac{1}{\lambda_2}}+c_1-c_2}\right)^{\lambda_1} - 1\right] & for\ b \in (\underline{b}, P_1),\ \lambda_1, \lambda_2 \neq 0 \end{cases} \tag{10}$$

and $Pr(b_1 = P_1) = 1 - \lim_{b \to P_1} F_1^n(b).$

$$F_2^n(b) = \begin{cases} 1 + \beta_2 \ln\left(\frac{b-c_1}{P_1-c_1}\right) & for\ b \in (\underline{b}, P_1),\ \lambda_1 = \lambda_2 = 0 \\ \frac{\beta_2}{\lambda_2}\left[\frac{\beta_2+\lambda_2}{\beta_2}\left(\frac{b-c_1}{P_1-c_1}\right)^{\lambda_2} - 1\right] & for\ b \in (\underline{b}, P_1),\ \lambda_1, \lambda_2 \neq 0 \end{cases} \tag{11}$$

□

The Case 2 equilibrium is less efficient in expectation than the Case 1 equilibrium because in Case 2, firm 2, the high cost firm, has a higher probability of being the low bidder. This result is reminiscent of the "Demand Reduction" result (Ausubel and Cramton (2002)), where large bidders in multi-unit UPAs, who often set the uniform price, have an incentive to increase their bids above marginal cost to increase revenue on inframarginal units. This creates an inefficiency if the large bidder is more efficient.

Equilibrium profits in Case 2 are:

$$\begin{aligned}\pi_1^n = &\ (P_1 - c_1) \int_{k_2}^{\bar{\theta}} [\theta - k_2]\, dG(\theta) \\ \pi_2^n = &\ (P_1 - c_2) \left[Pr(b_1 < P_1) \int_{k_1}^{\bar{\theta}} [\theta - k_1]\, dG(\theta) + Pr(b_1 = P_1) \int_{\underline{\theta}}^{\bar{\theta}} \min\{\theta, k_2\}\, dG(\theta) \right]\end{aligned} \tag{12}$$

where $Pr(b_1 < P_1) = \lim\limits_{b \to P_1} F_1^n(b)$ and $Pr(b_1 = P_1) = 1 - Pr(b_1 < P_1)$. As in Case 1, firm 1's expected profit is equal to the expected profit from bidding P_1, where it is the high bidder with probability one.

2.3 Uniform Price Equilibrium Conclusions

If the (MSE) condition holds, the unique Nash Equilibrium outcome in the UPA must be Case 1 or Case 2, but not both. Recall that α, the probability that firm 1 bids P_1 in Case 1, makes firm 2 indifferent between a bid in $(\underline{b}, P_1)$ and a bid of P_2. Define the probability that firm 1 bids P_1 in Case 2 as $\delta \equiv [1 - \lim\limits_{b \to P_1} F_1^n(b)]$. In Case 2, firm 2 does not bid P_2, hence the expected profit it earns in the Case 2 equilibrium must be at least as large in expectation as $\pi_2(P_2)$. Firm 2's IC constraint in Case 2, given by (9), is equivalent to:

$$\begin{aligned}&(P_1 - c_2) \left[(1 - \delta) \int_{k_1}^{\bar{\theta}} [\theta - k_1]\, dG(\theta) + \delta \int_{\underline{\theta}}^{\bar{\theta}} \min\{\theta, k_2\}\, dG(\theta) \right] \\ &\geq (P_2 - c_2) \int_{k_1}^{\bar{\theta}} [\theta - k_1]\, dG(\theta) \\ &= \pi_2(P_2)\end{aligned} \tag{13}$$

In Case 1, α is chosen to make equation (14) hold:

$$(P_1 - c_2)\left[(1-\alpha)\int_{k_1}^{\bar{\theta}}[\theta - k_1]\,dG(\theta) + \alpha\int_{\underline{\theta}}^{\bar{\theta}}\min\{\theta, k_2\}\,dG(\theta)\right] = \pi_2(P_2) \qquad (14)$$

The (MSE) condition guarantees that $\int_{\underline{\theta}}^{\bar{\theta}}\min\{\theta, k_2\}\,dG(\theta) > \int_{k_1}^{\bar{\theta}}[\theta - k_1]\,dG(\theta)$. Hence, firm 2's IC constraint holds if and only if $\delta \geq \alpha$. If both the Case 1 and Case 2 constitute feasible CDFs, the Case with the greater infimum is played in equilibrium.

Proposition 3. *The BSOC uniform price auction equilibrium is unique*

Proof. Suppose that both Case 1 and Case 2 constitute feasible equilibrium CDFs. This implies that:

$$\lim_{b\to P_1} F_2(b) < 1,\ \lim_{b\to P_1} F_1^n(b) < 1,\ \text{and } \pi_2^n \geq (P_2 - c_2)\int_{k_1}^{\bar{\theta}}[\theta - k_1]\,dG(\theta) \qquad (15)$$

Suppose that $\lambda_1, \lambda_2 > 0$ and the conditions in (15) hold. This leads to a contradiction because (15) implies that $\lim_{b\to P_1} F_2(b) < 1 \Leftrightarrow \delta < \alpha$, which violates (13). These results hold for all possible cases: $\lambda_1, \lambda_2 > 0$; $\lambda_1 > 0, \lambda_2 < 0$; $\lambda_1 < 0, \lambda_2 > 0$; $\lambda_1, \lambda_2 < 0$; and $\lambda_1 = \lambda_2 = 0$. Hence Case 1 and Case 2 are mutually exclusive. The mixed-strategy BSOC equilibrium is the Case with the greater infimum. In equilibrium the BSOC UPA infimum $\underline{b}^*$ is:

$$\begin{aligned}\underline{b}^* &\equiv \max\{\,\underline{b}, \underline{b}^n\} \\ &= \max\left\{(P_1 - c_2)\left(\tfrac{\beta_1}{(1-\alpha)\lambda_1+\beta_1}\right)^{\frac{1}{\lambda_1}} + c_2, (P_1 - c_1)\left(\tfrac{\beta_2}{\lambda_2+\beta_2}\right)^{\frac{1}{\lambda_2}} + c_1\right\}\end{aligned}$$

$\square$

Proposition 3 fully characterizes the BSOC equilibrium if the (MSE) condition holds, and if it doesn't hold, the equilibrium is in pure-strategies. Unfortunately, it is difficult to divide the parameter space into distinct intuitive groups given the complexity of $\underline{b}^*$. However, if the firms have equal capacity, the BSOC UPA equilibrium is Case 1.

Corollary *If the firms have equal capacity the BSOC UPA equilibrium is Case 1.*
Proof: Suppose by way of contradiction that Case 2 is played in equilibrium and $k_1 = k_2 = k$. *This implies that*

$$\left(\frac{P_1 - c_2}{P_1 - c_1}\right) < \left(\frac{\underline{b}^n - c_2}{\underline{b}^n - c_1}\right)$$

which leads to a contradiction because $\frac{x-c_2}{x-c_1}$ *is increasing in* x *and* $P_1 > \underline{b}^n$.

This corollary is intuitive because if the firms have the same capacity, they face the same incentives to be the low bidder in terms of quantity sold but firm 1 will bid more aggressively because it has a lower marginal cost and the BSOCs give firm 1 an additional incentive to bid below its rival. In the UPA with BSOCs, each firm prefers the equilibrium where it bids more aggressively than its rival. Firm 1 prefers the Case 1 equilibrium to the Case 2 equilibrium because firm 1 bids P_1 in both, but when firm 1 bids P_1 in Case 2, it is the high bidder with probability one and only serves firm 2's excess demand. In contrast, when firm 1 bids P_1 in Case 1, there is a probability that firm 1 will be the low bidder and receive a price of P_2. Firm 2 strictly prefers the Case 2 equilibrium given the IC condition (see (9)) associated with Case 2.

2.4 Effects of BSOCs in the Uniform Price Auction

This section summarizes the effect that BSOCs have on expected production efficiency, equilibrium bidding strategies, and expected profits. To determine the effects of BSOCs, one must make a comparison between two regimes; a regime with a system-wide offer cap (solved by FFH) and a regime with BSOCs that differ. Generators in PJM face the same system-wide offer cap and BSOCs are only imposed when market conditions are highly conducive to the exercise of market power by generators.[20] Hence, it is informative to study the case where both firms initially face a system-wide offer cap P_2 and the auctioneer then imposes BSOCs, lowering firm 1's offer cap to $P_1 < P_2$, while leaving firm 2's cap unchanged.

FFH found that in a UPA with a system-wide offer cap of P_2, the equilibria will

[20]In UPAs, all firms possess a degree of market power. BSOCs are imposed when market conditions, which are outlined in the Open Access Transmission Tariff, suggest that the degree of generator market power is excessive.

be either Case 1^s or 2^s:

- Case 1^s : $\lim_{b \to P_2} F_2^s(b) < \lim_{b \to P_2} F_1^s(b) = 1, \underline{b}^s = (P_2 - c_2)(\frac{\beta_1}{\lambda_1 + \beta_1})^{\frac{1}{\lambda_1}} + c_2$

- Case 2^s : $\lim_{b \to P_2} F_1^{sn}(b) < \lim_{b \to P_2} F_2^{sn}(b) = 1, \underline{b}^{sn} = (P_2 - c_1)(\frac{\beta_2}{\lambda_2 + \beta_2})^{\frac{1}{\lambda_2}} + c_1$

where $F_j^s(b)$ and $F_j^{sn}(b)$, $j = 1, 2$, take the form of equation (25). In Case 1^s, firm 1 is the more aggressive bidder and in Case 2^s, firm 2 is the more aggressive bidder. As with BSOCs, the case with the greater infimum is the one that gets played in equilibrium, thus $\underline{b}^{s*} \equiv \max\{\underline{b}^s, \underline{b}^{sn}\}$ is the equilibrium infimum of the UPA with a system-wide offer cap of P_2.

Efficiency in the UPA depends solely on the expected dispatch order. Clearly, dispatching firm 1 first is more efficient because firm 1 has a lower marginal cost. Since the ranking of b_1 and b_2 determines the dispatch order, the only relevant metric of efficiency is the probability that firm 1 bids below firm 2. For example, consider the expected production costs, $C(b_1, b_2)$, in the UPA are:

$$C(b_1, b_2) = Pr(b_1 < b_2)\left\{c_1 \int_{\underline{\theta}}^{\bar{\theta}} \min\{\theta, k_1\}\, dG(\theta) + c_2 \int_{\underline{\theta}}^{\bar{\theta}} \max\{0, \theta - k_1\}\, dG(\theta)\right\}$$
$$+[1 - Pr(b_1 < b_2)]\left\{ c_2 \int_{\underline{\theta}}^{\bar{\theta}} \min\{\theta, k_2\}\, dG(\theta) + c_1 \int_{\underline{\theta}}^{\bar{\theta}} \min\{0, \theta - k_2\}\, dG(\theta)\right\}$$

The terms in brackets do not vary with the bids and $C(b_1, b_2)$ is strictly decreasing in $Pr(b_1 < b_2)$. Therefore, a policy that increases $Pr(b_1 < b_2)$ will decrease the expected operating costs , or equivalently, increase expected efficiency. In the UPA, BSOCs unambiguously increase expected efficiency. This is fairly intuitive given that BSOCs suppress the bid of the more efficient firm. Furthermore, when firm 1 has BSOC $P_1 < P_2$, the Case 2 equilibrium becomes less likely because $\underline{b}^n < \underline{b}^{sn}$ and $\underline{b} > \underline{b}^s$. Thus, BSOCs that are increasing in marginal cost make the *ex ante* inefficient equilibrium (Case 2) *less* likely. The effects of the BSOCs on profits and efficiency in the UPA are summarized in tables 2 and 3.

If Case 1^s is the initial equilibrium with a system-wide cap of P_2, two outcomes are possible after imposing BSOCs: Case 1 and the pure-strategy equilibrium $(b_1 = P_1, b_2 = P_2)$. When the system-wide offer cap is P_2 and the equilibrium is Case 1^s, expected profits are:

$$\begin{aligned}
\pi_1^s = &\quad (P_2 - c_1)\left(Pr(b_2 < P_2)\int_{k_2}^{\bar{\theta}}[\theta - k_2]\,dG(\theta) + Pr(b_2 = P_2)\int_{\underline{\theta}}^{\bar{\theta}}\min\{\theta, k_1\}\,dG(\theta)\right) \\
\pi_2^s = &\quad (P_2 - c_2)\int_{k_1}^{\bar{\theta}}[\theta - k_1]\,dG(\theta)
\end{aligned}$$

where $Pr(b_2 < P_2) = \lim_{b \to P_2} F_2^s(b)$ and $Pr(b_2 = P_2) = [1 - Pr(b_2 < P_2)]$. BSOCs induce the pure-strategy equilibrium when the (MSE) condition fails. The expected profits of the pure-strategy equilibrium are:

$$\begin{aligned}
\tilde{\pi}_1 &= (P_1 - c_1)\int_{\underline{\theta}}^{k_1}\theta\,dG(\theta) + (P_2 - c_1)k_1[1 - G(k_1)] \\
\tilde{\pi}_2 &= (P_2 - c_2)\int_{k_1}^{\bar{\theta}}[\theta - k_1]\,dG(\theta)
\end{aligned}$$

Table 2 describes what happens when the initial equilibrium is Case 1^s and a BSOC equal to $P_1 < P_2$ is imposed on firm 1.[21] The BSOCs unambiguously

[21]In the tables, $\uparrow$ represents an unambiguous increase in expected profits, $\downarrow$ represents an unambiguous decrease, $-$ represents no change, and Δ means that the sign of the change is

Table 2: UPA Effects of BSOCs if Initial Eq'm is Case 1^s

Case 1^s with single cap P_2: $\underline{b}^s > \underline{b}^{sn}$			
	Direction of change in efficiency	New π	Direction of change in π
Case 1 if $\underline{b} > \underline{b}^n$	$\uparrow$	π_1	$\uparrow$
		π_2	-
Pure-strategy	$\uparrow$	$\tilde{\pi}_1$	Δ
		$\tilde{\pi}_2$	-

increase expected efficiency if the initial equilibrium is Case 1^s. Proofs are provided in the Appendix. The pure-strategy equilibrium is the first best in terms of efficiency because firm 1, the more efficient firm, is dispatched first with probability one. If the new equilibrium is Case 1, firm 1's expected profits increase. Handicapping firm 1 with a lower BSOC actually increases firm 1's expected profit because the BSOCs allow firm 1 to commit to bidding more aggressively relative to Case 1^s. This increases the expected quantity sold by firm 1 and hence expected profits. This result is consistent with the PJM finding that firms with BSOCs can experience an increase in profits. Firm 2's profits remain unchanged if the Case 1 or pure-strategy equilibrium results, as firm 2 bids P_2 with positive probability in Case 1^s.

Table 3 describes the effects of the BSOCs when the initial equilibrium with the system-wide offer cap of P_2 is Case 2^s. In Case 2^s, expected equilibrium profits

ambiguous and depends on the parameter values.

are:

$$\begin{aligned}\pi_1^{sn} = &\ (P_2 - c_1)\int_{k_2}^{\bar\theta}[\theta - k_2]\,dG(\theta)\\ \pi_2^{sn} = &\ (P_2 - c_2)\left(Pr(b_1 < P_2)\int_{k_1}^{\bar\theta}[\theta - k_1]\,dG(\theta) + Pr(b_1 = P_2)\int_{\underline{\theta}}^{\bar\theta}\min\{\theta, k_2\}\,dG(\theta)\right)\end{aligned}$$

where $Pr(b_1 < P_2) = \lim_{b \to P_2} F_1^{sn}(b)$ and $Pr(b_1 = P_2) = 1 - Pr(b_1 < P_2)$.

Table 3: UPA Effects of BSOCs if Initial Eq'm is Case 2^s

Case 2^s with single cap P_2: $\underline{b}^{sn} > \underline{b}^s$			
	Direction of change in efficiency	New π	Direction of change in π
Case 1 if $\underline{b} > \underline{b}^n$	$\uparrow$	π_1	Δ
		π_2	$\downarrow$
Case 2 if $\underline{b}^n > \underline{b}$	$\uparrow$	π_1^n	$\downarrow$
		π_2^n	$\downarrow$
Pure-strategy	$\uparrow$	$\tilde\pi_1$	Δ
		$\tilde\pi_2$	$\downarrow$

If the initial equilibrium with the system-wide cap is Case 2^s, imposing an offer cap of P_1 on firm 1 increases expected efficiency regardless of the equilibrium that results. Proofs are provided in the Appendix. Case 1 is clearly more efficient than Case 2^s as firm 1 bids more aggressively than firm 2 in Case 1. If the BSOC equilibrium is Case 1, the effect on firm 1's profit depends on parameter values. Firm 2's expected profit decreases when the BSOC equilibrium is Case 1 because the IC constraint from Case 2^s is $\pi_2^{sn} \geq (P_2 - c_2)\int_{k_1}^{\bar\theta}[\theta - k_1]\,dG(\theta)$. If the BSOC equilibrium is Case 2, the expected profit of both firms decreases.

Given tables 2 and 3, BSOCs unambiguously increase the expected efficiency of the UPA. Furthermore, firm 1's expected profit increases with BSOCs if the initial equilibrium is Case 1^s. Case 2 is the least efficient outcome in expectation, and as such, the auctioneer that chooses the BSOCs can avoid caps that induce the Case 2 equilibrium if she is concerned with production efficiency. The auctioneer can also pick a sufficiently low BSOC for firm 1 to ensure that the (MSE) condition fails and induce the pure-strategy equilibrium. This is tantamount to fixing the bids of the firms. The pure-strategy equilibrium may lead to higher prices, but given that demand is inelastic and always satisfied, this will not decrease total surplus.[22] If the auctioneer selects the BSOCs that induce the pure-strategy equilibrium, she should have a clear understanding of the production costs of both firms, which places a heavy burden on the auctioneer when fixed costs and start-up costs are involved, as they are in electricity generation.

3 Discriminatory Price Auction

PJM, ISONE, and NYISO do not use discriminatory price auctions ("DPA") to determine wholesale electricity prices. The United Kingdom, however, does. In 2001, the UK switched from UPAs to an exchange market coupled with a DPA

[22] History shows, however, that politicians are not compelled by this logic when retail electricity rates are concerned.

in response to concerns that the UPA encouraged collusion and led to high prices (Klemperer, 2004). The California Pubic Utilities Commission also considered using a DPA in California electricity markets during the 2000-2001 Western energy crisis (Kahn et al. 2001). Given this debate, this section extends the FFH model by imposing BSOCs in the DPA.

The DPA is similar to the UPA because the ranking of the bids determines the dispatch order. However, in the DPA, bidders are paid their own bids, and never receive the bids of their rivals.[23] The quantity sold by each firm in the DPA is given by equation (1).

Timing of the Discriminatory Price Auction:

1. Firms offer a minimum price for their entire capacity
2. Demand, represented by θ, is realized
3. The auctioneer uses a DPA to allocate θ between the firms and set the prices for each firm.

As in the UPA, the BSOC DPA equilibria assume one of three possible forms: pure-strategy, mixed-strategy Case 1^d, and mixed-strategy Case 2^d. The next subsections characterize the BSOC equilibria and all Lemmas and Propositions are analogous to those of section 2.

[23]Discriminatory price auctions are often referred to in the industry as "pay-as-bid" auctions.

3.1 BSOC Discriminatory Price Auction Equilibrium

It is easily shown using the Lemmas of the previous section that $(b_1 = b_2)$ and $(b_i < b_j)$ *s.t.* $b_1 \neq P_1$ and $b_2 \neq P_2$ do not constitute equilibrium strategies in the DPA. Lemma 6 shows that the (MSE) condition also plays a role in the DPA equilibria because it determines when the DPA BSOC equilibrium is in pure or mixed-strategies.

Lemma 6. *If the MSE condition holds, no pure-strategy equilibria exist in the DPA with BSOCs*

The pure-strategy profile $(b_1 = P_1, b_2 = P_2)$ *is not an equilibrium in the DPA if:*

$$(P_2 - c_2) \int_{k_1}^{\bar{\theta}} [\theta - k_1] \, dG(\theta) < (P_1 - c_2) \int_{\underline{\theta}}^{\bar{\theta}} \min\{\theta, k_2\} \, dG(\theta)$$

When the left hand side of the inequality above is greater than the right hand side, it is a strictly dominant strategy for each firm to bid its BSOC. As before, if the two sides are equal, the equilibria will be in pure-strategies. The inequality above is simply the (MSE) condition from the UPA.

The UPA and the DPA BSOC equilibria depend on the same (MSE) condition because when firm 2 bids P_2 in the UPA, it is essentially bidding in a DPA, because it receives its bid if dispatched. The equilibrium CDFs of the DPA with BSOCs are qualitatively similar to the CDFs of the UPA. In Case 1^d, firm 1 bids more aggressively than firm 2, and bids P_1 with positive probability, while firm 2 bids

P_2 with positive probability. In Case 2^d, firm 2 bids more aggressively and bids below P_1 with probability one while firm 1 bids P_1 with positive probability.

Hereafter, assume that the (MSE) condition holds. Arguments similar to Lemmas 4 and 5 can be used to show that the common support of the DPA BSOC CDFs in Case 1^d and Case 2^d are fully connected and contain no mass points, and that the infimum is strictly greater than c_2.

As in section 2, the profit functions will be used to solve for the DPA CDFs. Firm i's expected profit in the DPA, given that its rival bids according to mixed-strategy $H_j(b)$ for all $b \in (\underline{b}^d, P_1)$, is:

$$\pi_i(b) = (b - c_i)\left(H_j(b) \int_{k_j}^{\bar{\theta}} [\theta - k_j]\, dG(\theta) + [1 - H_j(b)] \int_{\underline{\theta}}^{\bar{\theta}} \min\{\theta, k_i\}\, dG(\theta) \right) \tag{16}$$

Taking the derivative of (16) with respect to b and solving the differential equation for firms 1 and 2 yields the BSOC DPA equilibrium CDFs. As in section 2, the terminal conditions are used to find the infima. Proposition 4 gives the Case 1^d and 2^s BSOC CDFs in the DPA. See the Appendix for proof.

Proposition 4. *BSOC discriminatory price auction equilibrium CDFs*

The Case 1^d equilibrium CDFs are:

$$\begin{aligned} H_1(b) &= \tfrac{\psi_1}{\phi} \cdot \tfrac{(b - [P_1 - \frac{\phi}{\psi_1}(P_1 - c_2)(1-\alpha)])}{(b - c_2)} \\ H_2(b) &= \tfrac{\psi_2}{\phi} \cdot \tfrac{(b - [P_1 - \frac{\phi}{\psi_1}(P_1 - c_2)(1-\alpha)])}{(b - c_1)} \end{aligned} \tag{17}$$

where $Pr(b_1 = P_1) = \alpha$ and $Pr(b_2 = P_2) = 1 - \lim_{b \to P_1} H_2(b)$.

The Case 1^d infimum is $\underline{b}^d = P_1 - \frac{\phi}{\psi_1}(P_1 - c_2)(1 - \alpha)$.

The Case 2^d equilibrium CDFs are:

$$\begin{aligned} H_1^n(b) &= \tfrac{\psi_1}{\phi} \cdot \tfrac{(b - [P_1 - \frac{\phi}{\psi_2}(P_1 - c_1)])}{(b - c_2)} \\ H_2^n(b) &= \tfrac{\psi_2}{\phi} \cdot \tfrac{(b - [P_1 - \frac{\phi}{\psi_2}(P_1 - c_1)])}{(b - c_1)} \end{aligned} \tag{18}$$

where $Pr(b_1 = P_1) = [1 - \lim_{b \to P_1} H_1^n(b)]$, and ϕ, ψ_1 and ψ_2 are defined in the Appendix.

The Case 2^d infimum is $\underline{b}^{dn} = P_1 - \frac{\phi}{\psi_2}(P_1 - c_1)$.

□

Equilibrium profits in Case 1^d are:

$$\begin{aligned} \pi_1^d &= (P_1 - c_2)\left(Pr(b_2 < P_1)\int_{k_2}^{\bar{\theta}}[\theta - k_2]\,dG(\theta) + Pr(b_2 = P_2)\int_{\underline{\theta}}^{\bar{\theta}}\min\{\theta, k_1\}\,dG(\theta)\right) \\ \pi_2^d &= (P_2 - c_2)\int_{k_1}^{\bar{\theta}}[\theta - k_1]\,dG(\theta) \end{aligned} \tag{19}$$

where $Pr(b_2 < P_1) = \lim_{b \to P_1} H_2(b)$ and $Pr(b_2 = P_2) = 1 - Pr(b_2 < P_1)$. Equilibrium profits in Case 2^d are:

$$\begin{aligned} \pi_1^{dn}(b) &= (P_1 - c_1)\int_{k_2}^{\bar{\theta}}[\theta - k_2]\,dG(\theta) \\ \pi_2^{dn}(b) &= (P_1 - c_2)\left(Pr(b_1 < P_1)\int_{k_1}^{\bar{\theta}}[\theta - k_1]\,dG(\theta) + Pr(b_1 = P_1)\int_{\underline{\theta}}^{\bar{\theta}}\min\{\theta, k_2\}\,dG(\theta)\right) \end{aligned} \tag{20}$$

where $Pr(b_1 < P_1) = \lim_{b \to P_1} H_1^{dn}(b)$ and $Pr(b_1 = P_1) = [1 - Pr(b_1 < P_1)]$. In Case 1^d, firm 2 bids P_2 with positive probability and firm 1 bids P_1 with positive probability. Note the difference between the BSOC UPA Case 1 and BSOC DPA Case 1^d profits. When firm 1 bids P_1 in the DPA and it is the low bidder, it will not receive firm 2's bid. Therefore, in the DPA, firm 1 will never receive a payment in excess of its BSOC P_1.

3.2 Discriminatory Price Auction Equilibrium Conclusions

As in the UPA, each firm receives higher expected profit in the case where it is the more aggressive bidder. For example, firm 2 strictly prefers the Case 2^d equilibrium given the Case 2^d IC constraint in equation (41). Firm 1 strictly prefers the Case 1^d equilibrium because when it bids P_1 in Case 2^d, it is the high bidder with probability one, but in Case 1^d, firm 1 is the high bidder with probability $\lim_{b \to P_1} H_2(b) < 1$ when it bids P_1. The mixed-strategy equilibria in the DPA are also mutually exclusive.

To prove uniqueness of the BSOC equilibrium in the DPA, note that firm 2 does not bid its BSOC P_2 in Case 2^d, hence the expected profit firm 2 earns in Case 2^d, π_2^{dn} must be at least as large as $\pi_2^d(P_2)$. Restating (41) and defining $\mu = Pr(b_1 = P_1)$, the probability firm 1 bids P_1 in Case 2^d yields:

$$\begin{aligned} \pi_2^{dn} &= (P_1 - c_1)\left\{(1-\mu)\int_{k_1}^{\bar{\theta}}[\theta - k_1]\,dG(\theta) + \mu\int_{\underline{\theta}}^{\bar{\theta}}\min\{\theta, k_2\}dG(\theta)\right\} \\ &\geq \pi_2^d \\ &= (P_1 - c_1)\left\{(1-\alpha)\int_{k_1}^{\bar{\theta}}[\theta - k_1]\,dG(\theta) + \alpha\int_{\underline{\theta}}^{\bar{\theta}}\min\{\theta, k_2\}dG(\theta)\right\} \end{aligned} \tag{21}$$

The right hand side of the first line of (21) above is greater than or equal to the third line if and only if $\mu > \alpha$ given the (MSE) condition. Hence, Case 2^d is an equilibrium in the DPA if and only if $\mu > \alpha$, and this fact rules out the possibility of multiple equilibria.

Proposition 5. *The BSOC discriminatory price auction equilibrium is unique.*

Proof. The logic is similar to Proposition 3. Suppose that both Case 1^d and Case 2^d constitute equilibria, which implies that the following four conditions hold:

$$\lim_{b \to P_1} H_1(b) = 1 - \alpha, \quad \lim_{b \to P_1} H_2(b) < 1, \quad \lim_{b \to P_1} H_1^n(b) = 1 - \mu, \quad \lim_{b \to P_1} H_2^n(b) = 1$$

Recall that Case 2^d is only feasible if $\alpha < \mu$, which comes from firm 2's Case 2^d IC constraint. However, $H_2(P_1) < 1 \Leftrightarrow \mu < \alpha$. Thus Case 1^d and Case 2^{2d} are mutually exclusive and the BSOC DPA mixed-strategy equilibrium is unique. Hence, the equilibrium infimum in the DPA, $\underline{b}^{d*}$, is the greater of the two infima:

$$\underline{b}^{d*} \equiv \max\{\underline{b}^d, \underline{b}^{dn}\} = \max\{P_1 - \frac{\phi}{\psi_1}(P_1 - c_2)(1 - \alpha), P_1 - \frac{\phi}{\psi_2}(P_1 - c_1)\}$$

□

In the DPA, if $k_2 \geq k_1$, Case 1^d is played in equilibrium because $k_2 \geq k_1$ implies that $\underline{b}^d > \underline{b}^{dn}$. This is intuitive because if firm 2 has more capacity than firm 1, firm 1 has a greater incentive to bid aggressively because the excess demand of firm 2 is lower than that of firm 1. Equivalently, firm 2 has relatively less incentive to bid aggressively as k_1 decreases because firm 1's expected excess demand rises. If $k_1 > k_2$, the DPA equilibrium can be Case 1^d or Case 2^d, depending on the parameter values.

The BSOC DPA and UPA equilibria are qualitatively similar because they share the (MSE) condition, have three mutually exclusive cases, and the Case 1 and Case 1^d equilibria contain the mass point α. Differences remain, however, and Proposition 6 shows that the DPA equilibrium infimum is lower than the equilibrium UPA infimum.

Proposition 6. *The equilibrium infimum in the discriminatory price auction is greater than the equilibrium infimum in the uniform price auction.*

Proof. Let $\underline{b}^* \equiv \max\{\underline{b}, \underline{b}^n\}$ represent the equilibrium infimum in the UPA with BSOCs and $\underline{b}^{*d} \equiv \max\{\underline{b}^d, \underline{b}^{dn}\}$ represent the equilibrium infimum in the DPA with BSOCs. Focusing on Case 1 and Case 1^d, note that $\underline{b}^d > \underline{b}$ because when firm 2 bids the infimum $\underline{b}^d$ in the DPA, the highest price it will receive for its output is $\underline{b}^d$. In contrast, when firm 2 bids the infimum $\underline{b}$ in the UPA, it will receive firm 1's bid, which is strictly greater than $\underline{b}$, if demand exceeds k_2. Furthermore, the equilibrium profits of firm 2 in Case 1 of the UPA and Case 1^d of the DPA are equal to each other, hence

$$
\begin{aligned}
\pi_2 &= (P_2 - c_2) \int_{k_1}^{\bar{\theta}} [\theta - k_1] \, dG(\theta) \\
&= (\underline{b} - c_2) \int_{\underline{\theta}}^{k_2} \theta \, dG(\theta) + (\mathrm{E}[b_1] - c_2) k_2 [1 - G(k_2)] \\
&= (\underline{b}^d - c_2) \int_{\underline{\theta}}^{k_2} \theta \, dG(\theta) + \ (\underline{b}^d - c_2) k_2 [1 - G(k_2)] \\
&= \pi_2^d
\end{aligned}
$$

Given that $\mathrm{E}[b_1] = \int_{\underline{b}}^{P_1} b dF_1(b) + \alpha P_1 > \underline{b}$, the equality of π_2 and π_2^d holds if and only if $\underline{b}^d > \underline{b}$. Focusing instead on Case 2 and Case 2^d, the same argument can be used to show that $\underline{b}^{dn} > \underline{b}^n$ because firm 1 earns equal profits in expectation in the UPA and DPA as it bids P_1 with positive probability in both, hence

$$
\begin{aligned}
\pi_1^n &= (P_1 - c_1) \int_{k_2}^{\bar{\theta}} [\theta - k_2] \, dG(\theta) \\
&= (\underline{b}^n - c_1) \int_{\underline{\theta}}^{k_1} \theta \, dG(\theta) + (\mathrm{E}[b_2] - c_1) k_1 [1 - G(k_1)] \\
&= (\underline{b}^{dn} - c_1) \int_{\underline{\theta}}^{k_1} \theta \, dG(\theta) + \ (\underline{b}^{dn} - c_1) k_1 [1 - G(k_1)] \\
&= \pi_1^{dn}
\end{aligned}
$$

where $\mathrm{E}[b_2] = \int_{\underline{b}^n}^{P_1} b \, dF_2^n(b) > \underline{b}^n$. Again, the equality between π_1^n and π_1^{dn} holds if and only if $\underline{b}^{dn} > \underline{b}^n$.

Suppose by way of contradiction that the UPA equilibrium infimum is greater than the DPA equilibrium infimum, or $\underline{b}^* \equiv \max\{\underline{b}, \underline{b}^n\} > \underline{b}^{d*} \equiv \max\{\underline{b}^d, \underline{b}^{dn}\}$. This leads to a contradiction because $\underline{b}^d > \underline{b}$ and $\underline{b}^{dn} > \underline{b}^n$. Hence with BSOCs, the equilibrium infimum in the DPA is greater than the equilibrium infimum in the UPA. These results also hold with a system-wide offer cap. $\square$

Proposition 6 is intuitive upon examination of the FOCs of the UPA and DPA given in (23) and (32), respectively. When firm i is the low bidder in the UPA, raising b only increases firm i's expected profit by $\int_{\underline{\theta}}^{k_i} \theta \, dG(\theta)$ because firm i receives its rival's bid if demand exceeds k_i. Hence, in the UPA, conditional on firm i being the low bidder and demand exceeding k_i, raising b_i doesn't increase firm i's expected profit. When firm i is the low bidder in the DPA, however, raising b slightly increases firm i's expected profits at the rate $\int_{\underline{\theta}}^{k_i} \theta \, dG(\theta) + k_i[1 - G(k_i)]$ because firm i always receives its own bid. Hence, firms have less incentive to submit low bids, conditional on being the low bidder, in the DPA as compared to the UPA.

3.3 Effects of BSOCs in the Discriminatory Price Auction

The techniques of section 2.3 can be used to study the effects of BSOCs in the DPA. Consider an initial regime with a system-wide offer cap of P_2. Then suppose that BSOCs are imposed and firm 1's BSOC is $P_1 < P_2$ while firm 2's BSOC is P_2. These effects are summarized in tables 4 through 6 below. As before, the relevant measure of efficiency is the probability that firm 1, the more efficient firm, submits the lower bid. BSOCs increase expected efficiency in almost every scenario in the DPA.

FFH found that with a system-wide offer cap of P_2, the equilibrium assumes one of two possible forms: Case 1^{sd} or 2^{sd}:

- Case 1^{sd} : $\lim_{b \to P_2} H_2^s(b) < \lim_{b \to P_2} H_1^s(b) = 1,\ \underline{b}^{sd} = P_2 - \frac{\phi}{\psi_1}(P_2 - c_2)$

- Case 2^{sd} : $\lim_{b \to P_2} H_1^{sn}(b) < \lim_{b \to P_2} H_2^{sn}(b) = 1,\ \underline{b}^{sdn} = P_2 - \frac{\phi}{\psi_2}(P_2 - c_1)$

where $H_i^s(b)$ and $H_i^{sn}(b)$, $i = 1, 2$, take the form of equation (33) which is provided in the Appendix. In Case 1^{sd} firm 1 bids more aggressively than firm 2, and in Case 2^{sd} firm 2 bids more aggressively than firm 1. When the system-wide cap is P_2, the case with the greater infimum gets played in equilibrium, thus $\underline{b}^{sd*} \equiv \max\{\underline{b}^{sd}, \underline{b}^{sdn}\}$, where $\underline{b}^{sd*}$ is the equilibrium infimum with a system-wide offer cap of P_2.

Suppose that $k_2 \geq k_1$, which implies that the initial equilibrium with a system-wide offer cap of P_2 is Case 1^{sd}. After imposing the offer cap P_1 on firm 1, three outcomes are possible: Case 1^d, Case 2^d, or the pure-strategy equilibrium $(b_1 = P_1, b_2 = P_2)$ if the (MSE) condition fails. Initial profits, π^{sd}, in Case 1^{sd} are:

$$\begin{aligned}
\pi_1^{sd} = &\quad (P_2 - c_1)\left[Pr(b_2 < P_2)\int_{k_2}^{\bar{\theta}}[\theta - k_2]\, dG(\theta) + Pr(b_2 = P_2)\int_{\underline{\theta}}^{\bar{\theta}} \min\{\theta, k_1\}\, dG(\theta)\right] \\
\pi_2^{sd} = &\quad (P_2 - c_2)\int_{k_1}^{\bar{\theta}}[\theta - k_1]\, dG(\theta)
\end{aligned}$$

where $Pr(b_2 < P_2) = \lim_{b \to P_2} H_2^{sd}(b)$ and $Pr(b_2 = P_2) = 1 - Pr(b_2 < P_2)$. If the (MSE) condition fails, the firms play the pure-strategy equilibrium $(b_1 = P_1, b_2 =$

P_2), which yields profits:

$$\begin{aligned} \tilde{\pi}_1^d &= (P_1 - c_1) \int_{\underline{\theta}}^{\bar{\theta}} \min\{\theta, k_1\}\, dG(\theta) \\ \tilde{\pi}_2^d &= (P_2 - c_2) \int_{k_1}^{\bar{\theta}} [\theta - k_1]\, dG(\theta) \end{aligned}$$

Table 4: DPA Effects of BSOCs if Initial Eq'm is Case 1^{sd}

Case 1^{sd} with single cap P_2: $\underline{b}^{sd} > \underline{b}^{sdn}$			
	Direction of change in efficiency	New π	Direction of change in π
Case 1^d if $\underline{b}^d > \underline{b}^{dn}$	$\uparrow$	π_1^d	-
		π_2^d	-
Pure-strategy	$\uparrow$	$\tilde{\pi}_1^d$	Δ
		$\tilde{\pi}_2^d$	-

Note: $k_2 \geq k_1$

Table 4 describes the effects of imposing BSOCs in the DPA if $k_2 \geq k_1$. The imposition of BSOCs unambiguously increases expected efficiency. When $k_2 \geq k_1$ in the DPA, firm 1 bids more aggressively than firm 2, with or without BSOCs.

If the (MSE) condition holds, the equilibrium changes from Case 1^{sd} to Case 1^d. Furthermore, the expected efficiency increases because the probability that firm 1 is the low bidder increases (see the Appendix for proof). Clearly, the pure-strategy equilibrium is more efficient than Case 1^{sd}. Firm 2's profits do not change if firm 1 is capped at P_1 because firm 2 bids P_2 with positive probability in both Case 1^d

and Case 1^{sd}. If the equilibrium switches from Case 1^{sd} to Case 1^{d}, the expected profit of firms 1 and 2 remain constant because the infimum doesn't change.

Table 5: DPA Effects of BSOCs if Initial Eq'm is Case 1^{sd}

Case 1^{sd} with single cap P_2: $\underline{b}^{sd} > \underline{b}^{sdn}$			
	Direction of change in efficiency	New π	Direction of change in π
Case 1^{d}	$\uparrow$	π_1^d	-
		π_2^d	-
Pure-strategy	$\uparrow$	$\tilde{\pi}_1^d$	Δ
		$\tilde{\pi}_2^d$	-

Note: $k_2 < k_1$

The infimum doesn't change when the BSOCs are imposed because firm 2 bids P_2 in both Case 1 and Case 1^{sd} and hence must have expected profits equal to $\bar{\pi}_2^d(P_2) = (P_2 - c_2)\int_{k_1}^{\bar{\theta}} [\theta - k_1]\, dG(\theta)$ in both equilibria. Hence $\underline{b}^{sd} = \underline{b}^{d} = \underline{b}^{*}$. It is surprising that the BSOCs have no impact on the expected profit of either firm and this result is driven by the fact that firm 2 bids P_2 in both Case 1 and Case 1^{d}. If the (MSE) condition fails, firm 1's expected profits increase if $P_1 > \underline{b}^{sd}$ and decrease otherwise, while firm 2's profits don't change.

If $k_2 < k_1$, both Case 1^{sd} and 2^{sd} are possible with a system-wide cap of P_2. The effects of the BSOCs on efficiency and equilibrium profits are described in tables 5 and 6. Table 5 summarizes the effects of the BSOCs if the initial equilibrium is Case 1^{sd}. As in table 4, the BSOCs are efficiency enhancing if the initial equi-

Table 6: DPA Effects of BSOCs if Initial Eq'm is Case 2^{sd}

Case 2^{sd} with single cap P_2: $\underline{b}^{sdn} > \underline{b}^{sd}$			
	Direction of change in efficiency	New π	Direction of change in π
Case 1^d if $\underline{b}^d > \underline{b}^{dn}$	$\uparrow$	π_1^d	$\downarrow$
		π_2^d	$\downarrow$
Case 2^d if $\underline{b}^{dn} > \underline{b}^d$	Δ	π_1^{dn}	$\downarrow$
		π_2^{dn}	$\downarrow$
Pure-strategy	$\uparrow$	$\tilde{\pi}_1^d$	Δ
		$\tilde{\pi}_2^d$	$\downarrow$

Note: $k_2 < k_1$

librium is Case 1^{sd}. The BSOCs don't affect equilibrium profits if the (MSE) condition holds because the infimum of the DPA doesn't change when the equilibrium changes from Case 1^{sd} to Case 1^d. If the (MSE) condition fails, handicapping firm 1 increases firm 1's profits if $P_1 > \underline{b}^{sd}$ and decreases them otherwise.[24]

If $k_2 < k_1$ and the system-wide offer cap equilibrium is Case 2^{sd}, three outcomes, which are summarized in table 6, are possible: Case 1^d, Case 2^d, and the pure-strategy equilibrium. If the initial equilibrium is Case 2^{sdn}, $\underline{b}^{sdn} > \underline{b}^{sd}$ and expected profits with the system-wide cap are:

$$\begin{aligned}
\pi_1^{sdn} &= (P_2 - c_1) \int_{k_2}^{\bar{\theta}} [\theta - k_2]\, dG(\theta) \\
\pi_2^{sdn} &= (P_2 - c_2) \left[Pr(b_1 < P_2) \int_{k_1}^{\bar{\theta}} [\theta - k_1]\, dG(\theta) + Pr(b_1 = P_2) \int_{\underline{\theta}}^{\bar{\theta}} \max\{\theta, k_2\}\, dG(\theta) \right]
\end{aligned}$$

[24]Table 5 does not include Case 2^d because if $k_2 < k_1$ Case 2^d is not possible because $\underline{b}^{ds} > \underline{b}^{sdn}$.

where $Pr(b_1 < P_2) = \lim_{b \to P_2} H_1^{sn}(b)$ and $Pr(b_1 = P_2) = 1 - Pr(b_1 < P_2)$.

BSOCs are efficiency enhancing if they cause the equilibrium to switch from Case 2^{sd} to Case 1^d or the pure-strategy equilibrium. When the equilibrium changes from Case 2^{sd} to Case 2^d, the effect on efficiency is ambiguous. If the BSOC equilibrium is Case 1^d, the expected profits of both firms decrease because the infimum falls as $\underline{b}^{dsn} > \underline{b}^{ds} > \underline{b}^{ds}$. If the Case 2^d equilibrium results, the expected profit of both firms decrease. As in the UPA, firm 1's expected profits increase provided $\underline{b}^{sdn} > P_1$, and decrease otherwise. Moving from the Case 1^{sd} equilibrium to the pure-strategy equilibrium leaves firm 2's profits unchanged because firm 2 bids P_2 with positive probability in both equilibria.

BSOCs have similar effects in UPA and DPA; Case 1 is analogous to Case 1^d while Case 2 is analogous to Case 2^d. The UPA and DPA also share the (MSE) condition, α, and expected efficiency increases with BSOCs. In the UPA, firm 1 can benefit from BSOCs provided P_1 is sufficiently high because it can receive a price greater than its BSOC if firm 2 sets the uniform price. In contrast to the UPA, BSOCs only increase firm 1's profits in the DPA if they induce the pure-strategy equilibrium and the initial infimum ($\underline{b}^{sd}$ or $\underline{b}^{sdn}$) is less than or equal to P_1. This follows from the nature of the DPA, where the firm with the low bid is paid its bid regardless of the realization of demand and the bid of its rival.

4 Numerical Examples

This section contains numerical examples of the BSOC equilibrium in the DPA and UPA. The numerical examples in table 7 show the equilibrium UPA CDFs for three capacity pairs before and after the imposition of BSOCs. All numerical examples assume an initial system-wide cap of P_2 and show the effects of imposing BSOCs of P_1 on firm 1 and P_2 on firm 2, where $c_1 = 1, c_2 = 2, P_1 = 10, P_2 = 15$, and $\theta \sim \text{unif}[0, 1]$. In example 1, $k_2 > k_1$ and the initial equilibrium with a system-wide offer cap of P_2 is Case 1^s, and firm 2 bids P_2 with probability 0.694. When the BSOCs are imposed, the equilibrium changes from Case 1^s to Case 1. In the BSOC equilibrium, firm 1 bids P_1 with probability $\alpha = 0.409$ and firm 2 bids P_2 with probability 0.829. The expected profit of firm 1 increases as a result of the BSOCs while firm 2's expected profits remain unchanged, which is consistent with table 3.

In example 2, $k_1 > k_2$ and the equilibrium changes from Case 2^s to Case 2 when BSOCs are imposed. With a system-wide cap of P_2, firm 1 bids the supremum P_2 with probability 0.594, while in the BSOC Case 2 equilibrium, firm 1 bids the supremum P_1 with probability 0.552. Recall from table 3 that the BSOCs are efficiency enhancing when the equilibrium changes from Case 2^s to Case 2. The profits of both firms decrease as a result of the BSOCs, which is expected because the firms are bidding on a lower interval. Example 2 is again reminiscent of Ausubel and Cramton's concept of supply reduction (which is equivalent to

Table 7: Uniform Price Auction Numerical Examples

Example 1: Case 1							
				Case 1^s		Case 1	
k_1	0.4	λ_1	-0.236	$Pr(b_1 < P_2)$	1	$Pr(b_1 < P_1)$	0.591
k_2	0.7	β_1	0.891	$Pr(b_2 < P_2)$	0.306	$Pr(b_2 < P_1)$	0.171
		λ_2	-0.127	$\underline{b}^s$	5.528	$\underline{b}$	5.889
		β_2	0.291	π_1^s	3.302	π_1	3.452
				π_2^s	2.340	π_2	2.340
Example 2: Case 2							
				Case 2^s		Case 2	
k_1	0.7	λ_1	-0.127	$Pr(b_1 < P_2)$	0.406	$Pr(b_1 < P_1)$	0.448
k_2	0.4	β_1	0.291	$Pr(b_2 < P_2)$	1	$Pr(b_2 < P_1)$	1
		λ_2	-0.236	$\underline{b}^{sn}$	4.799	$\underline{b}$	3.442
		β_2	0.891	π_1^{sn}	2.520	π_1^n	1.620
				π_2^{sn}	2.709	π_2^n	1.575

demand reduction since this is a procurement auction), as firm 1 is larger and more efficient than firm 2, yet bids less aggressively due to its relatively large size.

In general as $k_2 \downarrow \underline{\theta}$ and $k_1 \uparrow \bar{\theta}$, Case 1 is not possible in equilibrium because firm 1 becomes less aggressive as the probability that $\theta > k_2$ approaches one. Furthermore, firm 2 becomes more aggressive as $k_1 \uparrow \bar{\theta}$ because serving firm 1's excess demand becomes less profitable as k_1 increases. Similarly, the Case 2 equilibrium becomes infeasible as $k_1 \downarrow \underline{\theta}$ and $k_2 \uparrow \bar{\theta}$.

Table 8 contains two numerical examples of DPA equilibria with BSOCs. Examples 3 and 4 show the effects of switching from a system-wide offer cap of P_2 to BSOCs with a BSOC of P_1 on firm 1 and a BSOC of P_2 on firm 2. The examples in table 8 assume the same parameter values and demand distribution as table 7. Only the auction format differs. In example 3, the system-wide offer cap equi-

Table 8: Discriminatory Price Auction Numerical Examples

Example 3: Case 1^d							
				Case1^{sd}		Case 1^d	
k_1	0.4	ψ_1	0.455	$Pr(b_1 < P_2)$	1	$Pr(b_1 < P_1)$	0.591
k_2	0.7	ψ_2	0.32	$Pr(b_2 < P_2)$	0.653	$Pr(b_2 < P_1)$	0.369
		ϕ	0.275	$\underline{b}^{sd}$	7.143	$\underline{b}^d$	7.143
				π_1^{sd}	1.966	π_1^d	1.966
				π_2^{sd}	2.340	π_2^d	2.34
Example 4: Case 2^d							
				Case2^{sd}		Case 2^d	
k_1	0.7	ψ_1	0.32	$Pr(b_1 < P_2)$	0.757	$Pr(b_1 < P_1)$	0.791
k_2	0.4	ψ_2	0.455	$Pr(b_2 < P_2)$	1	$Pr(b_2 < P_1)$	1
		ϕ	0.275	$\underline{b}^{sdn}$	6.538	$\underline{b}^{dn}$	4.560
				π_1^{sdn}	2.520	π_1^{dn}	1.620
				π_2^{sdn}	1.452	π_2^{dn}	0.819

librium is Case 1^{sd} and the BSOC lead to the Case 1^d equilibrium. Recall that the infima of Case 1^{sd} and Case 1^d are equal, therefore the expected profits of firm 1 and 2 are not changed by the BOSCs. The BSOCs also increase expected efficiency. For example, in Case 1^{sd}, firm 2 bids the supremum P_2 with probability 0.347 and in Case 1^d, firm 2 bids P_2 with probability 0.631. Note that α, the probability that firm 1 bids P_1 in Case 1 of the UPA and Case 1^d of the DPA, is the same. The equilibrium infima in the DPA are higher than the infima in the UPA. This general result was proved in Proposition 6.

In example 4, the equilibrium switches from Case 2^{sd} to Case 2^d and the infimum falls. As a result, the expected profit of both firm 1 and firm 2 decreases. As in the UPA, as $k_1 \downarrow \underline{\theta}$ and $k_2 \uparrow \bar{\theta}$ in the DPA, the Case 1^d equilibrium is played. Similarly, as $k_2 \downarrow \underline{\theta}$ and $k_1 \uparrow \bar{\theta}$ the Case 2^d equilibrium is played. When comparing tables 7 and 8, note that the expected profits in the UPA are at least as high as the expected profits in the DPA. This result is consistent with Back and Zender's result that uniform price procurement auctions have higher prices than discriminatory-price procurement auctions (Back and Zender, 1993).

5 Conclusion

BSOCs affect the efficiency, equilibrium bidding strategies, and profits in the UPA and the DPA. The results suggest that BSOCs can unambiguously increase expected production efficiency in the UPA and in most cases in the DPA. Therefore, the BSOCs in the PJM, ISONE, and NYISO likely achieve their goal of mitigating the adverse effects of generator market power. The model also predicts that in the UPA, handicapping the more efficient firm by imposing BSOCs that are increasing in marginal cost can increase the expected profit of that firm. This result is consistent with PJM's 2004 State of the Market Report (PJM Interconnection 2005), which found that generators with lower BSOCs than their rivals earned revenues greater than or equal to the revenues of comparable generators that didn't face BSOCs. Given the BSOC model in this chapter, a lower BSOC will increase generator profit if the generator is relatively small because BSOCs help small generators commit to bidding more aggressively. However, BSOCs decrease the profits of the more efficient firm if that firm is large relative to its rival. As such, BSOCs may result in a dynamic inefficiency if they penalize generators for being more efficient. As such, BSOCs should be chosen carefully and with consideration for the long term implications.

The model can be extended to include multiple firms and step-supply functions to make direct inferences about BSOCs in wholesale electricity markets. Additional extensions include adding a capacity commitment stage, a two-part bid consisting of a startup cost and a per-MW energy cost, and exploring the effect of BSOCs on long-term investment. Two-thirds of US electricity customers live in regions served by centrally dispatched wholesale electricity markets.[25] Given that BSOCs increase expected efficiency in the UPA, they might be implemented with some success in other wholesale electricity markets in the US such as the ERCOT, the California ISO, and the Southwest Power Pool.

[25] "The Value Independent Regional Grid Operators" by the RTO/ISO Council, November 2005

6 Appendix

Proof of Lemma 4

Lemma 4.1: *Firm 2 will not place density in the interval* (P_1, P_2)

When firm 2 bids in the interval (P_1, P_2) it is the high bidder with probability one. For $b \in (P_1, P_2)$, raising b_2 does not change the expected quantity of electricity sold but strictly increases firm 2's revenue.

Lemma 4.2: $F_1(b)$ *and* $F_2(b)$ *have a common infimum* $\underline{b}$

Let $\underline{b}_1 \equiv \inf\{z|F_i(z) > 0, i = 1, 2\} \geq c_2$ represent the infimium bid of player i. Suppose that $\underline{b}_i > \underline{b}_j$. If firm j bids on the interval $[\underline{b}_j, \underline{b}_i)$ it is the low bidder with probability one and its expected profits are strictly increasing in b. Consequently, firm j will move any density in the interval $[\underline{b}_j, \underline{b}_i)$ to just below $\underline{b}_i$.

Lemma 4.3: $F_1(b)$ *and* $F_2(b)$ *have a common and fully connected support for* $b \in [\underline{b}, P_1]$*, where both firms place density in the interval* $(P_1 - \epsilon, P_1)$*, for any* $\epsilon \in (0, P_1 - \underline{b})$

Step 1: The common support $S \subset [\underline{b}, P_1]$ is fully connected (No Gaps)

Part A: No common gaps. Suppose there is a common gap in $F_1(b)$ and $F_2(b)$ such that both firms place zero density in the interval $[\underline{b}', \bar{b}']$. A profitable deviation exists for $\tilde{b} \in [\underline{b}' - y, \underline{b}']$ for firm i, in this case. Firm i will move density from the interval $(\underline{b}' - y, \underline{b}')$, for some $y > 0$, just below $\bar{b}'$. Firm i finds it profitable or at least as profitable to do so in Cases $i - iv$ described below.

- Case i.) If firm i is the low bidder but not the marginal firm (occurs with probability $[1 - F_j(\tilde{b})][1 - P_2(k_i)]$), firm j determines the market price and firm i's profits do not change.

- Case ii.) If firm i is the low bidder and the marginal firm (occurs with probability $[1 - F_j(\tilde{b})]P_2(k_i)$), firm i determines the market price and firm i's profits increase by $(\bar{b}' - \tilde{\epsilon} - \tilde{b})\mathrm{E}[\theta|\theta < k_i] > 0, \tilde{\epsilon} > 0$, when it moves the density just below $\underline{b}'$.

- Case iii.) If firm i is the high bidder and the marginal firm, moving the density increases profits by $(\bar{b}' - \tilde{\epsilon}' - \tilde{b})\mathrm{E}[\theta - k_j|\theta \geq k_j] > 0, \tilde{\epsilon}' > 0$.

- Case iv.) If firm i is the high bidder and not the marginal firm, moving the density does not affect firm i's profits.

The cost of moving the density from $(\underline{b}' - y, \underline{b}')$ to just below $\bar{b}'$ involves situations where a bid $\tilde{b}$ would have been lower than b_j and moving the density up makes firm i the high bidder. This happens when $b_j \in [\tilde{b}, \underline{b}')$ but y can be chosen to make the probability of this event arbitrarily close to zero.

Part B: No individual gaps. It cannot be the case for $b \in [\underline{b}, P_1]$ that $F_i(b)$ is constant in the interval $[\underline{b}'', \bar{b}'']$ and $F_j(b)$ is strictly increasing in that interval. As in Case 1 above, firm i has the incentive to move mass from $[\underline{b}'' - \kappa, \underline{b}'']$ for some

$\kappa > 0$, to just below $\bar{b}''$ because doing so does not change the expected ranking of the two bids and thus strictly increases firm i's profits.

Step 2: $\sup\{b|F_1(b) \leq 1\} = \sup\{b|F_2(b) \leq 1\} = P_1$ for $b \in [c_2, P_1)$

Suppose by way of contradiction that $s_j^* = \sup\{z|F_j(z) = 1\} > \sup\{z|F_i(z) = 1\} = s_i^*$. In this case, firm j has a profitable deviation: move all of the density in $(s_i^*, s_j^*]$ to P_1. Such a deviation will strictly increase firm j's profits because any bid in $(s_i^*, s_j^*]$ will be the high bid with probability one, hence firm j's profits are strictly increasing in its bid for any $b \in (s_i^*, s_j^*]$. Part A showed that if firm j places zero density in any interval $\Delta \in [\underline{b}, P_1]$, firm i will place density in Δ. Equilibrium behavior requires that both firms place density in the interval $(P_1 - e, P_1)$, for any $e > 0$ such that $P_1 - e \geq \underline{b}$.

Given Parts A and B, $F_1(b)$ and $F_2(b)$ have a common supremum of P_1 and the support is common and fully connected.

Lemma 4.4: *Neither firm places mass at the common infimum* $\underline{b}$

Suppose firm 1 has mass $\omega > 0$ at $\underline{b}$ and firm 2 has mass $\varphi > 0$ at $\underline{b}$. In this case, the firms will tie with probability $\omega\varphi$ and firm 2 will serve the excess demand of firm 1. Firm 2 has an incentive to move the mass φ to just below ω because its profits increase by: $\omega\varphi \mathrm{E}[\min\{\theta, k_2\}] > \omega\varphi \int_{k_1}^{\overline{\theta}} [\theta - k_1]\, dG(\theta)$.

Suppose firm j has mass at $\underline{b}$ while firm i does not. Firm i then has an incentive to undercut firm j and move some density from $(\underline{b}, \underline{b}+\xi)$ to $\underline{b}$ for some $\xi > 0$. Moving the density discretely increases firm i's expected quantity sold and has a continuous (negligible) effect on price. The only remaining possibility in equilibrium is that neither firm places mass at $\underline{b}$.

Proof of Lemma 5

Lemma 5.1: *Firm 2 has zero density at* P_1

Consider the following two cases:

Case A: Suppose firm 1 has mass $\omega' > 0$ at P_1 and firm 2 has mass $\varphi' > 0$ at P_1. If both firms bid P_1, firm 1 would be dispatched first and firm 2 would serve firm 1's excess demand. In this case, firm 2 can strictly increase its profits by moving the mass φ' to P_2 because doing so increases firm 2's expected revenue by $\omega'\varphi'(P_2 - P_1)\mathrm{E}[\theta - k_1|\theta > k_1]$.

Case B: Suppose firm 1 has no mass at P_1 and firm 2 has mass $\varphi' > 0$ at P_1. In this case, a bid of P_1 by firm 2 is the high bid with probability one, so firm 2 should move the mass φ' to P_2.

Hence, regardless of the behavior of firm 1, firm 2 will not bid P_1 with positive probability.

Lemma 5.2: *Firm 2 places nonzero mass at* P_2

Step 1: If firm 1 does not place positive mass at P_1, firm 2 will place positive mass at P_2.

Lemma 5.1 established that firm 2 will not place mass at P_1. Since both firms place density in some interval $(P_1 - \varepsilon, P_1)$, firm 2 will find it profitable to move density in this interval to P_2 as the probability of bidding below firm 1 is arbitrarily low in this interval for sufficiently small $\varepsilon > 0$. Hence, firm 2 will be the high bidder for all bids in $(P_1 - \varepsilon, P_1)$ and serve firm 1's excess demand whether it bids in $(P_1 - \varepsilon, P_1)$ or at P_2.

Step 2: If firm 1 places positive mass at P_1, there exists an α such that firm 2 will place positive mass at P_2

Suppose firm 1 has mass α at P_1. It has been established that firm 2 will not place mass at P_1 in this case. Given the (MSE) condition, there exists an $\alpha \in (0,1)$ such that:

$$\begin{aligned}\pi_2(P_1) &= (1-\alpha)\left\{(P_1 - c_2)\int_{k_1}^{\bar{\theta}}[\theta - k_1]\,dG(\theta)\right\} + \alpha\left\{(P_1 - c_2)\int_{\underline{\theta}}^{\bar{\theta}}\min\{\theta, k_2\}\,dG(\theta)\right\} \\ &= (P_2 - c_2)\int_{k_1}^{\bar{\theta}}[\theta - k_1]\,dG(\theta)\end{aligned} \tag{22}$$

If firm 1 places mass α at P_1, firm 2 will place positive mass at P_2 in equilibrium. Steps 1 and 2 show that in the Case 1 equilibrium firm 2 will always place mass at P_2.

Lemma 5.3: *Firm 1 places nonzero mass at* P_1

By Lemma 5.1, firm 2 will never place positive mass at P_1 but will bid P_2 with positive probability. Given that firm 2 has a mass point at P_2, firm 1 will put nonzero mass immediately below P_2. Since firm 1's BSOC prevents it from doing so, firm 1 will place mass at P_1. The (MSE) rules out the pure-strategy equilibrium, so firm 1 will not bid P_1 with probability one but will bid in the region $[\underline{b}, P_1]$.

Lemma 5.4: *The common infimum* $\underline{b} > c_2$

The expression in step 2 of Lemma 5.2 gives firm 2's expected profit in the Case 1 equilibrium. Suppose that $\underline{b} \leq c_2$. Bidding arbitrarily close to the infimum $\underline{b}$ yields an expected profit in the limit of:

$$G(k_2)(\underline{b} - c_2) \int_{\underline{\theta}}^{\overline{\theta}} \min\{\theta, k_2\} \, dG(\theta) + [1 - G(k_2)]k_2(E[b_1] - c_2)$$

which is strictly below $(P_2 - c_2) \int_{k_1}^{\bar{\theta}} [\theta - k_1] \, dG(\theta)$. This is easily seen by examining (22). Hence, firm 2's bids in the region $(\underline{b}, \underline{b} + \varrho)$, $\varrho > 0$ small, are strictly dominated by a bid of P_2. Therefore the common infimum $\underline{b}$ is strictly greater than c_2. Since firm 2 earns at least $\pi_2(P_2)$ in the Case 1 equilibrium (by the IC constraint) the same logic can be used to prove that the Case 2 infimum satisfies $\underline{b}^n > c_2$.

Comparative Statics of α

The comparative statics of α, the probability that firm 1 bids P_1 in Case 1 of the UPA and Case 1^d of the DPA, are provided below.

$$\frac{\partial\alpha}{\partial P_2} = \frac{\Omega}{(P_1 - c_2)} > 0,\ \frac{\partial\alpha}{\partial P_1} = \Omega\frac{c_2 - P_2}{(P_1 - c_2)} < 0,\ \frac{\partial\alpha}{\partial c_2} = \Omega\frac{P_2 - P_1}{(P_1 - c_2)} > 0$$

$$\frac{\partial\alpha}{\partial k_1} = (-1)\cdot\frac{\left(\frac{(P_2-P_1)}{(P_1-c_2)}\right)[1 - P_2(k_1)]\left(\Psi + \int_{k_1}^{\bar{\theta}}[\theta - k_1]\,dG(\theta)\right)}{(\Psi)^2} < 0$$

$$\frac{\partial\alpha}{\partial k_2} = (-1)\cdot\frac{\left(\frac{(P_2-P_1)}{(P_1-c_2)}\right)[1 - P_2(k_2)]\int_{k_1}^{\bar{\theta}}[\theta - k_1]\,dG(\theta)}{(\Psi)^2} < 0$$

where

$$\Omega = \frac{\int_{k_1}^{\bar{\theta}}[\theta - k_1]\,dG(\theta)}{\Psi} \text{ and } \Psi = \int_{\underline{\theta}}^{\bar{\theta}}\theta\,dG(\theta) - \int_{k_2}^{\bar{\theta}}[\theta - k_2]\,dG(\theta) - \int_{k_1}^{\bar{\theta}}[\theta - k_1]\,dG(\theta)$$

Proof of Proposition 1

Take the derivative of firm i's expected profit, given in (5), with respect to b to get the first-order condition ("FOC") that must be satisfied for all $b \in (\underline{b}, P_1)$.

$$\begin{aligned} &F_j(b)\int_{k_j}^{\bar{\theta}}[\theta - k_j]\,dG(\theta) + [1 - F_j(b)]\int_{\underline{\theta}}^{k_i}\theta\,dG(\theta)\ - \\ &(b - c_i)f_j(b)\left\{\int_{\underline{\theta}}^{\bar{\theta}}\min\{\theta, k_i\}\theta\,dG(\theta) - \int_{k_i}^{\bar{\theta}}[\theta - k_j]\,dG(\theta)\right\} = \ 0 \end{aligned} \tag{23}$$

The first term represents the gain to firm i from increasing its bid when it is the high bidder, which increases the revenue on the excess demand $(\theta - k_j)$ that firm i serves. The second term represents the benefit from increasing b if firm i is the low bidder and $\theta < k_i$. In this case, firm i receives its own bid for all output sold so increasing b increases the revenue on all quantity sold. The third term represents the cost of increasing firm i's bid when the increase changes the ranking of the bids from $b_i < b_j$ to $b_j < b_i$, which occurs with probability $f_j(b)$. This change in the bid ranking decreases the expected quantity firm i sells because it is forced to serve excess demand rather than serving demand up to capacity.

The FOCs in (23) are first-order differential equations in b for $j = 1, 2$ and can be written:

$$f_j(b) - \frac{\lambda_j}{(b - c_i)} F_j(b) = \frac{\beta_j}{(b - c_i)} \tag{24}$$

where

$$\lambda_j = \frac{\int_{k_j}^{\bar{\theta}} (\theta - k_j)\, dG(\theta) - \int_{\underline{\theta}}^{k_i} \theta\, dG(\theta)}{\int_{\underline{\theta}}^{\bar{\theta}} \theta\, dG(\theta) - \int_{k_j}^{\bar{\theta}} [\theta - k_j]\, dG(\theta) - \int_{k_i}^{\bar{\theta}} [\theta - k_i]\, dG(\theta)}$$

$$\beta_j = \frac{\int_{\underline{\theta}}^{k_i} \theta\, dG(\theta)}{\int_{\underline{\theta}}^{\bar{\theta}} \theta\, dG(\theta) - \int_{k_j}^{\bar{\theta}} [\theta - k_j]\, dG(\theta) - \int_{k_i}^{\bar{\theta}} [\theta - k_i]\, dG(\theta)}$$

The FOC of firm i defines the CDF of firm j's mixed-strategy for all $b \in (\underline{b}, P_1)$. Since there is no mass point at the common infimum $\underline{b}$ in either firm's CDF, the initial condition on the differential equation in (24) is $F_j(\underline{b}) = 0$. Hence, the differential equation becomes:

$$F_j(b) = \begin{cases} \beta_j \ln\left(\frac{b - c_i}{\underline{b} - c_i}\right) & for\ \lambda_j = 0 \\ \frac{\beta_j}{\lambda_j}\left[\left(\frac{b - c_i}{\underline{b} - c_i}\right)^{\lambda_j} - 1\right] & for\ \lambda_j \neq 0 \end{cases} \tag{25}$$

In Case 1, firm 1 places mass α at P_1 so the common infimum $\underline{b}$ can be calculated uniquely by imposing the terminal condition $\lim_{b \to P_1} F_1(b) = 1 - \alpha$.

$$\underline{b} = \begin{cases} = c_2 + e^{\frac{-(1-\alpha)}{\beta_1}}(P_1 - c_2) & if \lambda_1 = \lambda_2 = 0 \\ = c_2 + \left(\frac{\beta_1}{(1-\alpha)\lambda_1 + \beta_1}\right)^{\frac{1}{\lambda_1}}(P_1 - c_2) & if \lambda_1, \lambda_2 \neq 0 \end{cases} \tag{26}$$

$\square$

Proof of Proposition 2

Proof: In Case 2, firm 2 bids more aggressively than firm 1 and as in FFH, the terminal condition is $\lim_{b \to P_1} F_2^n(b) = 1$. This yields the Case 2 BSOC infimum $\underline{b}^n$:

$$\underline{b}^n = \begin{cases} = c_1 + e^{\frac{-1}{\beta_1}}(P_1 - c_1) & if \lambda_1 = \lambda_2 = 0 \\ = c_1 + (P_1 - c_1)\left(\frac{\beta_2}{\lambda_2 + \beta_2}\right)^{\frac{1}{\lambda_2}} & if \lambda_1, \lambda_2 \neq 0 \end{cases} \tag{27}$$

Inserting $\underline{b}^n$ into (25) yields $F_1^n(b)$ and $F_2^n(b)$ above. Note that $\underline{b}^n$ must be greater than c_2 for Case 2 to be feasible.$\square$

Proof of results in table 2

To compare the CDFs of Case 1 and Case 1^s, one must examine the infima, $\underline{b}$ and $\underline{b}^s$. If $\lim_{b \to P_1} F_1(b) < \lim_{b \to P_1} F_1^s(b)$, then $\underline{b} > \underline{b}^s$ because the CDF in (25) is strictly decreasing in the infimum. Given the properties of Case 1 and Case 1^s

$$\lim_{b \to P_1} F_1(b) + \alpha = \lim_{b \to P_2} F_1^s(b) = \lim_{b \to P_1} F_1^s(b) + [\lim_{b \to P_2} F_1^s(b) - \lim_{b \to P_1} F_1^s(b)] = 1$$

which implies that

$$\lim_{b\to P_1} F_1(b) - \lim_{b\to P_1} F_1^s(P_1) = [\lim_{b\to P_2} F_1^s(b) - \lim_{b\to P_1} F_1^s(b)] - \alpha \tag{28}$$

Hence $\underline{b} > \underline{b}^s$ if $\alpha > \lim_{b\to P_2} F_1^s(b) - \lim_{b\to P_1} F_1^s(b)$

$$\begin{aligned}
\lim_{b\to P_2} F_1^s(b) - \lim_{b\to P_1} F_1^s(b) &= \tfrac{\beta_1}{\lambda_1}[\left(\tfrac{P_2-c_2}{\underline{b}^s-c_2}\right)^{\lambda_1} - 1] - \tfrac{\beta_1}{\lambda_1}[\left(\tfrac{P_1-c_2}{\underline{b}^s-c_2}\right)^{\lambda_1} - 1] \\
&= \tfrac{\beta_1}{\lambda_1}\left[\left(\tfrac{P_2-c_2}{\underline{b}^s-c_2}\right)^{\lambda_1} - \left(\tfrac{P_1-c_2}{\underline{b}^s-c_2}\right)^{\lambda_1}\right] \\
&= \tfrac{\beta_1}{\lambda_1}\left[\left(\tfrac{\lambda_1+\beta_1}{\beta_1}\right) - \left(\tfrac{P_1-c_2}{\underline{b}^s-c_2}\right)^{\lambda_1}\right] \\
&= \tfrac{\beta_1}{\lambda_1}\left[\left(\tfrac{\lambda_1+\beta_1}{\beta_1}\right) - \left(\tfrac{P_1-c_2}{P_2-c_2}\right)^{\lambda_1}\left(\tfrac{\lambda_1+\beta_1}{\beta_1}\right)\right]
\end{aligned}$$

$$\alpha = 1 - \lim_{b\to P_1} F_1(b) = 1 - \frac{\beta_1}{\lambda_1}\left[\left(\frac{P_1-c_2}{\underline{b}-c_2}\right)^{\lambda_1} - 1\right]$$

The next step is to determine the relationship between $\lim_{b\to P_2} F_1^s(b) - \lim_{b\to P_1} F_1^s(b)$ and α.

$$\begin{aligned}
\lim_{b\to P_2} F_1^s(b) - \lim_{b\to P_1} F_1^s(b) &\lesseqgtr \alpha \\
\Rightarrow \quad \tfrac{\beta_1}{\lambda_1}\left[\left(\tfrac{\lambda_1+\beta_1}{\beta_1}\right) - \left(\tfrac{P_1-c_2}{P_2-c_2}\right)^{\lambda_1}\left(\tfrac{\lambda_1+\beta_1}{\beta_1}\right)\right] &\lesseqgtr 1 - \tfrac{\beta_1}{\lambda_1}\left[\left(\tfrac{P_1-c_2}{\underline{b}-c_2}\right)^{\lambda_1} - 1\right] \\
\Rightarrow \quad \tfrac{\lambda_1+\beta_1}{\lambda_1} - \left(\tfrac{P_1-c_2}{P_2-c_2}\right)^{\lambda_1}\left(\tfrac{\lambda_1+\beta_1}{\beta_1}\right)\tfrac{\beta_1}{\lambda_1} &\lesseqgtr 1 + \tfrac{\beta_1}{\lambda_1} - \tfrac{\beta_1}{\lambda_1}\left(\tfrac{P_1-c_2}{\underline{b}-c_2}\right)^{\lambda_1} \\
\Rightarrow \quad \tfrac{\lambda_1+\beta_1}{\lambda_1} - \left(\tfrac{P_1-c_2}{P_2-c_2}\right)^{\lambda_1}\left(\tfrac{\lambda_1+\beta_1}{\lambda_1}\right) &\lesseqgtr \tfrac{\lambda_1+\beta_1}{\lambda_1} - \tfrac{\beta_1}{\lambda_1}\left(\tfrac{P_1-c_2}{\underline{b}-c_2}\right)^{\lambda_1} \\
\Rightarrow \quad \tfrac{\beta_1}{\lambda_1}\left(\tfrac{P_1-c_2}{\underline{b}-c_2}\right)^{\lambda_1} &\lesseqgtr \left(\tfrac{P_1-c_2}{P_2-c_2}\right)^{\lambda_1}\left(\tfrac{\lambda_1+\beta_1}{\lambda_1}\right)
\end{aligned}$$

If $\lambda_1 < 0$ then $\lambda_1 + \beta_1 < \beta_1 \Rightarrow \frac{\lambda_1+\beta_1}{\lambda_1} > \frac{\beta_1}{\lambda_1}$ and
$\left(\frac{P_1-c_2}{P_2-c_2}\right)^{\lambda_1} > \left(\frac{P_1-c_2}{\underline{b}-c_2}\right)^{\lambda_1}$ because $\left(\frac{P_2-c_2}{P_1-c_2}\right)^{|\lambda_1|} > \left(\frac{\underline{b}-c_2}{P_1-c_2}\right)^{|\lambda_1|}$

Hence if $\lambda_1 < 0$ then $\lim\limits_{b\to P_2} F_1^s(b) - \lim\limits_{b\to P_1} F_1^s(b) < \alpha$ and $\underline{b} > \underline{b}^s$.

If $\lambda_1 > 0$

$$\begin{aligned} \frac{\beta_1}{\lambda_1}\left(\frac{P_1-c_2}{\underline{b}-c_2}\right)^{\lambda_1} &\lesseqgtr \left(\frac{P_1-c_2}{P_2-c_2}\right)^{\lambda_1}\left(\frac{\lambda_1+\beta_1}{\lambda_1}\right) \\ \Rightarrow \qquad \frac{\beta_1}{\lambda_1+\beta_1} &\lesseqgtr \left(\frac{\underline{b}-c_2}{P_2-c_2}\right)^{\lambda_1} \end{aligned}$$

Since $\left(\frac{\underline{b}-c_2}{P_1-c_2}\right)^{\lambda_1} = \frac{\beta_1}{(1-\alpha)\lambda_1+\beta_1} > \frac{\beta_1}{\lambda_1+\beta_1}$

$$\frac{\beta_1}{\lambda_1+\beta_1} < \frac{\beta_1}{(1-\alpha)\lambda_1+\beta_1} = \left(\frac{\underline{b}-c_2}{P_1-c_2}\right)^{\lambda_1} < \left(\frac{\underline{b}-c_2}{P_2-c_2}\right)^{\lambda_1}$$

Hence if $\lambda_1 > 0$, $\lim\limits_{b\to P_2} F_1^s(b) - \lim\limits_{b\to P_1} F_1^s(b) < \alpha$.

Given that $\lim\limits_{b\to P_2} F_1^s(b) - \lim\limits_{b\to P_1} F_1^s(P_1) < \alpha$, $\lim\limits_{b\to P_2} F_1(b) < \lim\limits_{b\to P_1} F_1^s(b)$. Thus, in the UPA, when the equilibria switches from Case 1^s to Case 1, the infimum increases: $\underline{b} > \underline{b}^s$. This is intuitive given that firm 2 must earn the same profit from bidding the infimum in Case 1 and Case 1^s, respectively, and firm 1's bids are lower in expectation when it has a BSOC of P_1 .

Given that $\underline{b} > \underline{b}^s$, if the initial equilibrium with a system-wide offer cap of P_2 is Case 1^s, only Case 1 and the pure-strategy equilibrium are possible if BSOCs are imposed because $\underline{b}^s > \underline{b}^{sn} \Rightarrow \underline{b} > \underline{b}^s > \underline{b}^{sn} > \underline{b}^n$, hence Case 2 is not feasible if the initial equilibrium is Case 1^s. Firm 2 bids P_2 in both Case 1^s and Case 1 so, in expectation, firm 2's profit in both equilibria equals $(P_2 - c_2) \int_{k_1}^{\bar{\theta}} [\theta - k_1] \, dG(\theta)$, hence, equation (29) below holds, where $\underline{b}^s$ and $\underline{b}$ are the infima of Case 1^s and Case 1, respectively.

$$\begin{aligned} \pi_2^s(\underline{b}^s) &= (\underline{b}^s - c_2) \int_{\underline{\theta}}^{k_2} \theta \, dG(\theta) + k_2[1 - G(k_2)] \int_{\underline{b}^s}^{P_2} (b - c_2) \, dF_1^s(b) \\ &= (P_2 - c_2) \int_{k_1}^{\bar{\theta}} [\theta - k_1] \, dG(\theta) \qquad (29) \\ \pi_2(\underline{b}) &= (\underline{b} - c_2) \int_{\underline{\theta}}^{k_2} \theta \, dG(\theta) + k_2[1 - G(k_2)] \int_{\underline{b}}^{P_1} (b - c_2) \, dF_1^s(b) \end{aligned}$$

Equation (29) can be rewritten as

$$(\underline{b} - c_2)x_1 + \mathrm{E}[b_1 - c_2]x_2 = (\underline{b}^s - c_2)x_1 + \mathrm{E}[b_1^s - c_2]x_2$$

which implies that:

$$\underline{b} - \underline{b}^s = \frac{x_2}{x_1} \left[\mathrm{E}[b_1^s - c_2] - \mathbb{E}[[]b_1 - c_2]\right]$$

where $x_1 = \int_{\underline{\theta}}^{k_2} \theta \, dG(\theta)$ and $x_2 = k_2[1 - P_2(k_2)]$ are both positive constants. Since $\underline{b} > \underline{b}^s$, $[\mathrm{E}[b_1^s - c_2] > \mathrm{E}[b_1 - c_2] \Leftrightarrow \mathrm{E}[b_1^s] > \mathrm{E}[b_1]$ which is intuitive as the support of firm 1's Case 1^s CDF is $(\underline{b}^s, P_2]$ while the support of the CDF in Case 1 is $(\underline{b}^s, P_1]$ and hence has a lower supremum.

When the BSOCs are imposed and the equilibrium is Case 1, hence $Pr(b_1 < b_2)$

equals:

$$\begin{aligned} Pr(b_1 < b_2) = &\ (1-\alpha)\int_{\underline{b}}^{P_1} \tfrac{1}{(1-\alpha)} F_1(b)dF_2(b) + (1-\alpha)[1 - \lim_{b \to P_1}] + \alpha[1 - \lim_{b \to P_1} F_2(b)] \\ = &\ \int_{\underline{b}}^{P_1} F_1(b)dF_2(b) + [1 - \lim_{b \to P_1} F_2(b)] \end{aligned} \tag{30}$$

If the system-wide cap is P_2,

$$Pr(b_1 < b_2) = \int_{\underline{b}^s}^{P_2} F_1^s(b)dF_2^s(b) + [1 - \lim_{b \to P_2} F_2^s(b)] \tag{31}$$

If the BSOCs are efficiency enhancing, they will increase the probability that firm 1 bids below firm 2, implying that equation (30) will be greater than (31). This holds if:

$$\int_{\underline{b}^s}^{P_2} F_1^s(b)dF_2^s(b) - \int_{\underline{b}}^{P_1} F_1(b)dF_2(b) < \lim_{b \to P_2} F_2^s(b) - \lim_{b \to P_1} F_2(b)$$

The left hand side of the inequality above has the following upper bound

$$\begin{aligned} \int_{\underline{b}^s}^{P_2} F_1^s(b)dF_2^s(b) - \int_{\underline{b}}^{P_1} F_1(b)dF_2(b) &< \int_{\underline{b}^s}^{P_2} dF_2^s(b) - \int_{\underline{b}}^{P_1} dF_2(b) \\ &= \lim_{b \to P_2} F_2^s(b) - F_2^s(\underline{b}^s) - [\lim_{b \to P_1} F_2(b) - F_2(\underline{b})] \\ &= \lim_{b \to P_2} F_2^s(b) - \lim_{b \to P_1} F_2(b) \end{aligned}$$

because $F_1(b)$ and $F_1^s(b)$ never exceed one.[26] Hence, if the equilibrium switches from Case 1^s to Case 1, the BSOCs are efficiency enhancing.

[26] $F_1(b) < 1$ for all $b < P_1$ and $F_1^s(b) < 1$ for all $b < P_2$

Firm 1's profits increase when the equilibrium switches from Case 1^s to Case 1. Firm 1 bids P_1 in both equilibria and in the system-wide offer-cap Case 1^s equilibrium, the expected bid of firm 2, conditional on being higher than P_1, is strictly less than P_2. With BSOCs, however, firm 2's bid, conditional on being higher than P_1, is P_2. Note further that $(P_1 > \underline{b} > \underline{b}^s)$. Comparing firm 1's expected profit from bidding P_1 in Case 1^s (π_1^s) and Case 1 (π_1) yields:

$$\begin{aligned}
\pi_1^s &= F_2^s(P_1)(P_1 - c_1)\int_{k_2}^{\bar{\theta}}[\theta - k_2]\,dG(\theta) + [1 - F_2^s(P_1)](P_1 - c_1)\int_{\underline{\theta}}^{k_1}\theta\,dG(\theta) \\
&\quad + [1 - F_2^s(P_1)](\mathrm{E}[\,b_2^s\,|b_2^s > P_1] - c_1)k_1[1 - G(k_1)] \\
&< \lim_{b \to P_1} F_2(b)(P_1 - c_1)\int_{k_2}^{\bar{\theta}}[\theta - k_2]\,dG(\theta) + Pr(b_2 = P_2)(P_1 - c_1)\int_{\underline{\theta}}^{k_1}\theta\,dG(\theta) \\
&\quad + Pr(b_2 = P_2)(P_2 - c_1)k_1[1 - G(k_1)] \\
&= \pi_1
\end{aligned}$$

where $Pr(b_2 = P_2) = 1 - \lim_{b \to P_1} F_2(b)$. This inequality holds because $F_2^s(P_1) > \lim_{b \to P_1} F_2(b)$ and $\mathrm{E}[\,b_2^s\,|b_2^s > P_1] < P_2$. Hence BSOCs increase firm 1's expected profit if the equilibrium changes from Case 1^s to Case 1.

Results in table 3

If the initial equilibrium with a system-wide cap of P_2 is Case 2^s and the BSOCs cause the equilibrium to change to Case 2, the probability that firm 1 is the low bidder increases. In this case, the infimum increases, as $\underline{b}^{sn} = (P_2 - c_1)(\frac{\beta_2}{\lambda_2 + \beta_2})^{\frac{1}{\lambda_2}} +$

$c_1 > \underline{b}^n = (P_1 - c_1)(\frac{\beta_2}{\lambda_2+\beta_2})^{\frac{1}{\lambda_2}} + c_1$

For any level $z \in (0,1)$ of $F_2^n(b)$ and corresponding bid such that $F_2^n(b(z)) = z:$

$$Pr(b_2 < b(z)) = F_2^n(b(z)) = \frac{\beta_2}{\lambda_2}\left[\left(\frac{b(z)-c_1}{\underline{b}^n - c_1}\right)^{\lambda_2} - 1\right] = z$$

and $b(z) = (\underline{b}^n - c_1)(\frac{z\lambda_2+\beta_2}{\beta_2})^{\frac{1}{\lambda_2}} + c_1$. The probability that firm 1 bids below $b(z)$ is

$$Pr(b_1^s < b(z)) = \frac{\beta_1}{\lambda_1}\left[\left(\frac{b(z)-c_2}{\underline{b}^n - c_2}\right)^{\lambda_1} - 1\right]$$

Similarly, for Case 2^s, for any level $z \in (0,1)$ of $F_2^{sn}(b)$

$$Pr(b_2 < b^s(z)) = \frac{\beta_2}{\lambda_2}\left[\left(\frac{b(z)-c_1}{\underline{b}^{sn} - c_1}\right)^{\lambda_2} - 1\right] = z$$

and $b^s(z) = (\underline{b}^{sn} - c_1)(\frac{z\lambda_2+\beta_2}{\beta_2})^{\frac{1}{\lambda_2}} + c_1$. The probability that firm 1 bids below $b(z)$ is

$$Pr(b_1^s < b^s(z)) = \frac{\beta_1}{\lambda_1}\left[\left(\frac{b^s(z)-c_2}{\underline{b}^n - c_2}\right)^{\lambda_1} - 1\right]$$

The fact that the infimum falls from $\underline{b}^{sn}$ to $\underline{b}^n$ and

$$\frac{d(\frac{b-c_2}{\underline{b}-c_2})}{d\underline{b}} = \frac{(c_1-c_2)\left[\left(\frac{z\lambda_2+\beta_2}{\beta_2}\right)^{\frac{1}{\lambda_2}} + 1\right]}{(\underline{b}-c_2)^2} < 0$$

implies that for every level of firm 2's CDF ($F_2^{sn}(b)$ or $F_2^n(b)$), the probability that firm 1 bids below firm 2 is higher in Case 2 than in Case 2^s. Equivalently,

$Pr(b_1 < b_2) = \int_{\underline{b}^n}^{P_1} F_1^n(b) dF_2^n(b) > \int_{\underline{b}^{sn}}^{P_2} F_1^{sn}(b) dF_2^{sn}(b) = Pr(b_1^s < b_2^s)$. Therefore, the BSOCs increase efficiency if the equilibrium switches from Case 2^s to Case 2.

Proof of Proposition 4

Taking the derivative of equation (16) with respect to b yields the DPA FOC in for bids in the joint support:

$$\begin{aligned} &H_j(b) \int_{k_j}^{\bar{\theta}} [\theta - k_j] \, dG(\theta) + [1 - H_j(b)] \int_{\underline{\theta}}^{\bar{\theta}} \min\{\theta, k_i\} \, dG(\theta) \\ &-h_j(b)(b-c) \left[\int_{\underline{\theta}}^{\bar{\theta}} \min\{\theta, k_i\} \, dG(\theta) - \int_{k_j}^{\bar{\theta}} [\theta - k_j] \, dG(\theta) \right] \end{aligned} \tag{32}$$

where $h_j(b), j = 1, 2$ is the probability density function of $H_j(b)$. The first (second) term represents the gain from increasing b, which is increased revenue, when firm i is the high (low) bidder. The third term represents the cost of increasing b, which could change the ranking of the bids and cause firm i to be dispatched second, which decreases its expected quantity sold. Solving the differential equation in (32) and imposing the initial condition $H_j(\underline{b}) = 0$ yields the following equation for $H_j(b)$:

$$H_j(b) = \frac{\psi_j}{\phi} \left(\frac{b - \underline{b}^d}{b - c_i} \right) \tag{33}$$

where $\underline{b}^d$ is the infimum of the DPA with BSOCs and

$$\begin{aligned} \phi &= \int_{\underline{\theta}}^{\bar{\theta}} \theta \, dG(\theta) - \int_{k_j}^{\bar{\theta}} [\theta - k_j] \, dG(\theta) - \int_{k_i}^{\bar{\theta}} [\theta - k_i] \, dG(\theta) \\ \psi_j &= \int_{\underline{\theta}}^{\bar{\theta}} \theta \, dG(\theta) - \int_{k_i}^{\bar{\theta}} [\theta - k_i] \, dG(\theta) \end{aligned}$$

The Case 2^d DPA equilibrium CDFs are qualitatively similar to Case 2 of the UPA. In Case 2^d, firm 2 bids more aggressively than firm 1, firm 2 always bids below P_1 , and firm 1 bids P_1 with positive probability. Imposing the terminal condition $\lim_{b \to P_1} H_2^d(b) = 1$ yields $\underline{b}^{dn}$, the infimum of Case 2^{dn} :

$$\underline{b}^{dn} = P_1 - \frac{\phi}{\psi_2}(P_1 - c_1) \tag{34}$$

Substituting $\underline{b}^{dn}$ into (33) yields the Case 2^d equilibrium CDFs, $H_1^n(b)$ and $H_2^n(b)$.

$$\begin{aligned} H_1^n(b) &= \tfrac{\psi_1}{\phi} \cdot \tfrac{(b - [P_1 - \frac{\phi}{\psi_2}(P_1 - c_1)])}{(b - c_2)} \\ H_2^n(b) &= \tfrac{\psi_2}{\phi} \cdot \tfrac{(b - [P_1 - \frac{\phi}{\psi_2}(P_1 - c_1)])}{(b - c_1)} \end{aligned} \tag{35}$$

The equilibrium CDFs of Case 1^d and Case 2^d are given by $H_j(b)$. Note that these sets of CDFs differ because the infima in Case 1^d and Case 2^d differ. Focusing on Case 1^d, the techniques of section 2 can be used to show that firm 1 bids P_1 with positive probability $\delta > 0$. As before, firm 2 will only bid P_2 if the profit from doing so equals the expected profit of bidding just below P_1, That is, $\lim_{b \to P_1} \pi_2(b) = \pi_2(P_2)$.

$$\begin{aligned} \lim_{b \to P_1} \pi_2(b) &= (\lim_{b \to P_1} \{b\} - c_2) \left\{ (1-\delta) \textstyle\int_{k_1}^{\bar{\theta}} [\theta - k_1] \, dG(\theta) + \delta \int_{\underline{\theta}}^{\bar{\theta}} \min\{\theta, k_2\} \, dG(\theta) \right\} \\ &= \pi_2(P_2) \\ &= (P_2 - c_2) \textstyle\int_{k_1}^{\bar{\theta}} [\theta - k_1] \, dG(\theta) \end{aligned}$$

Talking the limit as $b \to P_1$ and solving for δ yields:

$$\delta = \left(\frac{P_2 - P_1}{P_1 - c_2}\right) \frac{\int_{k_1}^{\bar{\theta}} [\theta - k_1]\, dG(\theta)}{\int_{\underline{\theta}}^{\bar{\theta}} \theta\, dG(\theta) - \int_{k_1}^{\bar{\theta}} [\theta - k_1]\, dG(\theta) - \int_{k_2}^{\bar{\theta}} [\theta - k_2]\, dG(\theta)} = \alpha \tag{36}$$

Hence, the probability that firm 1 bids P_1 in DPA Case 1^d is α, the same probability that firm 1 bids P_1 in Case 1 of the UPA. This results from the fact that when firm 2 chooses between bidding P_2 and arbitrarily below P_1 in the UPA, it faces the same payoffs as it would if it were bidding in a DPA because it will essentially be paid its bid if dispatched. To find the Case 1^d CDF infimum, impose the terminal condition $\lim_{b \to P_1} H_1(b) = 1 - \alpha$ on the differential equation in (33):

$$\underline{b}^d = P_1 - \frac{\phi}{\psi_1}(P_1 - c_2)(1 - \alpha) \tag{37}$$

Substituting the DPA Case 1^d infimum into (33) yields the Case 1^d equilibrium CDFs:

$$\begin{aligned} H_1(b) &= \tfrac{\psi_1}{\phi} \cdot \tfrac{(b - [P_1 - \frac{\phi}{\psi_1}(P_1 - c_2)(1-\alpha)])}{(b - c_2)} \\ H_2(b) &= \tfrac{\psi_2}{\phi} \cdot \tfrac{(b - [P_1 - \frac{\phi}{\psi_1}(P_1 - c_2)(1-\alpha)])}{(b - c_1)} \end{aligned} \tag{38}$$

The Case 2^d DPA equilibrium CDFs are qualitatively similar to Case 2 of the UPA. In Case 2^d, firm 2 bids more aggressively than firm 1, firm 2 always bids below P_1 and firm 1 bids P_1 with positive probability. Imposing the terminal condition

$\lim_{b \to P_1} H_2^d(b) = 1$ yields $\underline{b}^{dn}$, the infimum of Case 2^{dn} :

$$\underline{b}^{dn} = P_1 - \frac{\phi}{\psi_2}(P_1 - c_1) \tag{39}$$

Substituting $\underline{b}^{dn}$ into (33) yields the Case 2^d equilibrium CDFs, $H_1^n(b)$ and $H_2^n(b)$.

$$\begin{aligned} H_1^n(b) &= \tfrac{\psi_1}{\phi} \cdot \tfrac{(b - [P_1 - \frac{\phi}{\psi_2}(P_1 - c_1)])}{(b - c_2)} \\ H_2^n(b) &= \tfrac{\psi_2}{\phi} \cdot \tfrac{(b - [P_1 - \frac{\phi}{\psi_2}(P_1 - c_1)])}{(b - c_1)} \end{aligned} \tag{40}$$

The IC constraint on firm 2 in Case 2^d is:

$$\pi_2^{dn} \geq (P_2 - c_2) \int_{k_1}^{\bar{\theta}} [\theta - k_1] \, dG(\theta) = \pi_2^d \tag{41}$$

because firm 2's expected profit must be at least as large as the profit it earns from bidding P_2. Equilibrium profits in Case 2^d are:

$$\begin{aligned} \pi_1^{dn}(b) &= (P_1 - c_1) \textstyle\int_{k_2}^{\bar{\theta}} [\theta - k_2] \, dG(\theta) \\ \pi_2^{dn}(b) &= (P_1 - c_2) \Big(Pr(b_1 < P_1) \textstyle\int_{k_1}^{\bar{\theta}} [\theta - k_1] \, dG(\theta) + Pr(b_1 = P_1) \textstyle\int_{\underline{\theta}}^{\bar{\theta}} \min\{\theta, k_2\} \, dG(\theta) \Big) \end{aligned} \tag{42}$$

Results in table 4

In the DPA, when the equilibrium switches from Case 1^{sd} to Case 1^d, the infimum doesn't change, therefore, the CDF on the joint support remains constant. However, the support shrinks from $(\underline{b}^n, P_2)$ to $(\underline{b}^n, P_1)$. For $b \in (\underline{b}^n, P_1)$, the efficiency remains constant $(Pr(b_1^s < b_2^s) = Pr(b_1 < b_2))$. For $b > P_1$, however, firm 1 always bids below firm 2 in Case 1^d while in Case 1^{sd}, $Pr(b_1^s < b_2^s) < 1$. Hence, the BSOCs are efficiency enhancing when the equilibrium switches from Case 1^{sd} to Case 1^d.

Chapter 2: Equilibrium Bidding with Nonconvex Costs

(Co-authored with Ramteen Sioshansi, Ph.D.)

1 Introduction

Wholesale electricity markets facilitate the trade of electricity across a system of transmission lines. Such markets use uniform price auctions to determine the price of electricity, and the generators that submit the lowest bids, or equivalently offer to produce electricity at the lowest price, are selected to produce electricity. The two key outcomes of the auction process are generator commitment: which generators startup; and generator dispatch: the amount of electricity each generator produces. Independent system operators ("SO") conduct the uniform price auctions repeatedly throughout the day.

A debate exists as to which entity, the SO or the generators themselves, should make the dispatch decision. In centrally committed markets, generators submit two-part bids and the SO makes the commitment and dispatch decisions and guarantees that each generator recovers the startup costs stated in its energy offer. In a self committed market each generator makes its own commitment decision because it submits a single part bid for electricity, and must incorporate its startup costs into this bid. This chapter uses a simple theoretical model to compare equilibrium bidding behavior and the total cost of electricity in the centrally and self committed markets.

This is an unresolved issue in wholesale electricity market design because two markets in the U.S. use the self committed format while five others are centrally committed. Wholesale electricity auction design is important given the considerable size of the markets. In 2007, wholesale electricity market transactions totaled 52 billion dollars in four of the largest wholesale electricity markets in the U.S.[27] The revenues in these markets also have significant implications for investment in new generation capacity, which determines the future price of electricity. As such, it is important to compare the performance of centrally and self committed markets and determine which market design, if any, leads to the more efficient outcome.

The debate over the two market designs centers on the tradeoff between efficient dispatch and commitment, and generator incentives to truthfully reveal startup and energy costs. Ruff (1994), Hogan (1994), Hogan (1995), and Hunt (2002) supported centrally committed markets because they give the SO, which has the best information about the electric system as a whole, the authority to make both commitment and dispatch decisions. However, Oren and Ross (2005) showed that generators might have incentives to misstate their costs to increase profit if the SO collects a multi-part bids. As such, Wilson (1997) and Elmaghraby and Oren

[27]According to their 2007 Annual Reports, the sum of wholesale transactions in 2007 were: PJM Interconnection-$30.5 billion, New York ISO-$9.5 billion, ISO New England-$10 billion, and ERCOT-$1.9 billion.

(1999) suggested that commitment decisions are ultimately more efficient in self committed markets.

Despite the various claims about the two market designs, their incentive properties have not been directly analyzed and compared. To this end, we develop a single-period symmetric duopoly model of two markets: a centrally committed market with two-part offers (energy and startup); and a self committed market with one part offers (energy only).

By analyzing the market as a uniform price auction with system-wide caps on each bid element, we are able to characterize the Nash equilibria in each market. We then demonstrate with a numerical example that if the price caps of the two markets are chosen properly, the expected cost of electricity in the two markets are equal. Hence, generators in self committed markets are not necessarily more likely to bid their true costs than generators in centrally committed ones. We find that while electricity prices are lower in a centrally committed markets, the make-whole payments paid to generators make the two designs cost equivalent.

2 Background

Wholesale electricity auctions take place on a complex system of transmission lines that can cover more than 100,000 square miles.[28] The SO has the difficult task of

[28]The area served by the PJM Interconnection, the largest wholesale electricity market in the U.S. is 137,000 square miles. The PJM Interconnection system is comprised of 56,250 miles of

collecting the generator bids and choosing the least costly commitment and dispatch of each generator according to a uniform price auction. This process involves a complicated optimization problem given the presence of transmission constraints which limit the ability of electricity to flow throughout the grid. Furthermore, generators incur nontrivial startup costs, hence their costs are nonconvex. If the SO only paid the generators the uniform price for electricity, the generators might earn negative profits and choose not to participate.

Historically, wholesale markets in the U.S. have dealt with this problem in one of two ways: a centrally committed market with make-whole payments, and self committed markets without make-whole payments. In centrally committed markets, like the PJM Interconnection, New York ISO, ISO New England, and the Midwest ISO, generator bids consist of two parts: a one-time startup cost, and an energy bid for each unit of electricity it produces.[29] The SO uses this information to determine unit commitment (which generators to turn on), and dispatch (how much each generator will produce) for all generators in the auction. To ensure that generators do not operate at a loss according to their as-bid costs, which do not necessarily reflect true operating costs, the SO in a centrally committed system pays the generators make-whole payments if energy payments alone do not cover the sum of the generator's startup and variable energy costs.

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electric transmission lines.

[29] The PJM Interconnection is a wholesale electricity market that serves 7 states in the mid-Atlantic. The New York ISO market serves customers in New York State, ISO New England serves customers in 6 New England states, and the Midwest ISO serves customers in approximately 7 Midwestern states.

In self committed markets, like those in ERCOT and SPP, generators internalize their startup costs and fold them into their single part energy offers.[30] Generators in self committed systems do not receive any make-whole payments from the SO to recover startup costs. Hence, in self committed markets the generators make their own commitment decisions.

Originally, the debate on centralized versus self committed market designs focused on the 'just in time' nature of the power system, which requires that the supply of electricity produced by generators and the demand for electricity, referred to as load, be constantly balanced. Furthermore, the unique nature of power flows, which are not directed, makes managing the flow of electricity more difficult.

For these reasons and others, Ruff (1994), Hogan (1994), Hogan (1995) and Hunt (2002) suggest an SO with the economic authority to make binding and immediate commitment and dispatch decisions, based on forecasts of system conditions and multi-part generation offers. They claim that a centralized market is the only way to achieve fully co-optimized utilization of generation and transmission resources, and hence an efficient outcome. The efficiency arguments in favor of centrally committed markets are based on the assumption that the SO has accurate generator cost and constraint data with which to optimize the unit commitment. If this assumption is violated, a seemingly optimal commitment may not be, due to false data provided by generators. The complexity of the unit commitment problem

[30] ERCOT is a wholesale electricity market that serves the majority of the state of Texas and the SPP market serves Oklahoma, Kansas, and parts of neighboring states.

and the incentive properties of the auction used to determine the commitment, where generators submit their own cost and constraint data, cast doubt on the assumption that the SO has complete information.

Johnson et al. (1997) first raised the issue of the complexity of the unit commitment problem and the economic implications of having the SO rely on suboptimal solutions from a Lagrangian relaxation (LR) algorithm. Using a simplified representation of the Pacific Gas and Electric system, they demonstrated that different primal-feasible LR commitments, which are similar in terms of total commitment and dispatch costs, could yield vastly different payoffs and profits to individual units. Since LR was, at the time, the only tractable means of solving a commercial-scale unit commitment problem, this meant that if the SO made binding commitment decisions on the basis of a near- (but sub-)optimal LR commitment, 'winners' and 'losers' (in terms of payoffs) could be chosen arbitrarily. Generators, knowing the nature of the LR commitments, may have an incentive to misstate their costs or operating constraints to the SO in order to manipulate the resulting commitment.

Although recent advances in mixed-integer programming (MIP) software and computing hardware now make solution of the MIP-formulation of the unit commitment tractable, Sioshansi et al. (2007) demonstrated that unless the MIP can be solved to complete optimality (which cannot, as of yet, be tractably done), the issues raised by Johnson *et al* will still persist. They showed, in fact, that a solution which is a millionth of a percent away from optimal, can nonetheless result in nontrivial payoff differences to individual units.

Beyond the issues raised by unit commitment problem complexity, Oren and Ross (2005) studied the incentive properties of uniform price auctions where generators submit multi-part offers consisting of generating costs and operating constraints. They showed that the auction mechanism wasn't incentive compatible and used simple examples to show that generators can profitably misstate ramping constraints, the rate at which given generator can increase output, to manipulate energy prices and market outcomes. Oren and Ross also proposed alternate settlement rules and penalties to reduce generator incentives to misstate their ramp rates.

Because of the difficulties raised by centrally committed markets some authors, such as Wilson (1997) and Elmaghraby and Oren (1999), claim that commitment decisions are better left to individual generators which would trade energy with consumers either bilaterally or through simple energy markets. They argued that because generators would have to 'internalize' their startup and marginal energy costs when making commitment decisions, self committed markets would be less prone to manipulation than centrally committed ones. Hence they contend that while there would be some coordination losses due to generators individually making commitment decisions, these would be outweighed by the improved incentive properties of self commitment, resulting in greater efficiency and lower settlement costs for ratepayers. Given this debate, we develop a simple model to compare generator behavior and total costs across the self and centrally committed markets.

3 Model

Two identical generators, each with the capacity to generate K units of electricity, where $K > 0$, compete in a uniform price auction to serve demand, referred to as electric load, which is common knowledge. Each generator incurs a fixed startup cost $S > 0$ and a constant marginal generating cost, $c > 0$, when it produces a strictly positive quantity of electricity. Hence each generator has the following cost function:

$$C(q) = \begin{cases} 0 & for \quad q = 0 \\ cq + S & for \quad 0 < q \leq K \\ \infty & for \quad q > K \end{cases}$$

The market has a fixed deterministic demand, referred to as load, l, such that $0 \leq l < 2K$. We assume that the entire load l must be served, which is generally the case in practice.

Centrally Committed Market

With a centrally committed design, each generator submits a bid with two elements, an energy offer that specifies a marginal generating cost, $\epsilon \geq 0$, and a one-time fixed startup cost, $\sigma \geq 0$, that is incurred if any positive quantity of electricity is produced. Generator i submits offer $\omega_i = (\epsilon_i, \sigma_i)$ for $i = 1, 2$ subject to offer caps on each bid component, hence $0 \leq \epsilon_i \leq \overline{\epsilon}$ and $0 \leq \sigma_i \leq \overline{\sigma}$. The SO then uses a uniform price auction to determine the commitment and dispatch of each generator based on the two offers ω_i for $i = 1, 2$. The load l is common knowledge when the generators submit their bids. If $l \leq K$ only one generator needs to be committed and dispatched to serve load, and the quantity sold by generator i, for $i \neq j$, in the centrally committed market is

$$q_i^c(\omega_i; \omega_j, l) = \begin{cases} \min\{l, K\} & \text{if } \sigma_i + l\epsilon_i < \sigma_j + l\epsilon_j \text{ and } l \leq K \\ \frac{1}{2}\min\{l, K\} & \text{if } \sigma_i + l\epsilon_i = \sigma_j + l\epsilon_j \text{ and } l \leq K \\ 0 & \text{if } \sigma_i + l\epsilon_i > \sigma_j + l\epsilon_j \text{ and } l \leq K \end{cases} \tag{43}$$

and the uniform price is $p = \min\{\epsilon_i, \epsilon_j\}$. Hence, if $l \leq K$ the generator that submits the bid ω that coincides with the lowest total cost of producing l is committed to operate and dispatched to produce l units of electricity. We assume that ties are broken with equal probability. Conversely if $l > K$, both generators must be dispatched and the quantity sold by generator i is

$$q_i^c(\omega_i; \omega_j, l) = \begin{cases} K & \text{if } \epsilon_i < \epsilon_j \text{ and } l > K \\ \frac{1}{2}l & \text{if } \epsilon_i = \epsilon_j \text{ and } l > K \\ l - K & \text{if } \epsilon_i > \epsilon_j \text{ and } l > K \end{cases} \tag{44}$$

and the uniform price is $p = \max\{\epsilon_i, \epsilon_j\}$. When both generators are needed, the generator with the lower energy offer produces K units and the other generator produces $l - K$. Note that the startup costs σ_1 and σ_2 do not determine the dispatch of each plant because the SO must pay each generator at least its startup cost regardless of dispatch order.

Each generator faces non-convex costs due to the startup cost $S > 0$, so receiving payment just for the energy it produces, pq_i^c, may be economically confiscatory (*e.g.* they may cause the generator to operate at a loss). The only information the SO has about the costs of the generators is their "as bid" costs in ω, and the SO uses this information to ensure that no generator operates at a loss according to the bids in ω_i and ω_j. Suppose, for example, that $l \leq K$ and generator 1 wins the uniform price auction (hence $\epsilon_1 l + \sigma_1 < \epsilon_2 l + \sigma_2,\ q_1^c = l,$ and $q_2^c = 0$). If the energy payment alone is less than the generator 1's total costs as bid for producing l units, $\epsilon_i l + \sigma_i$, which it is by definition, then generator 1 will operate at a loss.

In centrally committed wholesale electricity markets in the U.S. (e.g. PJM Interconnection, New York ISO, ISO New England, Midwest ISO), SOs overcome this problem by giving generators supplemental 'make-whole' payments, which cover any revenue shortfall based on the costs specified in each generator's offer. If the uniform price is p and a generator is committed and dispatched to produce q_i^c units, its total payment T_i from the SO is the sum of an energy payment (for the energy it is dispatched to produce) and a make-whole payment W:

$$\begin{aligned} T_i &= pq_i^c + W_i \\ &= pq_i^c + \max\{0, \sigma_i + q_i^c(\epsilon_i - p)\} \end{aligned}$$

which ensures that each generator recovers all of its costs as bid associated with producing q units of electricity, $(\epsilon_i q + \sigma_i)$. We assume the centrally committed market includes such a make-whole payment provision. Make-whole payments are allocated to the load on a pro-rata basis.

Self Committed Market

In a self committed market design generators submit a single bid equal to the minimum price it is willing to accept for a unit of energy. The generators decide independently whether to commit themselves, and the SO does not pay generators make-whole payments.[31] The generation offers in the self committed market consist of an energy offer, $\delta \geq 0$. As with the centralized commitment regime, the energy offer is capped at $\overline{\delta}$, and we assume $\overline{\delta} > c$. Given the generation offers, the SO dispatches the generators to serve the load at least cost and uses a uniform price auction to determine commitment, dispatch order, and the uniform electricity price. The quantity sold in the self committed market $q_i^s(\cdot)$ given the energy bids δ_i and δ_j for $i \neq j$ is:

[31] Although some self committed markets operate bilaterally, such as the markets for balancing energy in ERCOT and SPP, we model our self committed market as a power exchange similar the design originally used in California.

$$q_i^s(\delta_i;\delta_j,l) = \begin{cases} \min\{l,K\} & \text{if } \delta_i < \delta_j \\ \frac{1}{2}\min\{l,K\} + \frac{1}{2}\min\{0,l-K\} & \text{if } \delta_i = \delta_j \\ \max\{l-K,0\} & \text{if } \delta_i > \delta_j \end{cases} \tag{45}$$

and the uniform price is $p = \min\{\delta_i,\delta_j\}$ if $l \leq K$ and $p = \max\{\delta_i,\delta_j\}$ if $l > K$. Unlike a centrally committed market, however, there is no make-whole payment so generators must incorporate their startup costs into their energy bids. The only source of generator revenue is the energy payment, which is equal to pq_i^s. In the self committed auction total payments from the SO to the generator equals $T_i = pq_i^s$ for $i = 1,2$.

In both markets, there will be two types of equilibria depending on whether the load can be served by a single generator ($l \leq K$), or both generators are needed ($l > K$). If one generator is needed ($l \leq K$), Bertrand competition will drive the generators to a pure-strategy equilibrium where both generators earn zero profit. If ($l > K$), the offers are characterized by a symmetric mixed-strategy Nash equilibrium, where equilibrium profits in both regimes are greater than the generators' total startup and dispatch costs. We proceed by analyzing each market design under these two load scenarios separately.

3.1 Centrally Committed Market Equilibrium

In the centrally committed market the SO chooses each unit's commitment, given by binary variables, u_i, $i = 1, 2$, and dispatch, given by continuous variables, q_i, to serve load at least cost subject to the units' capacity constraints. Thus, the SO's optimization problem is:

$$
\begin{aligned}
(\mathcal{P}_c): \quad \max_{u,q} \quad & \sum_{i=1}^{2} (u_i\sigma_i + q_i\epsilon_i) \\
\text{s.t.} \quad & \textstyle\sum_{i=1}^{2} q_i = l \\
& 0 \le q_i \le u_i K \quad \forall\, i \\
& u_i \in \{0, 1\} \qquad \forall\, i.
\end{aligned}
$$

We now show the following result, characterizing an optimum of $\mathcal{P}_c$:

Proposition 7. *In $\mathcal{P}_c$ it is optimal to commit one generator if $l \le K$. If $l > K$, it is optimal to commit both generators and dispatch one to its capacity.*

Proof. Suppose first that $l \le K$ and let $(\hat{u}, \hat{q})$ denote an optimum of $\mathcal{P}_c$ in which both generators are committed. The total cost of this commitment and dispatch is then given by $\hat{C} = \sum_{i=1}^{2}(\sigma_i + q_i\epsilon_i)$. The cost of starting up, or committing, generator 1 alone is $C_1 = (q_1 + q_2)\epsilon_1 + \sigma_1$, and the cost of committing only generator 2 is $C_2 = (q_1+q_2)\epsilon_2+\sigma_2$. The difference between these costs and the cost of committing both is given by $\hat{C}-C_1 = q_2(\epsilon_2-\epsilon_1)+\sigma_2$ and $\hat{C}-C_2 = q_1(\epsilon_1-\epsilon_2)+\sigma_1$, one of which must be non-negative, since $q_1, q_2, \sigma_1, \sigma_2 \ge 0$, implying that either

C_1 or C_2 is less than $\hat{C}$.

Suppose now that $l > K$. Clearly both generators must be committed to satisfy the load-balance and capacity constraints. Suppose by way of contradiction that $(\hat{u}, \hat{q})$ is an optimum of $\mathcal{P}_c$ in which neither generator is dispatched to its capacity and assume without loss of generality that $\epsilon_1 \leq \epsilon_2$. If $\epsilon_1 < \epsilon_2$ then clearly dispatching generator 1 to capacity K by reducing generator 2's dispatch will decrease total cost, which contradicts the claim that $(\hat{u}, \hat{q})$ is optimal. If $\epsilon_1 = \epsilon_2$ then dispatching generator 1 to its capacity by reducing generator 2's dispatch will leave total costs the same, but will still be optimal. $\square$

Thus it is optimal to commit one generator if $l \leq K$, and to commit both generators if $l > K$, where the generator with the lower energy offer (ϵ) should be dispatched to capacity. We will refer to the unit dispatched at full capacity when both generators are committed as the *inframarginal generator* and denote it with the subscript I. The generator dispatched below its capacity when both generators are dispatched will be referred to as the *marginal generator* and denoted with the subscript M. When $l \leq K$ and only one generator is committed, this generator will be referred to as the *unique generator* and denoted with the subscript U. Furthermore, it is trivial to show that the uniform energy price p will equal the energy bid in the unique generator's offer. Proposition 8 characterizes the equilibrium in the centrally committed market when only one generator is needed to serve the load ($l \leq K$).

Proposition 8. *In a centrally committed market with $l \leq K$, the total payment to the unique generator will be $T_U = \epsilon_U l + \sigma_U$, where $\omega_U = (\sigma_U, \epsilon_U)$ is the two-part bid of the unique generator.*

If $l > K$, both generators will produce a strictly positive amount, and the total payment to the marginal generator will be $T_M = \epsilon_M(l - K) + \sigma_M$ and the total payment to the inframarginal generator will be $T_I = max\{\epsilon_M K, \epsilon_I K + \sigma_I\}$, where the inframarginal generator's offer is $\omega_I = (\epsilon_I, \sigma_I)$ and $\omega_M = (\epsilon_M, \sigma_M)$ is the marginal generator's offer.

Proof. When $l \leq K$ the unique generator will be dispatched to serve the entire load, l and the uniform price for energy is $p = \epsilon_U$. If the startup cost in its offer is positive, $\sigma_U > 0$, then the unique generator's surplus according to as-bid costs is $\epsilon_U l - (\epsilon_U l + \sigma_U) < 0$. The make-whole payment will be $W_U = \max\{0, \sigma_U + q^c(\epsilon_U - \epsilon_U)\} = \sigma_U$. Hence, the unique generator's total payment is $T_U = \epsilon_U l + \sigma_U$. Clearly, if $\sigma_U = 0$ then the make-whole payment W_U is zero and the total payment from the SO is $T_U = \epsilon_U l$.

When $l > K$ the marginal generator will be dispatched to serve $(l - K)$ units of the load and the uniform price is $p = \epsilon_M$. Again, if $\sigma_M > 0$, the marginal generator's offer-based surplus will be negative, thus the total payments will be the sum of energy and make-whole payment, hence $T_M = \epsilon_M(l - K) + \sigma_M$, where the make-whole payment is $W_M = \sigma_M$. If $\sigma_M = 0$ then the make-whole payment

W is zero and total payments will be $T_U = \epsilon_M(l - K)$.

Finally, because of the make-whole provision, the SO will ensure the inframarginal generator's offer-based surplus, according to its as-bid costs, is $\max\{(\epsilon_M - \epsilon_I)K - \sigma_I, 0\}$. If $\max\{(\epsilon_M - \epsilon_I)K - \sigma_I, 0\} = (\epsilon_M - \epsilon_I)K - \sigma_I$, then $\epsilon_M K \geq \epsilon_I K + \sigma_I$ and the total payment to the inframarginal generator is simply the energy payment $\epsilon_M K$ because the energy payment alone is sufficient to cover the inframarginal generator's startup and variable operating bids. Otherwise, if $\max\{(\epsilon_M - \epsilon_I)K - \sigma_I, 0\} = 0$ then $\epsilon_M K < \epsilon_I K + \sigma_I$, and the total payment to the inframarginal generator is:

$$\begin{aligned} T_I = &\ pK + W_I \\ = &\ \epsilon_M K + \max\{0, \sigma_I + K(\epsilon_I - \epsilon_M)\} \\ = &\ \epsilon_I K + \sigma_I \end{aligned}$$

□

Having characterized an optimum of the SO's commitment problem, we now prove the following result which gives an equilibrium when only one of the generators is needed to serve the load.

Proposition 9. *If $l \leq K$, the unique pure-strategy Nash equilibrium of the centrally committed market consists of offers such that each offer $\omega_i = (\epsilon_i, \sigma_i)$ for $i = 1, 2$ belongs to the set $B = \{(\epsilon, \sigma) \in \mathbb{R}^2 : \epsilon l + \sigma = cl + S,\ \epsilon \leq \overline{\epsilon},\ \text{ and }\ \sigma \leq \overline{\sigma}\}$, and each generator has an expected profit of zero.*

Proof. First to show this is a Nash equilibrium, note that $\mathbb{E}[\pi_i(\epsilon_i^*, \sigma_i^*)] = 0$ for each generator, i. If generator i deviates by choosing $(\hat{\epsilon}_i, \hat{\sigma}_i)$ such that $\hat{\epsilon}_i l + \hat{\sigma}_i > \epsilon_i l + \sigma_i$, then generator i is never committed or dispatched and $\mathbb{E}[\pi_i(\hat{\epsilon}_i, \hat{\sigma}_i)] = 0$. If generator i deviates by choosing $(\hat{\epsilon}_i, \hat{\sigma}_i)$ such that $\hat{\epsilon}_i l + \hat{\sigma}_i < \epsilon_i l + \sigma_i$, then generator i is always dispatched but $\mathbb{E}[\pi_i(\hat{\epsilon}_i, \hat{\sigma}_i)] = (\hat{\epsilon}_i - c)l + \hat{\sigma}_i - S < 0$. Thus, neither generator has a profitable deviation.

Next to show this is the unique pure-strategy Nash equilibrium, we can show that the bid ω can be collapsed into one dimension. Given that $l \leq K$, the SO only needs to commit and dispatch one generator and the SO does so in the least costly way. Thus, the SO selects the generator with the lowest total energy cost, including the energy and the startup costs. The dispatch is determined by the ranking of these costs, which for simplicity we refer to as $b_i = \epsilon_i l + \sigma_i$ for $i = 1, 2$. This game is thus isomorphic to a simple Bertrand equilibrium, but in this case, each generator submits a total cost $b_i = \epsilon_i l + \sigma_i$. The total cost of each generator, b_i is such that $b_i = cl + S$ for $i = 1, 2$ and generator earns zero profit in equilibrium. Clearly, there are many sets of ω that belong to the set B but all vectors in (ϵ, σ) payoff equivalent because they result in the same commitment, dispatch, and expected profits. Hence the total costs of the offers must equal actual costs (*i.e.* $\epsilon_i l + \sigma_i = \epsilon_j l + \sigma_j = cl + S$) and expected profits are zero in equilibrium. □

We now turn to the case in which $l > K$ and both generators must be committed and dispatched to satisfy load l. Since both generators must be committed, the SO must pay each generator its as-bid startup costs, σ_1 and σ_2, regardless of each generators level of output, be it l or $l-K$. The optimal commitment and dispatch decisions will be made purely on the basis of each generator's energy offer ϵ. As we show in the following propositions, this characteristic of an optimum, coupled with the generators' binding capacity constraints, eliminates the possibility of pure-strategy Nash equilibrium in the offer-setting game. Because both generators will follow mixed-strategy equilibria, each has a strictly positive probability of receiving make-whole payments, thus each generators' expected profit function is a non-decreasing function of its startup bid σ_i for $i = 1, 2$. Thus, each generator will submit an offer with a startup cost equal to the startup offer cap, $\overline{\sigma}$.

Proposition 10. *If $l > K$, no pure-strategy Nash equilibria exist in the centrally committed market.*

Proof. Suppose $(\tilde{\epsilon}_i, \tilde{\sigma}_i)$, for $i = 1, 2$, constitute a pure-strategy Nash equilibrium, and assume without loss of generality that the generators have been labeled such that $\tilde{\epsilon}_1 \leq \tilde{\epsilon}_2$.

Suppose first that $\tilde{\epsilon}_1 < \tilde{\epsilon}_2$. Then generator 1 is the inframarginal generator and its profit is:

$$\tilde{\Pi}_1 = \max\{\tilde{\epsilon}_2 K, \tilde{\epsilon}_1 K + \tilde{\sigma}_1\} - cK - S.$$

If $\max\{\tilde{\epsilon}_2 K, \tilde{\epsilon}_1 K + \tilde{\sigma}_1\} = \tilde{\epsilon}_1 K + \tilde{\sigma}_1$ then generator 1 can profitably deviate by changing the energy portion of its offer to $\hat{\epsilon}_1 = \tilde{\epsilon}_2 - \eta$, with $\eta > 0$ and small, since its profits are increasing in ϵ_1. If, instead, $\max\{\tilde{\epsilon}_2 K, \tilde{\epsilon}_1 K + \tilde{\sigma}_1\} = \tilde{\epsilon}_2 K$ then generator 1 can profitably deviate by changing its offer to $(\hat{\epsilon}_1, \hat{\sigma}_1)$ such that $\hat{\epsilon}_1 = \tilde{\epsilon}_2 - \eta$, with $\eta > 0$ and small, and $\hat{\sigma}_1 > 0$ and sufficiently large, so that $\max\{\tilde{\epsilon}_2 K, \hat{\epsilon}_1 K + \hat{\sigma}_1\} = \hat{\epsilon}_1 K + \hat{\sigma}_1 > \tilde{\epsilon}_2 K$.

Suppose instead that $\tilde{\epsilon}_1 = \tilde{\epsilon}_2 = e$. Then both generators' expected profits are given by:

$$\mathbb{E}[\tilde{\Pi}_i] = \frac{1}{2}(e - c)l + \sigma_i - S.$$

Suppose $e \leq c$, then either generator can profitably deviate by submitting an offer with a higher ϵ_i, since this will guarantee it a strictly positive margin on energy sold whereas an offer of e gives it a non-positive margin. Otherwise, if $e > c$, either generator can profitably deviate by submitting an energy offer of $\hat{\epsilon}_i = e - \eta$, with $\eta > 0$ and small. This gives generator i an expected profit of:

$$\mathbb{E}[\hat{\Pi}_i] = (e - c)K + \sigma_i - S,$$

which is greater than $\mathbb{E}[\tilde{\Pi}_i]$ for η sufficiently small, since $K > \frac{1}{2}l$. $\square$

Having ruled-out pure-strategy Nash equilibria, we will let $F_i(\epsilon_i, \sigma_i)$ denote the cumulative distribution function (CDF) of generator i's mixed-strategy Nash equilibrium, and let $\underline{\epsilon}_i$ and $\overline{\epsilon}_i$ denote the infimum and supremum energy offers, respectively, of the support of the CDF F_i. We now show that the range of energy offers in the support of F_1 and F_2 must intersect, and as such generators will always submit the highest possible startup cost.

Proposition 11. *In equilibrium, the infimum energy offers are equal, hence* $\underline{\epsilon}_1 = \underline{\epsilon}_2$.

Proof. Suppose that $\inf\{z|F_i(z) > 0\} = \underline{\epsilon}_i < \underline{\epsilon}_j = \inf\{z'|F_j(z') > 0\}$ in equilibrium, and assume the generators are labeled such that $\underline{\epsilon}_1 < \underline{\epsilon}_2$. Generator 1 has a profitable deviation because it can move all of the density in the interval $[\underline{\epsilon}_1, \underline{\epsilon}_2)$, to $\underline{\epsilon}_2 - \varsigma$ for $\varsigma > 0$ small, as doing so increases generator 1's expected profit and does not change the probability that it is the low bidder. $\square$

We further characterize equilibrium CDFs by showing they cannot have mass points on their common support, are connected, and have a common supremum.

Proposition 12. *Neither* F_1 *nor* F_2 *can have a mass point on* Φ.

Proof. Suppose for contradiction that there is a $\epsilon' \in \Phi$ which is a mass point of F_i. Then there exist $\eta > 0$ and $\rho > 0$ such that generator j would have a profitable deviation by moving the density assigned to the interval $[\epsilon', \epsilon' + \eta)$ to $\epsilon' - \rho$, since the profit from offers in the interval $[\epsilon', \epsilon' + \eta)$ is at most:

$$(\epsilon' + \eta - c)(l - K) + \overline{\sigma}_1 - S,$$

and the profit from an offer of $\epsilon' - \rho$ is:

$$(\epsilon' - c)K + \overline{\sigma}_1 - S,$$

which is greater for η sufficiently small, contradicting the assumption of a mass point in an equilibrium. $\square$

Proposition 13. *Φ_i is a connected set (interval) for both generators.*

Proof. Suppose for contradiction that there is an interval $[\epsilon', \epsilon' + \eta]$, with $\eta > 0$ on which generator i places zero density. Consider a deviation by generator j wherein it moves the density assigned to the interval $(\epsilon' - \rho, \epsilon')$ to an energy offer of $\epsilon' + \eta - \xi$, with $\rho > 0$ and $\eta > \xi > 0$. We can bound the change in generator j's profits depending on whether it would be the marginal or inframarginal generator with the original strategy and deviation:

- If generator j is the marginal generator, the deviation will increase the price of energy and generator j's profits will increase by at least $(\xi - \eta)(l - K)$.
- If generator j is the inframarginal generator and would have been the inframarginal generator without deviating, its profits will either increase by at least $(\xi - \eta)(l - K)$ if it receives make-whole payments or not change if it would not receive make-whole payments.
- If generator j is the marginal generator but would have been the infra-

marginal generator without deviating, its profits will change by at most $(\epsilon' + \eta - \xi)(l - K) - \epsilon' K$.

Thus, the only cost to generator j involves situations where it would have been the inframarginal generator without deviating but becomes the marginal generator as a result of deviating. However ρ can be chosen to make the probability of this event arbitrarily close to zero. □

Proposition 14. *The suprema of $F_1(\epsilon)$ and $F_2(\epsilon)$ are equal, hence $\bar{\epsilon}_1 = \bar{\epsilon}_2 = \bar{\epsilon}$ in an equilibrium.*

Proof. Suppose the suprema are different such that $\sup\{z|F_i(z) < 1\} = \bar{\epsilon}_i < \bar{\epsilon}_j = \sup\{z'|F_j(z') < 1\}$. Generator i has a profitable deviation, which is to move some density from the interval $(\bar{\epsilon}_i - \zeta, \bar{\epsilon}_i]$ for some $\zeta > 0$ small, just below $\bar{\epsilon}_j$ because doing so increases generator i's expected profit without decreasing the probability that generator i will be the low bidder as there is no density in the interval $(\bar{\epsilon}_i, \bar{\epsilon}_j)$. Thus, in equilibrium, $\bar{\epsilon}_i = \bar{\epsilon}_j$ □

Proposition 15. *In equilibrium, each generator submits the maximum possible startup cost in its offer with certainty. That is, $\sigma_1 = \sigma_2 = \overline{\sigma}$*

Proof. Because there are only mixed-strategy Nash equilibria and the supports of $F_1(\cdot)$ and $F_2(\cdot)$ are equal, each generator has a strictly positive probability of being the marginal generator. Since the payoff to the marginal generator is strictly increasing in σ, the payoff to the inframarginal generator is non-decreasing in σ, and the value of σ does not impact the dispatch of the generators, it is optimal to submit an offer with $\sigma_i = \overline{\sigma}$. $\square$

The essence of Proposition 15 is that because the SO's dispatch depends solely on the energy portion of the generators' offers, the two-dimensional offer problem (energy and startup costs) collapses into a one-dimensional offer problem with only an energy cost. Therefore, we will hereafter denote the equilibrium CDFs as $F_i(\epsilon_i)$.

In order to characterize a mixed-strategy Nash equilibrium of this game, we express the expected profit of generator i as a function of its energy offer ϵ_i, given that generator j submits an energy offer, ϵ_j, according to a mixed-strategy characterized by the cumulative distribution function, $F_j(\epsilon_j)$:

$$\begin{aligned}
\mathbb{E}[\pi_i(\epsilon_i)] &= Pr(\epsilon_j \leq \epsilon_i)[(l-K)(\epsilon_i - c) + \overline{\sigma} - S] \\
&\quad + Pr(\epsilon_j > \epsilon_i)[\max\{\epsilon_j K, \epsilon_i K + \overline{\sigma}\} - cK - S] \\
&= F_j(\epsilon_i)[(l-K)(\epsilon_i - c) + \overline{\sigma} - S] \\
&\quad + [F_j(\epsilon_i + \frac{\overline{\sigma}}{K}) - F_j(\epsilon_i)][(\epsilon_i - c)K + \overline{\sigma} - S] \\
&\quad + \int_{\epsilon_i + \frac{\overline{\sigma}}{K}}^{\overline{\epsilon}} [(\epsilon_j - c)K - S] dF_j(\epsilon_j).
\end{aligned}$$

Differentiating and setting the result to zero gives the first-order necessary condition (FONC) for a maximum which must hold for all $\epsilon \in [\underline{\epsilon}, \overline{\epsilon}]$:

$$f_j(\epsilon_i)(l - 2K)(\epsilon_i - c) + F_j(\epsilon_i)(l - 2K) + F_j(\epsilon_i + \frac{\overline{\sigma}}{K})K = 0,$$

which can be re-written as:

$$f_j(\epsilon_i) = \frac{F_j(\epsilon_i)}{c - \epsilon_i} + \frac{F_j(\epsilon_i + \frac{\overline{\sigma}}{K})K}{(l - 2K)(c - \epsilon_i)}.$$

Finally, because we are restricting attention to symmetric equilibria, the subscript can be dropped giving:

$$f(\epsilon) = \frac{F(\epsilon)}{c - \epsilon} + \frac{F(\epsilon + \frac{\overline{\sigma}}{K})K}{(l - 2K)(c - \epsilon)}. \tag{46}$$

Equation (46) is a differential difference equation (DDE) characterizing a symmetric Nash equilibrium energy offer density function. We can find a particular solution of the DDE if we specify an interval of boundary conditions of width $\frac{\overline{\sigma}}{K}$. We do this by showing a Nash equilibrium density function must assign some probability to the offer cap $\overline{\epsilon}$ which implies $F(\epsilon) = 1$ for all $\epsilon \geq \overline{\epsilon}$.

Proposition 16. *A Nash equilibrium energy offer density function must have:*

$$F(\epsilon) \begin{cases} < 1, & \forall\ \epsilon < \overline{\epsilon} \\ = 1, & \forall\ \epsilon \geq \overline{\epsilon}. \end{cases}$$

Proof. We show this by contradiction. Suppose $\hat{F}(\epsilon)$ is a Nash equilibrium offer function and suppose there is a $\hat{\epsilon} < \overline{\epsilon}$ such that $\hat{F}(\hat{\epsilon}) = 1$ and $\hat{F}(\epsilon) < 1$ for all $\epsilon < \hat{\epsilon}$. This means any $\epsilon > \hat{\epsilon}$ has zero probability assigned to it. By definition of a Nash equilibrium, these $\epsilon > \hat{\epsilon}$ cannot give either generator a higher expected profit than $\hat{\epsilon}$.

Because both generators follow the same atomless Nash equilibrium offer function, generator i submitting an energy offer of $\hat{\epsilon}$ will ensure generator i is the marginal generator, and its profits will be given by:

$$\mathbb{E}[\pi_i(\hat{\epsilon}_i)] = (\hat{\epsilon} - c)(l - K) + \overline{\sigma} - S.$$

But if generator i submits an energy offer of $\overline{\epsilon}$ it will still be the marginal generator, but its profits will be given by:

$$\mathbb{E}[\pi_i(\overline{\epsilon}_i)] = (\overline{\epsilon} - c)(l - K) + \overline{\sigma} - S.$$

But $\mathbb{E}[\pi_i(\overline{\epsilon}_i)] > \mathbb{E}[\pi_i(\hat{\epsilon}_i)]$ because $\overline{\epsilon} > \hat{\epsilon}$, contradicting the assumption that $\hat{F}(\cdot)$ is a Nash equilibrium. $\square$

Although this boundary condition allows us to find a particular equilibrium, a closed-form solution to the DDE is difficult to obtain since it depends on the relative values of $\frac{\overline{\sigma}}{K}$ and $\overline{\epsilon}$. As such, we focus on the numerical computations discussed in section 4.

3.2 Self Committed Market Equilibrium

In the self committed market, generators independently decide whether to commit themselves, and submit single-part energy offers, $\delta \in [0, \overline{\delta}]$ to the uniform price auction conducted by the SO. The only revenue available to generators is the energy payment pq_i^s, where p is the uniform electricity price and q_i^s is the quantity sold in the self committed market defined in equation (45). We assume the offer cap is sufficiently high so that the generators always recover their startup cost if they offer $\overline{\delta}$. Thus, if $l \leq K$ we assume that $(\overline{\delta} - c)l \geq S$ and if $l > K$ that $(\overline{\delta} - c)(l - K) \geq S$. Otherwise, the market wouldn't clear because one of both of the generators would choose not to participate. We again proceed by analyzing equilibrium behavior depending on whether one generator or both are needed to serve the load.

We first consider the case in which $l \leq K$ and only one generator will be dispatched, the energy offer of which will set the uniform energy price. We can easily characterize this game as having a Bertrand-type Nash equilibrium in which the generators' expected profits are both zero.

Proposition 17. *When $l \leq K$ the unique pure-strategy Nash equilibrium of the self committed market is for each generator to offer $\delta_1 = \delta_2 = \frac{S}{l} + c$, with each generator having an expected profit of zero.*

Proof. To show this is a Nash equilibrium, note that $\mathbb{E}[\pi_i] = 0$ for each generator,

i. If generator i deviates by choosing $\hat{\delta}_i > \delta_i$, then generator i is never dispatched and $\mathbb{E}[\pi_i] = 0$. If generator i deviates by choosing $\hat{\delta}_i < \delta_i$, then generator i is always dispatched but $\mathbb{E}[\pi_i] = (\hat{\delta}_i - c)l - S < 0$. Thus, neither generator has a profitable deviation. This equilibrium is essentially a Bertrand equilibrium, where each generator earns zero profit. □

We now turn to the case in which $l > K$ and both generators must be dispatched to serve the load. The dispatch of the two generators will be determined by their energy offers. Again, the generator with the lower energy offer δ is dispatched to its capacity K and we call this generator the *inframarginal generator*. The other generator will serve the residual load $(l - K)$, and will be referred to as the *marginal generator*. Once again, it is trivial to show that the uniform energy price will equal the energy offer of the marginal generator. We now show that the nature of the optimal dispatch of the generators will once again rule out pure-strategy Nash equilibria.

Proposition 18. *When $l > K$ no pure-strategy Nash equilibria exist in the self committed market. Moreover, the unique mixed-strategy Nash equilibria will have a differentiable distribution function and an atomless density function.*

Proof. Again, the generators in this market are submitting energy bids into a uniform price auction with two capacity-constrained generators. The existence of only mixed-strategy Nash equilibria and the differentiability and atomlessness of the CDF has been shown by Fabra et al. (2006), to which the reader is referred for details of the proof. As before, there are no mass points at the infimum or supremum of the support of the CDF. $\square$

In order to characterize a mixed-strategy Nash equilibrium of this game, we express the expected profit of generator i as a function of its energy offer, assuming generator j's energy offer is distributed according to the cumulative distribution function, $F_j(\delta_j)$:

$$\begin{aligned}\mathbb{E}[\pi_i(\delta_i)] &= Pr(\delta_j \leq \delta_i)[(l-K)(\delta_i - c) - S] + Pr(\delta_j > \delta_i)[K(\delta_j - c) - S] \\ &= F_j(\delta_i)[(l-K)(\delta_i - c) - S] + \int_{\delta_i}^{\overline{\delta}} [K(\tau - c) - S] dF_j(\tau).\end{aligned}$$

Differentiating with respect to δ and setting the result equal to zero gives the FONC for a maximum which must hold for all $\delta \in [\underline{\delta}, \overline{\delta}]$, where $\underline{\delta} \equiv \inf\{\delta : F(\delta) > 0\}$:

$$f_j(\delta_i)[(l-K)(\delta_i - c) - S] + F_j(\delta_i)(l-K) - [K(\delta_i - c) - S] f_j(\delta_i) = 0,$$

which can be re-written as:

$$f_j(\delta_i) - \frac{F_j(\delta_i)(l-K)}{(2K-l)(\delta_i - c)} = 0,$$

or

$$f_j(\delta_i) - \lambda \frac{F_j(\delta_i)}{\delta_i - c} = 0, \tag{47}$$

where $\lambda = \frac{l-K}{2K-l}$. We can drop the subscripts as the generators and equilibrium strategies are symmetric. The differential equation (47) can then be solved by defining the integrating factor:

$$\begin{aligned} \mu(\delta) &= \exp\left\{-\int_a^\delta \frac{\lambda}{\tau - c} d\tau\right\} \\ &= \left(\frac{\delta - c}{a - c}\right)^{-\lambda}, \end{aligned}$$

where a is an arbitrary constant. Multiplying both sides of (47) by $\mu(\delta)$ and integrating with respect to δ yields:

$$F(\delta) = b \exp\left\{\int_a^\delta \frac{\lambda}{\tau - c} d\tau\right\} = b\left(\frac{\delta - c}{a - c}\right)^{\lambda},$$

where b is a constant of integration. In order to specify an exact solution to equation (47) we use the condition that neither generator has a mass point at the supremum offer $\overline{\delta}$ hence $F(\overline{\delta}) = 1$ which gives:

$$b\left(\frac{\overline{\delta} - c}{a - c}\right)^{\lambda} = 1 \Longrightarrow b = \left(\frac{a - c}{\overline{\delta} - c}\right)^{\lambda} \Longrightarrow F(\delta) = \left(\frac{\delta - c}{\overline{\delta} - c}\right)^{\lambda}.$$

There is also an individual rationality condition that $\mathbb{E}[\pi(\delta)] \geq 0$ for any δ in the support of $F(\cdot)$ which is $[\underline{\delta}, \overline{\delta}]$. We can rewrite this condition as:

$$\mathbb{E}[\pi(\delta)] = (l - K)(\delta - c)F(\delta) + K\int_\delta^{\overline{\delta}} (\eta - c) dF(\eta) - S \geq 0,$$

for $\delta = \overline{\delta}$ generator i's expected profit is:

$$(\overline{\delta} - c)(l - K) \geq S,$$

which we have assumed.

The infimum energy offer $\underline{\delta}$ is determined by solving the equation $F(\underline{\delta}) = 0$ which implies that $\underline{\delta} = c$. If generator i submits the infimum energy offer, its expected profit is:

$$\mathbb{E}[\pi(\underline{\delta})] = K \int_{\delta}^{\overline{\delta}} (\eta - c) dF(\eta) - S \geq 0, \tag{48}$$

because it is dispatched to capacity with probability one. The condition in equation (48) must hold for the mixed-strategy profile $(F_1(\delta), F_2(\delta))$ to constitute a Nash equilibrium, as profits cannot be negative. Since this is a mixed-strategy equilibrium, all offers in $[\underline{\delta}, \overline{\delta}]$ have the same expected profit, which means that $\pi_i(\overline{\delta}) = \pi_i(\underline{\delta})$:

$$\begin{aligned}
\pi_i(\overline{\delta}) &= (\overline{\delta} - c)(l - K) - S \\
&= \pi_i(\underline{\delta}) \\
&= K \int_{\delta}^{\overline{\delta}} (\eta - c) dF(\eta) - S \\
&= K(\mathbb{E}[\delta] - c) - S.
\end{aligned}$$

Equating $\pi_i(\underline{\delta}) = \pi_i(c)$ and $\pi_i(\overline{\delta})$ gives an expression for the expected energy offer in this equilibrium:

$$\mathbb{E}[\delta] = \frac{(\overline{\delta} - c)(l - K)}{K} + c.$$

In this equilibrium, the expected energy offer $\mathbb{E}[\delta]$ is decreasing in K, which is in keeping with economic theory. The larger each generator is, the greater the benefit of being the low bidder, and the greater the cost of being the high bidder. As the market supply of capacity ($2K$) increases, the generators become more aggressive and submit lower energy offers. The reverse is true as $K \downarrow \frac{l}{2}$, which, in the limit, means that both generators will be dispatched to capacity with probability one, and the expected energy offer increases to the energy offer cap $\overline{\delta}$ in this case. Additionally, as expected, $\mathbb{E}[\delta]$ is increasing in the energy offer cap $\overline{\delta}$ and the marginal cost c.

4 Numerical Example

We use a numerical example to compare the equilibrium behavior, energy prices, and settlement costs of the centralized and self committed market designs. Because both markets result in the same perfectly competitive outcome when $l \leq K$, we assume in our computations that $l > K$, which requires that both generators be dispatched. These calculations will of course depend on the costs and capacities of the generators and the load but also, importantly, on the price caps in the two markets. Because the equilibria in both market designs assign probability to all energy prices up to the price cap, the relative value of the caps could bias cost and equilibrium price calculations in favor of one design over the other. As such, we simulate the two markets over a set of load scenarios and select the offer caps $\overline{\epsilon}$, $\overline{\sigma}$, and $\overline{\delta}$ such that the expected profits over the load scenarios of a generator submitting offers at the price cap would be equal in the two markets. More specifically, we determine the price caps in such a way so that:

$$\mathbb{E}[\pi_i(\overline{\epsilon}, \overline{\sigma})] = \mathbb{E}[\pi_i(\overline{\delta})],$$

which can be written as:

$$(\overline{\epsilon} - c)(\mathbb{E}[l] - K) + \overline{\sigma} - S = (\overline{\delta} - c)(\mathbb{E}[l] - K) - S,$$

since the Nash equilibrium density functions are atomless and a generator bidding at the price cap will always be the marginal generator. This condition, in turn, reduces to:

$$\overline{\delta} = \overline{\epsilon} + \frac{\overline{\sigma}}{\mathbb{E}[L] - K}.$$

Table 9 summarizes the parameter assumptions underlying our example. The load profile was computed by assuming the loads would have a minimum of 550 and a maximum of 950.[32] We then computed 8160 loads in such a way to fit the 2006 load duration curve of the California ISO, a wholesale electricity market

[32]The DDE characterizing the equilibrium of the centrally committed market becomes difficult to solve if l is too close to either K or $2K$, which is why we chose these particular upper and lower bounds on l.

in California. Equilibria and expected costs for the self committed market were computed directly in closed form. The DDE for the self committed market was approximated numerically.

Table 9: Parameter Values of Numerical Example

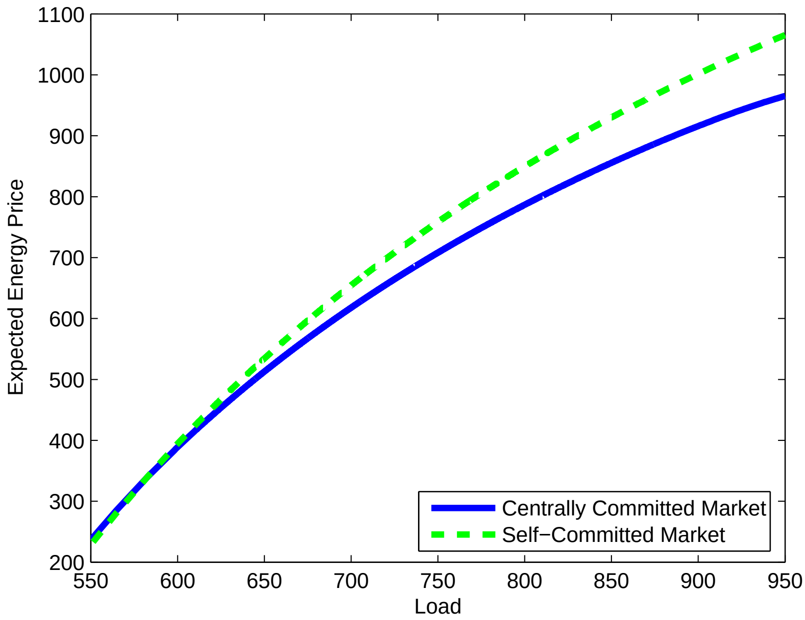
Parameter	Value
c	30
S	10000
K	500
$\mathbb{E}[l]$	703.3771203
$\overline{\epsilon}$	1000
$\overline{\sigma}$	25000
$\overline{\delta}$	1122.924348

Table 10 summarizes the cost comparison between the two markets. Although there is an approximately \$4.77 expected settlement cost difference between the two, we attribute this to approximation errors in solving and integrating the DDE for the centrally committed market. Otherwise, the two markets are cost equivalent, meaning that the SO will pay the generators the same total payments in the centrally committed and self committed markets. Although the two markets are cost equivalent, expected energy prices are not the same in the two markets, as shown in figure 1. Instead, the centrally committed market tends to have lower prices than the self committed, but make-whole payments account for a nontrivial portion of settlement costs which must be paid by the SO as well.

Table 10: Cost Comparison of Centrally and Self Committed markets

Market Design	Centrally Committed	Self Committed
Expected Energy Price	615.42	652.22
Expected Make-Whole Payments	26,790.75	n/a
Expected Settlement Costs	465,648.16	465,652.93

Figure 1: Expected Energy Prices in Centrally and Self Committed Markets



5 Conclusion

This basic issue in electricity market design has been and will likely continue to be contentious and unresolved. Although centrally committed markets can, in theory, maximize total surplus, they are fraught with computational issues which can present incentive issues. While self committed markets can overcome these problems, the non-convex nature of the generators' commitment decisions imply that there will be some coordination and productive efficiency losses, as Sioshansi et al. (2007) demonstrate. Furthermore, Sioshansi *et al* show that self committed markets will have higher energy prices than their centrally committed counterparts since there is no make-whole provision, which can result in allocative efficiency losses if demand is price-responsive.

Despite these pros and cons, we have demonstrated with our model that if the price caps of the two markets are chosen appropriately, they can be made cost equivalent. Importantly, computation of these price caps does not require the SO to know the generators' cost parameters, but only the expected load and their capacities.

Chapter 3: Investment in Generation Capacity after Electric Restructuring

1 Introduction

In the 1990s state and federal legislation introduced competition into the provision of electric service. Restructured electric systems were expected to lower the cost of investments in new electric generation capacity and increase the performance of existing capacity, such as electric power plants. Some states chose to restructure, while others essentially left their systems unchanged. The transition to wholesale markets has been difficult, and uncertainty and market power concerns have emerged as issues.

Despite its intentions to improve the performance of generation assets and lower investment costs, many believe that the policies associated with electric restructuring have stifled investment in the states that imposed them, particularly in the Northeast (Joskow (2007a,b) Cramton and Stoft (2008) Roques (2008)). For example, Peter Cramton and Steven Stoft claim that firms that invest in new generation capacity in states that unbundled their RPUs and joined wholesale electricity markets face "an investment market with a high risk premium, especially compared to regulated markets"(Cramton and Stoft, 2005). As such, many state and federal regulators and industry experts now fear that these restructuring policies have depressed incentives to invest in new electric generation capacity.

I seek to determine whether fears of underinvestment in electric generation capacity in restructured states are supported by empirical evidence. The states can be divided into three categories: states that unbundled vertically integrated regulated public utilities ("RPUs") and joined wholesale electricity markets; states that joined wholesale electricity markets without unbundling RPUs; and states that pursued neither policy. I investigate whether investment in new electric generation capacity has differed across these categories. I seek to determine whether electric restructuring is associated with lower levels of investment in new generation capacity. Given concerns about the Northeast in particular, I also examine whether investment is lower in this region compared to the rest of the U.S.

Seven states suspended or repealed electric restructuring legislation because they determined that the benefits of restructuring were outweighed by the costs. Arizona, Arkansas, Montana, Nevada, New Mexico, and Oregon considered unbundling their RPUs but each abandoned the idea at some point between 2001 and 2004 (EIA, 2007). Many attribute these reversals to the California energy crisis in 2001 and other problems associated with restructuring (Joskow, 2006). Virginia chose to repeal legislation that unbundled the state's RPUs in 2002 and will "re-regulate" RPUs in the state in 2009.[33]

Electric restructuring was a major initiative undertaken by various states in the

[33]See Virginia Senate Bill 1416 and House Bill 3068, passed in April 2007

U.S., hence it is important to evaluate its outcome. In light of the recent backlash against electric restructuring and concerns about underinvestment, it is important to examine investment in regions that restructured and compare it to investment in regions that did not.

To date, only one paper has empirically analyzed restructuring and aggregate investment levels in the U.S. Toru Hattori used a panel of the 50 states from 1990 to 2002 and found that electric restructuring did not have a significant affect on the growth of generation capacity. Most studies of electric restructuring have examined either the change in retail electricity price (see Kwoka (2008) for a review of recent price studies), or how restructuring affects electric generation efficiency (see Fabrizio et al. (2007)).

This chapter is the first to analyze investment levels and the number of new plants at the regional level, which accounts for the creation of wholesale electricity markets. I examine the total investment levels from large-scale investments in generation capacity between 1992 and 2007.[34] Given the fixed costs associated with investments in new generation capacity, I also examine the number of new plants built each year and whether it changed after restructuring. While Hattori used multiple restructuring variables, many of which were correlated with each other, I examine the two key electric restructuring policies: the unbundling of RPUs and wholesale electricity market membership. I use more precise environmental data

[34] The unit of measure for investment in new generation capacity is a megawatt, which measures the maximum amount of electricity the generator can produce at a given time.

and add five years of data. Lastly, I compare the size of new power plants across regions.[35]

Like Hattori, I find that the two key policies of electric restructuring are not associated with lower investment levels at a statistically significant level. The magnitudes of the insignificant estimates, however, are not trivial, thus I cannot rule out the possibility that electric restructuring decreased total investment levels and the number of new plants. The lack of significance of the restructuring policy variables, however, casts doubt on the claims that investment is depressed in restructured states and suggests that other factors are more important. I do not find an association between the two restructuring policies and the size of new plants.

1.1 Background

Prior to the mid-1990s, virtually all electric service in the U.S. was provided by regulated public utilities, many of which are publicly owned.[36] RPUs are locally-franchised monopolies that own and operate all sectors of the electricity supply chain. Electric service has three sectors: generation, transmission, and distribution. The generation sector consists of electric generators that produce electricity, such as power plants that comprise several generators. Once the electricity is

[35] I consider both new power plants and significant upgrades to existing plants.

[36] Publicly-owned RPUs are called Investor-Owned Utilities, and in 1998, 68 percent of generation capacity in the U.S. was owned by investor-owned RPUs.

produced by generators, it travels across a network of high voltage transmission lines called the transmission sector. To reach end users (e.g. residences and small businesses) the electricity flows through the distribution sector.

Historically, RPUs were regulated by state Public Utility Commissions ("PUCs") that employed cost-of-service regulation to ensure that the RPUs recovered all of the money they spent to provide electric service to retail customers through retail electric rates.[37] In addition to full recovery of expenses, RPUs were also paid a "reasonable rate of return" on the capital investments they made to provide customers with electric service, such as generation capacity, transmission lines, and sub-stations. Hence under cost-of-service regulation, retail ratepayers were responsible for fully reimbursing RPUs for all of their capital expenditures plus a rate of return.

As designed, the cost-of-service regulatory regime gave RPUs no incentive to minimize costs, and actually gave them an incentive to overinvest in capital-intensive generation capacity in an effort to increase the RPU's rate base, and hence its total return. The tendency of RPUs to overcapitalize is called the "Averch-Johnson Effect" (Averch and Johnson, 1962). Furthermore, RPUs were reluctant to invest in expensive cost saving technologies for fear that the state PUC would find the expenses imprudent and deny cost recovery through retail electric rates. By the early 1990s many policymakers believed that RPUs were spending too much

[37]These expenses include plant, labor, and operations and maintenance expenses.

money on new generation capacity and many states chose to restructure their electric systems (Fagan, 2006).[38]

1.2 Two Key Electric Restructuring Policies

Electric restructuring in the U.S. was a complex process that took place in stages and varied from state to state (Kwoka, 2008). The two most important restructuring policies were the unbundling of RPUs and the establishment of wholesale electricity markets.

Unbundling of RPUs

Unbundling vertically integrated RPUs opened the electric generation sector to competition by eliminating the virtual RPU monopoly in the electric generation sector.[39] Unbundling involved functionally separating the generation sector from the transmission and distribution sectors and dissolving cost-of-service regulation for investments in new generation capacity. The goal was that the private sector, rather than regulated vertically integrated RPUs, would finance and build new generation investments and sell the output (electric power) directly to wholesale customers, such as former RPUs or large industrial customers.

[38] One famous example of the AJ Effect and excessive RPU spending was a nuclear plant in Connecticut that had an initial cost estimate of $400 million and a delivered price of $3 billion (Fagan, 2006).

[39] RPUs were required by the Public Utility Regulatory Policies Act of 1978 to purchase a small percentage of electricity from Qualifying Facilities each year. Qualifying Facilities are cogenerators or small power plants that use renewable fuels.

Divestiture, which is explicitly forcing or compelling through regulatory policies RPUs to sell off some or all of their generation capacity, accompanied RPU unbundling in all of the states that pursued it.[40] Most of the divested RPU generation capacity was sold to independent power producers ("IPPs"), the largest class of non-RPU generators.[41] Through RPU divestiture, state PUCs hoped to eliminate or at least mitigate the dominant positions of unbundled RPUs in the generation sector. For example, an unbundled RPU might possess 80 percent of the generation capacity in a local region. PUCs and federal regulators feared that under such conditions, RPUs would exercise their market power to either raise electricity prices or deter entry into the generation sector. To avoid such outcomes, state PUCs compelled the RPUs to divest all or part of their generation assets.

Wholesale Electricity Markets

Firms in the private sector will not invest in new generation capacity if they cannot physically deliver electricity to wholesale customers. To make these sales, they must have access to the transmission grid. The Federal Energy Regulatory Commission required RPUs to open their transmission lines to non-RPU generators in 1996, but the regulations (Order 888) lacked specificity and the necessary enforcement mechanisms to ensure non-discriminatory access to all parties.[42]

[40] CA, CT, ME, NH, RI, and TX forced RPUs to divest all or part of their generation assets. RPU divestiture took place voluntarily due to PUC regulations that made divestiture the most profitable alternative to the RPUs in IL, DE, MA, MD, MI, NJ, NY, PA, and VA.

[41] Other non-RPU generators include cogenerators, municipalities, and generation owned by the federal government.

[42] 75 FERC ¶61,080 Federal Energy Regulatory Commission Docket No. RM95-8-000, Order No. 888 Promoting Wholesale Competition Through Open Access Non-discriminatory Trans-

An obvious antitrust issue arose as vertically integrated RPUs were expected to open their transmission networks to potential competitors. To create a more robust platform for competition, the Federal Energy Regulatory Commission encouraged the establishment of wholesale electricity markets in Order 2000 in 1999.[43]

Wholesale electricity markets are regional transmission systems that are operated by a disinterested third party that grants all parties equal and "non-discriminatory" access to the transmission grid.[44] These markets provide wholesale electricity price transparency because the price of electricity is determined through a centralized auction process. Before wholesale electricity markets existed, the wholesale price was negotiated through proprietary bilateral contracts, most of them long-term (e.g. 15 years).

Wholesale electricity markets also provide more liquidity than the old system with bilateral contracts because the auctions occur repeatedly throughout the day. Seven wholesale electricity markets were developed in the U.S.: PJM, which was the first to launch in 1997, ISO New England, New York ISO, ERCOT, the Midwest ISO, SPP, and the California ISO. Electricity in these markets is sold through centralized uniform price auctions, where both generators and wholesale consumers submit bids to either supply or purchase electricity.

mission Services by Public Utilities, Issued (April 24, 1996)

[43] 89 FERC ¶61,285, Federal Energy Regulatory Commission, Docket No. RM-99-2-000, Order No. 2000, "Regional Transmission Organizations" (December 20, 1999).

[44] While Order 888 required RPUs to grant non-RPU generators access to their transmission systems, it did not contain many provisions about the quality of transmission access. Many non-RPU generators claimed that RPUs offered them severely limited access to the grid.

1.3 Restructuring Varies by State

The electric restructuring policies pursued by the states fall into one of the following two categories: unbundling RPUs and joining wholesale electricity markets, and joining wholesale electricity markets without unbundling. A third group of states pursued neither policy. A list of the states in each category is provided in table 7.

RPU unbundling was the most important electric restructuring policy at the state level. Sixteen states and the District of Columbia unbundled their RPUs and belong to wholesale electricity markets. The traditional cost-of-service regulatory system that guaranteed RPUs full recovery of their generation investment expenses was dissolved in these states. Through electric restructuring legislation, states required RPUs to functionally separate the generation sector from the transmission and distribution sectors. By unbundling RPUs, the state PUCs gave non-RPUs the opportunity to sell power directly to wholesale and retail customers because the RPUs lost their monopoly power over the electric generation sector. RPUs still own the transmission and distribution sectors, but the transmission sector is operated by disinterested wholesale electricity market officials. The policy of retail access was expected to offer savings to retail customers by giving them the right to purchase the generation portion of their electric service from an alternate supplier, however it has generally been pursued by industrial rather than residential customers (Joskow, 2006).

Twenty-four states kept their RPUs vertically integrated and chose not to join wholesale electricity markets. In these traditionally regulated states, the state PUC still guarantees RPUs full recovery of their (prudently incurred) investments in new generation capacity through cost-of-service regulation. IPPs in these states sell their output directly to RPUs through Power Purchase Agreements, long-term agreements between generators and wholesale electricity customers (e.g. an RPU), often lasting 15 years or more.[45] However, these IPPs can not sell electricity directly to retail customers.

Ten states kept their RPUs vertically integrated but joined a wholesale electricity market. In these states, IPPs can sell their output directly to RPUs or to the wholesale electricity market, but IPPs cannot sell directly to retail customers. The RPUs in these states can purchase electricity from a wide range of sources in the wholesale electricity market or build generation themselves and be reimbursed by the state PUCs.

1.4 Concerns of Underinvestment

To ensure reliable electric service, the instantaneous supply of electricity must be greater than the demand for electricity by a predetermined rate called a reserve margin.[46] If this tenuous balance is disrupted, the transmission system can shut

[45]An IPP in a traditionally-regulated state may be able to sell its electricity to a wholesale electricity market if it is adjacent to a wholesale electricity market

[46]A common reserve margin is 15 percent, so the supply of *instantaneous* generation capacity must be at least 15 percent greater than demand.

down and electric service will be interrupted. Generator outages, transmission line problems, or unexpected increases in demand can cause blackouts. To protect against such imbalances, additional generation capacity must be available at all times to ensure reliable electric service. Unfortunately, many believe that investment in new generation capacity has been undersupplied in recent years in states that unbundled their RPUs and joined wholesale electricity markets.

The North American Electric Reliability Council ("NERC") oversees and enforces electric reliability standards in the U.S. In its 2007 Supply Assessment, NERC predicted that various regions will have reserve margins below desirable levels in the next three to five years (NERC, 2007).[47] NERC predicts that peak electric demand in the U.S. will grow 17.7 percent (135,000 MW) in the next ten years while generation capacity is expected to expand by at most 12.7 percent (123,000 MW) (NERC, 2007).[48]

[47]These regions, California, Rocky Mountain States, New England, Texas, the Southwest, and the Midwest may have to rely on inefficient sources of generation to meet future reliability needs if additional capacity isn't brought online.

[48]Peak demand is the maximum instantaneous level of demand for electricity in a given period.

Trouble in the Northeast

Concerns about underinvestment are often focused on wholesale electricity markets in the Northeast: PJM, a market in the Mid-Atlantic, ISONE in New England, and NYISO in New York state. Why would the unbundling of RPUs and wholesale electricity market membership depress investment in new generation capacity?

One hypothesis is that strict price controls in wholesale electricity markets in the Northeast, which attempt to curb generator market power, suppress the wholesale electricity price and inhibit IPP entry.[49] This is often referred to as the "missing money" problem because wholesale electricity market prices are sufficient to recover variable costs, such as fuel, but these revenues alone are not high enough to recover fixed costs (Joskow (2007a) Joskow (2008) and Cramton and Stoft (2005)).

Wholesale electricity market operators recognize this problem and according to NYISO, the New York state wholesale electricity market operator, "substantial investments in the high-voltage transmission systems and in large power plants are not on the horizon. Given the outlook for energy infrastructure needs over the next 10 years, this is cause for concern."[50] In response to these concerns, two of the wholesale electricity markets in the Northeast, PJM and ISO New England, established new forward capacity markets in 2008 that force the entities that resell power to retail customers (e.g. former RPUs) to purchase a large

[49] Generator market power arises from transmission constraints that limit the ability to import electricity from neighboring generators.

[50] Power Trends 2007, New York ISO, at 23

percentage of their forecasted demand plus a reserve margin up to three years ahead of time.[51] These new forward capacity markets are intended to overcome the perceived holdup problem and help IPPs secure the long-term contracts necessary to finance new investments in generation capacity.

Given the high fixed costs of new power plant construction, long-term contracts are essential to finance new IPP generation in any state (Task Force 2007 at 75). Unfortunately, the Federal Energy Regulatory Commission noted that generators in states that unbundled their RPUs and joined wholesale markets find it difficult to negotiate long-term contracts at prices high enough to finance new investment.[52] This reliance on long-term contracts for plant financing is relatively new because contracting problems did not exist when RPUs were vertically integrated.

Another hypothesis is that regulatory risk creates a holdup problem because non-RPUs fear that the states, for political reasons, will change the market rules after the fact and decrease the profitability of generation assets (Graves and Baker (2005), Brunekreeft and McDaniel (2007), and Joskow (2007a)). Joskow described non-RPU concerns that "market rules and market institutions change so frequently and that opportunities for regulators to 'holdup' incumbents by imposing new market or regulatory constraints on market prices is so great that uncertainty about future government policies acts as a deterrent to new investment"(Joskow,

[51] These wholesale markets recently expanded their capacity markets. PJM adopted a Reliability Pricing Model and ISO New England adopted Forward Capacity Markets. NYISO has a short-term (6 months) installed capacity market, while CALISO, MISO and ERCOT do not have capacity markets.

[52] 119 FERC ¶61,306 (June 22, 2007)

2008).

2 Historical Investment in Generation Capacity

Historically, generation investment in the U.S. has followed a cyclical pattern with regional variation (Ford (2002) and Hunt and Sioshansi (2002)). Figure 2 contains a graph of historical generation capacity in the U.S. along with the Gross Domestic Product. Prior to the late 1990s, there was excess generation capacity in the U.S., which is partially attributed to RPU incentives under cost-of-service regulation (Joskow, 2006).

An investment boom in the 2000-2003 period consisted almost exclusively of natural gas combined cycle generators, hence it is often called the CC boom. The CC boom is attributed to the availability of new combined cycle technology, which was cheaper to build than competing technologies, and low natural gas prices (Graves and Baker, 2005). The CC boom was also fueled by investor expectations of high profit margins in restructured electric systems and excess liquidity in capital markets (Hunt and Sioshansi, 2002). IPPs built most of the generation associated with this boom.

The CC boom ended in 2004, as the excess capacity built during the CC boom, high natural gas prices, and slow demand growth reduced profits. Furthermore, the IPPs that were building the gas-fired generation suffered significant losses as a result of financial scandals within the industry (e.g. Enron). Installed generation capacity has grown at a much slower rate in the 2004-2007 period (Joskow, 2007b). Since 2005, new investment has been increasingly wind powered, which is likely due to state policies that promote renewable energy. Some predict a "Green" boom in generation investment, where renewable energy makes up a greater proportion of new investment than it has historically (*The Economist*, 2008).

2.1 Current Investment Climate

Generation investment is undertaken rather infrequently because of the significant fixed costs of building new capacity. Both types of investors - RPUs and IPPs - are primarily concerned with the expected rate of return on a proposed investment in new generation. The difference between the two is that market forces determine the IPP's return, while the RPU's return is determined administratively by the state PUC. Again, many believe that the rate of return on IPP generation is too low to induce entry in states that unbundled their RPUs and belong to wholesale electricity markets, particularly in the Northeast (Joskow (2008) and Cramton and Stoft (2008)). Factors influence investment in all three regimes include regulatory uncertainty, power plant siting issues, climate change concerns, and building and construction costs.

One significant risk faced by any entity that invests in new generation capacity, IPPs in particular, is regulatory uncertainty. IPPs often fear that the state PUCs or the wholesale electricity market operators will force them to return profits earned in wholesale electricity markets (see Joskow (2006) and Brunekreeft and McDaniel (2007)). Ishii and Yan (2004) showed that regulatory uncertainty can indeed delay the investment decisions of IPPs. They first estimated a Tobit regression of new investment in generation in each state as a function of restructuring variables and found evidence that investment was lower in the period immediately preceding RPU unbundling. The data suggested that uncertainty about future restructuring caused IPPs to delay investment. They also examined the investment behavior of 20 IPPs and found that forward looking investment models, such as the Real Option Value model, described their behavior well.

Another major concern to any entity that invests in new generation is siting. State regulations such as permitting and transmission interconnection agreements play a major role in investment decisions (GAO, 2002). It is often difficult to build new generation given local opposition. Wallsa et al. (2007) examined detailed data on proposed power plants in the U.S. and found that developers often pursue multiple sites to build a single power plant, and abandon candidate sites that prove to be more costly as time goes on. For example, a particular site might be abandoned because of vigourous local opposition.

Wallsa et al. calculated sample hazard rates, which in this case is the probability that a proposed power plant gets canceled, and found that IPP investment projects had a greater risk of being canceled than RPU plants. These results are consistent with the widely held belief that generation investment in states that unbundled their RPUs is more risky than generation investment in traditionally regulated states with traditional cost-of-service regulation.

New federal legislation motivated by concerns about climate change will likely limit carbon dioxide emissions, but the federal government has not determined how it will achieve this goal.[53] This uncertainty troubles any entity that seeks to build new generation capacity that uses carbon-based fuel, coal in particular because it is generally the most polluting. Fears of excessive carbon dioxide legislation allegedly led to the cancelation of up to 50 coal plants in 2007 (Pastenak, 2008). Uncertainty about climate change is exacerbated by the fact that the U.S. Department of Energy abandoned its plans to build a clean coal plant called FutureGen, which would sequester carbon emissions.[54] As such, coal plants are particularly risky to build at this time.

Yet another factor that may depress investment levels is the rapid escalation of the price of power plant construction materials, such as iron, steel, copper, and concrete.[55] An equally important factor is the increased cost of the generating units themselves, the most expensive element of any power plant, because developers

[53] Congress is currently considering two major proposals: cap-and-trade or a carbon tax. Congress is also considering renewable energy mandates to encourage the development of generation capacity that uses renewable fuels, though many states have adopted them independently of federal legislation.

[54] U.S. Department of Energy http://www.netl.doe.gov/technologies/coalpower/futuregen/. According to the U.S. Government Accountability Office, the Dept. of energy has slashed its R&D budget by over 85 percent from 1978 to 2005 in real terms (GAO, 2006).

[55] The price of minerals such as steel, iron, copper, and aluminum has skyrocketed in recent years. This is largely attributed to increased global demand and a weak dollar. For example, the price of copper quadrupled between 2003 and 2007.

in the U.S. must increasingly compete with the rest of the world for these specialized goods that are produced by a small number of firms (The Brattle Group, 2007). Finally, there is a shortage of skilled labor in the electricity sector which is expected to reach critical levels in the future (NERC, 2007).

3 Generation Investment by Region

Research related to electric restructuring legislation and electric infrastructure investment often relies on panel data techniques where an outcome variable (e.g. investment in new generation capacity) is modeled as a linear function of controls and a set of policy variables associated with electric restructuring. Most of these empirical studies are conducted at a cross-national level (see Nagayama (2007), Hattori and Tsutsui (2004), and Zhang et al. (2008)). For example, Zhang et al. (2008) used panel data to estimate the effects of privatization, regulatory change, and competition on the price of electricity in 36 developing countries.[56]

The only study to date that examined recent investment levels in the U.S. was conducted by Hattori (2004), who used a panel of the 50 states from 1990 to 2002 and found that electric restructuring did not have a significant affect on the growth of generation capacity. Hattori used the percentage change in state capacity (in MW) as a dependent variable and restructuring policies and other controls as

[56] The electric utilities in most developing countries are state-owned.

independent variables. Four policy variables were used: the passage of Order 888, the implementation of retail access, wholesale electricity market participation, and the percentage of generation capacity owned by IPPs. The policy variables used were also interacted with each other.

Hattori found that restructuring did not contribute significantly to the growth in capacity investment in each state. Hattori also attempted to correct for the possible endogeneity of the retail access and IPP generation variables by using the average retail price for electricity and the difference between the residential and industrial electricity price but did not provide details on the suitability of these instruments. Nevertheless, the coefficients of the restructuring policy variables were either small or insignificant.

My approach differs from Hattori's because I include a smaller number of policy variables, especially given that some of the restructuring variables, such as retail access and IPP ownership, are highly correlated with each other. I exclude the retail access policy variable because it was implemented along with unbundling, and hence highly correlated with it. Furthermore, retail access was not terribly successful. I examine whether investment has differed across the following three groups; regions that unbundled RPUs and joined wholesale electricity markets, regions that joined wholesale electricity markets without unbundling, and regions that pursued neither policy.

As previously noted, many claim that investment is depressed in states that unbundled their RPUs and joined wholesale electricity markets, particulary in the Northeast. I seek to determine whether this belief is supported by empirical evidence. I first examine investment by creating eleven regions (groups of adjacent states). The states within each region either belong to the same wholesale electricity market and or share similar geographic and regulatory characteristics. Figure 3 contains a map of the eleven regions used as the basis for this analysis. Eight regions roughly match up with the seven wholesale electricity markets in the US: California ISO, Electric Reliability Council of Texas, Southwest Power Pool, the Midwest ISO, PJM Interconnection (PJM & WVAOH), ISO New England, and New York ISO.

The PJM wholesale electricity market is broken into two regions because three of the states, Ohio, West Virginia, and Virginia, joined PJM six years after it opened and have restructuring policies that differ from the rest of the states in PJM.[57]

It is important to analyze investment at the wholesale electricity market level because analyzing state-level investment alone, as Hattori did, neglects wholesale electricity trades across state borders. The rest of the states are grouped into a Pacific Northwest region, a Southwest region, a Southern region, and a central Atlantic region. Table 12 lists the states in each region. The sample is the sixteen year period between 1992 and 2007 and the panel is fully balanced. I also examine total investment levels at the state-level and compare my results to Hattori's.

[57] The part of the PJM market that is in Ohio and West Virginia is referred to as PJM West, and the Virginia portion is referred to as PJM South.

One could make the criticism that analysis of investment at the state or regional level is arbitrary and could conceivably be conducted at the county level instead. It is worthwhile, however, to analyze investment at the regional level for two reasons; electricity cannot travel vast distances without losses, and wholesale electricity markets were established to facilitate trade within each market. The longer the distance that an electric current travels over a transmission line, the greater the amount of electricity that is lost. Thus a power plant in California cannot supply electricity to a customer in Ohio. The electric generation sector is somewhat local and must be analyzed within a feasible geographic area. Furthermore, given that wholesale electricity markets were established to make trade between market participants possible, it is important to analyze electricity investment within each wholesale electricity market. Hence, the regions I develop coincide with the seven wholesale electricity markets in the U.S. and the restructuring policies pursued by various states.

3.1 Total Investment Model

This model compares investment outcomes across eleven regions in the continental U.S. that fall into one of the following three categories: regions that unbundled RPUs and joined wholesale electricity markets; regions that joined wholesale electricity markets without unbundling RPUs; and regions that pursued neither policy. Hawaii and Alaska are excluded from this analysis because they are geographically isolated and hence have different electric systems. This study focuses on new plants or plant upgrades that are at least 20 megawatts ("MW"), which accounted for 98 percent of total investment over the 1992-2007 sample period. For brevity's sake, I will refer to plant upgrades as plants. I exclude generation capacity from plants that are less than 20 MW because they are typically built at the end user's site, are significantly cheaper, and much easier to site.

The most important investment outcome is the level of installed capacity in MW built each year in the region. As in previous studies, I employ panel data techniques and model investment levels as a function of electric restructuring variables and other controls.

$$\begin{aligned} MWadd_{it} = \; & \beta_0 + \beta_1 WEM_{i,t-2} + \beta_2 WEM \times Treat_{i,t-2} + \beta_3 netgen/capacity_{i,t-2} \\ & + \beta_4 POP_{i,t-2} + \beta_5 EPACO_{i,t-2} + \beta_6 IronSteel_{i,t-2} + \beta_7 trend_t + \varepsilon_{it} \end{aligned}$$

The dependent variable $MWadd_{it}$ is the sum of investment in MW of new generation capacity from plants that were at least 20 MW in region i and year t. All of the explanatory variables are lagged two years to account for the financing and construction time of an average power plant. The policy variables of interest are WEM, which is a time-varying dummy variable that denotes wholesale electricity market membership, and $WEM \times Treat$, which interacts one of three variables with the wholesale market dummy. I estimate the total investment model three times and in each estimation, the *Treat* variable takes on a different value. The first set of estimates examines wholesale electricity markets in the Northeast, hence the

Treat variable is a dummy variable for the three Northeast regions: PJM, ISONE, and NYISO. The coefficient of $WEM \times Northeast$ will be negative if investment in these regions has been stifled by regulatory risk and severe price controls, as many have claimed.

In the second set of estimates, the *Treat* variable indicates whether RPU divestiture took place. The sum of the $WEM \times Divestiture$ and WEM coefficients applies to regions with states that unbundled their RPUs and joined wholesale markets. The WEM variable alone applies to regions that joined wholesale markets without unbundling, and neither coefficient applies to the regions that pursued neither policy. If indeed there is a regulatory holdup problem because RPUs were unbundled and electricity is sold in wholesale electricity markets β_2, the coefficient of $WEM \times Divestiture$, will be negative. In the third set of estimates, the *Treat* variable is the percent of electricity in the region produced by IPPs. The interaction between IPP production and the wholesale electricity market variable, $WEM \times \%IPP$, should also be negative if the regulatory holdup problem exists.

The first control variable is the ratio of net electric generation in megawatthours divided by the total generation capacity in the region.[58] This is a slightly imprecise measure of demand and intensity of use as it is averaged over the year but it gives a general sense of supply and demand conditions. I expect β_3, the coefficient of $netgen/capacity$, to have a positive sign as investment in new generation should

[58]Net generation figures are used because electricity is an input to the electric production process.

respond to the existing relationship between supply and demand. The POP variable is a two year lag of annual population (in 100,000s) in the region and I also expect β_4 will be positive, as the greater the population of a region, the greater its demand.

The $EPACO$ variable is a two year lag of the percent of counties in the region, weighted by county population, that were in violation of the Clean Air Act's standards for carbon monoxide. This variable is included to capture the effects of environmental regulations on new investment in generation capacity and I expect β_5 will be negative.[59] Construction costs are measured in the $IronSteel$ variable, which is the Producer Price Index for Iron and Steel from the Bureau of Economic Analysis (base year 1997). I expect that investment levels will decrease as power plant construction costs increase.

3.2 Investment Count Model

Given the high fixed costs of investment in new generation capacity, the number of new plants is an important outcome to study. Count models are a good tool for modeling such rare events. Similar to the total investment model above, I estimate the number of new plants in region i and year t, N_{it}, to be a linear function of

[59] When a county violates a Clean Air Act standard for a pollutant, all new sources of pollution, like a new power plant, must undergo additional regulatory hurdles to obtain the necessary operating permits from state officials.

policy and control variables.

$$
\begin{aligned}
N_{it} = \quad & \beta_0 + \beta_1 WEM_{i,t-2} + \beta_2 WEM \times Treat_{i,t-2} + \beta_3 netgen/capacity_{i,t-2} \\
& + \beta_4 POP_{i,t-2} + \beta_5 EPACO_{i,t-2} + \beta_6 IronSteel_{i,t-2} + \beta_7 trend_t + \varepsilon_{it}
\end{aligned}
$$

All independent variables are identical to those in the total investment model. I estimate two types of count models, a Poisson regression model and a negative binomial model.[60] The Poisson model has the desirable property that its coefficients are consistent even if the distributional assumption about the dependent variable is incorrect (Wooldridge, 2002).[61] However, given the difficulty of testing for over-dispersion with a fixed effects Poisson regression model, I also estimate a negative binomial model and compare the estimates. The negative binomial model relaxes the assumption that the conditional mean and variance of the underlying distribution are equal (Colin, 1998).[62]

[60] I consider both new power plants and upgrades to existing power plants.

[61] The Poisson distribution is $Pr(Y_i = y_i) = \frac{e^{-\lambda_i}\lambda_i^{y_i}}{y_i!}$ for $y = 0, 1, 2, ..$ where the mean and variance parameter λ is $\lambda_i = exp(X'\beta)$. The expected number of events per period is $E[y_i|x_i] = Var[y_i|x_i] = \lambda_i = exp(x_i'\beta)$

[62] The negative binomial regression model generalizes the Poisson model by introducing heterogeneity into the conditional mean: $\mu_i = exp(x_i'\beta + \epsilon_i = ln\lambda + lnu_i$. The distribution of y conditioned on X and u is $Pr(Y_i = y_i) = \frac{e^{-\lambda_i u_i}(\lambda_i u_i)^{y_i}}{y_i!}$. The negative binomial model assumes that $u_i = exp(\epsilon_i)$ has a gamma distribution. The count variable Y has a conditional mean λ_i and a conditional variance $\lambda_i(1 + \frac{1}{\theta}\lambda_i)$ where θ is the gamma parameter.

4 Estimation Results

It is helpful to examine summary statistics of the total investment across the three types of regions before reviewing the model estimates. Table 13 lists total investment from plants that are at least 20 MW over the 1992-2007 sample period. The figures are oversimplified, however, because they do not account for the varied implementation across time and within some regions.[63] Investment occurred in all regions but the growth in new investment was relatively lower in the 2004-2007 period in regions that joined wholesale electricity markets but did not unbundle their RPUs. A graph of annual total investment is shown in figure 4. Investment levels followed a similar pattern in each category, with low levels before restructuring took place, a CC boom between 2000 and 2003, and a subsequent slowdown.

While the estimates of the three treatment variables in the total investment equations, $WEM \times NEast$, $WEM \times DIV$, and $WEM \times \%IPP$ are insignificant and negative, the magnitudes are nontrivial so I cannot rule out the possibility that investment is lower in regions that pursued electric restructuring policies. The count estimates suggest that the number of new plants is lower in the Northeast and regions that joined wholesale markets as compared to regions that didn't. Table 15 displays $MWadd_{it}$, the dependent variable in the total investment estimates. Table 14 lists N_{it}, the annual counts of new plants in the 1992-2007 sample

[63] Two states in the MISO region and wholesale electricity market unbundled their RPUs but the majority of the region did not unbundle. The estimations take this into account by taking a state population weighted average of the policy variables.

period. A summary of the data sources is provided in the Appendix.

4.1 Northeastern Wholesale Electricity Markets

The first set of estimates seek to determine whether investment is depressed in the three wholesale electricity markets in the Northeast. The wholesale electricity markets in the Northeast are grouped together because they share a similar history and design relative to the other wholesale electricity markets in the U.S. The motivation behind this question is the widely held belief that these wholesale electricity markets do not provide sufficient incentives for investment (e.g. Cramton, Stoft, and Joskow).

Table 16 contains estimates of the count and total investment models based on the eleven regions. The estimates contain regional fixed effects because a Hausman specification test indicated a significant systematic difference between the fixed and random effects specifications.[64] This is not surprising as it would be difficult to argue that the differences across the regions was purely random. The count model estimates in table 16 are presented along with their incidence rate ratios.[65]

The coefficient of interest is $NEast \times WEM$ as it denotes the Northeast regions

[64] Fixed effects in the Poisson regression model are relative to the conditional mean while fixed-effects in the negative binomial regression model are relative to the dispersion parameter of the mean.

[65] The incidence rate ratio ("IRR") is the expected count of the dependent variable resulting from increasing the explanatory variable x_i by one unit to $x_i + 1$, divided by the expected count for x_i.

after the establishment of wholesale electricity markets and compares them to other regions with wholesale markets, captured in the WEM variable, and regions without wholesale markets. Focusing first on the count models, the estimate of the $WEM \times NEast$ coefficient in the Poisson and negative binomial models is negative and statistically significant. These estimates suggest that the number of new large-scale plants has fallen in the Northeast compared to the rest of the country by between 46.9 and 58.6 percent.

The estimates of the WEM coefficient are insignificant, but the magnitudes of the estimates suggest that the number of new plants each year ($\geq$ 20 MW) are between $100 \times (1 - .778) = 22.2$ and $100 \times (1 - .755) = 24.5$ percent lower in regions with wholesale markets compared to those without them. Although the WEM estimates are insignificant, magnitudes of the sum of the WEM and $WEM \times NEast$ coefficients are substantial and associated with a decrease in the number of plants in the Northeast of between 69 and 83 percent.

The $netgen/capacity$ coefficient estimate is positive and significant in both count specifications, which is as expected. The parameter estimates of $IronSteel$ and $EPACO$ are negative and statistically significant.[66] The estimate of the population coefficient is negative but insignificant, and it is possible that the fixed effects parameters explain all of the variation in population.

[66] The same equation was estimated with other minerals (e.g. copper oar and aluminium) instead of the Iron Steel PPI and the results were similar. Given the correlation between the three indexes, only one was included.

Note, however, that the count model does not account for the size of the new plants. Column (5) in table 16 contains estimates of a fixed-effects panel regression of annual investment in new generation capacity by region. Both the $NEast \times WEM$ and WEM coefficient estimates are insignificant. The average regional investment from new plants $\geq$ 20 MW between 1999, when wholesale markets in the Northeast launched, and 2007 was 2,440 MW and the sum of the $NEast \times WEM$ and WEM estimates is -364 MW, which constitutes a 15 percent decrease in investment levels. As such, I cannot rule out the possibility that total investment is lower in the Northeast than the rest of the nation but if it is, it is modestly so and belonging to a wholesale electricity market in the Northeast is not as important as other factors.

When eleven regions are used as the basis for estimation, PJM and WVAOH are considered separate regions because while Ohio, Virginia, and West Virginia belong to PJM, these states joined PJM approximately seven years later than the rest of the PJM states.[67] Furthermore, West Virginia has not pursued any restructuring policies and Virginia essentially reversed its decision to restructure the state's electric system.[68] Table 17 contains a robustness check of the separating the PJM wholesale electricity market into two regions.

I amend the eleven regions by combining the PJM and WVAOH regions into a single region and re-estimate the count and total investment models. If ten regions

[67]The original PJM states are PA, MD, NJ, and DE.

[68]The Virginia PUC suspended retail access in 2007 and reversed the legislation that unbundled the state's RPUs in the first place.

are used instead of eleven, the $WEM \times NEast$ estimates in the count models are still significant and negative, and have similar magnitudes to the estimates in table 16. Similarly, the estimate of $WEM \times NEast$ negative yet insignificant in the total investment estimation.

The estimate of the WEM coefficient in both the count and total investment models is lower when ten regions are used. This is because investment in the 2002-2007 period was relatively low in the sections of the PJM market that contain West Virginia, Virginia, and Ohio (the WVAOH region). Lumping these states together with the rest of PJM dampens the slowdown, which was coincident with PJM membership in 2005 and a motivating factor for separating PJM into two groups in the first place. The use of eleven regions and separating Ohio, Virginia, and West Virginia from the PJM states is not driving the result that the WEM and $WEM \times NEast$ estimates are insignificant in the total investment estimate.

The results of the count models suggest that the number of new plants in the Northeast has decreased relative to the rest of the U.S. The total investment estimates, however, are insignificant. If total investment is lower in the Northeast, it is by at most 15 percent. If total investment levels remained constant while the number of new plants decreased, the average size of new plants may have increased. Plant size will be explored further in section 5.

4.2 Divestiture

The next set of estimates use a divestiture variable to determine if there is evidence of a regulatory holdup problem in states that unbundled their RPUs and joined wholesale electricity markets. Divesture was used to implement unbundling in each state that pursued it. Divestiture did not occur in states that kept their RPUs vertically integrated. The divestiture variable DIV is the regional average, weighted by state population, of a state divestiture variable that equals one if an RPU in the state has divested any generation assets, and zero otherwise.

Table 18 contains count and total investment models with a divestiture treatment variable. The divestiture variable DIV is interacted with the WEM variable in an effort to compare investment in regions that unbundled their RPUs and joined wholesale electricity markets to the other two categories. The WEM variable applies to regions that joined wholesale electricity markets without divestiture\RPU unbundling.

The count model estimates of the Poisson and negative binomial models vary slightly but both estimates share the same sign, magnitude, and significance patterns. The first count estimates in columns (1) and (5) use a time trend called $avgDIV$ in an attempt to capture the nonlinear nature of the pace of divestiture in the U.S. Columns (4) and (7) use a year trend. The WEM estimates are negative and significant, suggesting that the number of new plants was approximately

30 percent lower in regions once they joined wholesale electricity markets.

The $WEM \times DIV$ estimates are negative and insignificant in all four count model specifications. The magnitudes of the $WEM \times DIV$ is modest and associated with the number of new plants falling by 15 percent in regions that both restructured and joined a wholesale electricity market. Together, although they are insignificant, the WEM and $WEM \times DIV$ estimates are associated with a 40 percent decrease in the number of new plants in regions that both unbundled their RPUs and joined wholesale markets.

Columns (9) and (10) of table 18 contain the total investment estimations with the DIV variable. The $avgDiv$ variable is used as a time trend in column (9) but the estimates of the $WEM \times DIV$ coefficient, -1065, is not consistent with the data. This is likely because the $avgDIV$ trend is correlated with the DIV variable. If the year trend is used (column (10)), the estimate of $WEM \times DIV$ is more reasonable yet insignificant. The magnitudes of the insignificant policy variables are relatively modest. Given the average annual regional investment level of 2,440 MW in the 1999-2007 period, the insignificant estimates correspond to a 17 percent decrease in total investment in regions that unbundled RPUs and joined wholesale markets and a five percent increase in investment in regions that joined wholesale markets without unbundling.

Given the modest magnitude associated with the $WEM \times DIV$ coefficient, I cannot rule out the possibility that investment is lower in regions that unbundled but if it is, it is by at most 17 percent. The estimates associated with the policy variables are insignificant, however, hence it is clear that other factors are more important.

4.3 Percent IPP Production

The divestiture variable is binary and equals one at the state level, before it is weighted by state population and averaged into a regional variable, once an RPU in the state has divested any generation assets. As such, the divestiture variable is constant after the wave of RPU divestiture in the 1998-2002 period. A more dynamic policy variable is $\%IPP$, the percent of electricity in the region that is produced by IPPs. The $\%IPP$ variable is an important characteristic of the investment landscape in each region. This rate is high in regions that unbundled their RPUs and belong to wholesale electricity markets, lower in regions with vertically integrated RPUs that belong to wholesale electricity markets, and lower still in states that pursued neither policy. A low $\%IPP$ value coincides with a high percentage of RPU generation in the region. If the hypothesized regulatory holdup problem exists, the sign of the coefficient on the $WEM \times \%IPP$ variable will be negative.

Table 19 contains the estimates of the count models and total investment models that use the $\%IPP$ variable. Focusing on the count model results in the first eight columns, the coefficient on the interaction between wholesale electricity markets and percent IPP production, $WEM \times \%IPP$, is negative and insignificant in all four specifications. The average magnitude of the $WEM \times \%IPP$ estimates is consistent with a 30 percent decrease in the number of new plants each year. The WEM estimates are significant in three of the four count specifications and suggest that the number of new plants is approximately 30 percent lower in regions after they joined wholesale electricity markets. As with the divestiture estimates, the magnitudes associated with the sum of the WEM and $WEM \times \%IPP$ estimates is considerable. Hence, I cannot rule out the possibility that the number of new plants is lower in regions that unbundled their RPUs and joined wholesale electricity markets.

Columns (9) and (10) of table 19 contain the total investment estimates with the $\%IPP$ policy variable. Both the WEM and $WEM \times \%IPP$ estimates are insignificant, regardless of which time trend is used. However, as before, the estimate of $WEM \times \%IPP$, -992, is unreasonable when the $avg\%IPP$ trend is used. The estimate of the $WEM \times \%IPP$ coefficient is -541, with a year trend (column (10)) which, though insignificant, is associated with investment being 21 percent lower in regions that unbundled their RPUs and joined wholesale electricity markets ((35-541)/2440=21). Although the coefficients of WEM and $WEM \times \%IPP$ are insignificant, I cannot rule out the possibility that investment is lower in regions that unbundled their RPUs and joined wholesale markets.

4.4 State Level Estimates

Aggregating state level investment data into regions clearly results in the loss of information. To determine whether this aggregation drove my results, I re-estimate the models at the state level using state level controls. I also amend the environmental regulation variable to include all pollutants, rather than just carbon monoxide. The new $EPAvio$ variable equals one if any county in the state violated the Clean Air Act standards for any of the criterion pollutants. Given the highly variable number of new plants at the state level, which is often zero, I do not estimate state-level count models and focus solely on modeling total investment.

Table 20 replicates the total investment estimates of tables 16, 18, and 19 at the state level. The estimates of the key interaction variables, $WEM \times NEast$, $WEM \times DIV$, and $WEM \times \%IPP$ are insignificant. Furthermore, the wholesale electricity market variable WEM is insignificant in all three specifications. Hence, the estimates in table 20 suggest that the region-level total investment results are not driven by aggregation effects. The average investment in capacity at the state level was approximately 547 MW. Though insignificant, the magnitude of the $NEast \times WEM$ variable in column (1) is consistent with a thirty percent decrease in investment in the Northeast regions. This is slightly higher than the magnitude of the regional estimations because it does not account for trade within wholesale markets. Some states within the Northeast markets experienced relatively lower levels of investment after restructuring while other states in the same wholesale market experienced higher levels due to trade across state borders.

The insignificant estimates of the WEM and $WEM \times DIV$ coefficients in column (2) are associated with a 20 percent decrease in new investment in states that unbundled their RPUs and joined wholesale markets, as it was in the regional estimates. The magnitude of the sum of the state-level estimates of WEM and $WEM \times \%IPP$ in column (3) is consistent with a 40 percent decrease in new investment, which is higher than the regional estimate and likely associated with the fact that investment was lower in the regions that joined wholesale electricity markets but didn't unbundle their RPUs. These states have higher percentages of IPP production than states that didn't unbundle their RPUs or join wholesale markets. Given these estimates, aggregating state investment figures into regions did not drive the result that the key policy variables are insignificant in the total investment estimations.

4.5 Endogeneity

The state-level decision to restructure the electricity system may be endogenous. For example, many states (or regions) that restructured had higher electricity prices to begin with (see Fagan (2006) and Joskow (2006)). Another hypothesis is that states that elect their state Public Utility Commissioners were more likely to adopt consumer friendly policies like restructuring (Fagan, 2006). If this is the case, than a fixed effects model will difference these factors out. See Zhang (2007) for a demonstration of this point in the context of electricity markets.

The electricity price and process by which Public Utility Commissioners are selected are not included as independent variables, however, because the electricity price variables are not exogenous, and there is no theoretical reason to believe that the nature in which public officials are selected affects the fundamentals of electric supply and demand. It is difficult to find suitable instruments for the complicated political process involved in both unbundling and developing wholesale electricity markets (Jamasb et al., 2005).

Indeed, the two variables Hattori used, the ratio of the state residential price to the average residential electricity price and the difference between the residential and industrial prices, and another common restructuring instrument, a dummy variable denoting whether the state PUC commissioners are elected, are insignificant in estimates of the two policy variables associated with unbundling, divestiture and the percent of IPP generation in the region. The probit estimate of wholesale market participation, WEM, does not converge when all three instruments are used but if the residential electricity price is excluded, the coefficients of the remaining instruments are insignificant. As such, the standard variables used to instrument for electric restructuring policies are not relevant to this study.

The purpose of this chapter is to determine whether the claims of regulators and industry experts that investment in new generation capacity is stifled by electric restructuring policies is supported by empirical evidence. After controlling for differences across states and regions, such as the balance between supply and demand and environmental regulations, I do not find statistically significant evidence that total investment is lower in regions that restructured as compared to those that did not. However, I cannot rule out the possibility that states or regions that chose not unbundle their RPUs or join wholesale electricity markets experienced a decrease in investment for reasons that are unaccounted for the model, making total investment lower than it otherwise would have been, and thus statistically indistinguishable from investment in states or regions that adopted one of the two key restructuring policies.

4.6 Regional Investment Conclusions

The count estimates suggest that the number of new plants is lower in the Northeast and other regions that joined wholesale electricity markets compared to regions that did not. The results of the total investment estimations do not provide statistically significant evidence that investment is lower in regions that unbundled their RPUs and joined wholesale markets. The estimates of the variables of interest, WEM, $WEM \times NEast$, $WEM \times DIV$, and $WEM \times \%IPP$ are insignificant in the total investment specifications at both the state and regional level. However, the magnitudes of the coefficients of the electric restructuring policy variables are not trivial, thus I cannot rule out the possibility that investment is lower in regions that chose to adopt one or both restructuring policies. The fact that all of the estimates are insignificant, however, suggests that other variables, such as supply and demand and environmental regulation, are more important. Hence, the claims that investment is stifled in regions that restructured are not proved conclusively, but they cannot be ruled out.

5 Plant-Level Analysis

Given that the number of new plants was significantly lower in the Northeast and regions with wholesale electricity markets, it is important to examine whether the size of new plants differs across the three types of states: states that unbundled RPUs and joined wholesale electricity markets; states that joined wholesale electricity markets without unbundling; and states that pursued neither policy. I use data on individual plants and upgrades and control for important characteristics such as technology choice, investor type, and environmental variables to answer this question.

Table 21 compares new plant size in the Northeast with the rest of the country. The left side of table 21 has calculations for plants that were at least 20 MW, while the right side focuses on plants that were at least 100 MW. In the top panel, new plants in the Northeastern regions are compared to the rest of the U.S. In the middle panel the Northeast regions are compared to traditionally regulated regions that didn't unbundle their RPUs and don't belong to wholesale electricity markets ("Traditional"). Finally, in the bottom panel, the Northeast is compared to regions that didn't unbundle their RPUs but belong to wholesale electricity markets. There is no statistically significant difference in the growth of plant size between the 1992-1995 and 2004-2007 periods for plants that were 20 MW or greater.

There is, however, a statistically significant difference in the growth of plant size when focusing on plants of at least 100 MW. The average size for such plants in the Northeast was 603 MW in the 2004-2007 period compared to 346 MW in the rest of the U.S. The number of plants in the Northeast wholesale electricity markets also fell from 24 in the 1992-1995 period to 13 in the 2004-2007 period. This explains why the count estimations showed significantly negative signs when the WEM variable was interacted with the Northeast, divestiture, and IPP variables, which are the greatest in the Northeast and trend up over time.

The difference-in-differences between the Northeast and the other regions was statistically significant, as the growth in plant size was about 250 MW greater in the Northeast as compared to the other groups. This suggests that plant size, conditional on being at least 100 MW, was growing much faster in the Northeast as compared to the rest of the U.S. Upon further examination, however, the results of table 21 are slightly misleading, which is largely due to the limited number of observations in the Northeast.

If the two largest plants in the Northeast from the 2004-2007 period are excluded, the mean plant size decreases from 603 MW to 501 MW, so the average is heavily influenced by two observations.[69] Table 22 contains summary statistics of new plants in the 2000-2003 period. The average size of a new investment in generation capacity in the 2000-2003 period, conditional on being at least 20 MW, was 264 MW in the Northeast regions compared to 301 MW in the rest of the U.S.

Focusing on plants at least 100 MW in 2000-2003, the average size in the Northeast was 442 in the Northeast, compared to 431 in the rest of the U.S. There was no significant difference for either plant size between the Northeast and the rest of the U.S. Given that the figures in table 21 are heavily influenced by time periods and the small number of observations, differences in plant size across the three categories is difficult to discern.

I estimate the following model to determine whether plant size differed across the three categories of electric restructuring policies:

$$\begin{aligned} GenMW_{is} = \; & \beta_0 + +\beta_1 WEM + \beta_2 WEM \times Treat + \beta_3 netgen/capacity_{s,t-2} \\ & +\beta_4 wind + \beta_5 other + \beta_6 coal + \beta_7 hydro + \beta_8 nuclear + \beta_9 upgrade \\ & +\beta_{10} IPP + \beta_{11} INDcg + \beta_{12} EPAvio_{s,t-2} + \beta_{13} trend + \epsilon_{is} \end{aligned}$$

Where $GenMW_{is}$ is the size (in MW) of the generation investment i in state s.

Approximately 70 percent of the generation built each year during the 1992-2007

[69] The two large power plants are a 2006 1,1186 MW upgrade to PSEG's Linden Generating station in New Jersey, and Dominion's Fairless Energy Center, a 1,151 MW plant in Pennsylvania built in 2004. Both plants are fired by natural gas.

sample period was natural gas fired, so the technology dummy variables ($\beta_4 - \beta_8$) are relative to natural gas generation. $Upgrade$ is a binary variable that equals one if the investment was an upgrade to an existing power plant and zero otherwise. To account for characteristics of the investing party, IPP is a binary variable that equals one if the generation was built by an IPP, and $INCcg$ is a binary variable that equals one if the investor is an industrial cogenerator. The environmental regulation variable $EPAvio$ is a dummy variable that equals one if any county in the state violated the EPA's Clean Air Act for any pollutant, and zero otherwise.

The estimates in table 23 focus on the size of new plants in the Northeast compared to the rest of the country. The first column is restricted to plants that were at least 20 MW, while the second column focuses on plants that are least 100 MW. All specifications include state fixed effects due to the results of Hausman specification tests. After accounting for the state supply and demand, technology, investor characteristics, and state fixed effects, the WEM and $WEM \times NEast$ variables are insignificant in both specifications. The magnitudes are also trivial, as the average investment $\geq$ 20 MW built in the 1999-2007 period after restructuring was 272 MW, and the average investment $\geq$ 100 MW was 402 MW. The insignificant estimates of WEM and $WEM \times NEast$ are associated with a seven percent decrease in plants that were $\geq$ 20 MW and a four percent decrease in plants that were $\geq$ 100 MW. This suggests that the size of new plants have not grown faster or slower in the Northeast states compared to the rest of the nation. Hence, the calculations on table 21, which suggested that plant size grew at a faster rate in the Northeast, are misleading.

Table 24 compares new plant size across the three types of states. The estimates of the WEM and $WEM \times DIV$ coefficients are insignificant and trivial. The WEM estimates are positive and associated with an increase in plant size ranging from five to ten percent, while the magnitudes of $WEM \times DIV$ estimates are associated with a five percent decrease in plant size.

Table 25 compares plant size across the three categories but uses the $WEM \times \%IPP$ to account for IPP production. The WEM estimates are insignificant and trivial, and the greatest magnitude associated with the WEM coefficient is a four percent increase in plant size. The estimates of the $WEM \times \%IPP$ coefficients are more variable, however, with the greatest magnitude in column (4) associated with a 20 percent increase in size in plants $\geq$ 100 MW. The $WEM \times \%IPP$ estimate in column (1) that focuses on plants $\geq$ 20 MW of -74.16 is both insignificant and inconsistent with the observed data. The estimates in tables 23, 24, and 25 do not suggest that plant size is different across three electric restructuring policies. Factors such as generation technology, investor type, and environmental regulation are more important.

6 Conclusion

The estimates in this chapter suggest that the number of new plants is lower in regions that adopted wholesale electricity markets compared to those that did not. However, the estimates do not prove conclusively, as many have claimed, that total investment levels are lower in regions that unbundled their RPUs and joined wholesale electricity markets. The variables associated with electric restructuring policies in the total investment estimations are insignificant in virtually every specification. Though they are insignificant, however, some of the magnitudes suggested by the estimates are nontrivial. As such, I cannot rule out the possibility that investment is lower in states and regions that joined wholesale electricity markets and unbundled their RPUs.

If indeed total investment levels are lower in regions that restructured their electric systems, is this cause for concern? Joskow explained that investors in states that both unbundled their RPUs and joined wholesale electricity markets should be more responsive to market signals than RPUs in traditionally regulated states. Hence, lower investment levels in restructured regions may simply be a desirable response to overcapacity (Joskow, 2006). Therefore, lower investment levels in restructured states or regions might be evidence of the success of electric restructuring policy in overcoming the shortcomings of cost-of-service regulation, which led to overinvestment in generation capacity in the past. Furthermore, lower investment levels in wholesale electricity markets might result from the fact that wholesale electricity markets make better use of existing generation capacity, as they facilitate trade between power plants.

While I studied three important outcomes of investment in generation capacity, total investment, the number of new plants, and the size of each investment, other outcomes warrant further study. For example, there is some evidence that RPU unbundling has increased efficiency (Fabrizio et al., 2007). Other important concerns are the types of generation technology used and financing issues.

The earliest restructuring policies were enacted eleven years ago, but it may be too early to evaluate electric restructuring policies because firms in the electric power industry are still adjusting to the restructured environment. For example, Ishii and Yan (2002) found that IPPs learned to respond to market signals over time. As such, this study and others like it clearly need to be extended and repeated as the electric power industry continues to operate in the restructured era.

7 Appendix

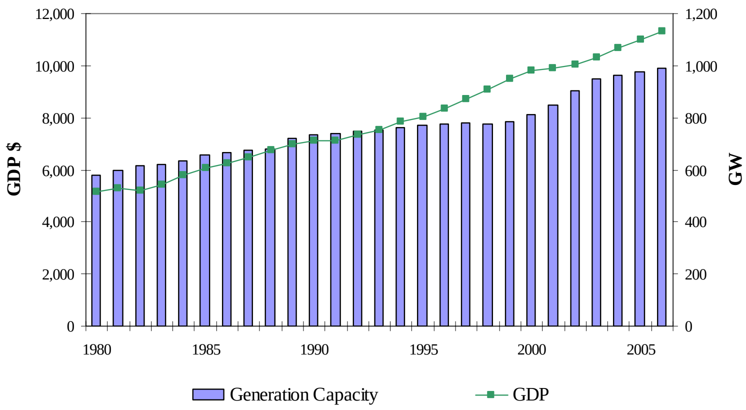
Data

The data used in this study are publicly available from various sources. Generator data come from the U.S. Department of Energy's Energy Information Administration's ("EIA") 860 database. Generator-level variables include: generator capacity in MW, technology used (internal combustion, gas turbine, combined cycle, etc.), primary fuel source (natural gas, coal, nuclear, etc.), owner name(s), in-service date, retirement date (if applicable), and location. The EIA also provides data about the annual stock of generation capacity within each state. Regulatory variables for divestiture, IPP generation, and wholesale market formation are also included.

The Clean Air Act stipulates that any state with a county in violation a pollution standard of one of the five criterion pollutants must perform a New Source Review for any new source of that criterion pollutant.[70] I use annual data on the historical attainment/non-attainment status of each county in the U.S. from the U.S. Environmental Protection Agency to capture these effects. The Producer Price Index for Iron&Steel and other minerals, and population data come from the Bureau of Economic Analysis.

[70]The criterion pollutants that are monitored under the Clean Air Act are: Ozone, SO_2, NO_2, CO, PM25, and PM100

Figure 2: Generation Capacity and GDP in the U.S., 1980-2006



GDP in billions of chained 2000 dollars, source: U.S. Bureau of Economic Analysis. Generation capacity figures represent net summer capacity in GW, source: U.S. Dept. of Energy, Energy Information Administration

Figure 3: Map of Investment Regions

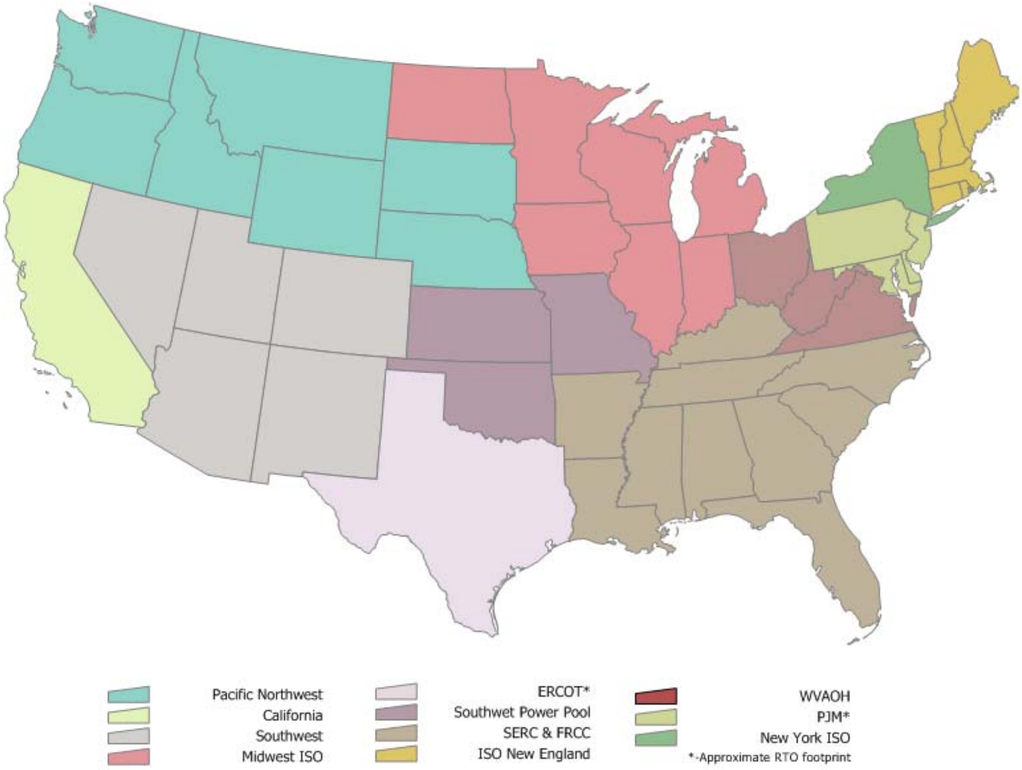


Figure 4: Total Investment $\geq$ 20 MW by Region

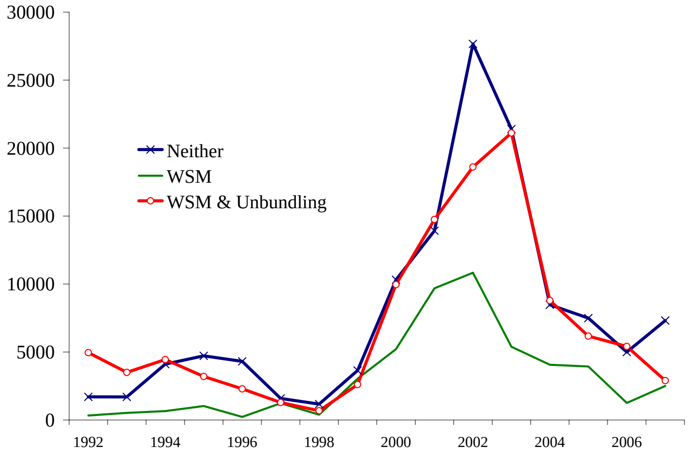


Table 11: Summary of Major Electric Restructuring Policies

RPU Unbundling and wholesale electricity market	CA, CT, DC, DE, IL, MA, ME, MD, NH MI, NJ, NY,OH, PA, RI, TX, VA*
Wholesale Market	IA, KS, IN, OK, ND, MN, MO, VT, WI, WV
Neither	AL, AK, AR, AZ, CO, FL, GA, HI, ID, KY, LA, MS, MT, NC, NE, NM, NV, OR, SC, SD, TN, UT, WA, and WY

*In 2007, Virginia reversed its decision to unbundle the state's RPUs.

Table 12: Investment Regions

Pacific Northwest	ID, NE, MT, OR, SD, WA, WY
Southwest	CO, AZ, NM, NV, UT
California	CA
MISO	IA, IL, IN, MI, MN, ND, WI,
Southwest Power Pool	KS, MO, OK
SERC&FERC	AL, AR, GA, FL, KY, LA, MS, NC, SC, TN
WVAOH	OH, VA, WV
PJM	DE, DC, MD, NJ, PA
ISO New England	CT, NH, MA, ME, RI, VT,
ERCOT	TX
New York ISO	NY

Table 13: Summary of Total Investment $\geq$ 20 MWby Restructuring Policy

	Neither	Wholesale Market	Wholesale Market and Unbundling
(a) 1992-1996	16,544	2,761	18,393
(b) 1997-2001	30,627	19,555	29,281
(c) 2002-2007	77,335	27,974	62,981
Difference			
(a)-(b)	14,083	16,794	10,888
(c)-(b)	46,708	8,419	33,700
(c)-(a)	60,791	25,213	44,588

Neither: PNW, SWest, SERC&FERC, Wholesale market: MISO and SPP
Wholesale market and unbundling: PJM, WVAOH, NYISO, ISONE, CA, and ERCOT

Table 14: Count of Generation Investments $\geq$ 20 MW, 1992-2007

	Regions										
Year	PNW	CA	SWest	MISO	SPP	SERC &FRCC	ISONE	PJM	WVAOH	TX	NYISO
1992	1	3	6	4	1	8	5	6	11	3	8
1993	3	7	3	6	0	11	4	6	1	3	6
1994	5	8	6	8	0	15	0	7	2	4	9
1995	7	4	2	10	2	13	3	6	2	4	5
1996	4	9	4	6	1	13	1	3	3	3	1
1997	3	2	1	9	2	8	0	2	2	4	0
1998	1	0	3	3	1	6	1	1	2	2	0
1999	2	3	4	16	4	20	4	2	1	8	2
2000	3	1	5	25	5	28	4	5	9	17	0
2001	15	23	12	26	11	37	5	8	11	19	10
2002	14	17	17	32	11	47	6	10	6	10	6
2003	11	18	10	16	8	28	6	10	5	11	4
2004	2	5	8	10	1	14	3	4	2	9	3
2005	8	12	7	16	4	11	0	0	0	7	6
2006	7	10	11	6	3	8	1	3	0	6	2
2007	7	7	8	13	1	13	2	3	0	13	2

Figures represent the number of new investments that were $\geq$ 20 MW

Note: PNW: Pacific Northwest, SWest: Southwest, MISO: Midwest ISO, ISONE: ISO New England, NYISO: New York ISO, WVAH: WV, VA, and OH PJM and WVAOH are combined into one region in the amended region estimations. The others remain unchanged.

sample mean: 7.0397, sample variance: 7.0907

Table 15: Total Generation Investment $\geq$ 20 MW, 1992-2007

	Regions										
	PNW	CA	SWest	MISO	SPP	SERC &FRCC	ISONE	PJM	WVAOH	TX	NYISO
Calendar	Region										
1992	0	226	201	251	80	1501	219	1323	1897	651	636
1993	362	305	176	523	0	1159	447	779	77	1437	458
1994	567	445	763	654	0	2782	0	849	304	849	1999
1995	636	448	104	896	133	3980	491	1052	518	400	290
1996	631	363	226	186	38	3456	119	440	762	379	230
1997	330	281	28	933	295	1224	0	284	230	491	0
1998	25	0	571	309	81	573	297	33	110	239	0
1999	66	110	279	2500	535	3300	616	268	42	1499	73
2000	129	49	972	4236	979	9210	1036	644	1676	6556	0
2001	1632	2369	2127	6589	3098	10161	1638	1732	2950	5509	549
2002	1544	2713	4102	8504	2325	22016	2466	3799	2549	6650	432
2003	1619	4000	5601	2980	2406	14178	2919	3744	3927	5925	595
2004	293	745	3061	2921	1144	5120	582	2983	1374	2124	979
2005	1071	3332	1208	3171	763	5213	0	0	0	1042	1794
2006	851	1876	2669	960	296	1474	23	1228	0	1617	665
2007	1242	614	1758	2353	151	4315	113	141	0	1975	55

Figures represent the sum of MW from investments that were $\geq$ 20 MW.
Note: PNW: Pacific Northwest, SWest: Southwest, MISO: Midwest ISO, ISONE: ISO New England, NYISO: New York ISO, WVAH: WV, VA, and OH PJM and WVAOH are combined into one region in the amended region estimations. The others remain unchanged.

Table 16: Fixed Effects Count and Total Investment Models - Northeast

dependent variable:	plant count				investment level
	Poisson		Negative Binomial		
	Coef.	IRR	Coef.	IRR	Coef.
	(1)	(2)	(3	(4)	(5)
Netgen/capacity lag2	.0011*	1.001	.0010*	1.001	2.287*
	(.0001)		(.0002)		(.5705)
Population lag2	-.0188	.998	.0013	1.001	55.481*
	(.0028)		(.0016)		(14.147)
EPACO lag2	-.5352*	.586	$-.5535^{+}$	.575	-1164.703
	(.2194)		(.3012)		(808.869)
IronSteel lag2	-.0188*	.981	-.0190*	.981	-61.705*
	(.0028)		(.0040)		(12.668)
WEM lag2	-.2804	.755	-.2503	.778	158.962
	(.1199)		(.1614)		(556.322)
WEM×NEast lag2	-.8816*	.414	-.6332*	.531	-523.324
	(.1960)		(.2650)		(734.558)
year	.1066*	1.111	.0857*	1.089	60.517
	(.0191)		(.0174)		(70.175)
const			-171.82*		-136489
			(34.269)		(136672)
no. obs.	176		176		176
no. groups	11		11		11
Rsq within					.3920
Rsq between					.7882
Rsq overall					.3192
Wald χ^2	267.61		123.25		

* significant at the 5% level, + significant at the 10% level

Table 17: Fixed Effects Count and Total Investment Models- Amended Northeast

dependent variable:	plant count				investment level
	Poisson		Negative Binomial		
	Coef.	IRR	Coef.	IRR	Coef.
	(1)	(2)	(3)	(4)	(5)
Netgen/capacity lag2	.0011*	1.001	.0010*	1.000	2.438*
	(.0001)		(-.0002)		(.634)
Population lag2	-.0045	.996	-.0004	.996	53.031*
	(.0032)		(.0015)		(15.695)
EPACO lag2	-.5634*	.569	-.6285*	.534	-1212.4
	(.2254)		(.3026)		(892.8)
IronSteel lag2	-.0187*	.981	-.0176*	.983	-68.771*
	(.0028)		(.0039)		(14.208)
WEM lag2	$-.2223^{+}$	.801	-.1478	.863	39.065
	(.1241)		(.1680)		(645.34)
WEM×NEast lag2	-.9807*	.375	-.9431*	.389	-574.798
	(.1798)		(.2498)		(827.927)
year	.1185*	1.126	.0988*	1.104	85.995
	(.0195)		(.0175)		(79.183)
const			-197.72*		-187771
			(34.49)		(154067)
no. obs.	160		160		160
no. groups	10		10		10
Rsq within					.3954
Rsq between					.7835
Rsq overall					.2899

* significant at the 5% level, + significant at the 10% level

Table 18: Fixed Effects Count and Total Investment Models - Divestiture

dependent variable:	plant count								investment level	
	Poisson				**Negative Binomial**					
	Coef.	IRR	Coef.	IRR	Coef.	IRR		IRR	Coef.	Coef.
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Netgen/capacity lag2	.0012*	1.001	.0011*	1.001	.0011*	1.001	.0009*	1.001	2.3347*	2.1866*
	(.0001)		(.0001)		(.0002)		(.0002)		(.5423)	(.5758)
Population lag2	-.0012	.999	.0022	1.002	.0013	1.000	.0020	1.002	40.487*	55.491*
	(.0027)		(.0031)		(.0015)		(.0015)		(12.669)	(13.977)
EPACO lag2	-.1345	.874	-.6095*	.544	-.1539	.857	$-.5486^{+}$	.578	-366.654	-1351.2
	(.2403)		(.2236)		(.3155)		(.3151)		(889.701)	(835.1)
IronSteel lag2	-.0108*	.989	-.0185*	.982	-.0123*	.988	-.0197*	.980	-56.413*	-63.369*
	(.0027)		(.0029)		(.0037)		(.0042)		(11.527)	(12.824)
WEM lag2	-.4250*	.654	-.3760*	.687	-.3929*	.675	-.3498*	.705	-144.916	116.307
	(.1160)		(.1213)		(.1636)		(.1714)		(479.982)	(520.504)
WEM×DIV lag2	-.1620	.850	-.0593	.942	-.2318	.794	-.1200	.887	-1065.3^{+}	-538.419
	(.1416)		(.1421)		(.2099)		(.2154)		(580.59)	(578.212)
avgDIV lag2	1.757*	5.798			1.589*	4.900			3291.8*	
	(.2680)				(.2824)				(1107.5)	
year			.0829*	1.086			.0815*	1.085		79.385
			(.0192)				(.0184)			(75.005)
const					-2.043*		-163.677*		-13221*	-173555
					(.935)		(36.217)		(3644.9)	(146186)
No. obs	176		176		176		176		176	176
No. groups	11		11		11		11		11	11
R-sq: within									.4215	.3934
between									.8078	.7892
overall									.3641	.3200

* significant at the 5% level, + significant at the 10% level

Table 19: Fixed Effects Count and Total Investment Models - % IPP

dependent variable:	plant count								investment level	
	Poisson				**Negative Binomial**					
	Coef. (1)	IRR (2)	Coef. (3)	IRR (4)	Coef. (5)	IRR (6)	Coef. (7)	IRR (8)	Coef. (9)	Coef. (10)
Netgen/capacity lag2	.0014*	1.001	.0010*	1.001	.0013*	1.001	.0009*	1.000	2.6594*	2.2277*
	(.0001)		(.0001)		(.0002)		(.0002)		(.5833)	(.5753)
Population lag2	.0052^{+}	1.005	.0010	1.001	.0027^{+}	1.003	.0018	1.002	51.873*	55.771*
	(.0028)		(.0032)		(.0016)		(.0015)		(12.659)	(14.307)
EPACO lag2	-.4834*	.616	-.6605*	.517	-.3592	.698	$-.6066^{+}$	.545	-841.75	-1271.8
	(.2328)		(.2244)		(.3265)		(.3204)		(893.03)	(840.01)
IronSteel lag2	-.0147*	.985	-.0185*	.982	-.0151*	.985	-.0194*	.981	-60.550*	-61.632*
	(.0027)		(.0028)		(.0039)		(.0042)		(11.981)	(12.678)
WEM lag2	-.2238*	.799	-.3485*	.706	-.2131	.808	-.3287*	.720	23.228	35.024
	(.1125)		(.1199)		(.1611)		(.1663)		(464.22)	(510.77)
WEM× %IPP lag2	-.3437	.709	-.3835	.681	-.4052	.667	-.3890	.678	-992.18	-541.90
	(.2816)		(.2715)		(.3826)		(.3698)		(1073.8)	(1035)
avg %IPP lag2	2.026*	7.584			2.204*	9.064			3478.2	
	(.539)				(.5518)				(2184.5)	
year			.0922*	1.096			.0852*	1.089		69.431
			(.0198)				(.0185)			(76.597)
const					-3.123*		-170.932*		-16769*	-154107
					(.917)		(36.409)		(3421)	(149311)
No. obs	176		176		176		176		176	176
No. groups	11		11		11		11		11	11
R-sq: within									0.3967	.3911
R-sq: between									0.7962	.7876
R-sq: overall									0.3289	.3186

*significant at the 5% level, + significant at the 10% level

Table 20: Fixed Effects State-level Total Investment Models

dependent variable:	investment level		
	(1)	(2)	(3)
Netgen/capacity lag2	.1789*	.1705*	.1711*
	(.0836)	(.0799)	(.0820)
Population lag2	34.753*	37.522*	36.386
	(4.459)	(6.961)	(4.445)
EPAvio lag2	-115.696	-114.374	-106.199
	(90.236)	(95.569)	(97.092)
IronSteel lag2	-15.671*	-15.785*	-15.539*
	(2.883)	(3.149)	(2.896)
WEM lag2	75.327	11.560	17.068
	(232.428)	(217.493)	(185.77)
WEM×NEast lag2	-234.889		
	(209.073)		
WEM×DIV lag2		-120.914	
		(265.770)	
WEM×%IPP lag2			-235.252
			(289.175)
year	35.356*	35.611*	36.840*
	(9.273)	(9.059)	(9.464)
const	-71501*	-72124*	-74543*
	(18310)	(17896)	(18691)
no. obs.	768	768	768
no. groups	48	48	48
Rsq within	.2125	.2122	.2109
Rsq between	.5733	.5698	.5700
Rsq overall	.1988	.1959	.1945

Robust standard errors clustered at the state shown in parentheses.

* significant at the 5% level, + significant at the 10% level

Table 21: Summary of New Plant Size (MW)

		≥ 20 MW			≥ 100 MW		
		Rest of US	Northeast		Rest of US	Northeast	
		(1)	(2)	(2)-(1)	(3)	(4)	(4)-(3)
	mean	148.824	137.789	-11.035	290.4793	261.354	-29.125
(A) 1992-1995	se	15.004	20.602	25.48627	29.037	42.265	51.278
	n	150	62		60	24	
	p.v			0.6658			0.573
	mean	242.180	295.314	53.13	346.370	603.399	257.029*
(B) 2004-2007	se	16.698	66.002	68.082	21.844	91.029	93.613
	n	226	29		144	13	
	p.v.			0.441			0.0163
Difference		93.356*	157.525*	64.169	55.890	342.044*	286.154*
(B)-(A)	se	23.868	54.078	56.968	38.695	87.868	95.149
	p.v.	0.000	0.005	0.261	0.150	0.000	0.003

		≥ 20 MW			≥ 100 MW		
		Traditional	Northeast		Traditional	Northeast	
		(1)	(2)	(2)-(1)	(3)	(4)	(4)-(3)
	m	172.254	137.789	-34.465	303.099	261.354	-41.744
	se	24.515	20.602	32.022	40.667	42.265	58.652
(A) 1992-1995	n	71	62		34	24	
	p.v.			0.284			0.480
	m	279.947	295.314	15.367	405.602	603.399	197.797+
(B) 2004-2007	se	28.168	66.002	71.762	36.036	91.029	97.902
	n	101	29		64	13	
	p.v.			0.832			0.060
Difference	mean	107.693*	157.525*	49.832	102.504+	342.044*	239.541*
(B)-(A)	se	39.397	54.078	68.188	57.679	54.078	108.185
	p.v.	0.007	0.005	0.466	0.079	0.005	0.029

		≥ 20 MW			≥ 100 MW		
		Just WEM	Northeast		Just WEM	Northeast	
		(1)	(2)	(2)-(1)	(3)	(4)	(4)-(3)
(A) 1992-1995	m	121.1939	137.7892	16.595	248.215	261.354	13.139
	se	15.98399	20.6018	26.075	27.333	42.265	50.333
	n	44	62		14	24	
	p.v.			0.526			0.796
	m	234.506	295.314	60.808	325.133	603.399	278.266*
(B) 2004-2007	se	34.924	66.002	74.673	46.256	91.029	102.107
	n	56	29		37	13	
	p.v.			0.4198			0.014
Difference		113.312*	157.525*	44.213	76.918	342.044*	265.126*
(B)-(A)	se	41.903	54.078	67.644	77.458	87.868	116.633
	p.v.	0.008	0.005	0.514	0.326	0.000	0.026

p.v.=pvalue *statistically significant at the 5 percent level.
+ statistically significant at the 10 percent level.
Figures represent Summer Capacity in MW. Upgrades and new plants
Standard Errors corrected for unequal variances where appropriate.
Source: EIA and own calculations

Table 22: Plant Size 2000-2003, Northeast vs. the Rest of the U.S.

	$\geq$ 20 MW			$\geq$ 100 MW		
	Rest of U.S.	Northeast	Difference	Rest of U.S.	Northeast	Difference
mean	301.572	264.238	-37.334	431.114	442.020	10.906
se	13.554	31.409	34.283	16.493	40.732	46.944
n. obs	495	74		326	40	
p value			.279			0.805

Standard Errors corrected for unequal variances. Figures represent Summer Capacity in MW. Source: EIA and own calculations.

Table 23: Plant Size with State Fixed Effects - Northeast

dependent variable:	plant size in MW	
	$\geq$ 20 MW	$\geq$ 100 MW
	(1)	(2)
Netgen/capacity lag2	.-0196	.0328
	(.0224)	(.0304)
wind	-268.969*	-316.243*
	(42.322)	(38.312)
other	-181.472*	126.547
	(26.445)	(61.511)
coal	-83.298*	-51.588
	(37.985)	(53.892)
hydro	-63.281	81.313
	(44.826)	(183.195)
nuclear	857.353*	793.962
	(19.531)	(43.712)
upgrade	-93.671*	-98.737*
	(22.650)	(26.953)
IPP	133.001*	125.340
	(22.296)	(27.206)
INDcg	-77.334*	-48.639
	(17.637)	(35.499)
EPAvio lag2	-45.473^{+}	-114.066^{+}
	(26.627)	(67.472)
WEM	11.642	32.144
	(41.113)	(41.877)
WEM×NEast	-31.418	-14.004
	(49.106)	(48.527)
year	14.861*	17.002*
	(2.417)	(3.880)
const	-29365*	-33485*
	(4808.6)	(7703)
no. obs	1194	687
no. groups	48	47
R-sq: within	.2522	.2149
R-sq: between	.3862	.3587
R-sq: overall	.2383	.2218

*statistically significant at the 5 percent level.
+ statistically significant at the 10 percent level.

Table 24: Plant Size with State Fixed Effects - Divestiture

dependent variable:	plant size in MW			
	$\geq$ 20 MW	$\geq$ 100 MW	$\geq$ 20 MW	$\geq$ 100 MW
	(1)	(2)	(3)	(4)
Netgen/capacity lag2	.0230	.0352	-.0220	-.0333
	(.0203)	(.0302)	(.0224)	(.0896))
wind	-264.886*	-309.660*	-268.124*	-315.621*
	(23.976)	(40.589)	(41.020)	(38.194)
other	-179.897	155.145	-180.498*	124.952+
	(37.468)	(146.226)	(26.911)	(62.419)
coal	-90.806*	-56.277	-80.978*	-50.749
	(44.273)	(66.126)	(37.072)	(51.457)
hydro	-62.746	91.220	-68.243	81.117
	(56.843)	(143.310)	(46.099)	(183.563)
nuclear	842.068	773.849*	856.405*	792.308*
	(158.557)	(175.703)	(20.791)	(50.197)
upgrade	-94.718*	-98.920*	-93.756*	-98.884*
	(14.815)	(21.621)	(22.770)	(26.937)
IPP	133.695*	124.019*	132.534	124.987*
	(15.285)	(21.497)	(22.091)	(26.359)
INDcg	-78.399*	-45.252	-79.022	-49.420
	(27.810)	(59.097)	(18.683)	(38.733)
EPAvio lag2	-3.909	-77.097	-44.337	-113.926*
	(36.586)	(65.699)	(28.018)	(55.414)
WEM	27.439	40.249	15.176	29.784
	(26.090)	(40.219)	(44.033)	(60.685)
WEM×DIV lag2	-37.648	-18.941	-26.126	-1.778
	(28.803)	(44.878)	(59.021)	(83.870)
avgDIV lag2	377.471	440.777*		
	(53.539)	(79.220)		
year			15.203*	16.967
			(2.420)	(3.475)
cons	285.247*	436.044*	-30036*	-33411
	(90.763)	(138.191)	(4821.8)	(6904)
no. obs.	1194	687	1194	687
no. groups	48	47	48	47
R-sq: within	0.1960	.2249	.2524	.2148
R-sq: between	0.2454	.3700	.3676	.3526
R-sq: overall	0.1739	.2306	.2400	.2213

* statistically significant at the 5 percent level.
\+ statistically significant at the 10 percent level.

Table 25: Plant Size with State Fixed Effects - %IPP

dependent variable:	plant size in MW			
	≥ 20 MW (1)	≥ 100 MW (2)	≥ 20 MW (3)	≥ 100 MW (4)
Netgen/capacity lag2	.0265	.0208	.0205	-.0302
	(.0206)	(.0313)	(.0204)	(.0298)
wind	-278.469*	-335.179	-267.354*	-320.131*
	(24.054)	(40.762)	(24.309)	(38.732)
other	-188.606*	142.549	-179.209*	122.956*
	(36.916)	(144.564)	(37.555)	(60.028)
coal	-93.326*	-53.122	-80.686^{+}	-49.392
	(43.629)	(65.392)	(44.657)	(52.203)
hydro	-62.069	85.940	-66.524	79.133
	(56.108)	(141.896)	(56.930)	(184.671)
nuclear	837.140*	754.474*	854.404*	787.171*
	(156.745)	(173.864)	(159.150)	(43.984)
upgrade	-94.284*	-98.896*	-94.019*	-99.913*
	(14.654)	(21.448)	(14.859)	(26.944)
IPP	141.723*	133.445	132.070*	126.083*
	(15.154)	(21.181)	(15.386)	(26.951)
INDcg	-76.648*	-60.736	-79.165	-56.163
	(27.490)	(58.646)	(27.892)	(39.269)
EPAvio lag2	-11.259	-96.104	-46.363	-126.878*
	(36.382)	(64.567)	(37.353)	(60.252)
WEM lag2	12.342	9.044	6.954	15.428
	(24.477)	(38.213)	(26.163)	(55.462)
WEM×%IPP lag2	-74.164	8.050	-14.603	69.886
	(50.168)	(74.755)	(49.744)	(125.270)
avg%IPP lag2	883.588*	894.557*		
	(101.259)	(155.236)		
year			14.876*	16.149*
			(2.297)	(3.597)
const	59.141	187.276	-29393*	-31788*
	(93.613)	(145.502)	(4584.3)	(1740.1)
no. obs.	1194	687	1194	687
no. groups	48	47	48	47
R-sq: within	0.2724	.2391	.2519	.2159
R-sq: between	0.2200	.3876	.3734	.3542
R-sq: overall	0.2528	.2566	.2378	.2220

*statistically significant at the 5 percent level.
+ statistically significant at the 10 percent level.

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