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Does Divestiture Crowd-Out New Investment? The "Make or Buy" Decision in U.S. Electricity Generation Investments

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Does Divestiture Crowd-Out New Investment? The "Make or Buy" Decision in the U.S. Electricity Generation Industry

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Abstract

The paper presents an empirical model of the "make or buy" decision faced by independent power producers (IPPs) in restructured U.S. wholesale electricity markets. The model is applied to plant-level data that track the investment decisions of major IPPs from 1996 to 2000, yielding estimates of each firm's investment cost and expected profit functions. The estimates are used to evaluate the effectiveness of divestiture programs (which sold utility power plants to IPPs) in encouraging greater IPP participation. The estimates and counterfactual simulations indicate that a minimal amount of new power plant investments were "crowded out" by divestiture and that divestiture encouraged greater (short-run) entry, especially among utility-affiliated IPPs.

Keywords: Divestiture, Independent Power Producer, Electricity Restructuring, Power Plant Investment JEL Codes: L94, L51, D92, C51

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Introduction

Beginning with California in 1996, many state governments in the United States have enacted restructuring legislation aimed at transforming the electricity supply industry away from the traditional regulated structure toward a more competition-based marketplace. Historically, the industry has been dominated by vertically integrated investor-owned utilities (IOUs) whose regulated geographic monopolies controlled all three main sectors of the industry: generation, transmission and distribution (T&D), and retail services. One of the main goals of the restructuring process is to introduce competition into the electricity generation sector and allow non-utility, independent power producers (IPPs) to invest and compete for market-based returns.[1] In order to facilitate the introduction of competition, many state policymakers have argued for and implemented a plan under which incumbent IOUs were enticed to sell their existing generation assets to entrant IPPs.

Policymakers felt that the divestiture of IOU generation assets would serve three purposes. First, it would help prevent the incumbent utilities from using their existing generation capacity and transmission and distribution facilities to exert market power in the restructured generation sector. Second, divestiture would provide a market-based method of evaluating the "stranded cost" that IOUs would incur due to restructuring.[2] In fact, stranded cost recovery was the primary reason many IOUs agreed to divestiture: many state restructuring programs required divestiture as a condition for state assistance in recovering stranded cost. Third, many policymakers believed that divestiture sales would help encourage greater entry and new generation investment by IPPs. IPPs buying these divested assets would be able to participate immediately in these restructured markets. Moreover, divestiture could help encourage IPP participation by signalling a greater commitment to restructuring, reducing the regulatory risk faced by IPPs; a state that has transferred a greater amount of its existing generation supply out of the hands of regulated IOUs and into the hands of unregulated IPPs would be harder pressed putting the "genie back in the bottle."

The empirical evidence from the past seven years of electricity restructuring in the United States has been mixed on the effectiveness of divestiture in achieving these goals. Much of the existing analysis of this evidence has concentrated on evaluating the first two goals: the proceeds from divestiture sales have greatly mitigated the amount of state-assisted stranded cost recovery, but divestiture – while restraining *vertical* market power – may have exacerbated *horizontal* market

[1] As of the end of 2001, 23 states have enacted electricity restructuring legislation or implemented comprehensive regulatory orders on restructuring. Since 2001, restructuring has come to a standstill

[2] Stranded cost can be thought of as the difference in revenue the IOU expects to earn from existing generation assets between the non-restructured (price regulated) and restructured industry.

power. The induced reduction in generation capacity (making some IOUs net buyers of electricity generation), combined with a freeze on the *retail* prices charged to the end electricity users, effectively limited both the incentive and ability of incumbent IOUs to exercise vertical market power in wholesale electricity markets.[3] But independent power producers who bought these divested plants have seemingly been able to exercise horizontal market power, exploiting both the lumpiness with which capacity was divested and constraints in the existing transmission network to drive up the relatively unconstrained *wholesale* prices.[4]

In contrast, there is little in the developing literature that evaluates the effectiveness of divestiture in achieving the more long-run, competitive goal of encouraging greater IPP entry and investment. Divestiture may be overall desirable if it helps foster beneficial long-run competition. Nominally, divestiture has increased IPP participation in wholesale electricity markets in the United States; many of the current major IPP participants participate through their ownership of divested IOU assets. However, whether divestiture led to greater IPP participation in *real* terms is unclear. Divestiture may have just *"crowded out"* new power plant investments: acquisition of divested plants may have simply substituted for new power plant investments by those same IPPs. The relevant comparison is not the actual comparison between IPP participation before and after divestiture but rather the counterfactual comparison between IPP participation in a market *with* divestiture and IPP participation in the same market but *without* divestiture. The main focus of this paper is the calculation of such a counterfactual.

In order to calculate this real difference in IPP investment, a structural model of an IPP's power plant investment decision is proposed and estimated. A structural model is necessary in order to estimate the optimal investment decision of an IPP in the counterfactual world without divestiture. Trying to deduce such a decision by means of cross-sectional regression on IPP investment data in markets with and without divestiture is problematic as the presence of divestiture no doubt induces structural change in the IPP (reduced form) investment function. Divestiture not only changes the investment opportunity for an IPP but also the relationship between one IPP's investment decision and the investment decisions of its potential competitors: in order for an IPP to buy a divested power plant, the IPP must be willing to pay more for the divested asset than any of its competitors. As a consequence, there is a need to model explicitly how IPPs evaluate both the "making" of new power plants and the "buying" of existing, divested utility power plants.

The model adopted in this paper specifies the expected profit stream associated with a power

[3]See Bushnell, Mansur, & Saravia (2005) and Mansur (2005)

[4]See Borenstein, Bushnell, & Wolak (2002), Joskow & Kahn (2002), Puller (2001), & Wolak (1999)

plant, both new and old, and the investment cost associated with a new power plant as functions of exogenous plant, firm, market, and regulatory variables. In a market without divestiture, an IPP invests when the expected profit stream from a new power plant is greater than the investment cost associated with the plant.[5] In a market with divestiture, an IPP must not only choose whether to invest but also how. This "make or buy" decision creates a link between an IPP's valuation of a new power plant and the maximum amount an IPP is willing to pay for a divested power plant: an IPP is willing to buy a power plant as long as the value of the acquired power plant (expected profit stream minus transaction price) is no less than either the value earned from building a new power plant or the value from making no investment. Assuming efficient divestiture sales, an IPP succeeds in buying a divested power plant if the IPP has the highest willingness to pay among competitors. Similarly, an IPP builds a new power plant if the IPP faces an expected profit stream from building a new power plant that exceeds its investment cost and the opportunity cost of the capital. These revealed preference type arguments provide the constraints on the data which identify the relevant expected profit and cost parameters.

The empirical model is applied to data on the investment decisions of 20 major IPPs during the period 1996 to 2000 for all 48 contiguous U.S. states. Although the primary motivation underlying the estimation is the calculation of counterfactual investment decisions, the estimated expected profit stream and investment cost functions, in of themselves, provide some insights into observed IPP investment behavior. First, the estimates indicate a clear difference in the evaluation of power plants between IPPs affiliated and unaffiliated with electric utilities. Specifically, IPPs affiliated with electric utilities are found to face a greater investment cost associated with building a new power plant and a modest profit advantage in running older power plants. The result helps explain why the majority of divested power plants have been bought by IOU affiliated IPPs. Second, the estimates argue that the main incentive underlying the buying of power plants is the avoidance of the upfront investment cost associated with new power plant construction, rather than the value associated with the (possibly desirable) location of old power plants. Last, market characteristics reflecting the tightness of supply are found to have a significant, positive impact on expected profits in markets further along in restructuring. However, the estimates also find that for markets with suitably adequate supply, further restructuring lowers expected profits.

In order to evaluate the real difference in IPP participation introduced by divestiture, the estimated expected profit stream and investment cost functions are used to calculate the counterfactual investment decisions of IPPs in the absence of divestiture. The counterfactuals show that

[5]The model is based on the standard net present value (NPV) approach to investment. Ishii & Yan (2004) presents a model of IPP capacity investment based on a real options approach.

among the 32 (firm, market, year) observations in the sample where an IPP buys a divested power plant, on average only *one* would have resulted in the construction of a new power plant in the absence of divestiture. Furthermore, the simulations find that the *total* amount of new generation capacity "crowded out" by divestiture is very small, on average 177 megawatts (MW). This indicates that while divestiture has not "crowded out" a large amount of new generation capacity, it has encouraged some new IPP participation in the restructured market.

The remainder of the paper is organized as follows. Section 1 provides an overview of generation investment since state-level electricity restructuring. Section 2 presents the theoretical model for the "make or buy" decision. Section 3 describes in detail the empirical analog to the theoretical framework. Section 4 presents and analyzes the parameter estimates of the model as well as the policy simulations based on the estimates. The paper then concludes with some final thoughts.

1 Overview

Since 1996, independent power producers (IPPs) have had the opportunity to enter and participate in some U.S. wholesale electricity market without the explicit invitation of the incumbent electric utilities.[6] Figures 1a and 1b illustrate, geographically, the total generation investments made by the 20 IPPs in our sample between 1996 and 2001.[7] Figure 1a depicts the total for new power plant investments and Figure 1b the total for power plants acquired through divestiture. The sampled IPPs have acquired sizable ($>$ 100 MW) generation capacity in 35 of the 48 contiguous states. Although much of the investment is in the major restructured states, some new power plant investments have been made in states that had not yet initiated restructuring, most notably in the Southeast. Furthermore, some divested utility power plants were available to IPPs in "non-restructured" states, such as Montana. These investments in non-restructured states were spurred, in part, by the then conventional wisdom that restructuring would eventually occur nation-wide. This led some firms to "jump the gun" in an effort to establish an early presence in the market.

The generation investment data also reveals that much of the electricity provided by IPPs during the study period was generated from divested utility power plants acquired by IPPs. During our study period, the main divestiture concern was vertical market power: incumbent utilities could provide entrant IPPs unequal access to their downstream transmission and distribution (T&D)

[6]This excludes limited opportunities to build "qualifying facilities" as outlined in the Public Utility Regulatory Policy Act (PURPA)

[7]Details about our sample can be found in the data appendix

network, thus raising their rivals' costs. Regulators felt that they could best circumvent this problem by having incumbent utilities largely exit the generation sector, creating not only a functional but ownership separation between generation and T&D. The fact that these assets were sold in large lots, sometimes entire power systems to a single buyer, demonstrates the greater concern regulators placed on vertical than horizontal market power.[8] Consequently, divestiture allowed IPPs to acquire large capacity in restructured markets quickly.

Table 1a: Generation Capacity (MWs) Acquired by IPPs in Sample

Year[1]	Source: Divestiture	Source: Non-Divestiture[2]
1996	0	1886
1997	21239	2260
1998	36501	5572
1999	11508	21049 [3]
2000	2761 [4]	26481
Total	69248	57249

[1] Acquisition year is defined as year before first operational year for the IPP
[2] Non-Divestiture includes capacity that were built by the IPP as well as capacity acquired from other non-utility power producers
[3] Includes Reliant's acquisition of former PA utility power plants from Sithe
[4] Overall, less than 3000 MW fossil-fuel utility plants were available in 2000

A pattern can be found from categorizing the generation capacity acquired from non-divestiture sources as capacity acquired in non-restructured states, restructured states with no utility divestiture that year, and restructured states with some utility divestiture that year.

Table 1b: Non-Divestiture Generation Capacity (MWs) Acquired by IPPs in Sample

Year[1]	In Non-Restructured States	In Restructured States	
		With No Divestiture Sale	With Some Divestiture Sale
1996	1662	224	0
1997	2009	129	123
1998	3882	389	1301
1999	3301	12806	4163 [3]
2000	6826	19656	0.00
Total	18460	33203	5586

See Table 1a footnotes

[8] Since the energy crisis of 2001, regulators have been more open to utilities transferring some of their assets to independent subsidiaries and have placed caps on the share of capacity any one firm can own in a local region. Bushnell & Wolfram (2005) examine the difference in operation between a transferred and sold plant

There are few new power plants built by IPPs in (state,year) where the acquisition of utility power plants is an option. This raises the concern that divestiture may be crowding out new power plant investments and underscores the need to investigate the impact of divestiture on IPP generation investment decisions.

Although the due diligence involved in both the acquisition of divested utility power plants and the development of new power plants is substantial and complicated, we consider two main reasons why an IPP might prefer buying a divested power plant over developing a new one. First, the divested power plants may have characteristics unavailable to potential new power plants. A prominent example of such desirable characteristics is the location of the power plant. Given transmission constraints and the lack of available (comparable) industrial sites, an utility power plant may be situated in a location that makes the power plant particularly valuable in satisfying local electricity demand.[9] Consequently, the potential revenue stream from an existing utility power plant may be better than that of a new power plant located at a less desirable site. Second, buying divested power plants may allow the IPP to avoid some of the investment costs associated with the development of new power plants. The extent of this cost saving will depend on the price paid for the divested power plant. By buying an existing plant, the IPP may avoid some of the siting and permitting costs associated with developing a new power plant.

Divestiture can be an attractive option for an IPP from both a revenue and cost perspective. However, an acquisition of a divested utility power plant does not necessarily imply a "crowding out" of new power plant investment. In the absence of divestiture, the IPP is not left with just the option of building a new power plant; the IPP always has the "third" option of not investing at all. The lack of new generation investments in states with divestiture sales observed in table 1b does not necessarily imply a significant crowding out if such new investments were not economically viable.[10] Let $\{ V_{buy}, V_{make}, V_{none} \}$ represent the value an IPP places on buying a divested plant, building a new plant and not investing in any plant, respectively. Observing an IPP buying a power plant implies $V_{buy} \geq V_{make}$ and $V_{buy} \geq V_{none}$ but provides no information about the ordering of V_{make} and V_{none}. Crowding out happens only when $V_{make} \geq V_{none}$. Hence, observing an IPP buy a power plant is insufficient to tell us whether any new power plant investment by that IPP was "crowded out." A study that investigates how an IPP evaluates both its new power plant and divestiture investment options is necessary in order to investigate the counter-factual of what firms *would* have done in the *absence* of divestiture.

[9] Fox (1999), Stavros(1999)

[10] The cost of a new power plant implicitly includes the cost of getting regulatory approval. A substantial regulatory cost may make a new power plant project not viable even if new power plants were viable absent such costs.

In the rest of the paper, we propose and implement such a study. A key aspect of our chosen approach is its ability to distinguish between the two main benefits from buying a divested power plant: the desirable plant characteristics and the avoidance of some of the investment cost associated with new power plant development. We would expect "crowding out" to be of more concern if the main motive underlying the acquisition is heterogeneous taste for utility power plant characteristics – a firm can always avoid investment cost by not investing at all. Moreover, we do not base our study on the limited, published transaction prices for divestiture sales. Kahn (1999) discusses the cons of such an analysis. A theoretical model is developed which helps identify how IPPs evaluate "make" and "buy" projects based on the most basic level of information: whether an IPP bought a divested plant, built a new plant, or invested in no plants.

2 Theoretical Model

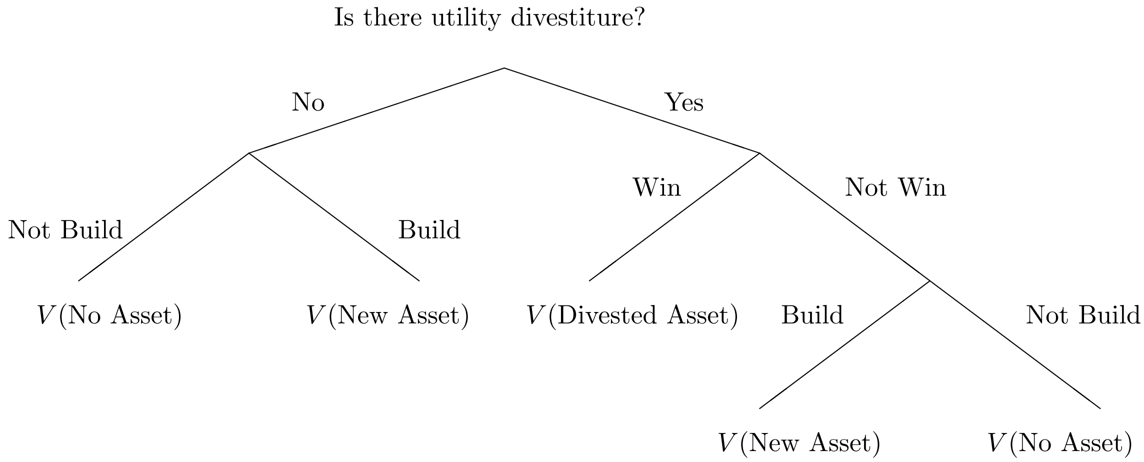
We assume that in the same year and market, an IPP only considers carrying out at most one type of positive investment: either acquisition of divested utility assets or the construction of new power plants. The idea is supported by the data on IPP investment decisions: no firm is observed buying a divested asset and sinking a large amount of investment costs toward a new power plant in the same market and year. The idea is also consistent with the presence of some binding resource constraint that prevents the firm from exploring both "make" and "buy" options.[11] There are some evidence for such a constraint in the industry literature which discuss IPPs having difficulty raising capital through traditional means during this transition period.[12] However, this constraint is neither modeled nor directly observed; rather, it is simply imposed.

Given this basic assumption, we make the following specification concerning the elements in a firm's choice set and the timing of its decision. First, in a year when there is no divestiture in the market, the firm chooses between investing through building a new plant and not investing at all.[13] Second, in a year when an IOU in the market is selling some of its generation assets, the firm always participates in the divestiture sale first. If the firm succeeds in buying the divested asset, it does not build new power plants in that market during that same year. The firm only *explicitly* considers building a new power plant if it fails to buy any divested asset available in the market during that year. These assumptions lead us to the following decision tree for a firm:

[11] In addition to financial, the constraints may be managerial. We thank Richard Green for pointing this out.

[12] Stern (1998), Rigby (1999)

[13] Technically, investment in a new power plant occurs over many years. In this paper, we focus on the very last decision: whether to exercise the actual option to build. We explain the full investment timeline in the appendix



When a firm participates in a divestiture sale, it takes into consideration its option to build a new power plant, an option which is forsaken if the firm is successful in buying a divested asset. Therefore, the value the firm places on acquiring the divested power plant, net the sales price, must not only be greater than the value of not investing; it must also be greater than the value the IPP places on the option of building a new power plant. Let V denote the expected return from an asset (old or new). In a divestiture sale, a firm's willingness to pay for the divested asset can be derived from the following inequalities:

$$\begin{aligned}
\underbrace{\Pi(\text{divested asset}) - \text{Pay}}_{V(\text{divested asset})} &> \max \left\{ 0 \, , \, \underbrace{\Pi(\text{new asset}) - C(\text{new asset})}_{V(\text{new asset})} \right\} \qquad (1) \\
\Longrightarrow \quad \text{Pay} &< \underbrace{\Pi(\text{divested asset}) - \max \left\{ 0, \, \Pi(\text{new asset}) - C(\text{new asset}) \right\}}_{W^*}
\end{aligned}$$

where

$$\begin{aligned}
\Pi &= \text{Expected discounted profit stream from asset} \\
C &= \text{Investment cost associated with the new asset} \\
W^* &= \text{Maximum willingness to pay}
\end{aligned}$$

where the return to not investing is normalized to be zero. Also, $V(\text{new asset})$ is the highest return the firm expects to receive from building new plants. The expression above makes clear a fundamental feature of the model: the maximum amount that an IPP is willing to pay for a divested asset is weakly increasing with the cost of building a new power plant (C).[14] Willingness

[14] In the case of "make" being profitable, $\Pi(\text{new asset}) - C(\text{New Asset}) > 0$, we have

$$W^* = \{\Pi(\text{divested asset}) - \Pi(\text{new asset})\} + C(\text{new asset})$$

The value for the divested asset is determined by the difference in expected profit stream between the divested and new assets, as well as the cost of building the new asset to pay is higher in markets where the cost of building a new power plant is greater and for firms who have a relative disadvantage in building new power plants, *ceteris paribus*.

We assume that every firm participates in all available divestiture sales; so all firms in our sample are potential buyers of a divested asset. The winner of a divestiture sale is determined from the comparison of the maximum willingness to pay (W^*) across all firms. We assume that divestiture sales are efficient: the firms with the highest W^*'s succeed in buying the assets. So, if firm i is observed buying a particular divested asset, we infer that firm i must have had the highest maximum willingness to pay for the asset among all firms.[15]

$$W^*(i) > W^*(j) \quad \forall\ j \neq i\ , \qquad j \in \{\text{Other potential IPP buyers}\} \tag{2}$$

Following the same logic, if a firm is observed building a new power plant, two things can be inferred. First, it cannot have had the highest maximum willingness to pay for any of the available divested assets. And second, the value that the IPP placed on building the new power plant must be greater than the value of making no investment. Thus we have the following inequalities :

$$W^*(i) < W^*(j) \quad \text{for some } j \neq i \tag{3}$$

$$\Pi(\text{new asset}) - C(\text{new asset}) > 0 \tag{4}$$

Analogously, observing an IPP make no investment translates into the following set of inequalities

$$W^*(i) < W^*(j) \quad \text{for some } j \neq i \tag{5}$$

$$\Pi(\text{new asset}) - C(\text{new asset}) < 0 \tag{6}$$

These sets of constraints together capture the information contained in observing a firm's "make or buy" decision in a given market and year.

For the case of multiple divestiture sales in the same market and year, we assume that each firm evaluates the assets independently across the sales. The firm's willingness to pay for a divested asset is related to neither the asset nor the outcome of another concurrent sale. This assumption is necessitated by the nature of divestiture sales. Divestiture sales are informal, resembling asset sales (e.g. real estate) more than formal auctions (e.g. spectrum). Moreover, of the 19 (state, year) in which we observe a divestiture, only 5 have multiple divestiture sales. This makes it difficult to model and estimate any dynamic consideration across sales. This is a problem to the extent that the presence of other divestiture sales alters the difference in maximum willingness to pay across firms for a given divested asset. Common shifts in the willingness to pay due to the presence of other sales does not affect our inference as such shifts cancel out.

[15]We make no inference about the final purchase price, which can vary with the rules of the divestiture sale

We accept this assumption as a limitation of our model and note that inference from those 5 (state, year) may be problematic.[16] Given this assumption, multiple divestiture sales translate into additional constraints of similar form. For example, in the case where a market has two sales and IPP i is observed buying asset 1 but not asset 2, the implied set of constraints for IPP i would be

$$\begin{aligned} W_1^*(i) &> W_1^*(j) \quad \forall\, j \neq i \\ W_2^*(i) &< W_2^*(j) \quad \text{for some} \quad j \neq i \end{aligned}$$

Once an IPP buys any divested asset, the IPP will no longer consider building a new power plant. However, an IPP can win multiple divestiture sales in the same market and year.

What remain to be specified are the characteristics a firm chooses for the new power plant built under a "make" investment. In the model, a firm only decides on the capacity of the new plant. The capacity is chosen to maximize the return on the new asset (the $(\Pi - C)$ of the asset). We make this assumption because new power plants built by IPPs during the sample period are very similar to one another in other dimensions. For example, many of the new IPP plants use the same natural gas based combined-cycle (CCGT) technology.[17] If a firm is observed building more than one plant in the same market and year, we treat the plants as one asset whose capacity is equal to the sum of the capacity of each plant in the portfolio.[18]

The theoretical model establishes the inter-connection between the "make" and "buy" options. On one hand, the value of the "make" option is explicitly modeled as one of two factors that determine the value of the "buy" option. By imposing a sequential timing on the two options ("buy" first), the model is able to disentangle the channels through which different plant, firm, market, and regulatory variables affect the evaluation of the divested and new assets (Π(divested asset), Π(new asset) and C(new asset)). On the other hand, the model attributes the outcome of the divestiture sales to the comparison of willingness to pay across firms. Thus, the investment decision a firm makes under a certain scenario not only depends on its own evaluation of the available options but also on how other firms evaluate these options and the relative order of these valuations.

Next section, we discuss the empirical specification of the profit stream and investment cost that determines a firm's valuation of each asset. We specify the functional forms and the error structure. Based on this specification, we derive the likelihood used to estimate the model parameters.

[16] We explore our buy specification with formal statistical tests later in the paper

[17] "For example, the application of new combined-cycle/gas turbine facilities seems to be the preferred – in fact, the only – path being pursued in many areas as restructuring unfolds." Fox (1999), p.22

[18] The model does not explicitly consider possible future resale of plants by IPPs. Thus far, there have only been one major resale of divested utility assets: Sithe resold the plants it acquired from Pennsylvania utility GPU Inc. to Reliant a year after the original purchase. Sithe is excluded from our sample of major IPPs.

3 Empirical Model

An observation in our data is an IPP's investment decision in a state/year.[19] We map exogenous plant, firm, market and regulatory variables to observed firm investment decisions ("make", "buy", or not investing) by specifying the function of the expected variable profit stream (Π) associated with an asset (old or new) and the function of the investment cost (C) incurred for building a new asset a by firm i in state g and year t. We distinguish between the information observed by a firm from that observed by the econometrician; based on this distinction, we formulate the stochastic structure of the empirical model, solve the model, and derive the associated likelihood function.

We model firms as deriving their expected profits based on forecasts of market characteristics and their own firm characteristics. This contrasts with the current empirical entry literature, e.g. Bresnahan & Reiss (1991), where expected profits are modeled as varying with the number and type of competitors. We choose not to adopt a more explicit market equilibrium approach for two reasons. First, we found the computational burden and data requirement for such an approach prohibitive for our study.[20] Second, our chosen approach follows the characterization of IPP investment behavior in the industry press, e.g. Vaninetti (2002). It seems that IPPs respond more to forecasts of key market characteristics, such as the reserve margin, than the potential action of a given competitor. This is because firms care primarily about the *aggregate* response of all potential firms. Even the largest new plants are small relative to both electricity demand and existing capacity in the region. Combined with their superior thermal efficiency, a single new plant is largely inframarginal and has little expected impact on the market clearing price.[21]

Firms may care about the aggregate response as the combined investment may adequately shift the supply curve. However, such aggregate responses are most likely captured by market forecasts. Our approach can be considered as specifying the equilibrium expected profits directly, assuming that the aggregate response can be represented by an appropriate function of the forecasted market characteristics. This raises some concerns about the structural interpretation of our profit parameters. We investigate these concerns using formal specification tests later in the paper.

[19] We provide a detailed description of the data in the Appendix

[20] The key problem lies with the inter-temporal aspect of our study, which contrasts with the one-shot problem considered by much of the entry literature

[21] Own firm characteristics matter as the profit for the firm can differ depending on its cost, even if the market clearing price is the same

3.1 Expected Profit

The per-unit profit a firm expects to receive from a generation asset in a year (denoted as r) is modeled as a hedonic function of the exogenous characteristics of the asset, the market in which the asset operates, and the firm itself. Under this formulation, the difference in expected profit between divested and new assets in the same market and year for the same firm is driven by differences in plant characteristics between the two assets. The expected profit stream (Π) is modeled as the discounted sum of the expected annual profit over a finite horizon:

$$\begin{aligned}
\Pi_{igta} &= \overline{\Pi}_{igta}\ K_{igta} \\
&= \left(\sum_{\tau=1}^{10} \beta^{\tau} E_t\ r(X^r_{ig(t+\tau)a}\ ;\ \theta^r)\right) \cdot K_{igta} \qquad (7)
\end{aligned}$$

where

$$\begin{aligned}
(i,g,t,a) &= \text{(firm, market, year, asset)} \\
E_t\ r(X^r_{ig(t+\tau)a}\ ;\ \theta^r) &= \text{Expected annual profit per unit of capacity} \\
X^r_{ig(t+\tau)a|t} &= \text{Forecasted variables in expected profit function} \\
K_{igta} &= \text{Generation capacity of the asset} \\
\overline{\Pi}_{igta} &= \text{Expected discounted profit stream per unit of capacity}
\end{aligned}$$

The specification does not distinguish between the lead times for the "make" and "buy" options. In both cases, a firm incurs the investment cost (for a new asset or for a divested asset) in year t and begins to earn revenue from the asset in year $t+1$. While new power plant projects may be announced as early as three years before commercial start, the construction and installation of new plants – at which time much of the investment cost is sunk – usually begins 12–18 months before commercial start. On the other hand, a divestiture sale usually takes 6–12 months to close. Therefore, we set the time lag for both investment options to be one year.[22] In addition to the time lag, the specification also assumes that an IPP focuses on the profit stream from the first ten years of the asset's operation after its acquisition/construction ($\tau \leq 10$). This assumption follows industry practice.[23] The shorter horizon (vis-a-vis physical life) is also consistent with the idea that firms are more anxious to earn their return over a shorter horizon in a more competitive environment.

We specify the expected per-unit annual profit function in the following linear manner:

[22] Preliminary analysis allowing for the "make" lag to be longer (2 years) yield similar qualitative results.

[23] See Vallen & Bullinger (1999)

$$
\begin{aligned}
E_t\ r_{igt+h} \quad = \quad & \theta_0^r \ + \ \theta_1^r \mathsf{P96}_g + \ \theta_2^r \mathsf{LOGLOAD}_{gt+h|t} + \ \theta_3^r \mathsf{INT96}_i + \ \theta_4^r \mathsf{US96}_i \ + \ \theta_5^r \mathsf{USIOU} \\
& + \mathsf{LOGYRLEG}_{gt+h|t} \times (1 \ + \ \theta_6^r \mathsf{DIVSHARE}_{gt+h|t} \ + \ \theta_7^r \mathsf{PUC}_{gt}) \\
& \times [\ \theta_8^r + \ \theta_9^r \mathsf{LOGLOAD}_{gt+h|t} + \ \theta_{10}^r \mathsf{RM}_{gt+h|t} + \ \theta_{11}^r \mathsf{LDFACT}_{gt+h|t} \\
& \quad + \ \theta_{12}^r \mathsf{INT96}_i + \ \theta_{13}^r \mathsf{US96}_i + \ \theta_{14}^r \mathsf{USIOU}_i \\
& \quad + \ \mathsf{POP}_a \times (\theta_{15}^r \mathsf{INT96}_i + \theta_{16}^r \mathsf{US96}_i \ + \ \theta_{17}^r \mathsf{USIOU}_i)\ ] \\
& + \mathsf{AGE}_a \times (\theta_{18}^r \mathsf{INT96}_i + \theta_{19}^r \mathsf{US96}_i \ + \ \theta_{20}^r \mathsf{USIOU}_i) \\
& + \mathsf{USIOU_i} \times [\ \mathrm{I}(\mathsf{AGE} = 0) \times (\theta_{21}^r \mathsf{OM_i} + \theta_{22}^r \mathsf{GEN_i}) \\
& \quad + \ \mathrm{I}(\mathsf{AGE} > 0) \times (\theta_{23}^r \mathsf{OM_i} + \ \theta_{24}^r \mathsf{GEN_i})\ ] \qquad (8)
\end{aligned}
$$

The subscript g refers to the market. The subscript $t + h|t$ refers to the forecasted value for time $t + h$ based on information at time t. Lastly, the subscript a refers to the asset – either the new or divested ("old") power plant. Details on the data can be found in the Appendix.

The chosen expected profit function includes elements from all four sets of data: plant and firm characteristics, market conditions, and measures of restructuring progress. The adopted specification acknowledges that firm profit expectations differ greatly depending on the degree to which a state has enacted and implemented market-oriented regulatory restructuring. The relevant firm and market characteristics are interacted with a "commitment index" and a measure of the length of time since enactment of restructuring:

$$
\mathsf{LOGYRLEG}_{gt+h|t} \times \underbrace{(1 \ + \ \theta_6^r \mathsf{DIVSHARE}_{gt+h|t} \ + \ \theta_7^r \mathsf{PUC}_{gt})}_{\text{Commitment Index}}
$$

In a state with no restructuring (LOGYRLEG$= 0$), the interaction has no impact. However, in a state that has enacted restructuring legislation (LOGYRLEG> 0), the impact of the interaction depends on whether a state has experienced some utility power plant divestiture and whether the main regulating authority (usually the state public utility commission) is elected.[24] The *a priori* belief is that firms will perceive a greater commitment to market-based restructuring in a state with some divestiture and an appointed PUC. Divestiture makes it more difficult to "put the genie back in the bottle," as regulated utilities control a smaller share of the existing generation base. Elected regulators may be more responsive to consumer complaints and, hence, more likely to react to short-run market driven price fluctuations.[25] Assuming that independent power producers see more profit potential in a more restructured, market-based regime, we expect θ_6^r and θ_7^r to be positive and negative, respectively.

[24] Estimation using a simpler interaction (just a restructuring dummy) does not yield qualitatively different results

[25] See Besley & Coate (2003)

The profit function utilizes five observed firm characteristics, of which two represent merchant power experience and three affiliation with a U.S. investor-owned utility. INT96 and US96 reflect the amount of merchant power capacity owned by the IPP outside and within the U.S., respectively, in 1996.[26] The two variables are meant to be proxies for merchant power experience. IPPs with large INT96 and/or US96 values would presumably have an advantage in building and operating the more recent gas-based merchant power plants.[27] Similarly, IPPs with affiliation with investor-owned utilities (USIOU= 1) may draw upon the experience of its affiliated utilities when operating older power plants. We allow the value of this utility experience to differ based on two characteristics of the affiliated utility: the per unit output non-fuel steam power operations & maintenance (O&M) cost (OM) and the total amount of steam power electricity generation (GEN). We conjecture that firms with high INT96 and/or US96 expect greater profits operating newer power plants and firms with extensive IOU experience higher expected profits operating older, divested power plants.

Differences in observed market conditions help explain differences in expected profits across states. We utilize three relevant measures of electricity demand (LOGLOAD, RM, LDFACT) and the 1996 average retail electricity price for the state (P96).[28] The natural log of the (forecasted) peak electricity demand for the NERC region (LOGLOAD) is used to capture possible scale effects from demand; IPPs may prefer to participate in a state where the "pie" is larger. The ratio of total available generation supply over expected peak hourly demand (RM) reflects the tightness of supply. The ratio of peak hourly demand over average hourly demand (LDFACT) indicates the degree of demand fluctuation within a calendar year. A market with low RM and high LDFACT is more likely to be hit by price spikes. Thus, we anticipate IPPs to expect greater profit opportunities in such markets, especially in more market-oriented, further restructured states. We include P96 as a control for other, excluded market condition variation: considering that the economic fundamentals

[26]The year 1996 is chosen as capacity available then was built before the enactment of state level electricity restructuring in the U.S.

[27]It is reasonable to think that experience matters more with the number of plants run than the total capacity. We observe the former with much noise. Consequently, based on the capacity distribution in the data, we discretize the two variables in the following manner:

$$\mathsf{INT96} = \begin{cases} 0 & \text{if no intn'l projects in 1996} \\ 1 & \text{if less than 500 MW} \\ 2 & \text{if less than 1500 MW} \\ 3 & \text{if at least 1500 MW} \end{cases} \qquad \mathsf{US96} = \begin{cases} 0 & \text{if no US projects in 1996} \\ 1 & \text{if less than 500 MW} \\ 2 & \text{if less than 1000 MW} \\ 3 & \text{if at least 1000 MW} \end{cases}$$

[28]We use load data (including forecasts) for the North America Electricity Reliability Council (NERC) subregion in which the state is located rather than those for just the state itself. Given the interconnection between electricity grids across state borders, NERC subregions better reflect the potential demand satisfied by a power plant.

for a market usually exhibit strong time-persistence, a high $\mathsf{P96}$ may indicate, *ceteris paribus*, a high likelihood of having high market prices after 1996.

Plant characteristics reflect the differences between divested plants and the newly built plants, as well as across divested plants. We consider two plant characteristics: age and location. The age of a plant indicates the general competitiveness and implied profitability of the plant in the market, with older plants less efficient. Moreover, the effect of age is most likely discrete as what matters are plant vintages. An one year old plant may not be that different from a two year old plant but may be quite different from a 15 year old plant as the underlying technology is very different. Thus, we discretize the age of a plant in the following way:

$$\mathsf{AGE} = \begin{cases} 0 & \text{if plant is less or equal to 10 years old} \\ 1 & \text{if 10 to 20 years old} \\ 2 & \text{if 20 to 30 years old} \\ 3 & \text{if more than 30 years old} \end{cases}$$

All new plants have an age value of zero. Therefore, the effect of age can only be identified by the variation across divested plants. This identification depends on the comparison of the willingness to pay among firms. As a result, any effect of age that is common to all firms cannot be identified by the observed data.[29] So only the effect of age that vary across firms is estimated.

Additionally, the location of an existing plant can affect how an IPP values the plant. Plants located in an area with growing, high demand where it is also difficult to build new plants or import electricity may confer some local market power to the operator. Thus, firms that are experienced in "gaming" the market may value these plants more. We use the population density (POP) at the location (county) of the plant to capture this effect. For new plants, we assume their site has the average population density of the state.[30] We considered other plant characteristics, most prominently the plant fuel type, but could not find any substantial impact of such characteristics. This might best be explained by the limited variation in fuel type among new power plants and the lack of a real "choice" in fuel type for divested power plants.

The plant characteristics are not fully interacted with measures of a state's regulatory status. Plant characteristics (in our data) do not differ much among "new" plants. Given that divestitures occur predominantly in restructured states, it is difficult to estimate a fully interacted set of plant characteristics parameters. Thus, we interact only POP with the regulatory variables. We believe

[29] As discussed later, the logit probability that firm i has the highest willingness to pay ($W_i > W_j$, $\forall j$) is determined by the differences ($W_i - W_j$). Any additive common element in W_i and W_j will cancel out.

[30] While we observe the actual value of POP for plants that do get built, we do not for plants only being *considered*. We adopt the average as a consistent compromise.

that while population density, as an indicator of the opportunity to exercise local market power, can have an impact that varies significantly with the degree of market-based regulatory restructuring, the main impact of age (production inefficiency) is relatively invariant.[31]

3.2 Investment Cost

We decompose investment cost into two parts: a fixed (C^f) and variable (C^v) component. The former captures size-invariant costs such as those associated with obtaining regulatory approval and finding a suitable site. The latter reflects capital costs that explicitly vary with the size of a project, such as the cost of generation equipment and construction. A firm incurs a positive investment cost only if it invests $K > 0$: $C = C^f + C^v = 0$ for $K = 0$. For $K > 0$, we have

$$\begin{aligned} C_{igt} &= C^f_{igt} + C^v_{igta}(K_{igta}) \\ &= X^c_{igt}\ \theta^c + \alpha_1\ K_{igta} + \alpha_2\ K^2_{igta} \\ &\quad (\text{ with } \alpha_2 = \exp\{X_i^{\alpha 2}\theta^{\alpha 2}\} > 0\ ) \end{aligned} \tag{9}$$

The quadratic form of the capital cost allows marginal capacity cost to increase with total capacity, effectively binding the maximum economic size of a new power plant. We account for firm heterogeneity in capital cost by parameterizing α_2 as a function of firm characteristics.[32] The profit from a new power plant (before subtracting fixed cost) must be sufficiently large in order for a firm to invest through "make" – the higher the fixed cost, the less likely a firm is to build a new plant. The presence of fixed cost also binds the minimum size of a new power plant and eliminates trivial (and unrealistic) sized projects.

Given that the linear term in the capacity cost function is not separately identified from the constant in the expected profit function, we specify only the quadratic coefficient in the variable cost component (C^v_{igta})

$$\alpha_2 = \exp\left(\theta^\alpha_0 + \ \theta^\alpha_1 \mathsf{INT96}_i + \ \theta^\alpha_2 \mathsf{US96}_i + \ \theta^\alpha_3 \mathsf{USIOU}_i\right) \tag{10}$$

We expect firm characteristics to affect investment cost mostly through the capacity cost, with merchant and utility power experience helping to alleviate the increasing costs associated with building larger, more complex power plants. Consequently, we make capacity cost a function of (INT96, US96, USIOU).

[31] Allowing for age to be interacted similar to POP does not qualitatively alter the results

[32] Regulatory variables are included in the fixed cost as they constitute largely size-invariant "barriers"

On the other hand, we imagine the fixed cost to be similar across firms: the fixed cost reflects the degree to which a state welcomes *any* new power plant construction. As such, the fixed cost is a function of regulatory and environmental variables that reflect stakeholder concerns about new power plant construction

$$C^f_{igt} = \theta^f_0 \; + \; \theta^f_1 \mathsf{AGE30}_g + \; \theta^f_2 \mathsf{STNOX}_g + \; \theta^f_3 \mathsf{DMLEG}_{gt} + \; \theta^f_4 \mathsf{HOUSE}_{gt} + \; \theta^f_5 \mathsf{PUC}_{gt} \tag{11}$$

$\mathsf{AGE30}$ is the share of utility generation supply that is more than 30 years old in the state as of 1996. We expect $\theta^f_1 < 0$, as a state with a large $\mathsf{AGE30}$ is one where much of its existing capacity needs to be replaced. STNOX and HOUSE are two variables capturing environmental concerns associated with the construction of new power plants. STNOX is the 1996 NO_x emission (lbs. per MMBtu) from utility power plants in the state and HOUSE is the 5 year moving average of the "scorecard" for votes on environmental legislation by House of Representatives from the state, as tallied by the League of Conservation Voters (LCV).[33] The impact of these variables are *ex ante* ambiguous: an environmentally strict state may want to curb new construction to prevent additional emissions; a strict state may also want to encourage new plants to replace existing, more polluting plants. We also include two regulatory variables, DMLEG and PUC. DMLEG, a dummy for whether restructuring has been enacted, is included to allow for differences in regulatory investment "barriers" due to regulatory restructuring. PUC, a dummy for whether the PUC is elected, is included as an elected PUC may be more responsive to various local stakeholder concerns, making the development of new power plants more politically complicated.

A key difference between a new plant investment and a divestiture acquisition is that a firm can choose the capacity of a new plant but not a divested plant. We would expect the capacity for the two types of asset to differ as the fixed capacity of the divested asset will not generally be optimal at the time of the investment decision, as can be the capacity for the new plant. The optimal capacity (K) corresponds to the size that maximizes the value of the plant:

$$\max_{K \geq 0} \; \{ \; \underbrace{-C(K) \; + \; \Pi(K)}_{V(\text{new asset}, K)} \; , \; 0 \; \} \tag{12}$$

First order condition on $V(\text{new asset}, K)$ yields

$$\begin{aligned} 0 \;\; &= \;\; \frac{\partial}{\partial K} \left(\overline{\Pi} \; K - X^c_t \; \theta^c - \alpha_1 K - \alpha_2 K^2 \right) \\ &= \;\; \overline{\Pi} - \alpha_1 - 2\alpha_2 K \end{aligned} \tag{13}$$

[33] The LCV scorecard is from 0 to 100 with 100 being pro-environment. LCV is a leading non-partisan environmental lobbying group

If $K_0^* = \frac{1}{2\alpha_2}(\overline{\Pi} - \alpha_1) > 0$ and $V(\text{new asset}, K_0^*) > 0$ then we have an interior solution $K^* = \frac{1}{2\alpha_2}(\overline{\Pi} - \alpha_1)$.[34] Otherwise, we have a corner solution ($K^* = 0$), which is possible under two scenarios. First, even without any fixed cost of investment ($C^f = 0$), building a new plant may not be profitable ($-C^v(K) + \Pi(K) < 0$). This corresponds to $K_0^* = \frac{1}{2\alpha_2}(\overline{\Pi} - \alpha_1) < 0$. Second, it may seem profitable to build before considering the fixed cost but unprofitable after accounting for the fixed cost. This corresponds to $V(\text{new asset}, K_0^*) < 0$ for $K_0^* > 0$. Given the optimal value a firm can get from "make," we can infer the firm's maximum willingness to "buy" a divested asset a as

$$W_{igta}^* = \overline{\Pi}_{igta}\ K_{igta} - \max\ \{\ 0\ ,\ V(\text{new asset}\ ,\ K^*)\ \} \tag{14}$$

3.3 Error Structure

We assume that there are three sets of information known to the firm but unknown to the econometrician. The first error, ξ, captures the unobserved component in the capital cost per unit of capacity for a new asset. The second error, η, captures the unobserved component in the fixed cost associated with building a new asset. The third error, ϵ, captures the unobserved component of an IPP's valuation of the divested asset a. The three errors account for the following variations that cannot be fully explained by the observed variables: ξ for the variation in the capacity of new plants, η for the variation in the investment barrier a firm faces in a market and ϵ for the variation in the willingness to pay for a divested asset.

We impose a timing rule concerning the realization of these three errors to the firm. If there are divestiture sales, a firm observes ϵ when it participates in the sales but does not observe the errors related to the new asset (ξ and η) until after the conclusion of the divestiture sales. Therefore, when evaluating the divested assets, the firm's information about ξ and η is just the distribution of the two errors, just like the econometrician. If the firm does not buy any divested asset or there is no divestiture sale, the firm gets to observe the values of ξ and η when deciding whether to build a new plant. So, the errors are introduced into the empirical model in the following manner:

$$\begin{aligned} V_{igt}(\text{new asset}, K^*) &= \overline{\Pi}_{igt(new)} \cdot\ K^* - \left(C_{igt}^f + \eta_{igt} + (\alpha_1 - \xi_{igt}) \cdot K^* + \alpha_2 \cdot (K^*)^2\right) && (15) \\ W_{igta}^* &= \overline{\Pi}_{igta}\ K_{igta} + \epsilon_{igta} - E_t \max\{\ 0,\ V_{igt}(\text{new asset}, K^*)\ \} \\ &= \overline{W}_{igta} + \epsilon_{igta} && (16) \end{aligned}$$

By separating the realization of ϵ and (ξ, η), the model simplifies the likelihood by stochastically separating the "make" and "buy" observations. We feel that this assumption is not a gross misrepresentation. The capital constraint implies that once a firm builds, it cannot buy. Given that the

[34] For $\alpha_2 > 0$, the objective function is concave for $K > 0$

make option does not depend on the decision of other firms as much as the buy option, it is plausible that firms would explore buy before make. Moreover, while there is some agreement within the industry on the non-site-specific component of investment cost, there is much less agreement on the full cost which includes installation and final regulatory approval. Therefore, we think it reasonable to model firms as using some unbiased industry-wide estimate of investment cost and individually updating their estimate (factoring in more site-specific info) after the divestiture. To complete the specification, we make the following distributional assumptions for the three errors:

$$\begin{aligned} \xi_{igt} &\overset{i.i.d.}{\sim} N(0, \sigma^2_\xi) \\ \eta_{igt} &\overset{i.i.d.}{\sim} N(0, \sigma^2_\eta) \\ \epsilon_{igta} &\overset{i.i.d.}{\sim} \text{Type I Extreme} \end{aligned}$$

To keep the model computationally tractable, the three errors are further assumed to be independent of each other. The Type I Extreme distribution is adopted for ϵ as it allows the probability of a firm having the greatest willingness to pay (and hence be the buyer of the divested plant) be represented analytically by the standard logit form.[35]

There are two main concerns surrounding the error specification. First, the included explanatory variables may be correlated with the errors, introducing an "endogeneity" issue. There may be common omitted factors that drive both investment and some of the included regulatory/market variables. This concern is especially troublesome in the presence of autocorrelation in the errors across time; if these explanatory variables are influenced by past IPP investments, then they will be affected by past errors and correlated with current errors. Second, actual correlation within the errors across (state, year) implies that the likelihood is misspecified, making standard maximum likelihood inference inappropriate even if there is no endogeneity issue.

We address the first concern by including fixed effects in our empirical model to account for some of the potential common omitted factors. We add 4 year fixed effects (excluding 1996) and 12 market fixed effects, with markets defined as major NERC sub-regions (excluding ECAR).[36] We also include a subset of firm fixed effects. The firms in our sample can largely be split between those with and without IOU affiliation. Firms without IOU affiliation have more diverse backgrounds. Consequently, excluding AES, we include a firm fixed effect for each of those non-IOU-affiliated independent power producers (7 total). In comparison, the IOU-affiliated firms have roughly similar backgrounds. Each are subsidiaries of leading utility holding companies with substantial generation

[35] We have also considered the model where ϵ is assumed to be distributed *i.i.d.* standard normal, with the variance set to 1 for normalization. The results are qualitatively similar to the results using the logit specification

[36] The major populous states, California, Florida, New York, and Texas, are their own NERC subregions

experience.[37] Instead of representing each with its own fixed effect, we include some observed 1996 characteristics of their affiliated utility, obtained from their 1996 FERC Form 1 filing.[38]

To the extent that the relevant omitted common factors are firm-and-market, time-and-firm, or time-and-market invariant, the included fixed effects should largely address the endogeneity concern. We do not include interacted market-year fixed effects as, examining the data, much of the within market but across year variation in investment behavior seem to correspond to changes in the market observables, most notably shifts in regulatory condition and demand forecasts. Computational burden prevents us from including firm-market fixed effects which would allow for unobserved regional specialization by firms.[39] Additionally, we do not believe that regional specialization is a major issue in our sample as [1] the firms in our sample are national players who are comfortable building and operating plants in many regions [2] we have earlier examined a version of our model that accounts for two leading candidates of regional specialization, IOU-affiliated firms investing in the same markets as their affiliated utilities and firms associated with natural gas pipelines investing along their pipelines, and found little empirical support for either having a substantial impact.

Even if the explanatory variables are independent of the errors, correlation within the error across (market, year) can invalidate conventional ML inference as our likelihood is misspecified. The parameter estimates may still be consistent, as demonstrated in the quasi-maximum likelihood literature.[40] But the conventional "BHHH" method of calculating standard errors will be inappropriate as the information matrix equality condition will not generally hold. We address this second concern by calculating asymptotic standard errors for our parameter estimates using the more robust "sandwich" method.[41] In addition, we calculate a version of the "sandwich" standard errors which explicitly accounts for misspecification due to serial correlation across years within a state. The two yield similar results. We report the former, which are, in general, modestly larger than the latter. We provide details of these calculations in the appendix. We note that this correction does not resolve any endogeneity issue introduced by the presence of such serial correlation; we rely on the fixed effects to address that issue.

[37] More information can be found in Ishii (2003)

[38] We choose 1996 as it is the last year of utility operation before the implementation of state-level regulatory restructuring anywhere in the U.S.

[39] The general form of firm-market effects would require us to add well over 200 parameters

[40] See Gouréroux, Monfort, & Trognon (1984) and, more generally, White (1994)

[41] see Davidson & MacKinnon (2004), p.416

3.4 Likelihood

Given the stochastic structure of the model, if there is no divestiture sale in a market/year, the investment decisions of all firms are independent from one another.[42] However, if there is a divestiture sale, the observed "buy" decisions of all firms are correlated with each other; in order for one firm to win in a divestiture sale, its willingness to pay, which has an unobserved term (ϵ), must be greater than that of any other firm. The investment decision of a firm i in market g for year t is fully characterized by the following variables: [43]

$$\delta_{igta} = \begin{cases} 1 & \text{if IPP } i \text{ buys asset } a \\ 0 & \text{otherwise} \end{cases}$$

$$\psi_{igt} = \begin{cases} 1 & \text{if IPP } i \text{ builds a new plant} \\ 0 & \text{otherwise} \end{cases}$$

$$K^*_{igt(new)} = \begin{cases} K_{igt(new)} & \text{if IPP } i \text{ builds a new plant} \\ 0 & \text{otherwise} \end{cases}$$

Consider first the case where there is no divestiture sale in market g and year t. With no divestiture, δ does not enter into a firm's decision under this scenario. So the likelihood for the observed investment decision of firm i takes the form $l_{igt}(\psi_{igt}, K^*_{igt(new)})$. Furthermore, under the adopted stochastic structure, each firm's "make" decision is independent of each other. Therefore, the likelihood for the observed investments in market g year t can be expressed as:

$$l_{gt} = \prod_{i=1}^{N} l_{igt}(\psi_{igt}, K^*_{igt(new)}) \tag{17}$$

Next, consider the case where there are A divestiture sales ($A \geq 1$). Firm i's investment decision in the market g year t takes the form $\left(\delta_{igt1}, \cdots, \delta_{igtA}, \psi_{igt}, K^*_{igt(new)}\right)$. According to the model, $(\psi_{igt}, K^*_{igt(new)}) = (0, 0)$ with probability 1 if $\delta_{igta} = 1$ for any $\delta_{igta} \in (\delta_{igt1}, \cdots, \delta_{igtA})$. Moreover, because there is only one winner in a divestiture sale, the conditional probability of $\delta_{jgta} = 0$ given that $\delta_{igta} = 1$ is 1 for all $j \neq i$. Therefore, keeping in mind that divestiture sales are assumed to be independent of each other, the likelihood of the observed investments in market g year t is:

[42] In this case, the decision is between "make" or "do not invest"

[43] Note, the capacity of a divested plant is fixed, not a choice of the firm.

$$
\begin{aligned}
l_{gt} &= \texttt{Prob}\left\{(\delta_{1gt1},\cdots,\delta_{1gtA},\psi_{1gt},K^*_{1gt(new)}),\cdots,(\delta_{Ngt1},\cdots,\delta_{NgtA},\psi_{Ngt},K^*_{Ngt(new)})\right\} \\
&= \left\{\prod_{a=1}^{A}\texttt{Prob}(\delta_{1gta},\cdots,\delta_{Ngta})\right\}\times\left\{\prod_{i=1}^{N}\texttt{Prob}(\psi_{igt},K^*_{igt(new)}\mid\delta_{1gta},\cdots,\delta_{NgtA})\right\} \\
&= \left\{\prod_{a=1}^{A}\texttt{Prob}(\text{firm } i^a \text{ wins } a)\right\}\times\left\{\prod_{i\in\{j:\ \delta_{jgta}=0,\ \forall a\leq A\}} l_{igt}(\psi_{igt},K^*_{igt(new)})\right\} \qquad (18)
\end{aligned}
$$

As is explicitly shown in the appendix, both $\texttt{Prob}(\text{firm } i^a \text{ wins } a)$ and $l_{igt}(\psi_{igt},K^*_{igt(new)})$ can be derived based on the three sets of constraints raised in the theoretical model. Given $\{l_{gt}\}$, the parameter estimates are obtained by maximizing the joint log-likelihood:

$$
L=\sum_{g=1}^{G}\sum_{t=1996}^{2000}\log[\ l_{gt}\ ] \qquad (19)
$$

4 Results

4.1 Estimates

The parameters in the model are estimated using Maximum Likelihood (ML). Table 3a shows the parameter estimates for the expected profit function. Following the empirical specification, the results are divided into four groups: the coefficients for the base variables, the interaction terms, and the plant characteristics (AGE and POP), and the affiliated IOU characteristics.

Table 3a: Estimates for the Expected Profit Function				
Parameter	Baseline		w/ F.E. in Profit	
	Estimate	Std Error	Estimate	Std Error
Non-interacted				
θ_0^r : CONSTANT	-1.10701	0.08123	-0.96472	0.04290
θ_1^r : P96	-0.00763	0.00126	0.00707	0.00270
θ_2^r : LOGLOAD	0.01478	0.00104	-0.00800	0.00160
θ_3^r : INT96	-0.02695	0.00314	-0.00507	0.00166
θ_4^r : US96	-0.02190	0.00334	-0.00152	0.00024
θ_5^r : USIOU	0.11600	0.00951	0.07266	0.01342
Interacted with LOGYRLEG $\times$ (1 + θ_6^r DIVSHARE + θ_7^r PUC)				
θ_6^r : DIVSHARE	0.27985	0.02570	0.79974	0.14526
θ_7^r : PUC	-0.14572	0.06483	-0.15315	0.10773
θ_8^r : CONSTANT	-0.82414	0.04542	-0.79410	0.03402
θ_9^r : LOGLOAD	-0.16646	0.00901	-0.16571	0.00354
θ_{10}^r : RM	-0.48241	0.02185	-0.47231	0.02486
θ_{11}^r : LDFACT	1.46962	0.046491	1.49681	0.02875
θ_{12}^r : INT96	0.00009	0.00000	0.00220	0.00129
θ_{13}^r : US96	-0.00748	0.00050	-0.00055	0.00027
θ_{14}^r : USIOU	-0.09554	0.00688	-0.10521	0.01966
Interacted with POP				
θ_{15}^r : INT96	-0.00001	0.00002	0.00000	0.00002
θ_{16}^r : US96	0.00000	0.00002	-0.00001	0.00002
θ_{17}^r : USIOU	0.00001	0.00009	0.00003	0.00008
Interacted with AGE				
θ_{18}^r : INT96	0.01049	0.00148	0.00056	0.00118
θ_{19}^r : US96	0.01307	0.00167	0.00083	0.00075
θ_{20}^r : USIOU	0.03733	0.00490	0.06654	0.00769
Interacted with USIOU				
θ_{21}^r : OM(NEW)	-0.08828	0.00113	-0.15984	0.02166
θ_{22}^r : GEN(NEW)	0.09590	0.00513	0.07588	0.01192
θ_{23}^r : OM(OLD)	-0.00308	0.00342	0.00014	0.00226
θ_{24}^r : GEN(OLD)	-0.00200	0.00298	-0.00106	0.00267

The table above provides estimates for the model with and without fixed effects. We focus on the estimates with fixed effects, which are more general and robust. The qualitative results are similar across the two, with the most substantial and statistically significant effects being largely the same.

Prior to restructuring, an IPP's expected profit is largely negative. The estimates suggest that the IPP with the best prospect in a regulated market is an IPP affiliated with an IOU but with limited merchant power experience. The advantage of IOU affiliation is intuitive as such affiliated IPPs can draw upon valuable experience and skills associated with operating in an explicitly regulated market. Domestic merchant power experience has a puzzlingly negative impact, albeit very small in magnitude.

The coefficients for the variables interacted with LOGYRLEG and the "commitment" index reflect the difference in expected profits between a more and less restructured market. We find that divestiture (DIVSHARE) has a substantial impact on the "commitment" to market restructuring perceived by the sampled IPPs. The estimate suggests that, for firms not buying divested plants, divestiture encourages new power plant investment. The estimate for the PUC coefficient is in accordance with the *ex ante* hypothesis that IPPs expect elected PUCs to extract more surplus from them. Elected PUCs, who face a more explicit incentive to act as consumer advocates, may intervene in the market more frequently, especially during periods of high prices and profits.

A theme arises from among the interacted market variables: the estimated coefficients show a positive impact of a "tight supply" on expected profits in markets further along in restructuring. This result is reflected by the significant coefficients for RM and LDFACT. A market with a high RM is one where existing generation supply more than adequately covers demand. Therefore, a possible interpretation of the negative coefficient before RM is the presence of significant scarcity rents in restructured markets with an overall tight supply. Along the same lines, a high LDFACT indicates a high demand volatility; the positive LDFACT coefficient may be reflecting scarcity rents during peak demand, as a market is unlikely to support too many "peakers" that remain idle much of the year. These results echo the current empirical literature on electricity restructuring in suggesting that there may be opportunity to earn sizable rents in restructured markets.

With respect to the interacted firm variables, IOU affiliation seems to matter most. The negative coefficient for the interacted USIOU coefficient most likely reflects the relative disadvantage (in restructured markets) of affiliated IPPs compared to the non-affiliated IPPs *in the sample*. The non-affiliated IPPs in the sample include AES and Calpine, both of which are recognized leaders in merchant power production. Furthermore, USIOU affiliated IPPs appear to have an advantage in operating older (high AGE) plants. These two results, jointly, are consistent with the idea that IOU affiliated and unaffiliated IPPs draw upon different skills: an affiliated IPP has more knowledge concerning older utility power plants while an unaffiliated IPP is more familiar with modern merchant power plants. The coefficients for the utility characteristics (OM, GEN) indicate that firms associated with utilities with greater generation experience and lower O & M costs are less disadvantaged in dealing with new plants and no more advantaged with older plants. The estimates for the firm characteristics interacted with POP indicate that the value of a power plant's location does not vary across firms.[44] This suggests that any expected profit motive explaining why one IPP chose to buy a divested plant over other IPPs is more likely based on the IPP's advantage in running the older power plant than in "leveraging" the plant location.

The estimates for the firm, market, and year fixed effects can be found in the appendix. The fixed effects are jointly significant, using the standard likelihood ratio test (LRT $= -2 \times [763.69 - 817.20] = 107.02$, $\chi^2_{df=23}$ critical value for 1% significance ≈ 43). Two points of interest can be seen from the fixed effects estimates. First, the estimates suggest that IPPs consider regulatory risk when evaluating their power plant projects. The fixed effects suggest that, *ceteris paribus*, expected profits are lower during early in the period (year fixed effects) and for markets undergoing substantial regulatory restructuring (WSCC-CA, NPCC-NY, NPCC-NE, MAAC). Second, the firm fixed effects (for non-IOU affiliated firms) are statistically substantial for only 4 firms: ANP, Coastal, Cogentrix, and El Paso. All four firms were found to face much lower expected profits. El Paso, Coastal and Cogentrix were early "casualties" of the industry, selling much of their capacity by the end of 2003.

Table 3b shows the estimates for the parameters in the investment cost function.

Table 3b: Estimates for the Investment Cost Function

Parameter	Baseline		w/ F.E. in Profit	
	Estimate	Std Error	Estimate	Std Error
Fixed Cost				
θ_0^f : CONSTANT	-2.19349	26.09951	-7.09479	10.64310
θ_1^f : AGE30	15.28987	31.19576	22.18324	21.46281
θ_2^f : STNOX	1.98951	9.38423	2.02104	1.72450
θ_3^f : DMLEG	-9.34262	50.46497	-10.02195	16.98385
θ_4^f : HOUSE	-0.17633	0.85679	-0.28037	0.31877
θ_5^f : PUC	6.97326	19.53042	-2.75103	14.83798
σ_η	16.85841	66.92359	15.43065	15.94876
Capacity Cost (α_2)				
θ_0^α : CONSTANT	-0.84552	0.00113	-0.56638	0.31115
θ_1^α : INT96	-0.09683	0.00513	-0.18158	0.07095
θ_2^α : US96	-0.25653	0.00342	-0.28504	0.10503
θ_3^α : USIOU	-0.02004	0.00298	-0.10107	0.17415
σ_ξ	4.40189	0.06293	3.68918	0.49965

[44] This does not imply that location does not contribute to the overall value of the plant - just the differential value.

The coefficients in the fixed cost are imprecisely estimated. Furthermore, the large variance for η indicates that much of the barriers to new power plant investment is unobservable in the model. Difficulty in pinning down the fixed investment cost is expected as much of the politics involved in getting approval for power plant projects is local, involving a myriad of potential stakeholders that vary by location.

While precision is a problem in the estimation of the fixed cost, the coefficients in the capacity cost are estimated more precisely. Firms with substantial merchant power experience are found to be better capable of controlling the costs of large size projects. For an IPP with more than 1000 MW of domestic merchant power capacity in 1996 ($\mathsf{US96} = 3$), its capital cost[45] is half of that of a firm without any domestic merchant power capacity, *ceteris paribus*. This is evidence supporting the presence of cost advantages for experienced generators. While the impact of merchant power experience on expected profits seem largely non-existent, the sizable impact on investment cost suggest that merchant power experience raises the return from building new power plants, especially those with large capacity. This result helps explain a major feature of observed divestiture sales thus far: most divested power plants have been bought by IOU affiliated IPPs

Table 4: Divestiture by Year and Acquiring IPP

Year[1]	Capacity (Megawatts)	
	Total Amount of Divestiture	Total Amount Acquired by IPPs Affiliated with U.S. IOUs
1998	24976	17835 (71.4%)
1999	50942	40108 (78.7%)
2000	15689	14204 (90.5%)
Total	91607	72147 (78.8%)

Divestiture data from various issues, EIA “Electric Power Monthly”
Excludes transfers between IOU and affiliated IPP
IPP classification from various industry resources
[1] Year refers to year asset was officially transferred to IPP

In our sample, there is a strong negative correlation between IOU affiliation and merchant power experience: almost all of the unaffiliated IPPs have considerable merchant power experience (high $\mathsf{INT96}$ and/or high $\mathsf{US96}$). Among the 31 divestiture sales won by affiliated IPPs, 11 were won by affiliates who had $\mathsf{INT96}$ and $\mathsf{US96}$ less than or equal to 1. Consequently, an explanation for the preponderance of divested assets bought by affiliated IPPs that is supported by the estimated model is that IOU affiliated IPPs have a higher willingness to pay due to the larger premium they place on

[45] Ignoring the linear term of the capacity cost, which is not separately identified

being able to avoid the investment cost associated with a "make" investment. The opportunity cost of buying a divested plant is different between an affiliated IPP with low merchant experience and an unaffiliated IPP with high merchant experience. The unaffiliated IPP can build a new power plant much cheaper, and, thus, values the "make" option more.

The estimated coefficients elaborate how each explanatory variable affects the estimated profit and investment functions. In order to examine the combined impact of these coefficients, we calculate the estimated "make" probabilities for each (firm, state, year) after a discrete change in one of the key variables. This exercise is akin to marginal effects calculation in standard discrete choice studies.[46] We consider the probability changes due to [1] +1 increase in INT96 [2] +1 increase in US96 [3] 5% point addition to the RM forecasts [4] 5% point addition to the LDFACT forecasts [5] 5% proportional increase in LOGLOAD forecasts. For the latter three market characteristics, we also examine the estimated make probability after a one standard deviation (sample) addition.

Table 5: $\frac{1}{N}\sum_{igt}\hat{\text{Prob}}$ (firm i invests in a new plant in state g, year t)

ΔX	Full Sample	Restructured Markets	Divested Markets	"Making" Firms
No Change	0.0227	0.0475	0.0510	0.1036
+1 INT96_i	0.0233	0.0492	0.0524	0.1072
+1 US96_i	0.0237	0.0500	0.0531	0.1091
+0.05 $\text{RM}_{gt+h\|t} \|_{h=1}^{10}$	0.0208	0.0421	0.0457	0.0936
+0.05 $\text{LDFACT}_{gt+h\|t} \|_{h=1}^{10}$	0.0338	0.0793	0.0818	0.1496
1.05 $\times$ $\text{LOGLOAD}_{gt+h\|t} \|_{h=1}^{10}$	0.0189	0.0367	0.0413	0.0844
+1 Std Dev (+0.2) $\text{RM}_{gt+h\|t} \|_{h=1}^{10}$	0.0146	0.0238	0.0286	0.0641
+1 Std Dev (+0.1) $\text{LDFACT}_{gt+h\|t} \|_{h=1}^{10}$	0.0482	0.1204	0.1226	0.2033
+1 Std Dev (+0.57) $\text{LOGLOAD}_{gt+h\|t} \|_{h=1}^{10}$	0.0144	0.0235	0.0283	0.0636
# of (i,g,t) obs (N)	4800	1380	860	102
Using estimates from model with fixed effects				

The above table shows the average estimated probabilities for firm i investing in a new plant in state g and year t, conditional on not buying any available divested plants. The averages are calculated over the full sample and three sub-samples: observations corresponding only to (i,g,t) that involve [1] g that has enacted restructuring as of t [2] g that have implemented divestiture as of t [3] i investing in a new plant in g at t. As expected, the average make probabilities are greater in restructured and divested markets, and much greater for the case when the firm is observed investing in a new plant. Furthermore, the average make probability for a firm not observed "making" in a

[46] We do not calculate the probability derivatives as many of the variables are discrete, not continuous.

(g,t) where at least one firm did "make" is 0.0486, half the value of the average "make" probability for firms actually observed investing in new plants (0.1036). Combined, these results indicate that the empirical model does help explain the IPP investment decisions observed in the data.

An increase of one category in either merchant experience measures (INT96, US96) only modestly increases the average make probability. This is not surprising as these measures have a small impact on the expected profit function. The main impact of (INT96, US96) on make is through the variable investment cost, suggesting that merchant experience primarily affects the size of new plant investments. Among the four market characteristics, the one standard deviation addition to the load factor, measuring the within-year demand volatility, has the most substantial impact, doubling the average make probability in all (sub)samples. A similar one standard deviation addition to the reserve margin or the log load nearly halves the average make probabilities.

Overall, we draw four main conclusions from the parameter estimates. First, we find that the an IPP's evaluation of the expected return from generation investment evolves with restructuring. Market fundamentals, such as the reserve margin RM and the load volatility LDFACT, seem to play a more important role the further restructured a market becomes. Second, we find that firm characteristics do help explain the difference in the investment choices adopted by different IPPs. IPPs with greater merchant experience (often unaffiliated with IOUs) face a discount in the capital costs incurred from developing large, new plants while IOU affiliated IPPs face a greater expected profit from operating older, divested plants. These results help explain why IOU affiliated IPPs are observed to be the major buyers in divestiture sales. Third, we find no substantial impact of plant characteristics on relative valuation of divested power plants. This suggests that the main motivation underlying the "buy" investment is the avoidance of the investment cost associated with the "make" investment. Last, we find evidence supporting the idea that divestiture encourages IPP investment as a "commitment device" that reduces the regulatory risk faced by IPPs.

4.2 Specification Tests

Before we consider the counterfactual implications of our estimates, we conduct conditional moment specification tests that investigate how well the conditional moments associated with buy and make, implied by our estimated model, reflect the observed data. We use the specification test proposed in Tauchen (1985), operationalized by regressing the difference between the observed moment and the moment predicted by the estimated model against a constant and the gradient of the log-density with respect to the parameter vector (evaluated at the estimated values, $\hat{\theta}$):

$$\text{Observed Moment - Predicted Moment} \quad = \quad \alpha + h_{gt}(\hat{\theta})'\beta + u_{gt}$$

An observation for the auxiliary regression is (state, year). The specification adopted in the model is rejected if the estimated intercept ($\hat{\alpha}$) is significantly different from zero. The gradient of the log density, $h_{gt}(\hat{\theta})$, is included in the regression to account for the estimation error in the parameter vector. The above regression can be used to examine whether the conditional moment holds for an *individual* firm. To test whether the conditional moment holds *jointly* for all 20 firms, the Tauchen test statistic is the quadratic form $\tau'[\hat{\Omega}/N]^{-1}\tau$ where τ is the vector of $\hat{\alpha}$ intercepts for the 20 firms, $\hat{\Omega}$ the estimated residual covariance matrix across the 20 regressions, and $N = 48 \times 5 = 240$ the number of observations. Under the null hypothesis that the conditional moment holds jointly for all 20 firms, the quadratic test statistic is asymptotically distributed χ^2_{20}.

We explore possible misspecification in the "buy" aspect of our model by examining the following conditional moment for each of our 20 firms: the expected value of a dummy variable set to 1 if the firm buys a power plant in the given (state, year). The difference between the data and our estimated model is simply the difference between a dummy variable set to 1 if the firm is observed buying and the estimated probability of buying some available plant in the given (state, year). The table below summarizes the results from the individual Tauchen specification tests.

Table 6a: Specification Test for "Buy" Probability

Sample	Avg. $\hat{\alpha}$	Avg. T-stat $\frac{\hat{\alpha}}{\sqrt{\hat{\text{Var}}(\hat{\alpha})}}$
Full (20 firms)	-1.63E-07	-0.60
IOU Affiliated (12 firms)	0.00013	-0.61
Not IOU Affiliated (8 firms)	-0.00019	-0.59
US96=0 (3 firms)	-0.00241	-1.55
US96=1 (8 firms)	0.00014	-0.45
US96=2 (6 firms)	-0.00092	-0.68
US96=3 (3 firms)	0.00386	0.10
Reliant (USIOU=1, US96=0)	-0.00367	-2.70
Duke (USIOU=1, US96=1)	-0.00362	-2.56
EPG (USIOU=1, US96=0)	-0.00384	-2.05
CMS (USIOU=1, US96=2)	-0.00393	-1.88
U.S. Gen. (USIOU=1, US96=3)	0.01403	1.68
NRG (USIOU=1, US96=1)	0.00950	1.64
Specification test run on model w/ F.E. in Profit		
Excluding above 6, all other IPPs have T-stats < 1.15		

We summarize the individual results from the 20 firm-level regressions. The average $\hat{\alpha}$ and average T-stat are the sample averages of the $\hat{\alpha}$ and T-stat, respectively, estimated separately for each firm in the sample. The results represent an evaluation of the "buy" specification for a single firm. The value of the quadratic test statistic that jointly tests the "buy" specification for all 20 firms is 27.67 – a value that fails to reject at conventional significance levels.[47] With the exception of six IPPs, the firm-specific Tauchen test of the "buy" specification fails to reject. This suggests that the data does not reject the "buy" aspect of the estimated model for most of our sampled firms. A common characteristic of the six IPPs for whom the Tauchen specification fails, at significance levels varying from 1 to 10%, is their IOU affiliation. The estimated model does a good job discriminating *between* the buy probability of an IOU unaffiliated and affiliated IPP but has difficulty discriminating *among* the buy probabilities of IOU affiliated firms.

This is borne out in estimated profit parameters for the 1996 utility characteristics of IOU affiliated firms ($\theta^r_{21} \cdots \theta^r_{24}$). The characteristics that most distinguish one IOU affiliated IPP from another, the 1996 utility generation (GEN) and O&M costs (OM), are significant and substantial in the evaluation of profits for *new* plants but insignificant and insubstantial in the evaluation of profits for *old, existing* plants. The Tauchen specification tests largely reiterate the message spoken by the parameter estimates: the estimated model does well in explaining "buy" differences between IOU affiliated and unaffiliated firms and how lower merchant experience, in general, increases the attractiveness of "buy" but does less well in explaining "buy" differences among similar IOU affiliated firms – whether low merchant experience (US96 = 0 or 1) or high (US96 = 2 or 3).

A possible solution is to include firm fixed effects for each IOU-affiliated firm. For example, we were not surprised to see the "buy" specification test fail for Duke Energy. Although Duke's ability to build and operate new plants would seemingly be low based on its observed merchant experience (USCAP=1), the utility to which Duke Energy is affiliated is considered a leader among electric utilities, having won numerous industry awards. Such unobserved quality would lead to the model over-estimating the buy probability for Duke (the opportunity cost from "make" is greater than implied by the observables) and could be controlled with a "Duke Energy" dummy. However, adding 12 new parameters would stress data and computational limits. We acknowledge the difficulty our estimated model has of discriminating the "buy" probabilities among similarly experienced IOU affiliated firms. But we emphasize that differences between affiliated and unaffiliated and between "high" and "low" merchant experience firms seem to be well captured by the estimated model.

We also consider misspecification in the "buy" aspect of our empirical model due to possible

[47] The critical value for a χ^2_{20} is 28.41 for the 10% significance level

errors in our assumed set of participants for each divestiture sale. Given the way divestiture sales occurred – usually over a long period with abundant industry awareness – we believe that it is reasonable to assume that all 20 of our major IPPs participated in each sale. However, there may be other IPPs involved in the sale (none of whom are observed buying). To address this issue, we conducted sensitivity analysis by re-estimating the model taking out a firm not observed buying the divested plant (19 firms) as well as adding a firm we had previously excluded from our sample (21 firms). This resulted in no major qualitative difference.

We explore possible misspecification in the "make" aspect of our model by examining two sets of conditional moments. In the first, we consider the expected number of new power plant projects in a given (state, year) across all 20 sampled firms. The difference between data and our estimated model is the difference between the total number of new plant investments observed and the sum of the make probability across all 20 firms for a given (state, year). This specification test informs us whether the estimated model might be under or over-estimating the total number of new power plant investments. The table below summarizes the results

Table 6b: Observed vs. Expected Number of New Investments

Model	Total	Restructured Markets	Divested Markets	Specification Test $\hat{\alpha}$	Specification Test T-stat
Data	102	60	44	n/a	n/a
No Firm FE	104.92	60.96	33.23	0.00239	0.31
Firm FE	108.68	65.13	43.38	-0.00342	-0.52
Firm FE (but $\theta_6^r = 0$)	100.59	57.75	35.70	n/a	n/a

For either model (with or without fixed effects), the Tauchen specification test on the expected number of total new investments fails to reject, with T-statistics of 0.31 and −0.52. This implies that the data does not reject the "make" component of the estimated model, with respect to the total number of new power plant investments in a given (state, year). This result supports our upcoming counterfactual exercise as misspecification with respect to the total number of new plants would lead to over/under-estimate of the extent of divestiture-induced crowding out.

A possible concern is that we focus on the total number of new plants, rather than total capacity. While calculating our counterfactual simulations, we found that, given a new investment, our model estimates reasonable capacity sizes for new plants. The average capacity was 420 MW, within the standard range for new combined cycle gas turbine units, the popular technology choice among IPPs during our study period. This range is not explicitly imposed by the model, suggesting that our estimated model, on average, does a good job estimating the capacity size of new plants.

We do not expect the results to differ qualitatively, whether we focus on total new investments or total new capacity.[48]

In addition to the Tauchen specification test results, the table above shows the "fit" of the model for different types of markets. The "fit" (except for "Data") is the expected number of new investments (across all years) in the given market type according to the estimated model. In addition to the fit for the fixed effect and no fixed effect model, we calculate a third fit based on the estimates from the fixed effect model but setting $\theta_6^r = 0$. This corresponds to the prediction of the fixed effect model *sans* the direct impact of divestiture on the profit function. By comparing the prediction of the fixed effect model with the fixed effect model (but $\theta_6^r = 0$), we can quantify the direct impact of divestiture on the expected profits perceived by our sampled IPPs.

The "fit" comparisons suggest that the estimated model fits the total number of new power plants well. The difference in the total across the different sub-samples is small and further confirms the basic result from the specification test. If anything, the estimated model slightly over-estimates new investments, mostly in restructured markets that have not yet partaken in any divestiture. This suggests that our counterfactuals may slightly over-estimate the extent of crowding out. The difference in the fit between the last two rows, estimated model with fixed effects and estimated model with fixed effects except $\theta_6^r = 0$, illustrates the magnitude of the direct impact of divestiture. The direct effect of divestiture increases the overall expected number of new investments by 8 in markets that have undertaken some divestiture. This is consistent with the view that divestiture, as a signal of commitment to restructuring, encourages new plant investments.

We also conduct a second specification test centered on the probability that a given firm will invest in a new power plant in a given (state, year). The moment associated with this test is: $E($ i invests in new plant in (g,t) $|$ data $) - E($ i invests in new plant in (g,t) $|$ model $) = 0$. The difference between data and our estimated model is the difference between the dummy indicating whether the firm invested in a new plant and the estimated make probability associated with the firm i investing in a new plant in state g, year t. We conduct this specification test for each of the 20 firms in our sample. The table below summarizes the results

[48] The expected number of new investments can be calculated analytically given the parameter estimates but the expected total capacity requires an involved simulation-based numerical integration.

Table 6c: Specification Test for "Make" Probability		
Sample	Avg. $\hat{\alpha}$	Avg. T-stat $\frac{\hat{\alpha}}{\sqrt{\hat{\text{Var}}(\hat{\alpha})}}$
Full (20 firms)	-0.00172	-0.88
IOU Affiliated (12 firms)	0.00298	-0.47
Not IOU Affiliated (8 firms)	-0.00876	-1.50
BUYER (13 firms)	-0.00007	-0.30
Not BUYER (7 firms)	-0.00504	-1.95
US96=0 (3 firms)	-0.00366	-0.91
US96=1 (8 firms)	0.00494	-0.33
US96=2 (6 firms)	-0.00757	-1.83
US96=3 (3 firms)	-0.00580	-0.41
Specification test run on model w/ F.E. in Profit		
BUYER: firm is observed buying a divested plant		

Of the 20 firms, the specification test for 8 of the firms rejects the moment condition at the 5% significance level: AES, ANP, Coastal Power, Cogentrix, Duke Energy, Edison Mission, and Enron. The specification test fails to reject for most firms, especially for IOU affiliated firms and firms who buy at least one divested plant during our study period. However, the joint test of the conditional moments across all 20 firms does reject at conventional significance levels, with a test statistic value of 175.54. Among the 8 troubling firms, 4 successfully bought a divested plant during our study period – these are the relevant firms for our later "crowding out" calculation. For only one of these four firms, Duke, does the model under-estimate the make probability.[49] Moreover, Duke is observed buying in only one (state, year). This suggests that the model is likely to under-estimate the extent of crowding out in only one (state, year) observation. This re-iterates our earlier finding that any bias in our counterfactual simulation will be toward finding greater crowding out.

4.3 Simulation

Given the parameter estimates, we can use the model to run policy simulations that examine IPP investment behavior under different scenarios. One important policy simulation related to the "make or buy" decision is whether and how much divestiture has "squeezed" out investment in new generation capacity. In other words, would those IPPs that are observed "buying" divested power plants have chosen to "make" instead if the "buy" option was not available? The answer to this question gets at the heart of evaluating whether divestiture has truly succeeded in achieving the long-run goal of encouraging greater IPP participation.

[49] We were not surprised to see this for similar reasons as the buy specification test.

Consider the case where there are no divestitures in any market during any year in our sample. Under this scenario, “buy” is not an option anymore and cannot squeeze out “make” investments. Nor does divestiture explicitly alter the expected profit or investment cost functions for an IPP as the variable DIVSHARE is set to be 0 for all observations. Table 6 shows the new capacity investments (“make”) in the simulation by those IPPs who chose to “buy” in reality. Note, multiple “buys” by the same firm in the same year and market are aggregated into one observation. Thus, there are 32 instead of 38 “buy” observations. The reported values for “Make” (except for min and max total investment at the end) are the values of the sample mean across the 500 draws.

Table 7: “Make” to “Buy”

Case	# of Inv.	Total Inv.	Min Total Inv.	Max Total Inv.
“Buy” (Data)	32	69248		
“Make” (Sim.) No F.E. (DIVSHARE = 0)	1.35 (1.14)	601.4 (714.9)	0	3847.5
“Make” (Sim.) w/ F.E. (DIVSHARE = 0)	0.42 (0.63)	177.1 (381.0)	0	2714.7

1. Results are based on 500 draws 2. Investments are in MW
3. Standard deviation in parentheses

The simulation exercise finds that divestiture crowds out very little new generation investments, 177 MW *in total* on average (for the model with fixed effects). This corresponds roughly to a third of the standard capacity for a single combined cycle gas-fired unit. The simulation also finds that most of the IPPs who chose to enter and participate in these markets would have chosen not to do so if divested assets was not available. On average, only one of the 32 divestiture acquisitions (and no more than 2 with any sizable probability) would have led to a new power plant investment in the absence of divestiture. This suggests that divestiture has greatly encouraged the number of IPPs active in the restructured market without “crowding out” substantial new generation capacity.

A possible concern is that our simulation only reflects crowding out among our 20 sampled firms. There might be substantial crowding out among non-sampled firms. However, there are good reasons to believe that if there is crowding out, it will be localized among our sampled major IPPs. Our estimates demonstrate that crowding out occurs only if the firm buys the divested plant. Otherwise, divestiture serves to encourage new investment. The 20 sampled firms span the set of main participants of divestiture sales, except one: Sithe Energies. We chose to exclude Sithe as they were participants in early divestiture sales (no new plant investments) who quickly exited the industry, selling their divestiture acquisitions to Reliant by end of 2000.[50] Unless the

[50]This re-sale by Sithe helps ameliorate concerns associated with the failed “buy” specification test for Reliant,

direct impact of divestiture is different between sampled and non-sampled firms, we do not expect much "crowding out" among non-sampled firms. Moreover, we stress that the 20 sampled firms are, for the most part, the major participants in restructured U.S. wholesale generation. The data appendix provides details on our sample construction.

The simulation results are consistent with the earlier discovery that the main factor contributing to a high willingness to pay is the desire to avoid incurring a high investment cost, implying that IPPs who buy divested assets have a low "make" valuation. In order to investigate this interpretation further, we revisit the estimated make and buy probabilities used to construct Table 5. If a high "make" value – relative to other firms – discourages the firm from submitting a winning bid in a divestiture sale, then we should expect to see a negative correlation between the estimated "make" and "buy" probabilities. This correlation should be particularly negative for the two extremes: firms observed bypassing divestiture and investing in a new plant and firms observed buying divested plants. The table below investigates such correlation. In order to capture whether an estimated "make" probability is relatively high, we subtract the average estimated "make" probability across the 20 firms for the given (state, year) from the firm's estimated "make" probability.[51]

Table 8: Correlation between Estimated "Make" and "Buy" Probabilities
For (State g, Year t) where Divestiture Sale was Present

	Whether Firm i Bought		Whether Firm i Built	
	Buy = 1	Buy = 0	Make = 1	Make = 0
Pearson Correlation	-0.1706	-0.0345	-0.4406	-0.0133
P-value ($H_o : \rho = 0$)	0.3057	0.3540	0.0401	0.7189
# (i,g,t) observations	38	722	22	738

We find a negative correlation for the two extremes, firms "buying" and firms "making." The correlation is particularly negative, both substantially and statistically, for firms observed bypassing divestiture and investing in a new plant. This supports the contention that the firm's "make" valuation plays an important role in the firm's buy decision. In the absence of divestiture, many of these IPPs would not enter the market. Therefore, by giving IPPs the option to buy existing plants, divestiture provides some IPPs with limited "make" abilities the opportunity to enter the market profitably. This increases the number of IPPs participating in the market. These IPPs who participate in the market through divestiture acquisitions consist mostly of affiliates of U.S. investor-owned utilities. Such IOU-affiliated IPPs are willing to pay more for divested power plants

supporting the estimated model's finding of a strong buy interest for Reliant

[51]The average estimated buy probability across the 20 firms is always $\frac{1}{20}$

than unaffiliated IPPs because [1] the opportunity cost (the "make valuation") is less and [2] they have an advantage in operating the older power plants.

This raises the question: what are the consequences of greater participation by IOU-affiliated IPPs? A main factor driving restructuring is the hope that competition would lead to the replacement of existing IOU generation by more efficient IPP generation. If these IOU-affiliated IPPs are among the low-cost generators, then divestiture may be helping to foster such cost savings.[52] However, if these affiliated IPPs only have an advantage in buying and running existing plants based on older technology, then divestiture may be hurting the long-run prospects for the market. Although not explicitly explored in this paper, there may be strategic consequences of investment: affiliated IPPs, by buying and controlling the lion's share of the initial capacity in the restructured market, may be curtailing participation by unaffiliated IPPs who may be more competitive in the long-run when new power plants become necessary. An important concern may be that divestiture is subsidizing the participation of the wrong IPPs. Divestiture, while not "crowding out" much current new plant investment, may be "crowding out" future new plant investments by lower cost unaffiliated IPPs. We leave this dynamic issue for future research.

Conclusion

We present an empirical model of the "make or buy" decision faced by independent power producers in many restructured wholesale electricity markets. Applying this empirical model to plant-level data that track the investment decisions of major IPPs from 1996 to 2000, we obtain estimates of each firm's investment cost and expected profit functions. Although there are many reasons why an IPP might prefer to buy a divested plant rather than build its own, the estimates provide evidence corroborating one particular explanation: IPPs buy divested plants to bypass the high investment cost they otherwise would have had to incur in order to participate in the market. This contrasts the lack of evidence found for differences in firm evaluation of plant characteristics. Extending this line of reasoning, the estimates provide an explanation why IPPs affiliated with U.S. investor-owned electric utilities seem to buy most of the divested plants: affiliated IPPs are relatively less experienced in merchant power production and, hence, face a larger investment cost that they wish to circumvent. Consistent with these findings are the simulation results that find that divestiture "crowds out" little new generation investment, with "buyers" discouraged from building new plants due to high investment cost. Thus, the main impact of divestiture on IPP generation investment

[52] Results from Ishii (2003) suggests that the IOUs that have branched out into IPP are among the more efficient utility generators.

appears to be the encouragement of greater IPP participation, particularly among IPPs affiliated with investor-owned utilities.

Even with these results, it is difficult to say that divestiture was, overall, desirable. Given the way divestiture was implemented during the study period, many IPPs were able to buy power plants that played "pivotal" roles in satisfying local electricity demand.[53] This allowed such IPPs to earn wholesale prices much greater than system marginal cost during periods of tight supply. Consequently, it is not obvious that divesting plants to IPPs has, in the short-run, mitigated the horizontal market power concern in a restructured, wholesale electricity market. In fact, such a transfer of plants may have exacerbated the situation; given that many of the IOUs are the major buyers of electricity in the wholesale market and face regulator frozen retail prices, IOUs may have been more tempered in their bidding (with much of the proceeds from high electricity prices coming from their own pockets) than their non-buying IPP counterparts.[54]

However, there are mitigating factors, such as the understanding that some price volatility is unavoidable given the way the electricity system was developed under the vertically integrated, price regulated regime. To the degree that divestiture facilitates further restructuring and new electricity supply, divestiture may be desirable: it may behoove a state to "bite the bullet," divest utility power plants, and accelerate toward full restructuring as quickly as possible. We find some empirical evidence that divestiture encourages new generation investment: divestiture has a statistically significant positive impact on expected profits. Our estimated model suggests that the impact of divestiture on expected profits, by itself, increased the expected number of new power plants built by 8 for our studied period and firms. But this result is tempered by the fact that the IPPs that presumably benefit the most from divestiture tend to be the ones less suited to build new plants.

Lastly, we stress that we do not address the normative issue of whether new power plant investments are necessarily socially desirable in a given market. The answer to such a question depends on the existing stock of generators, the transmission system, and expected demand growth, among others. What we investigate is the positive issue of whether divestiture encourages greater entry and new generation investment. A major policy goal underlying some state (and national) electricity restructuring programs in the U.S. and abroad has been the stimulation of greater privately-funded power plant investment. We take a normative stance on policy in so far as such a goal is desirable: our results suggest that divestiture may be an effective tool for such a goal, with the *caveat* that buyers of divested plants may not be the ideal builders of future new plants.

[53] See Wolak (1999)for the California case

[54] See Bushnell, Mansur, and Saravia (2005)

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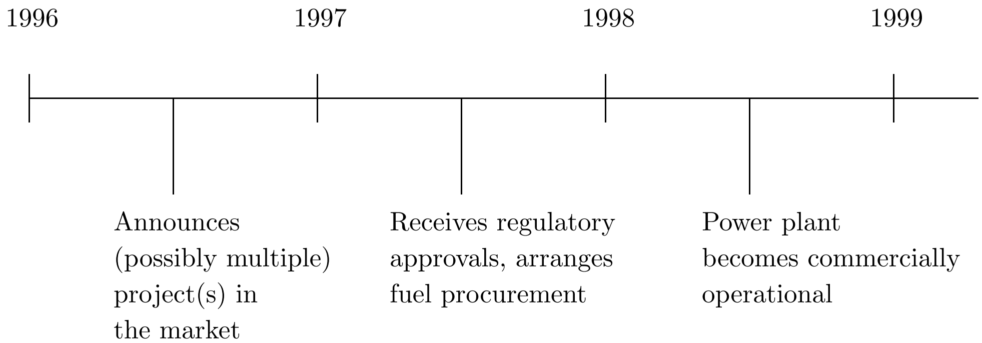
Appendix

Summary Statistics				
Variable	Mean	Std Dev	Min	Max
Investment Data				
ψ_{igt} (=1 if i makes in g,t)	0.0213	0.1442	0.0000	1.0000
$K_{igt(\mathsf{new})}$ (100 MWs)	0.0913	0.9261	0.0000	33.0000
δ_{igt} (=1 if i buys in g,t)	0.0067	0.0814	0.0000	1.0000
$K_{igt(\mathsf{old})}$ (100 MWs)	0.1443	2.4878	0.0000	107.6600
Market Characteristics				
$\mathsf{DIVSHARE}_{gt}$	0.0237	0.0730	0.0000	0.3591
DMLEG_{gt}	0.2875	0.4535	0.0000	1.0000
LDFACT_{gt}	1.6530	0.1016	1.4819	1.9647
$\mathsf{LOGLOAD}_{gt}$	5.4486	0.5677	4.5878	6.3546
$\mathsf{LOGYRLEG}_{gt}$	0.3204	0.5400	0.0000	1.7918
RM_{gt}	1.2585	0.1999	0.9074	2.0681
$\mathsf{AGE30}_{g}$	0.2877	0.1443	0.1275	0.9756
HOUSE_{g}	42.7917	24.8584	0.0000	100.0000
PUC_{g}	0.2292	0.4212	0.0000	1.0000
STNOX_{g}	5.9350	2.4734	1.2320	15.6650
Firm Characteristics				
$\mathsf{INT96}_{i}$	1.3500	1.0400	0.0000	3.0000
$\mathsf{US96}_{i}$	1.5000	1.0000	0.0000	3.0000
USIOU_{i}	0.6000	0.5026	0.0000	1.0000
GEN_{i}	4.0006	2.8935	1.6106	12.0025
OM_{i}	5.3599	2.6547	2.2500	12.0180
Plant Characteristics				
AGE_{a}	32.92	12.50	14.00	74.46
POP_{a}	1596.74	3711.43	2.80	24997.24
The summary statistics for the market variables are for the the actual values for (gt). The forecasted values are around the same range as the actual.				

Investment Timeline

Figure: Example of Investment Timing with One Year Lead Time ($L = 1$)



In this illustration, the firm "decides to invest" in 1997 as it is the year that the IPP sinks considerable resources into the project and commits to entering the market

Investing in a new plant requires many steps, completed over several years. These steps include the scouting of potential sites, the purchase of generators, the obtaining of regulatory permits, the bargaining of fuel and power purchase agreements, and, finally, the actual construction of the plant. However, the vast majority of these projects are cancelled during the interim steps, resulting in no new plants. The industry practice is for firms to pursue many projects in a market, with the intention of completing few, if any. It is not unusual to see firms back out of purchase agreements (land, generator, fuel, power) and cancel projects. For example, Calpine paid General Electric (GE) over $160 million in March 2002 to cancel an order for 35 generators, generators for projects that were subsequently cancelled. However, it is very unusual to see a firm cancel a project once construction is sufficiently undertaken. Case in point is the decision by American National Power to finish constructing a power plant in Texas that the firm realized might have to be mothball-ed due to changes in the market environment. Consequently, we consider the "decision to invest" as being attached to the "final" decision of whether to undertake construction.

Given that construction usually takes around 12-18 months, with delay/cancellation still a distinct possibility very early in construction (backed by observed investment decisions in recent EIA-860 reports), we believe that modeling new investment as occurring a year before commercial start is appropriate. It is right before the construction decision that firms must decide whether they want to sink the major portion of the investment costs associated with the project. It is also then that firms must decide whether they want to spend their available capital on buying an existing power plant or exercising their option to finish building a new plant.

Deriving $\texttt{Prob}$(firm i^a wins a)

According to the model, firm i^a's willingness to pay for asset a ($W^*_{i^a gta}$) must be the highest among all firms. Given that ϵ_{igta} is distributed i.i.d. Type I Extreme across firms, we have

$$\begin{aligned}
\texttt{Prob}(\text{firm } i^a \text{ wins } a) &= Pr\left\{W^*_{i^a gta} > W^*_{jgta}\ ,\quad \forall j \neq i^a\right\} = \frac{\exp\{\overline{W}_{i^a gta}\}}{\sum_{j=1}^N \exp\{\overline{W}_{jgta}\}} \\
&\text{where} \\
\overline{W}_{jgta} &= \overline{\Pi}_{jgta}\ K_{jgta} - \\
&\quad E_t \max\left\{\ 0,\ \left(\overline{\Pi}_{jgt(new)} \cdot K^*_{jgt(new)} - (C_{jgt}(K^*_{jgt(new)}, \xi_{jgt}) + \eta_{jgt})\right)\right\}
\end{aligned}$$

Due to the truncation at 0, it is infeasible to calculate the value of $E_t \max\{\cdot\}$ analytically. Instead, simulation methods are used.

$$\begin{aligned}
E_t \max\{\cdot\} &\approx \frac{1}{S}\sum_{s=1}^S \max\ \left\{\ 0, \left(\overline{\Pi}_{igt(new)} \cdot K^*_{igt(new)}(\xi^s_{igt}) - (\ C_{igt}(K^*_{igt(new)}, \xi^s_{igt}) + \eta^s_{igt})\right)\ \right\} \\
\xi^s_{igt} &\overset{i.i.d.}{\sim} N(0, \sigma^2_\xi) \qquad \eta^s_{igt} \overset{i.i.d.}{\sim} N(0, \sigma^2_\eta)
\end{aligned}$$

$S = 500$ was used to obtain our estimates.

Deriving $l_{igt}(\psi_{igt}, K^*_{igt(new)})$

There are two types of investment decisions that must be considered. In the first type of investment decision, firm i is observed buying no divested asset but building a new power plant ($\psi_{igt} = 1$) of size $K_{igt(new)}$. This investment decision implies the following set of constraints:

$$\begin{aligned}
\overline{\Pi}_{igta} \cdot\ K_{igt(new)} &- \left((\alpha_1 - \xi_{igt}) \cdot K_{igt(new)} + \alpha_2 \cdot K^2_{igt(new)} + C^f_{igt} + \eta_{igt}\right) > 0 \\
K_{igt(new)} &= \frac{1}{2\alpha_2}(\overline{\Pi}_{igt(new)} + \xi_{igt} - \alpha_1) > 0
\end{aligned}$$

The first constraint ensures that the expected profit stream from a new plant with observed capacity must exceed the investment cost of building the plant ($V(\text{new asset}, K) > 0$). The second constraint sets the observed capacity equal to the optimal capacity (satisfying the first order condition). Rearranging the first inequality, we get the range of η that is consistent with the observed investment given ξ. The idea here is that for a firm to build a new plant, the investment cost should not be too high relative to the profit stream the firm expects to receive.

$$\underbrace{\overline{\Pi}_{igta} \cdot K_{igt(new)} - C_{igt}(K_{igt(new)}\ ,\ \xi_{igt})}_{\eta^*_{igt}} \quad > \quad \eta_{igt}$$

The second constraint can be inverted to obtain the implicit value of ξ_{igt}.

$$\xi^*_{igt} \;=\; 2\alpha_2\ K_{igt(new)} + \alpha_1 - \overline{\Pi}_{igt(new)}$$

The likelihood for this case can be expressed as follows, keeping in mind that η^*_{igt} is a function evaluated at $\xi_{igt} = \xi^*_{igt}$

$$l_{igt} \;=\; \frac{2\alpha_2}{\sigma_\xi}\phi\left(\frac{\xi^*_{igt}}{\sigma_\xi}\right)\ \int_{-\infty}^{\eta^*_{igt}/\sigma_\eta}\ \phi(u)\ du = \frac{2\alpha_2}{\sigma_\xi}\phi\left(\frac{\xi^*_{igt}}{\sigma_\xi}\right)\ \Phi\left(\frac{\eta^*_{igt}}{\sigma_\eta}\right)$$

where the term $\frac{2\alpha_2}{\sigma_\xi}\phi\left(\frac{\xi^*_{igt}}{\sigma_\xi}\right)$ captures the second constraint: we observe the size of the new power plant that was built by the firm i.[55]

In the second type of investment decisions, firm i is observed making no investment, "buy" or "make" ($\psi_{igt} = 0$). The main difference between the derivation of the likelihood for this case and the first case is that the exact value of ξ_{igt} cannot be inverted from the constraints. There are two possible reasons why $K^*_{fgt(new)} = 0$. First, the value of K^*_0 that maximizes $V(\text{new asset}, K^*_0)$ may be negative and the constraint $K^*_0 \geq 0$ may be binding (corner solution). Second, the value of K^*_0 that maximizes $V(\text{new asset}, K^*_0)$ may be positive but $V(\text{new asset}, K^*_0) < 0$ (interior "solution" but IPP better off not investing at all). Taking these two possibilities into consideration, the constraints that characterize this investment decision are

$$\begin{aligned}
\overline{\Pi}_{igta}\cdot\ K_{igt(new)} \;&-\; \Big((\alpha_1 - \xi_{igt})\cdot K_{igt(new)} + \alpha_2\cdot K^2_{igt(new)} + C^f_{igt} + \eta_{igt}\Big) < 0 \\
&\quad\ \text{for } K_{igt(new)} > 0 \\
\text{or}\ \ K_{igt(new)} \;&=\; \frac{1}{2\alpha_2}(\overline{\Pi}_{igt(new)} + \xi_{igt} - \alpha_1) < 0
\end{aligned}$$

So the likelihood can be derived as

$$l_{igt} \;=\; \underbrace{\int_{\xi^0_{igt}/\sigma_\xi}^{+\infty}\ \left(1 - \Phi\left(\frac{\eta^*_{igt}}{\sigma_\eta}\right)\right)\ \phi(u)\ du}_{K^*_0 > 0 \text{ but } V(\text{new}, K^*_0) < 0} + \underbrace{\int_{-\infty}^{\xi^0_{igt}/\sigma_\xi}\ \phi(u)\ du}_{K^*_0 < 0}$$

The value of ξ^0_{igt} is obtained simply from inverting $0 = \frac{1}{2\alpha_2}(\overline{\Pi}_{igt(new)} - \xi^0_{igt} - \alpha_1)$. It represents the threshold value that needs to be surpassed in order for $\max_K\ V(\text{new asset}, K)$ to have an interior solution.

[55] $\frac{2\alpha_2}{\sigma_\xi}$ is the Jacobian from the transformation of variables from $K^*_{igt(new)}$ to the standard normal $\frac{\xi^*_{igt}}{\sigma_\xi}$

Calculating Standard Errors

Let

$$\begin{aligned}
L &= \text{Joint Log-likelihood} = \sum_{g=1}^{G}\sum_{t=1}^{T} L_{gt} \\
L_{gt} &= \ln(l_{gt}) = (\text{state } g, \text{ year } t) \text{ contribution to } L \\
\hat{A} &= \frac{\partial^2 L}{\partial\theta\partial\theta'} \mid_{\hat{\theta}} \\
\hat{B} &= \sum_{g=1}^{G}\sum_{t=1}^{T} \frac{\partial L_{gt}}{\partial\theta} \mid_{\hat{\theta}} \frac{\partial L_{gt}}{\partial\theta'} \mid_{\hat{\theta}} \\
\tilde{B} &= \hat{B} + \sum_{g=1}^{G}\sum_{s=1}^{T-1}\sum_{t=s+1}^{T} \left[\frac{\partial L_{gt}}{\partial\theta} \mid_{\hat{\theta}} \frac{\partial L_{gt-s}}{\partial\theta'} \mid_{\hat{\theta}} + \frac{\partial L_{gt-s}}{\partial\theta} \mid_{\hat{\theta}} \frac{\partial L_{gt}}{\partial\theta'} \mid_{\hat{\theta}} \right]
\end{aligned}$$

where G = number of states = 48 and T = number of years = 5.

When there is no serial correlation across (state g, year t), the "BHHH" method of calculating the standard errors translates into $\hat{B}^{-1}$. However, under the presence of serial correlation across (g, t) – for example, correlation across years within a state ("clustering" by states) – the "BHHH" method is no longer valid as the serial correlation generally leads to the violation of the necessary information equality condition. In this situation, the more appropriate method of calculating the standard error is the "sandwich" method, $\hat{A}^{-1}\hat{B}\hat{A}^{-1}$, which does not explicitly rely on the information matrix equality condition. Additionally, the method provides the appropriate asymptotic standard errors for the estimator under the quasi-maximum likelihood framework. Serial correlation across years within a state (but independence across states), can be explicitly accounted in the sandwich estimator of the standard errors by replacing $\hat{B}$ with $\tilde{B}$. This modification allows for an arbitrary pattern of serial correlation across years within a state, with the asymptotic argument being $G \to \infty$ holding T fixed. White (1994) Chapter 8.3 provides more details.

The standard errors presented in Tables 3a and 3b are the square root of the appropriate diagonal elements of $\hat{A}^{-1}\hat{B}\hat{A}^{-1}$. The derivatives were evaluated numerically. Computationally, we found the standard error estimates for the two sandwich methods to be qualitatively similar.

Fixed Effects

Table 3c: Fixed Effects in Expected Profit Function		
Parameter	w/ F.E. in Profit	
	Estimate	Std Error
Firm Fixed Effects		
ANP	-0.22736	0.06502
Calpine	-0.00592	0.00129
Coastal Power	-0.44315	0.05908
Cogentrix	-0.36383	0.04427
Dynegy	-0.00539	0.05086
El Paso Energy	-0.22801	0.04273
Enron Intn'l	-0.03473	0.01183
Market Fixed Effects		
ERCOT	-0.00014	0.00135
FRCC	-0.12145	0.02811
MAAC	-0.56492	0.05662
MAIN	-0.23965	0.04412
MAPP	-0.31765	0.10723
NPCC-NE	-0.50893	0.05638
NPCC-NY	-0.90287	0.15226
SERC	-0.21696	0.08544
SPP	-0.39302	0.04392
WSCC-CNV	-0.94461	0.10486
WSCC-NWP	-0.31147	0.05096
WSCC-RA	-0.31147	0.05455
Year Fixed Effects		
1997	0.07931	0.01580
1998	0.41299	0.03660
1999	0.42071	0.03277
2000	0.52606	0.07877
The omitted groups were: AES, ECAR, 1996		

IPP Sample

Data on 42 IPPs were collected. All of them satisfy the following qualifications: [1] the firm must be listed in either *UDI Who's Who at Electric Power Plants (Ninth Edition)* published by the Utility Data Institute or *205 Independent Power Producers (1999 Edition)* published by the Global Energy Report, McGraw-Hill Companies [2] the firm must have at least 750 Megawatts (MW) of net equity in merchant power plants as of January 1, 2001. These two conditions help ensure that fairly comprehensive data will be available for the firms and that the firms will be non-utility generators whose main line of business is serving the general wholesale electricity market. The sample includes almost all of the major IPPs affiliated with large investor-owned electric utilities (e.g. Duke Energy North America), all of the large U.S. based players in the international wholesale electricity markets (e.g. AES), and several of the major U.S. energy traders (e.g. Enron). Following (Table A2.1) is the full list of the IPPs for which data was collected.

Table A2.1: The 42 Independent Power Producers in the Data

AES Corp	American National Power	Aquila Energy / UtilCo
Caithness Energy	CalEnergy	Calpine
CMS Generation	Coastal Power Corp	Cogentrix Energy
Columbia Electric	Constellation Power	Continental Energy Services
CSW Energy	Dominion Energy	Duke Energy North America
Dynegy	Edison Mission Energy	El Paso Energy
Enron International	EPG (Entergy Power Group)	FPL Energy
GE Global O&M Service	GPU International Inc	Illinova Generating
Indeck Energy Services	LG&E Energy Corp	LS Power
NRG Energy	Ogden Energy	Panda Energy International
PP&L Global	PSEG Global	Reliant Energy
Sempra Energy Resources	Sithe Energies	Southern Energy
Tenaska	Texaco Global Gas & Power	Tomen Power
Tractebel Power	U.S. (PG&E) Generating	Wheelabrator Technologies

The analysis in this paper focuses on major IPPs which have the capability of entering generation markets nationwide. To determine whether an IPP is "major," we employ the following criteria: [1] the firm must own at least 500 MW of capacity internationally or domestically or at least 100 MW both internationally and domestically before the first year of our sample period (1996); [2] if a firm does not satisfy [1] it can still be selected if it is affiliated with large investor-owned electric utilities and owned some capacity internationally or domestically before 1996; [3] there is no information in *205 Independent Power Producers (1999 Edition)* that indicates that the firm is not a national player. [1] and [2] are meant to ensure that the firm has the experience and financial strength to enter generation markets nationwide during our sample period. [3] is an additional selection criterion that relies on more specific information about an individual firm. Using [1] and [2], we exclude the following firms: Aquila Energy, Caithness Energy, Columbia Electric, Continental Energy, Indeck Energy Services, LS Power, Panda Energy Interational Inc, Sempra Energy Resources and Tenaska. Using [3], we further eliminate the following firms:

Table A2.2: IPPs Eliminated by Criterion [3]

Firm	Reason
CalEnergy	its core business is geothermal generation
CSW Energy	it has targeted Texas and southeastern U.S. markets[56]
Dominion Energy	its business focus is on Midwest and Northeastern markets
GE Global O&M Services and Texaco Global Gas & Power	both are affiliates of firms that own significant generating technologies and use their plants as "displays"
GPU International	its business focus is on Australia and UK
Illinova Generating	merged with Dynegy during the sample period
Ogden Energy	its business focus is on overseas markets. [57]
PSEG Global	its business focus is on overseas markets, e.g., Latin America
Sithe Energies	bought some capacity but promptly exited industry [58]
Tomen Power	most of its activities are outside U.S. [59]
Tractebel	its focus is on the Northeastern market
Wheelabrator Technologies	its core business is waste-to-energy facilities[60]

After these steps, we are left with 20 major IPPs. Table A3 shows their characteristics.

[56] *205 Independent Power Producers (1999 Edition)*, p. 90. Another factor for our exclusion of CSW Energy is that the firm had been in the process of being taken over by American Electric Power (AEP) during our sample period. AEP was an active player internationally but had no domestic IPP activities and hence is not in our sample.

[57] "the company's first efforts were mostly mass-burn waste-to-energy plants, but more recently, it has focused on fossil-fueled projects in overseas markets" (*205 Independent Power Producers (1999 Edition)*, p. 227.). Ogden has also been acquiring renewable energy project in the U.S. But none of these is the focus on "major" IPPs, whose plant are mostly gas-based.

[58] Sithe has sold their merchant power capacity, mostly to Reliant

[59] Tomen Power is owned by a Japanese company, Tomen Corp. of Tokyo.

[60] "It no longer develops non-waste-to-energy projects in the U.S.", *205 Independent Power Producers (1999 Edition)*, p. 340.

Table A3: The 20 "major" Independent Power Producers in the Sample				
Firm	IOU Aff.	TRADE	INT96 (MW)	US96 (MW)
AES Corp	0[a]	0	3	2
American National Power	0	0	3	2
CMS Generation	1	1	2	2
Calpine	0	0	0	2
Coastal Power	0	1	1	1
Cogentrix Energy	0	1	0	2
Constellation Energy Services	1	1	1	1
Duke Energy North America	1	1	1	1
Dynegy	0	1	0	3
EPG	1	1	1	0
Edison Mission	1	1	3	3
El Paso Energy	0	1	1	1
Enron International	0[b]	1	2	1
FPL Energy	1	1	1	2
LG&E Energy	1	1	1	1
NRG Energy	1	1	2	1
PP&L Global	1	1	1	0
Reliant Energy	1	1	1	0
Southern Energy	1	1	3	1
U.S. Generating	1	1	0	3
a. AES bought CILCORP, an U.S. utility in late 1998.				
b. Enron bought the utility Portland General Electric in 1997 but have since sold it				

Data Source

The investment and firm characteristic data for each of the independent power producers in the sample were collected over several years (1996-present). The actual data set contains 42 IPPs. The sample used for estimation was whittled down to 20, as described in the last section.

The main foundation of the IPP data comes from the firms themselves, either through postings on their web sites or through personal communication. Data was also augmented with information from popular trade presses. Many of the trade presses, such as the weekly *Global Report* published by the McGraw-Hill Companies, have a section that lists power plant transactions. Also of particular help was the online newsletter e-published by *Energyonline*.[61] The newsletter provides notification and summaries of the relevant press releases associated with the electricity industry. Data was also acquired from various releases of the McGraw-Hill publication *205 Independent Power Producers*. This data source was very useful in detailing the international operations of the IPPs. As much as possible, data acquired from third-party sources were later confirmed with sources closer to the firm. Utility information for IOU-affiliated IPPs were obtained from the appropriate 1996 FERC Form 1 filing. More information on the IOU data can be found in Ishii (2003).

Information on utility divestiture sales were gathered from various issues of the *Electric Power Monthly* published by the Energy Information Administration, the primary agency within the U.S. Department of Energy that collects and publishes data on energy industries. Each issue contains a list of the utility power plants that were transferred to non-utility power producers. Information about the divested power plants themselves were obtained from the EIA annual publication *Inventory of Power Plants*. All EIA publications mentioned in this appendix are available in electronic format at the EIA web site (http://www.eia.doe.gov). Forecasts for the regulatory variables (DIVSHARE, DMLEG, LOGYRLEG) were calculated as follows: for years up to 2002, the actual realized values were used. For later years, the values were calculated assuming no change after 2002 (except for the incremental additions to LOGYRLEG for states that had restructured by 2002).

The market forecast data used in this analysis were obtained from the EIA. The forecasts are from the supplemental tables of the Annual Energy Outlook (AEO) forecast publication. Releases of the forecast from 1996 to 2000 were obtained. Although our copy came from correspondence with the very capable and helpful staff at the EIA, an archive of the forecasts have since been posted on the EIA website.[62] Market forecast data was also obtained from the North American Electric Reliability Council (NERC), the private governing association of electric transmission and distribution utilities in North America. Most of the data is similar to the AEO data as AEO bases much of their forecast on this NERC information. The NERC information can be found in their annual "Electricity Supply and Demand" (ES&D) publication. The AEO data is used for all market forecasts except LDFACT which is based on NERC data. The regulatory information is obtained from the EIA as well. The EIA, on their web site, maintains a monthly update of the status of electricity restructuring.[63] The information on independent system operators (ISOs) mostly came from ISO press releases and trade press reports. The information about utility NO_x emissions was obtained from the Environmental Protection Agency (EPA) E-GRID database.

[61] http://www.energyonline.com

[62] Previously, they only posted the current forecasts. URL is http://www.eia.doe.gov/oiaf/aeo/index.html

[63] http://www.eia.doe.gov/cneaf/electricity/chg_str/regmap.html

FIGURE 1A

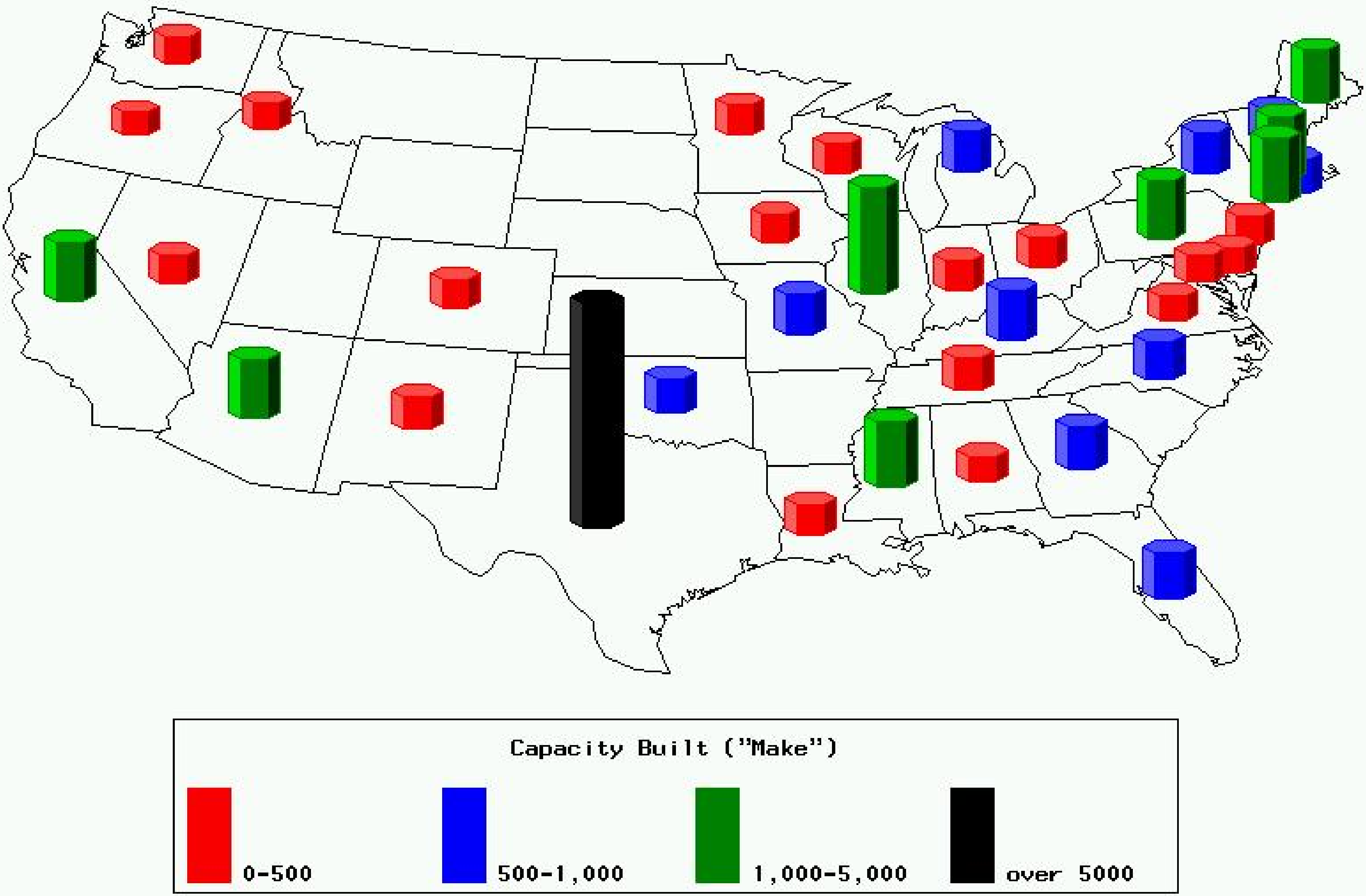


FIGURE 1B