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The "Make or Buy" Decision in U.S. Electricity Generation Investments

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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 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 IOUs were enticed to sell their existing generation assets to non-utility, independent power producers (IPPs). From 1997 through 1999, "over 15% of the IOU generating capacity has been sold or is for sale" (Joskow (2000)).

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 ownership of transmission and distribution facilities to exert market power in the restructured electricity 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 of the state restructuring programs required divestiture as a condition for regulatory 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, without having to undergo the costly and time consuming process of permitting and building new power plants. Moreover, divestiture could help encourage greater IPP participation by signalling a greater commitment to restructuring by the state, which reduces 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 trying to put the "genie back in the bottle."

The empirical evidence from the past five years of electricity restructuring in the United States

[1] As of the end of 2001, 23 states have enacted electricity restructuring legislation or implemented comprehensive regulatory orders on restructuring. This excludes Oregon, which has only enacted a limited retail choice program.

[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.

has provided mixed evidence on the effectiveness of divestiture sales in achieving these goals. Divestiture sales have been very successful in resolving the stranded cost issue: for many utilities, the proceeds they received from their divestiture sales have largely covered their negotiated stranded cost figure. This has mitigated the degree to which state governments have had to provide stranded cost assistance, either through the issuance of government-backed bonds or the imposition of price supports in the form of "competition transition charges" (CTC).[3] Moreover, early divestiture sales signalled what has become clear during recent times: earlier discussions on the magnitude of "stranded cost" have been overstated.

However, at the same time, the evidence on the effectiveness of divestiture in restricting market power has been less encouraging. While IOUs may not have been able to exert *vertical* market power in the restructured generation sector, the recent academic literature suggests that IPPs who bought the divested IOU power plants have, instead, been able to exercise sizable *horizontal* market power. Borenstein, Bushnell, & Wolak (2000), Joskow & Kahn (2001), and Puller (2001) all find empirical evidence that demonstrate the ability of IPPs to earn wholesale electricity prices much greater than marginal cost during periods of tight supply in California. Consequently, it is not obvious that divesting generation assets to IPPs has, in the immediate short-run, mitigated the market power concern in a restructured, wholesale electricity market. In fact, such a transfer of generation assets may have exacerbated the situation; given that many of the IOUs are the major buyers of electricity in the wholesale electricity market, IOUs may have been more tempered in their electricity bidding (with much of the proceeds from high electricity prices coming from their own pockets) than their non-buying IPP counterparts.

Although current empirical research suggest that divestiture may have driven up wholesale electricity prices in the short-run, 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. This distinction between the short-run and long-run consequences of divestiture is important, especially given the understanding that some amount of high wholesale prices is unavoidable during the initial transition period of electricity restructuring.[4] Despite pos-

[3]San Diego Gas & Electric (SDGE), one of California's three major IOUs, was able to recover much of its stranded cost through sale of its generation assets. As a result, SDGE customers no longer pay the CTC.

[4]During this initial period, the physical electricity system is still very much the same as the system built by the IOUs under the principle of minimizing *total* cost of electricity supply; IOUs built a system, consisting of a few large power plants and a correspondingly limited transmission network, that reduced transmission costs while taking advantage of scale economies in electricity generation. Such a system is not conducive to wholesale competition, conferring each large power plant some degree of local market power. It is more acceptable in the vertically integrated, regulated monopoly regime as state commissions are able to regulate explicitly the price charged by IOUs

sible complications from divestiture in the short-run, divestiture may still be overall desirable if it helps foster beneficial long-run competition through the encouragement of greater IPP participation. Nominally, divestiture has increased IPP participation in wholesale electricity markets in the United States; many of the current major IPP participants, such as the California "Big Five," participate through their ownership of divested IOU assets.[5] However, whether divestiture led to greater IPP participation in *real* terms is unclear as many of these IPPs may have chosen to participate even in the absence of divestiture by building new power plants. Divestiture may have just "crowded out" new power plant investments without necessarily encouraging any additional IPP participation. Therefore, 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 plant, both new and old, and the investment cost that needs to be incurred in order to build 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.[6] However, 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

[5] The "Big Five" are AES, Duke, Dynegy, Reliant, and Southern

[6] The model is based on the standard net present value (NPV) approach to investment. Ishii (2001a) presents a model of IPP capacity investment based on a real options approach.

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 that divestiture sales are efficient, whether an IPP ends up buying a divested power plant depends on whether the IPP has the highest willingness to pay among competitors. Similarly, whether an IPP builds a new power plant depends on whether 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 parameters in the IPP's expected profit stream and investment cost functions.

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. More specifically, IPPs affiliated with electric utilities are found to face a much greater investment cost associated with building a new power plant and a modest profit advantage in running older power plants. The result is intuitive and 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 investment cost associated with the "making" of new power plants, rather than the value associated with the (possibly desirable) location of old power plants. Last, the estimates echo some of the market power and scarcity rent concerns found in the recent literature on IPP bidding behavior: 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 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 607 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. A *caveat* to this result is that much of this new IPP participation has been by IPPs affiliated with investor-owned electric utilities.

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 discusses the data used to estimate the model. Section 5 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 the enactment of the first state electricity restructuring legislation in 1996, there have been over five years during which independent power producers have had the opportunity to enter and participate in some U.S. wholesale electricity market without the explicit invitation of the incumbent electric utilities.[7] An examination of the generation investment decisions of the 20 independent power producers in our sample illustrates an important fact about IPP generation during this transition period: much of the merchant power provided by IPPs during this transition period has been generated by formerly utility power plants acquired by IPPs from divesting electric utilities. A smaller fraction can be attributed to generation from power plants originally developed by IPPs.

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

Year[1]	Source: Divestiture	Source: Non-Divestiture[2]
1996	0.00	1885.64
1997	21239.00	2260.22
1998	36501.00	5571.99
1999	11508.00	21049.42 [3]
2000	2761.00 [4]	26481.30
Total	69248.00	57248.57

[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

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

Moreover, a pattern can be found from categorizing the generation capacity acquired from non-divestiture sources as capacity acquired in non-restructured states, acquired in restructured states with no utility divestiture that year, and acquired in 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	1661.84	223.80	0.00
1997	2009.07	128.65	122.50
1998	3882.12	389.25	1300.61
1999	3301.10	12805.53	4162.79 [3]
2000	6825.50	19655.80	0.00
Total	18459.64	33203.03	5585.90
See Table 1a footnotes			

There are few new power plants built by IPPs in (state,year) where the acquisition of utility power plants is a viable 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 generally unavailable to potential new power plants. Perhaps the most prominent example of such desirable characteristics is the location of divested power plants. 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. Consequently, the potential revenue stream from an existing utility power plant may be better than that of a new power plant located in 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 extent to which the price paid for the divested power plant is less than the cost of building a comparable new power plant. The idea here is that by buying an existing plant, the IPP can 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 potential new generation capacity 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 deciding not to invest 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 effect if new power plant projects were not economically viable in those states during those years.[8] Let $\{ V_{buy}, V_{make}, V_{none} \}$ represent the value an IPP places on buying a divested power plant, building a new power plant and not investing in a power plant, respectively. Observing an IPP only buying a power plant implies $V_{buy} \geq V_{make}$ and $V_{buy} \geq V_{none}$. However, such an observation, by itself, provides no information about the relative 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 new power plant investment by that IPP was "crowded out." This demonstrates the difficulty of measuring the amount of new generation investment crowded out by divestiture and the need to examine how IPPs evaluate the "make" and "buy" projects individually.

Moreover, thinking of divestiture as simply providing a possible alternative option to building new power plants may not capture the full story. Although divestiture may, contemporarily, divert some resources away from new generation capacity investment, divestiture may increase overall new generation investment by signalling a greater commitment to electricity restructuring and, hence, encouraging more future IPP generation investment. To illustrate this point, we run a simple regression where the total amount of non-divestiture generation capacity investment (in megawatts) made in the state during that year by the 20 IPPs in the sample is regressed against market characteristics including dummy variables indicating whether electric utilities in that state had already divested some power plants and whether any are currently holding divestiture sales.

$$
\begin{aligned}
Y_{gt} &= \text{DIVFLAG}_{gt}\ \gamma_1 + \text{DIVID}_{gt}\ \gamma_2 + X_{gt}\ \beta + \epsilon_{gt} \qquad (1) \\
&\text{where} \\
(g,t) &= \text{index for (state,year)} \\
Y_{gt} &= \text{total non-divestiture investments by sample IPPs in state g, year t} \\
\text{DIVFLAG}_{gt} &= \text{indicator whether state g has had any divestiture by year t} \\
\text{DIVID}_{gt} &= \text{indicator whether state g is holding a divestiture sale in year t} \\
X_{gt} &= \text{various other market characteristics for state g, year t}
\end{aligned}
$$

[8] Note: the cost of a new power plant implicitly includes the cost of getting regulatory approval. So a substantial regulatory cost may make a new power plant project not viable even if IPPs may have wanted to build new power plants in the absence of such costs. The ability to avoid such costs by buying divested power plants is one of the factors we are investigating in our examination of why divested power plants are an attractive asset to some IPPs.

Table 1c: Regression on Total Non-Divestiture Capacity Investments (MWs) by State/Year		
Variable[1]	Estimate	Std Error
Dummy for Divestiture ($\mathbf{DIVFLAG}_{gt}$)	354.60	141.33
Dummy for Current Divestiture ($\mathbf{DIVID}_{gt}$)	-326.17	161.17
Total Observations = 48 continental states x 5 years = 240 $R^2 = 0.2125$		
[1] Full table in appendix		

The regression results are qualitatively consistent with the earlier tables, showing that years with divestiture sales (DIVID= 1) are associated with about 330 MWs less total non-divestiture investment (in the state) from the 20 IPPs in the sample. At the same time, the results show that states that have experienced divestiture, either currently or in the past (DIVFLAG= 1), are associated with about 350 MWs more total non-divestiture investment. Taking these estimates at face value, this would seem to paint the following picture: divestiture appears to encourage new power plant investments in the long-run but this effect is largely cancelled contemporarily by a divestiture "crowding out" effect. But these regression results are not so conclusive. Utility power plant divestitures usually occur two years after the enactment of restructuring legislation. Moreover, in years absent of divestiture, an IPP wishing to expand generation capacity in the state must turn toward non-divestiture investments. Consequently, the positive DIVFLAG coefficient may largely reflect the desire of IPPs to invest in further restructured ("mature") markets and not necessarily any divestiture-related inducement.

The analysis above shows how utility power plant divestitures may be crowding out IPP investment in new generation capacity. At the same time, the analysis shows some suggestive evidence that divestiture may be encouraging more long-term IPP investment and participation. However, conclusive evidence on either point is not readily available from the straight-forward analysis of the data. A more structural approach that investigates how an IPP evaluates both its new power plant and divestiture investment options is necessary. In the rest of the paper, we propose and implement such an approach. One of the key difficulties in studying IPP investment behavior in restructured wholesale electricity markets is the lack of readily available, comprehensive data. Although major IPP power plant developments and acquisitions are announced in both trade and mainstream media, the details of such investments are often missing. Moreover, even when transaction information is made available for a power plant project, the "numbers" are usually not directly comparable with numbers from another project. This is because power plant projects, especially acquisition of divested power plants, often include assets and liabilities apart from the rights to the power plant itself. To the extent that these additional assets and liabilities are unobserved and vary across projects, a comparison of the transaction prices among different projects may be a comparison of apples and oranges.[9] In order to overcome these difficulties, in the next section, a theoretical model is developed which can help identify how IPPs evaluate "make" and "buy" projects based on the most basic level of information: whether an IPP bought a power plant, built a power plant, or invested in no power plant projects.

2 Theoretical Model

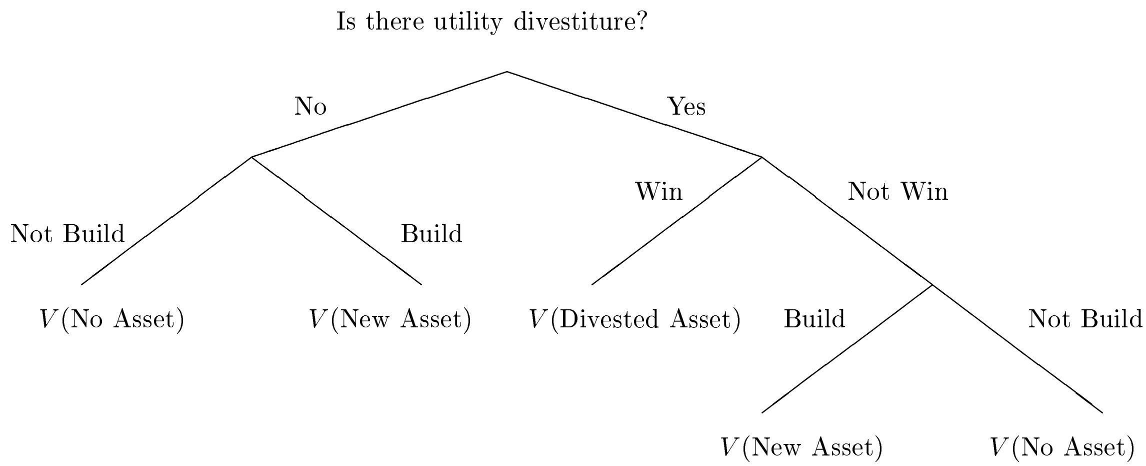
We assume that in the same year and market, an IPP only considers carrying out at most one type of positive investment: either acquisition of divested utility assets or the construction of new power plants. The idea is supported by the data on IPP investment decisions: no firm is observed buying a divested asset and sinking a large amount of investment costs toward a new power plant in the same market and year. One economic rationale behind this assumption is that there may be some kind of resource constraint that prevents the firm from exploring both "make" and "buy" options.[10] 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. 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.[11] 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. The assumptions lead us to the following decision tree for a firm:

[9] See Kahn (1999) for an overview

[10] In addition to financial (capital) constraints, there may be binding managerial and organizational constraints. We thank Richard Green for pointing this out.

[11] For the case of multiple divestiture sales in the same market and year, the model assumes that the sales occur concurrently and the firm takes part in all of them. However, a firm evaluates the assets independently across the sales. In other words, the firm's willingness to pay for a divested asset is neither related to the asset involved in another sale nor contingent on the outcome of that sale.



The idea underlying the timing assumption is that 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 rights to 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. Otherwise an IPP would prefer redirecting the resources it spent on acquiring the divested power plant toward the construction of 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:

$$\begin{aligned} \underbrace{\Pi(\text{divested asset}) - \text{Pay}}_{V(\text{divested asset})} &> \max\ \{\ 0\ ,\ \underbrace{\Pi(\text{new asset}) - C(\text{new asset})}_{V(\text{new asset})}\ \} \\ \text{Pay} &< \underbrace{\Pi(\text{divested asset}) - \max\ \{\ 0,\ \Pi(\text{new asset}) - C(\text{new asset})\ \}}_{W^*} \end{aligned} \tag{2}$$

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 takes advantage of the fact that, to a profit maximizing firm, the value of a power plant is based on the expected profit stream from the asset (Π). Furthermore, the expression 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).[12] Therefore, willingness to pay is more likely to be higher in markets where the cost of building a new power plant is higher 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. Therefore, the winner of a divestiture sale is determined from the comparison of the maximum willingness to pay (W^*) across all firms. We assume that the divestiture sales are efficient: the firms with the highest W^*'s are always the firms that succeed in buying the assets.[13] So, if firm i succeeds in buying a particular divested asset, we know from the observation that firm i must have had the highest maximum willingness to pay for the asset among all firms

$$W^*(i) > W^*(j) \quad \forall\, j \neq i \ , \qquad j \in \{\text{Other potential IPP buyers}\} \tag{3}$$

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 :

$$W^*(i) < W^*(j) \quad \text{for some } j \neq i \tag{4}$$

$$\Pi(\text{new asset}) - C(\text{new asset}) > 0 \tag{5}$$

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

$$W^*(i) < W^*(j) \quad \text{for some } j \neq i \tag{6}$$

$$\Pi(\text{new asset}) - C(\text{new asset}) < 0 \tag{7}$$

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 where there are multiple divestiture sales, the only modification is that an additional constraint is derived from the observed outcome of each additional sale. 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

[12] 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

[13] Assuming there are no ties.

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

The model continues to assume that an IPP, once it buys a divested asset, will no longer consider building a new power plant. However, an IPP can win multiple divestiture sales in the same market and year. Moreover, an IPP will only consider building a power plant if it fails to acquire any of the divested assets (or no divested assets were available) in the market for the given 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. 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.

Overall, the key point of the theoretical model is to establish 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 key factors that determine the value of the "buy" option. By imposing the sequential timing for 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 assets and the 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. Consequently, the model is able to address how the evaluation of generation asset is affected by firm heterogeneities.[14]

[14] Note, the model does not explicitly consider the impact of possible future divestment or resale of the asset on a firm's decision to invest in the asset. Thus far, there have only been one major resale of divested utility generation assets: Sithe resold the power 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.[15] Given the theoretical model described in the last section, 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 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 during year t. In addition, we distinguish between the information set that is 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.

3.1 Expected Profit and Investment Cost Functions

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 per-year profit over a finite horizon:

$$
\begin{aligned}
\Pi_{igta} &= \overline{\Pi}_{igta}\ K_{igta} \\
&= \left(\sum_{\tau=1}^{10} \beta^{\tau} E_t\ r(X^r_{ig(t+\tau)a}\ ;\ \theta^r)\right) \cdot K_{igta} \qquad (8)\\
&\text{where} \\
(i,g,t,a) &= \text{(firm,market,year,asset)} \\
E_t\ r(X^r_{ig(t+\tau)a}\ ;\ \theta^r) &= X^r_{ig(t+\tau)a|t}\theta^r \\
X^r_{ig(t+\tau)a|t} &= \text{Forecasts for variables related to profit per unit of capacity} \\
K &= \text{Generation capacity of the asset} \\
\overline{\Pi} &= \text{Expected revenue stream per unit of capacity}
\end{aligned}
$$

Note, 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 $t+1$. The reason is that while new power plant projects may be announced as early as three years before commercial start, the construction

[15] For a detailed description of the data, please refer to the Appendix

and installation of the new plants usually begins 12–18 months before commercial start. The period just prior to construction, associated with the earning of various regulatory approval, is considered the time during which the significant portion of the investment cost is sunk. On the other hand, a divestiture sale usually takes 6–12 months to close. Therefore, we set the time lag in both cases to be one year.[16] The time lag reflects the fact that a firm has to sink substantial investment cost up front before it can get a plant ready for commercial operation. 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 as the dispatch models used by IPPs only predict key economic variables (such as production levels, annual revenues, and fuel costs) up to ten years in the future.[17] This is also consistent with the observation that under a more competition-based environment, firms tend to focus on earning their return over a shorter horizon.

As for the investment cost, we assume that it consists of two parts: the fixed component (C^f) and the variable component (C^v). The former is meant to capture costs related to matters like obtaining regulatory approval and finding a suitable site while the latter represents capital costs that are directly related to the size of a project, such as the cost of purchasing generation equipment and the cost of construction. Furthermore, we assume that a firm incurs positive investment cost only if it invests $K > 0$. In other words, $C = C^f + C^v = 0$ for $K = 0$. Also, we do not allow divestment or resale ($K < 0$).[18] For $K > 0$, we have

$$\begin{aligned}
C_{igt} &= C^f_{igt} + C^v_{igta}(K_{igta}) \\
&= X^c_{igt}\ \theta^c + \alpha_1\ K_{igta} + \alpha_2\ K^2_{igta} \qquad (9)\\
&\quad (\text{ with } \alpha_2 = \exp\{X_i^{\alpha 2}\theta^{\alpha 2}\} > 0\ ) \\
C &= \text{Investment cost for building a new asset} \\
C^f &= \text{Fixed cost } (X^c\theta^c) \\
C^v &= \text{Capital cost } (\alpha_1 K + \alpha_2 K^2)
\end{aligned}$$

The quadratic form of the capital cost reflects the assumption that it becomes more costly to build per unit of capacity as the total capacity increases, thus helping to bind the maximum size of a new power plant project. We account for firm heterogeneity in capital cost by parameterizing

[16] We have done some preliminary analysis allowing for the "make" lag to be longer (2 years). The qualitative results remain largely the same.

[17] See Vallen & Bullinger (1999)

[18] As mentioned earlier, there are very few observed divestment/resale by IPPs in the data. By excluding this action from the choice set, we abstract away from the task of modeling the value a firm expects to receive from its divestment/resale – a difficult complication

α_2 as a function of firm characteristics. The presence of a fixed cost corresponds to a barrier to investment.[19] The profit from a new power plant (before subtracting the fixed cost) must be large enough before a firm is willing to invest through "make." The higher the fixed cost, the less likely a firm is to build a new plant. In addition, the existence of fixed cost helps bind the minimum size of a new power plant and eliminate the trivial case where capacity is tiny ($K \to 0$).

Details on the variables that are included in the investment cost and per-unit expected profit functions are discussed later in the Data section. However, it is important to highlight one key difference in plant characteristics between a divested asset and a new asset. For a new asset, the firm can choose the capacity size (K) of the asset. But, for a divested asset, K is fixed. Therefore, when comparing the relative values of the two types of assets, the comparison is between the value of the divested asset with a fixed K (generally not optimal for the firm) and the value of the new asset with optimal K ($K^* \geq 0$). The optimal K of a new project is the solution to the following problem:

$$\max_{K \geq 0} \ \{ \ \underbrace{-C(K) \ + \ \Pi(K)}_{V(\text{new asset}, K)} \ , \ 0 \ \} \tag{10}$$

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

$$\begin{aligned} 0 &= \frac{\partial}{\partial K}\left(\overline{\Pi}\ K - X_t^c\ \theta^c - \alpha_1 K - \alpha_2 K^2\right) \\ &= \overline{\Pi} - \alpha_1 - 2\alpha_2 K \end{aligned} \tag{11}$$

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 $K^* = \frac{1}{2\alpha_2}(\overline{\Pi} - \alpha_1)$.[20] 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 the "make" option, we can infer the firm's maximum willingness to pay for a divested asset a as

$$W_{igta}^* = \overline{\Pi}_{igta}\ K_{igta} - \max\ \{\ 0\ ,\ V(\text{new asset}\ ,\ K^*)\ \} \tag{12}$$

Thus far, the discussion has assumed that the econometrician observes all aspect of the information set characterizing a firm's investment decision. Next, we describe the stochastic structure

[19] Such as from local environmental and economic regulation.

[20] Because $\alpha_2 > 0$, the objective function is concave for $K > 0$ and the second order condition for the interior solution is satisfied.

of the empirical model. We assume that there are three sets of information that are 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. And lastly, the third error, ϵ, captures the unobserved component of an IPP's valuation of the divested asset a. The three random terms account for the corresponding variations that cannot be fully explained by the observed variables for a given set of parameters: ξ for the variation in the capacity of new plants, η for the variation in the level of the investment barrier a firm faces in a market and ϵ for the variation in the order of the willingness to pay for a divested asset.

Furthermore, 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 depends on its expectation based on 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:

$$\begin{aligned} V_{igt}(\text{new asset}, K^*) &= \overline{\Pi}_{igt(new)} \cdot\ K^* - \left(C^f_{igt} + \eta_{igt} + (\alpha_1 - \xi_{igt}) \cdot K^* + \alpha_2 \cdot (K^*)^2\right) \quad (13) \\ W^*_{igta} &= \overline{\Pi}_{igta}\ K_{igta} + \epsilon_{igta} - E_t \max\{\ 0,\ V_{igt}(\text{new asset}, K^*)\ \} \\ &= \overline{W}_{igta} + \epsilon_{igta} \quad (14) \end{aligned}$$

By separating the time of realization for ϵ and (ξ, η), the model simplifies the derivation of the likelihood because the "make" and "buy" observation are stochastically separated. Moreover, we assume that if a firm succeeds in acquiring a divested asset, the IPP does not receive draws of ξ and η because "make" is not an option for the period anymore. 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.[21] The Type I Extreme distribution is adopted for ϵ as it allows the probability

[21] This simplification is further justified by the fact that we have no natural prior as to how they should be correlated.

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.[22]

3.2 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.[23] 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: [24]

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

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

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

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:

$$l_{gt} = \prod_{i=1}^{N} l_{igt}(\psi_{igt}, K^*_{igt(new)}) \tag{15}$$

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

[22]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

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

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

independent of each other, the likelihood of the observed investments in market g year t is:

$$\begin{aligned} l_{gt} &= \texttt{Prob}\left\{(\delta_{1gt1}, \cdots, \delta_{1gtA}, \psi_{1gt}, K^*_{1gt(new)}), \cdots, (\delta_{Ngt1}, \cdots, \delta_{NgtA}, \psi_{Ngt}, K^*_{Ngt(new)})\right\} \\ &= \left\{\prod_{a=1}^{A} \texttt{Prob}(\delta_{1gta}, \cdots, \delta_{Ngta})\right\} \times \left\{\prod_{i=1}^{N} \texttt{Prob}(\psi_{igt}, K^*_{igt(new)} \mid \delta_{igta}, \cdots, \delta_{igta})\right\} \\ &= \left\{\prod_{a=1}^{A} \texttt{Prob}(\text{firm } i^a \text{ wins } a)\right\} \times \left\{\prod_{i \in \{j:\ \delta_{jgta}=0,\ \forall a \leq A\}} l_{igt}(\psi_{igt}, K^*_{igt(new)})\right\} \end{aligned} \tag{16}$$

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:

$$L = \sum_{g=1}^{G} \sum_{t=1996}^{2000} \log[\ l_{gt}\ ] \tag{17}$$

4 Data and Model Specifications

To estimate the parameters in the empirical model, we collect four sets of data in addition to the data on firm investment decision: plant and firm characteristics, market conditions and regulatory conditions. The source of the data is described in the Appendix. The data are then categorized into groups that are related to investment cost and per-unit return of a project. To capture differences in firms' evaluation of a project due to observed firm heterogeneity, we also utilize selected interaction terms between (plant, market, regulatory) variables and firm characteristics. We first describe the variables used to control for plant characteristics and then discuss briefly the specifications for the expected profit and investment cost functions.

4.1 Plant Characteristics

Plant characteristics are meant to capture the differences between divested plants and the newly built plants as well as the differences across divested plants. In the estimation, we use information on two characteristics of a plant: the age of a plant and the location of a plant. Both of these potentially affect the return a firm expects to receive on a plant and are included in the group of variables characterizing per-unit return (X^r).

The age of a plant is used as a proxy for the general competitiveness and implied profitability of the plant in the market. Older plants tend to be less efficient. Moreover, the effect of age is most likely to be discrete. An one year old plant may not be that different from a plant that is two years old but may be quite different from a plant that is 15 years old. So we discretize the age of a plant in the following way:

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

By definition, all new plants have an age value equal to zero. Therefore, the effect of age can only be identified by the variation across divested plants. Furthermore, as described in the model section, 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.[25] So only the effect of age that vary across firms is estimated.

Additionally, the location of an existing plant can affect how an IPP evaluates the plant. The plant may be located in an area with growing, high demand (e.g. urban population center) where it is both difficult to build new plants (due to the lack of appropriate sites) and to import electricity (due to transmission constraint), conferring some local market power to the plant. As a result, firms that are experienced in "gaming" the market may put higher value on these plants. We use the relative population density (RELPOP) at the location of the plant to capture this effect. RELPOP is the ratio of the population density at the plant site to the average population density of the state. For new plants, we assume their site has the average population density of the state (RELPOP=1). Lastly, we would like to note that other plant characteristics, most prominently the fuel type of the plant, were included in earlier specifications of the model. At least in our sample, we could not find any substantial impact of such characteristics. For the case of fuel type, this might best be explained by the fact that the observed fuel types of new power plants do not vary substantially: most new power plants generate electricity using natural gas.[26] Moreover, for "old" power plants, an IPP does not have much of a choice in fuel type as the IPP can only select from what exists and is made available by the incumbent, divesting utility.

[25] To see this, recall that the logit probability that firm i has the highest willingness to pay ($W_i > W_j, \ \forall j$) is determined by differences ($W_i - W_j$). So any additive common part in W_i and W_j will cancel each other out.

[26] There are not enough observations to be able to identify separately the value for different types of natural gas generation technology

4.2 Model Specifications

4.2.1 Expected Profit Function

The expected per-unit annual profit function takes the following linear form:

$$
\begin{aligned}
E_t\, r_{igt+h} \;=\;& \theta_0^r \;+\; \theta_1^r \mathsf{P96}_g + \;\theta_2^r \mathsf{LOGLOAD}_{gt+h|t} + \;\theta_3^r \mathsf{INT96}_i + \;\theta_4^r \mathsf{US96}_i \\
& + \theta_5^r \mathsf{USIOU}_i + \;\mathsf{LOGYRLEG}_{gt+h|t} \times (1 \;+\; \theta_6^r \mathsf{DIVFLAG}_{gt+h|t} \;+\; \theta_7^r \mathsf{PUC}_{gt}) \\
& \times [\; \theta_8^r + \;\theta_9^r \mathsf{LOGLOAD}_{gt+h|t} + \;\theta_{10}^r \mathsf{RM}_{gt+h|t} + \;\theta_{11}^r \mathsf{LDFACT}_{gt+h|t} \\
& \quad + \;\theta_{12}^r \mathsf{INT96}_i + \;\theta_{13}^r \mathsf{US96}_i + \;\theta_{14}^r \mathsf{USIOU}_i \\
& \quad + \;\mathsf{RELPOP}_a \times (\theta_{15}^r \mathsf{INT96}_i + \theta_{16}^r \mathsf{US96}_i \;+\; \theta_{17}^r \mathsf{USIOU}_i)\;] \\
& + \mathsf{AGE}_a \times (\theta_{18}^r \mathsf{INT96}_i + \theta_{19}^r \mathsf{US96}_i \;+\; \theta_{20}^r \mathsf{USIOU}_i)
\end{aligned} \tag{18}
$$

$\mathsf{P96}_g$	:	Average retail electricity price in state g in 1996
$\mathsf{LOGLOAD}_{gt+h\|t}$	:	Log of the forecasted demand (load) in the NERC subregion for state g
$\mathsf{INT96}_i$	:	Generation capacity owned by firm i outside the U.S. in 1996
$\mathsf{US96}_i$	:	Generation capacity owned by firm i inside the U.S. in 1996
USIOU_i	:	Dummy for whether firm i is affiliated with some major utilities
$\mathsf{LOGYRLEG}_{gt+h\|t}$	:	Log of 1 + number of years since enactment of restructuring legislation
PUC_{gt}	:	Dummy for whether state g has an elected PUC in year t
$\mathsf{DIVFLAG}_{gt+h\|t}$	:	Dummy for whether major divestitures have occurred in state g by $t+h$
$\mathsf{RM}_{gt+h\|t}$	:	Forecasted reserve margin in the NERC subregion for state g
$\mathsf{LDFACT}_{gt+h\|t}$	:	Forecasted load factor in the NERC subregion for state g
AGE_a	:	Age of divested asset a
RELPOP_a	:	Ratio of population density at the location of a to state average

The chosen expected profit function includes elements from all four sets of data: plant and firm characteristics, market conditions, and measures of restructuring progress. Furthermore, 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. This is done by interacting the relevant firm and market characteristics with a "commitment index" and a measure of how long since a state has enacted restructuring:

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

In a state with no restructuring (LOGYRLEG$=0$), none of the interaction terms enter into a firm's profit expectation. However, in a state that has enacted restructuring legislation (LOGYRLEG>0), the interacted firm and market characteristics enter, weighted by whether a state has experienced some utility power plant divestiture and whether the main regulating authority (usually the state public utility commission) is elected. 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. The former is based on the idea that 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. The latter is based on current literature that find some suggestive theoretical and empirical evidence that elected regulators may be more responsive to consumer complaints and, hence, more likely to react to short-run market driven price fluctuations.[27] Assuming that independent power producers see more profit potential in a restructured, market-based regime than an explicitly price-regulated regime, we expect to see θ_6^r and θ_7^r to be positive and negative, respectively.

The profit function utilizes three observed firm characteristics, of which two represent merchant power experience and one affiliation with a U.S. investor-owned utility. $\mathsf{INT96}$ and $\mathsf{US96}$ reflect the amount of merchant power capacity owned by the IPP outside and within the U.S., respectively, in 1996.[28] The two variables are meant to be proxies for merchant power experience. IPPs with large $\mathsf{INT96}$ and/or $\mathsf{US96}$ values would presumably have an advantage in building and operating the more recent gas-based merchant power plants.[29] Similarly, IPPs with affiliation with investor-owned utilities ($\mathsf{USIOU}= 1$) may have an advantage in operating the older power plants, such as those being offered for sale by divesting utilities, by drawing upon the experience of its parent company's utility subsidiaries. Consequently, we might expect firms with high $\mathsf{INT96}$ and/or $\mathsf{US96}$ to expect greater profits operating newer power plants and affiliated firms with operating older, divested power plants. Moreover, the degree of merchant and utility power experience may alter firm profit expectations depending on the regulatory status of the state, with merchant power experience more important in further restructured markets and utility experience in less restructured markets.

[27] See Besley & Coate (2001)

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

[29] It is reasonable to think that the difference in experience gained from operating power plants vary coarsely with the size of capacity. Consequently, based on the capacity distribution in the data, we choose to discretize the two variables in the following manner:

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

Differences in observed market conditions are used to help explain differences in profit expectations across states. Specifically, we utilize three measures of the relevant electricity demand (LOGLOAD, RM, LDFACT) and the 1996 average retail electricity price for the state (P96).[30] LOGLOAD is the natural log of the (forecasted) peak electricity demand for the NERC region and is used to capture possible scale effects from demand; IPPs may prefer to participate in a state where the "pie" is larger. RM is the ratio of total available generation supply over expected peak hourly demand and LDFACT the ratio of peak hourly demand over average hourly demand. The former reflects the tightness of supply and the latter the degree of fluctuation in demand over a year. A market with a low RM and a high LDFACT is more likely to be hit by price spikes due to low demand elasticity and significant short-run capacity constraint in the electricity market. Hence, we would expect IPPs to expect greater oppotunities to earn scarcity rents in such markets, especially in more market-oriented, further restructured states. We include P96 as a type of control for other, excluded market condition variation: considering that the economic fundamentals for a market usually exhibit strong time-persistence, a high P96 may indicate, *ceteris paribus*, a high likelihood of having high prices in the market after 1996.

Lastly, we should note that the while the expected profit function does vary with plant characteristics (AGE and POP), the plant characteristics are not fully interacted with measures of a state's regulatory status. This is because plant characteristics (in our data set) do not differ much among "new" plants. Given that divestitures (and hence "old power plant investments") occur predominantly in restructured states, it is difficult to estimate a fully interacted set of plant characteristics parameters. Consequently, we allow only RELPOP to enter interacted with the regulatory variables. We believe that while population density, as an indication of the opportunity to exercise local market power, can have a significant differential impact depending on the degree to which a state has implemented market-based restructuring, the main impact of age (production inefficiency) is relatively invariant.[31]

4.2.2 Investment Cost Function

The investment cost function (for a new power plant) is separated into two part, a fixed investment cost and a variable capacity cost. The idea is that the fixed cost reflects the general barriers to

[30]Note, we use the load data (including the forecasts) for the North America Electricity Reliability Council (NERC) subregion in which the state is located rather than those for the state itself. Given the interconnection between electricity grids, oftentimes spanning across state borders, these NERC subregions capture the potential demand that can be satisfied by a power plant better than the pure geography of a state.

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

investment while the capacity cost represent the greater complexities and capital costs associated with larger power plants. A high fixed cost would primarily lead to less power plant investments and a high capacity cost to smaller power plants. Given that the linear term in the capacity cost function is not identified separately from the constant in the expected profit function, we specify only the coefficient for the quadratic term:

$$\alpha_{igt} = \exp\left(\theta_0^\alpha + \ \theta_1^\alpha \mathsf{INT96}_i + \ \theta_2^\alpha \mathsf{US96}_i + \ \theta_3^\alpha \mathsf{USIOU}_i\right) \tag{19}$$

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).

On the other hand, we imagine the fixed cost to be roughly the same across firms: the fixed cost largely 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 help capture stakeholder concerns about new power plant construction

$$C_{igt}^f = \theta_0^f \ + \ \theta_1^f \mathsf{AGE30}_g + \ \theta_2^f \mathsf{STNOX}_g + \ \theta_3^f \mathsf{DMLEG}_{gt} + \ \theta_4^f \mathsf{HOUSE}_{gt} + \ \theta_5^f \mathsf{PUC}_{gt} \tag{20}$$

AGE30 is the percentage of utility generation supply that is more than 30 years old in the state as of 1996. We expect $\theta_1^f > 0$, as a state with a large AGE30 is one where much of its existing generation 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).[32] The impact of these variables are *ex ante* ambiguous, depending on whether new power plant construction will replace existing power plants. An environmentally strict state may want to curb new power plant construction to prevent additional harmful emissions; but at the same time, such a strict state may also want to encourage new power plants as they may replace more polluting existing power plants. Lastly, we include two regulatory variables, DMLEG and PUC. DMLEG, a dummy indicated whether restructuring has been enacted, is included based on the belief that the general attitude toward investment is dramatically different between a restructured and non-restructured market. PUC, a dummy 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.

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

5 Results

5.1 Estimates

The parameters in the model are estimated using the Maximum Likelihood (ML) method. Table 2a shows the parameter estimates for the expected profit function. Following the empirical specification, the results are divided into three groups: the coefficients for the base variables, the interaction terms, and the plant characteristics (AGE and RELPOP)

Table 2a: Estimates for the Expected Profit Function		
Parameter	Estimate	Std. Error
Non-interacted		
θ_0^r : CONSTANT	-1.023	0.027
θ_1^r : P96	-0.024	0.004
θ_2^r : LOGLOAD	0.033	0.005
θ_3^r : INT96	0.000	0.004
θ_4^r : US96	-0.051	0.006
θ_5^r : USIOU	0.055	0.011
Interacted with LOGYRLEG $\times$ (1 + θ_6^r DIVFLAG + θ_7^r PUC)		
θ_6^r : DIVFLAG	-0.056	0.116
θ_7^r : PUC	-0.382	0.129
θ_8^r : CONSTANT	-1.472	0.026
θ_9^r : LOGLOAD	-0.085	0.005
θ_{10}^r : RM	-0.615	0.029
θ_{11}^r : LDFACT	1.718	0.017
θ_{12}^r : INT96	-0.001	0.000
θ_{13}^r : US96	-0.001	0.005
θ_{14}^r : USIOU	-0.080	0.011
Interacted with RELPOP		
θ_{15}^r : INT96	0.000	0.000
θ_{16}^r : US96	0.000	0.000
θ_{17}^r : USIOU	0.000	0.001
Interacted with AGE		
θ_{18}^r : INT96	0.001	0.001
θ_{19}^r : US96	0.019	0.004
θ_{20}^r : USIOU	0.038	0.012

Prior to restructuring, an IPP's expected profit appears largely determined by the overall market size (LOGLOAD), with a larger market size leading to a higher expected profit. Moreover, the estimates suggest that the IPP with the best profit prospect in a regulated market is an IPP affiliated with an IOU but with limited U.S. merchant power experience. The advantage of IOU affiliation is intuitive as we would expect such affiliated IPPs to be able to draw upon valuable experiences and skills concerned with operating in a explicitly regulated market. However, the apparent disadvantage of domestic merchant power experience is unexpected and difficult to rationalize.

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 the presence of divestiture does not have a substantial nor significant impact on the "commitment" to market restructuring perceived by the sample IPPs, assuming IPPs associate greater market restructuring with greater expected profits. In the minimum, the estimate suggests no conclusive evidence in favor of divestiture encouraging investments. In the maximum, the estimate provides very weak support that IPPs associate divested markets with lower expected profits. However, 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, having a more direct relationship with the electorate and hence willing to be a more active consumer advocate, may intervene in the market more frequently, especially during times of high prices (and high profit opportunities).

A strong 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 level of demand volatility; the positive LDFACT coefficient may be reflecting scarcity rents during peak demand, as a market is unlikely to support too many "peak units" 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 scarcity rents in restructured markets.[33]

With respect to the interacted firm variables, only IOU affiliation seems to matter. The negative coefficient for the interacted USIOU coefficient is most likely a reflection of the relative

[33] With RM ranging from 0.9 to 2, LDFACT from 1.4 to 1.9, and all other expected profit variables bounded between 0 and 10, the estimates indicate that the estimates for RM and LDFACT are economically substantial as well as statistically significant

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 a modest advantage in operating older (high AGE) power plants. These two results, coupled together, are consistent with the idea that IOU affiliated and unaffiliated IPPs draw upon different skill sets. An affiliated IPP has more knowledge concerning older utility power plants while an unaffiliated IPP is more familiar with modern merchant power plants. At the same time, the estimates for the firm characteristics interacted with RELPOP seem to indicate that the value of a power plant's location does not vary across firms.[34] 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 location of the plant.

Next, Table 2b shows the estimates for the parameters in the investment cost function.

Table 2b: Estimates for the Investment Cost Function		
Parameter	Estimate	Std. Error
Fixed Cost		
θ_0^f : CONSTANT	-2.369	9.559
θ_1^f : AGE30	10.657	21.412
θ_2^f : STNOX	1.547	1.567
θ_3^f : DMLEG	-0.856	6.102
θ_4^f : HOUSE	-0.157	0.150
θ_5^f : PUC	-2.430	6.278
σ_η	13.262	10.172
Capacity Cost (α)		
θ_0^α : CONSTANT	-0.590	0.453
θ_1^α : INT96	-0.187	0.188
θ_2^α : US96	-0.293	0.105
θ_3^α : USIOU	-0.164	0.279
σ_ξ	3.979	0.202

The coefficients in the fixed cost function do not appear to be estimated with precision. Furthermore, the large variance for η indicates that much of the barriers to new power plant investment is not explicitly accounted for in the model. This is expected as much of the politics involved in getting approval for power plant construction is local, involving a myriad of potential stakeholders that vary by location.

[34] Note that the coefficient estimates do not imply that plant location does not contribute to the overall value of the plant - just the differential value.

While precision is a problem in the estimation of the fixed cost, the coefficients in the capacity cost seem more precise. Firms with substantial merchant power experience are found to be more capable of controlling the costs of large size projects. For an IPP with more than 1500MW of generation capacity overseas in 1996 ($\mathsf{INT96} = 3$), its capital cost[35] is less than 50% of that of a firm without any international generation capacity, *ceteris paribus*. Similar results also hold when comparing capital costs between IPPs with more than 1000MW of domestic merchant power capacity and those with none. This is evidence supporting the existence 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 significantly 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 3: 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 $\mathsf{US96}$). Furthermore, among the 31 divestiture sales won by affiliated IPPs (in our data), 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 being able to avoid the investment cost associated with a "make" investment. Note that the opportunity cost of buying a divested power plant is different between an affiliated IPP with low merchant power experience and an unaffiliated IPP with high merchant power experience. The unaffiliated IPP can build a new power plant much cheaper, due to its substantial capital cost advantage, and, thus, places a higher value on the "make" option.

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

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 the progress of 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. This alludes to the growing importance of market-based signals (as opposed to regulator-based signals) in IPP generation investment. Second, we find that firm characteristics do help explain the difference in the investment choices adopted by different IPPs. IPPs with greater merchant power experience (larger values of INT96 and US96) face a substantial discount in the capital costs incurred from developing a large, new power plant while IOU affiliated IPPs face a modestly larger expected profit from operating older, divested power plants. Combined with the fact that many of the IPPs with substantial merchant power experience are unaffiliated with IOUs (e.g. AES and Calpine), 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 no empirical evidence supporting the idea that divestiture encourages IPP generation investment as a "commitment device" that reduces the regulatory risk faced by IPPs.

5.2 Simulation

Given the parameter estimates, we can use the model to run policy simulations that examine IPP investment behavior under different scenarios. The estimated model has two general sources of uncertainty: the uncertainty surrounding the parameter estimates $(\theta^r, \theta^\alpha, \theta^f)$ and the uncertainty stemming from the unobserved components of the IPP investment decision, as characterized by $(\xi_{igt}, \eta_{igt}, \epsilon_{igta})$.[36] Consequently, simulations are run based on 500 joint draws from the estimated asymptotic distribution of $(\theta^r, \theta^\alpha, \theta^f)$ and $\{\xi_{igt}, \eta_{igt}, \epsilon_{igta}\}_{i=1,\ g=1,\ t=1996,\ a=1}^{N\quad 48\quad 2000\quad A}$

One important policy simulation related to the "make or buy" decision is whether and how much divestiture have "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. The question is of particular policy interest in states like California where a low reserve margin combined with low price elasticity in demand has allowed owners of existing generation ca-

[36] We are, for now, ignoring the uncertainty surrounding model specification.

pacity to earn significant scarcity rents.[37] 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 DIVFLAG is set to be 0 for all observations.[38] Table 3a 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 4a: "Make" to "Buy"

Case	# of Inv.	Total Inv.	Avg. Inv.	Min Total Inv.	Max Total Inv.
"Buy" (Data)	32	69248	2164		
"Make" (Sim.)	1.27 (1.07)	607.0 (723.6)	339.1 (363.8)	0	3592.8

1. Results are based on 500 draws 2. All Inv. numbers are in MW
3. Standard deviation in parentheses

The simulation exercise finds that the divestiture crowds out very little new generation investments, 607 MW *in total* on average. This corresponds roughly to the generation output of a single combined cycle gas-fired unit. On the other hand, the simulation finds that most of the IPPs who chose to enter and participate in these newly restructured markets would have chosen not to do so if the option to buy existing generation assets was not available. On average, only one of the 32 divestiture investments (and no more than 3 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. This result is not surprising given the earlier discovery that the main factor contributing to a high willingness to pay for a divested asset is the desire to avoid incurring a high investment cost — implying that IPPs who buy divested assets place a low valuation on the "make" option.

To demonstrate this point, consider the simulation exercise where all IPPs are assumed to have the same "make" valuation. In this situation, the difference among firm valuations of the "buy" option stems solely from the difference in the profit stream each firm expects to earn from the divested asset. Table 4b compares the characteristics of the actual winner of a divestiture with

[37]Note that the estimated expected profit function is consistent with the recent California experience.

[38]A simulation where divestiture sales existed as in reality but none of the 20 major IPPs were allowed to buy resulted in qualitatively similar results.

the average characteristics of simulated winner, under the assumption that all firms value "make" equally, for 13 divestiture sales.

Table 4b: "Buy" with Identical "Make" Valuation											
State	Year	AGE	POP	CAP (MW)	Change	Actual Winner			Average of Sim Winner		
						INT96	US96	IOU	INT96 (+)	US96 (+)	IOU
CA	1997	21	69	294	62%	2	1	1	1.9 (30%)	1.4 (34%)	50%
CA	1997	31	4	2406	87%	1	0	1	2.4 (76%)	1.6 (85%)	88%
CA	1997	35	69	500	56%	0	3	0	1.1 (42%)	2.3 (0%)	17%
CA	1997	26	29	2881	53%	1	1	1	1.9 (48%)	1.5 (26%)	88 %
CA	1997	25	11	1613	61%	1	0	1	1.5 (34%)	0.8 (55%)	56%
CA	1998	19	8	1354	90%	0	3	0	2.2 (89%)	1.6 (0%)	15%
CA	1998	29	19	674	79%	0	3	0	2.0 (76%)	2.3 (0%)	59%
MD	1999	28	92	3755	82%	1	1	1	2.0 (69%)	1.2 (22%)	49%
ME	1998	51	0.2	1067	32%	1	2	1	1.4 (23%)	2.0 (14%)	94%
NY	1998	31	1.1	1427	46%	3	2	0	2.7 (0%)	2.2 (27%)	43%
NY	1998	20	0.5	1806	56%	2	1	1	1.5 (2%)	1.0 (2%)	54%
PA	1999	30	2	1002	38%	1	1	1	1.6 (32%)	1.4 (32%)	63%
PA	1999	40	0.4	5774	92%	1	0	1	2.7 (88%)	1.8 (92%)	21%

1. Results are based on 500 draws.
2. Change (column 6) is the share of simulations where the non-actual IPP wins the divestiture
3. The categories for INT96 and US96 are defined in the Data section.
4. The numbers in the brackets next to INT96 and US96 (+) are the percentage of sims where the INT96 and US96 of sim winner are greater than actual winner.

As the table demonstrates, when the difference in "make" valuation is eliminated, more divested assets are bought by IPPs with greater merchant power experience. Consider the first divestiture sale in Table 4b. The asset has an age of 21 years and a capacity of 294 MW. The population density at the location of the asset is 69 times that of the California state average. In the data, the asset was bought by an IOU affiliate (IOU=1) who, in 1996, had an international generation capacity in the range of 500 MW to 1500 MW and a domestic generation capacity less than 500 MW. If all firms valued "make" equally, the simulations indicate that there is a 62% probability that some other IPP than the actual winner would have had a higher willingness to pay for the asset. On average, 30% of those possible winners would have an 1996 international capacity greater than 1500 MW and 34% of them a 1996 domestic capacity greater than 500 MW. Only 50% of the new winners are likely to be affiliated with utilities. Similar changes are also exhibited in the other 12 divestiture sales. The simulation demonstrates that it is the difference in the evaluation of the "make" option that drives much of the difference in the evaluation of the "buy" option.

The two simulation exercises indicate that, contrary to the impression given by the earlier tables and regression, concerns about divestiture "crowding out" new generation investment are unfounded. The IPPs who buy divested power plants generally face high investment costs that discourage them from building new power plants. However, divestiture does appear to encourage the participation of a greater number of IPPs in the market. By giving IPPs the option to buy existing power plants, divestiture provides some IPPs with limited "make" abilities the opportunity to enter profitably in the market. As raised in earlier discussion, these IPPs consist mostly of affiliates of U.S. investor-owned utilities. Such IOU-affiliated IPPs are willing to pay more for divested power plants 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 (presumably from the familiarity gained from utility operations).

This raises the question: what are the consequences of greater participation by IOU-affiliated IPPs? One of the main factors driving restructuring is the hope that competition would lead to the replacement of existing IOU generation by more efficient generation from IPPs. If these IOU-affiliated IPPs are among the more efficient generators, then divestiture may be helping to foster healthy competition in the market.[39] However, if these affiliated IPPs only have an advantage in buying and running existing power plants based on older technology, then divestiture may be hurting the more long-run prospects for a competitive 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 generation capacity in the restructured market, may be able to curtail the participation of unaffiliated IPPs who may be more competitive in the long-run when new power plants become necessary.[40] Thus, an important concern may be that divestiture is subsidizing the participation of the wrong types of IPPs. Divestiture, while not "crowding out" much current new generation investment, may be "crowding out" future new generation investments by more efficient unaffiliated IPPs. We leave this dynamic issue for future research.

[39] Preliminary results from Ishii (2001b) suggests that the IOUs that have branched out into IPP are among the more efficient utility generators. Earlier efforts to include explicitly into the "make or buy" model more detailed information about IOU affiliated IPPs (such as the affiliated IOU's average generation costs and whether the IOU had recently divested some utility capacity) have been largely uninformative.

[40] This would correspond to some kind of first-mover advantage in the market.

Conclusion

In this paper, we present an empirical model of the "make or buy" decision faced by independent power producers in many restructured wholesale electricity markets. The model is based on observing whether an IPP buys a divested power plant, builds a new power plant, or chooses not to invest at all. This revealed preference approach provides a feasible method of examining IPP investment behavior without relying on extensive, difficult-to-obtain transaction data. Furthermore, the empirical model has applications in other, especially regulated, industries. Wholesale electricity is not the only industry in which firms face a "make or buy" decision. In retail gasoline and telecommunciations (long distance), firms often have the option of buying (or leasing) existing facilities from incumbents as an alternative to building their own. The empirical model developed here seems well suited for studying investment behavior in those industries as well.

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 power plant rather than build its own, the estimates provide strong evidence corroborating one particular intuitive explanation: IPPs buy divested power plants to bypass the high investment cost they otherwise would have had to incur in order to participate in the restructured 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 power 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. Consequently, the main impact of divestiture on IPP generation investment appears to be the encouragement of greater IPP participation, particularly among IPPs affiliated with investor-owned utilities.

Given these results, it is difficult to say that divestiture is, overall, desirable. There are some evidence in the developing literature that link divestiture to greater wholesale price volatility during the initial transition period of restructuring. However, there are mitigating factors, one of which is the understanding that some level of price volatility is unavoidable given the way the electricity system was developed under the vertically integrated, price regulated regime. Another is our finding that expected profits (and presumably wholesale electricity prices) apparently fall as a market both advances further into restructuring and develops new electricity supply. 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" during the initial years, divest utility power plants, and accelerate toward full restructuring as quickly as possible. But we find no empirical evidence that divestiture encourages new generation investment: divestiture has a statistically insignificant *negative* impact on expected profits and IPPs that presumably benefit the most from divestiture (the ones that "bought") tend to be the least suited to build new power plants. While divestiture may confer benefits by mitigating potential utility *vertical* market power, divestiture does not appear to further the goal of encouraging new, low cost, power plant development.

Lastly, we stress that we do not take a normative stance on whether new power plant investment is necessarily socially desirable in a given restructured market. The answer to such a question depends on the profile of the existing stock of generators, the transmission system, and expected demand growth, among many other things. What we choose to investigate is the positive issue of whether divestiture encourages greater entry and new generation investment. A major policy initative underlying many state (and national) electricity restructuring programs in the U.S. and abroad has been the desire to stimulate greater privately-funded power plant investment. We take a normative stance on policy in so far as such an initiative is desirable: our results suggest that policy makers seeking to encourage new IPP investment would be better served considering more direct measures such as steam-lining the permitting process and providing siting assistance that helps reduce "not in my backyard" (NIMBY) opposition. Such efforts to lower the investment cost associated with building new power plants would seem to be more effective than relying on divestiture (as a commitment device) to enhance the appeal of new power plant projects.

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Appendix

Variable List

AGE_a	:	Age of divested asset a
$\mathsf{AGE30}_g$	:	Percentage of generation capacities more than 30 years old in a state in 1996
$\mathsf{DIVFLAG}_{gt+h\|t}$	:	Dummy for whether major divestitures have occurred in state g by $t+h$
DIVID_{gt}	:	Dummy for whether there was some major divestiture in state g in year t
$\mathsf{DMLEG}_{gt+h\|t}$	:	Dummy for whether the restructuring legislation has been enacted in state g by $t+h$
$\mathsf{INT96}_i$	:	Generation capacity owned by firm i outside the U.S. in 1996
HOUSE_{gt}	:	Average of LCV Scorecard for House of Representatives from state g, year $t-4$ to t
$\mathsf{LDFACT}_{gt+h\|t}$	:	Forecasted load factor in the NERC subregion where state g is located
$\mathsf{LOGLOAD}_{gt+h\|t}$	:	Log of the forecasted demand (load) in the NERC subregion where state g in located
$\mathsf{LOGYRLEG}_{gt+h\|t}$	:	Log of one plus the years since the restructuring legislation was passed in state g
$\mathsf{P96}_g$	:	Average electricity price in state g in 1996
PUC_{gt}	:	Dummy for whether state g has an elected public utilities commission in year t
RELPOP_a	:	Ratio of the population density at the location of a to state average
$\mathsf{RM}_{gt+h\|t}$	:	Forecasted reserve margin in the NERC subregion where state g is located
STNOX_g	:	Average level of NO_x emission related to electricity generation in a state in 1996
USIOU_i	:	Dummy for whether firm i is affiliated with some major utilities
$\mathsf{US96}_i$	:	Generation capacity owned by firm i inside the U.S. in 1996

Full Version of Table 1c

Regression on Total Non-Divestiture Capacity Investments (MWs) by State/Year		
Variable[1]	Estimate	Std Error
Dummy for Divestiture ($DIVFLAG_{gt}$)	354.60	141.33
Dummy for Current Divestiture ($DIVID_{gt}$)	-326.17	161.17
Other Market Variables		
Constant	-2411.69	923.38
Dummy for Restructuring Enacted	354.60	141.33
Dummy for PUC Elected	-165.95	101.91
Load Factor	1580.41	407.69
Reserve Margin	-330.32	205.60
Log(Load)	122.72	80.23
1996 Average Retail Price	-34.15	35.65
1996 Power Plant NO_x Emission	-28.73	17.79
LCV House Scorecard	1.41	2.52
Total Observations = 48 continental states x 5 years = 240 $R^2 = 0.2125$		

Deriving `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

$$\texttt{Prob}(\text{firm } i^a \text{ wins } a) \quad = \quad Pr\left\{W^*_{i^a gta} > W^*_{jgta}\ , \quad \forall j \neq i^a\right\} \ = \ \frac{\exp\{\overline{W}_{i^a gta}\}}{\sum_{j=1}^{N}\exp\{\overline{W}_{jgta}\}}$$

where

$$\overline{W}_{jgta} \quad = \quad \overline{\Pi}_{jgta}\ K_{jgta} - E_t \max\left\{\ 0,\ \left(\overline{\Pi}_{jgt(new)} \cdot K^*_{jgt(new)} - (C_{jgt}(K^*_{jgt(new)}, \xi_{jgt}) + \eta_{jgt})\right)\right\}$$

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

$$E_t \max\{\cdot\} \quad \approx \quad \frac{1}{S}\sum_{s=1}^{S} \ \max\ \left\{\ 0, \left(\overline{\Pi}_{igt(new)} \cdot K^*_{igt(new)}(\xi^s_{igt}) - (\ C_{igt}(K^*_{igt(new)}, \xi^s_{igt}) + \eta^s_{igt})\right)\ \right\}$$

$$\xi^s_{igt} \overset{i.i.d.}{\sim} N(0, \sigma^2_\xi) \qquad \eta^s_{igt} \overset{i.i.d.}{\sim} N(0, \sigma^2_\eta)$$

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:

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

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}.

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

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

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

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.[41]

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

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

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

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

So the likelihood can be derived as

$$l_{igt} \quad = \quad \underbrace{\int_{\xi^0_{igt}/\sigma_\xi}^{+\infty} \left(1 - \Phi \left(\frac{\eta^*_{igt}}{\sigma_\eta} \right) \right) \ \phi(u) \ du}_{K_0^* > 0 \text{ but } V(\text{new}, K_0^*) < 0} + \underbrace{\int_{-\infty}^{\xi^0_{igt}/\sigma_\xi} \phi(u) \ du}_{K_0^* < 0}$$

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.

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[42]
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. [43]
PSEG Global	its business focus is on overseas markets, e.g., Latin America
Sithe Energies	bought some capacity but plan to exit industry [44]
Tomen Power	most of its activities are outside U.S. [45]
Tractebel	its focus is on the Northeastern market
Wheelabrator Technologies	its core business is waste-to-energy facilities[46]

After these steps, we are left with 20 major IPPs. Table A3 shows some summary statistics for these IPPs.

[42] *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.

[43] "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.

[44] Sithe has sold or are in the process of selling most of their merchant power capacity

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

[46] "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*.[47] The newsletter provides notification and summaries of the relevant press releases associated with the electricity industry. Lastly, 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.

Information on utility divestiture sales were gathered from various issues of the *Electric Power Monthly* published by the Energy Information Adminsitration, 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).

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.[48] 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.[49] 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.

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

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

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