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From Investor-owned Utility to Independent Power Producer

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Abstract

In this paper, we examine the issue of why some parent companies of U.S. electric utilities have expanded into domestic independent power production (IPP) but not others. We evaluate the conjecture that the parent companies who have chosen to participate in recently restructured U.S. wholesale electricity markets are those with the most generation cost advantages. Specifically, we empirically investigate the link between apparent advantages in two types of generation costs, operation & maintenance (O&M) and capital, and the IPP participation decision. We use electric utility data from FERC Form 1 and combine it with IPP data collected from various industry sources. The data is analyzed using both a descriptive approach and the estimation of a simple competitive entry model. The results indicate that utility parent companies that expand into domestic IPP do tend to have much lower reported utility generation O&M costs. Moreover, they also tend to have divested some of their own utility power plants. The former provides some hope that restructuring is having the desired entry/exit effect while the latter raises some concerns about power plant "swapping" among utilities. Other measures capturing the financial health of the utility parent company seem to have little explanatory power, after controlling for other benefits stemming from utility scale of operation.

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1 Introduction

Much of the current academic literature on electricity restructuring has focused on the behavior of electricity generation firms in restructured wholesale electricity markets. Prominent recent works include Borenstein, Bushnell, & Wolak (2000) (hereafter BBW), Joskow & Kahn (2002), and Puller (2001) — all of which examine the bidding behavior and capacity utilization decision of independent power producers (IPPs) in the California Power Exchange (CalPX). In each of these papers, the focus has been on how regulatory restructuring has altered firm behavior in the electricity generation sector. In this paper, we stray from this theme of firm behavior and focus more on the firm itself.

Although the identities of the electricity power producers participating in many of these restructured wholesale electricity markets are now well known (especially given recent news coverage), little analysis has been made on why these are the very firms who have become the major participants in the restructured markets. This is an important policy issue considering the original motives underlying electricity restructuring: one of the main motives was the hope that by opening up the generation sector to competition, less efficient power producers would be replaced by more efficient power producers. As explored in White (1996), a main factor explaining the early adoption of electricity restructuring by some states is the high electricity prices suffered by consumers in those states, especially relative to consumers in neighboring states. While some of the price differences can be attributed to differences in cost advantages inherent to each state (e.g. access to hydro power, proximity to fuel sources), much of it has also been attributed to the different vertically integrated investor-owned utilities running each state's electricity industry. Therefore, some states welcomed the opportunity for out-of-state power producers to come in and replace the local investor-owned utilities (IOUs) in the generation sector.

Thus far, a large majority of the independent power producers (IPPs) that have replaced local IOUs in U.S. wholesale electricity markets have been subsidiaries of parent companies that also own IOUs in other states.[1] In fact, one of the major phenomena observed during the initial transition period for electricity restructuring is the "swapping" of generation assets among IOU parent companies: much of the power plants sold by IOUs in divestiture sales have been bought by subsidiaries of IOU parent companies. There are good reasons why we might expect IOU parent companies, through their IPP subsidiaries, to be the major players in the newly restructured wholesale markets. Given that IOUs have controlled much of the electricity generation business in

[1] The "independent" in independent power producer refers to the fact that the IPP is not operationally affiliated with the investor-owned utility that provides the service in the downstream transmission and distribution (T&D) sector.

the U.S. over the past 60 years, IOU parent companies are the firms with the most experience in providing generation services in the U.S.[2] Moreover, the variation in the costs reported by IOUs in different states raises the possibility that some IOUs may be more efficient than others. Thus, a possible rationale helping to explain the large share of IPP activity controlled by IOU parent companies is that less efficient IOUs are being replaced in the generation sector by subsidiaries run by more efficient out-of-state IOUs.

In this paper, we empirically explore this claim that the IOUs who have expanded their generation activities outside of their regulated franchises and into "out-of-state" independent power production are in some sense the "lower cost" IOUs in the country.[3] While much of the current independent power production is provided by subsidiaries of IOU parent companies, not all major IOU parent companies have chosen to participate in independent power production. Among the 81 major IOU parent companies analyzed in this essay, 32 own IPP subsidiaries. The working hypothesis in this essay is that the remaining 49 firms has chosen (as of 2000) not to participate in IPP because they feel that they cannot compete for the right to provide generation services without regulatory protection. We infer the generation costs that an IOU parent company potentially faces in IPP activities - and thus the level of competitiveness of the firm - from observed information about the utility operations of the IOU parent company. Specifically, we focus on utility operations along two dimensions: the reported operations and maintenance costs for utility generation and the financial health of the utility. The former is used to arrive at some measure of the short-run variable cost that an IOU parent company may face while running an IPP merchant power plant. The latter is used to infer the capital costs that an IOU parent company may incur in order to develop or acquire IPP power plant projects. Combined, they provide an expansive view on the potential IPP generation costs faced by each IOU parent company.

Two empirical strategies are employed to examine the link between observed utility operations and the level of IPP activities engaged by the IOU parent company. First, a descriptive approach is adopted where the focus is the correlation between various utility characteristics and the IPP participation decision of the parent. The descriptive section introduces the utility variables of interest and demonstrates that there is sufficient correlation between these utility characteristics and IPP participation to merit a closer examination. Second, a cost function for making IPP capacity available in a market, based on observed utility characteristics, is estimated using a simple

[2]Investor-owned utilities have controlled most of U.S. electricity generation since the passage of the Federal Power and Public Utilities Act in 1935.

[3]Some IOU parent companies have IPP activities in the same state as where they have their regulated franchises. Most state laws only require the parent company to maintain an "operational" separation between IPP and utility, not different ownership.

competitive entry model. The purpose of this empirical model is to measure the relative importance of each of these utility characteristics, taking into joint consideration all of the capacity investments made by IOU parent companies in a market. Estimates from the entry model reveal that much of the descriptive analysis can be misleading. While at first glance it may seem that "capital cost" factors such as net income and revenue play a significant role in an IOU parent company's IPP participation decision, the estimates from the entry model suggest that it is in fact the prowess of a parent company's utility power plant operations and maintenance that appears to matter. The significant correlation between net income / revenue and IPP participation disappears once such financial characteristics are considered jointly with other utility characteristics that change with the parent company's scale of utility operations.

The paper is organized as follows: section 2 provides an overview of the relevant utility characteristics and examines the correlation between those characteristics and observed IPP activities of the parent company. Section 3 builds upon this descriptive analysis by proposing a simple, empirical competitive entry model for the upstream "generation capacity" market. Estimates from the model, obtained by maximum likelihood, are then used to explain the observed variation in IPP activities by IOU parent companies. The estimates are also used to examine the price sensitivity of the IPP capacity supplied by IOU parent companies. The paper then concludes with some final remarks.

2 Overview

Even a casual overview of the major independent power producers participating in the various U.S. wholesale electricity markets reveals a significant presence by IOU parent companies. In California, of the five major IPPs controlling most of the non-utility electricity generation supply, three (Duke Energy North America, Reliant Energy, Southern Energy) are subsidiaries of parent companies that own U.S. investor-owned utilities.[4] The significant and, perhaps more accurately, dominant presence of IOU parent companies in U.S. IPP activity can be further established by examining the outcome of the utility divestiture sales conducted thus far during this transition period for electricity restructuring. Given that there has been only a limited amount of new merchant power plants constructed and brought online during the past few years, an analysis of who bought divested power plants provides a good indication of who controls much of the IPP activity right now.

[4] Interestingly enough, the two remaining IPPs (AES, Dynegy) have both bought IOUs in recent years.

Table 1: Divestment by Year and Acquiring IPP		
Year	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%)
Divestment data from various issues, EIA "Electric Power Monthly" Excludes transfers between IOU and affiliated IPP IPP classification from various industry resources		

Table 1 shows the amount of divested utility generation capacity acquired by IPPs during each year from 1998 to 2000 (excluding transfers from the utility to non-utility business unit of a parent company).[5] As the table shows, 79 percent of the divested assets overall (71 percent in 1998, 79 in 1999, 91 in 2000) was acquired by subsidiaries of IOU parent companies. These numbers demonstrate the large share of IPP electricity capacity (in the form of acquired assets) controlled by IOU subsidiaries. A possible explanation for this result may be that IOUs, having run similar power plants for their own utility operations, are more familiar with and better at operating and maintaining these aging, divested power plants.[6] Hence, IOU subsidiaries have greater interest in these power plants than non-IOU affiliated IPPs.

Table 2: Divestment by Year and Divesting IOU		
Year	Capacity (Megawatts)	
	Total Amount of Divestiture	Total Amount Divested by IOUs Active in U.S. IPP
1998	24976	15419 (61.7%)
1999	50942	32446 (63.6%)
2000	15689	2561 (16.3%)
Total	91607	50426 (55.0%)
Divestment data from various issues, EIA "Electric Power Monthly" Excludes transfers between IOU and affiliated IPP IOU classification from various industry resources "Active" includes IOUs that merged or were acquired by IPPs		

[5]Some states did not require the local IOUs to divest their generation assets to outside firms. The IOUs were given the option to transfer the assets to a separate subsidiary of the parent company

[6]Ishii & Yan (2002) provides some empirical support for this explanation.

Exploring the flip-side is Table 2. Table 2 shows the amount of utility generation capacity divested by IOUs during each year from 1998 to 2000 (excluding transfers). The table shows that 55 percent of the divested generation capacity was capacity divested by IOUs owned by parent companies who currently participate in U.S. IPP activity. Table 2 shows that not only are IPP subsidiaries of IOU parent companies the major buyers in divestiture auctions, they may potentially be the major beneficiaries of the proceeds from the divestiture sales. Divestiture sales lead to large immediate cash flows for the IOU parent company which can, in theory, be used to finance IPP investments. In fact, examining the timing between the divestment of power plants by an IOU parent company's electric utility and the acquisition of "out-of-state" utility power plants by its IPP subsidiary provide some anecdotal support for such a theory. For example, both Southern California Edison and Pacific Gas & Electric, the two major divesting IOUs in California, announced deals to acquire significant amounts of divested generation capacity (in the Midwest and East Coast respectively) within 6 months of divesting their own California utility plants.[7]

Combining the information from Table 1 and Table 2, we get that 90 percent of the utility divestiture (by capacity) from 1998 to 2000 involved an IOU parent company that owns an IPP subsidiary, either as buyer or seller. Divested utility power plants appear to play a major role in the IPP activities of IOU parent companies. In particular, the analysis above suggests that possible differences across IOUs in their ability to run and maintain power plants similar to those being divested and in the amount of utility divestiture (proceeds) may help explain why some IOUs are more active in IPP, especially as buyers of divested power plants. The former point may be explored using the cost information reported annually by the major IOUs to the Federal Energy Regulatory Commission (FERC Form 1 Report). The FERC Form 1 Report provides the total annual cost of an electric utility, broken down into several useful categories. One of the categories is operations and maintenance (O&M) costs. To the extent that reported utility O&M costs reflect potential O&M costs in IPP activities, the reported utility O&M costs can be used to evaluate the potential short-run variable costs of running merchant power plants faced by different IOU parent companies.[8] Below, we examine several of these reported O&M cost for the 1996 edition of the report. 1996 is chosen as it is the last full year before the introduction of electricity restructuring in any state in the U.S. More information about these data sources can be found in the Data Appendix.

[7]However, at the same time, it should be noted that not all major divesting utilities have acquired out-of-state power plants or otherwise made IPP investments: the parent company of GPU, one of the main divesting utilities in Pennsylvania, has thus far stayed clear of any U.S. independent power production.

[8]O&M costs make up most of an electric utility's short run variable cost. It includes factor payments, such as for fuel and labor, that vary with the amount of electricity supplied. It excludes the amortized capital costs.

Table 3a: Top 10 Lowest ROM			
Investor-owned Utility	Parent Company	IPP	ROM
Indiana-Kentucky Electric Corp	American Electric Power Co Inc	Y	0.0163
South Carolina Generg Co Inc	SCANA Corp	N	0.0208
Electric Energy Inc	LG&E Energy Corporation	Y	0.0255
Southern Electric Generatg Co	The Southern Company	Y	0.0255
AEP Generating Co	American Electric Power Co Inc	Y	0.0255
Idaho Power Co	IDACORP	Y	0.0286
Ohio Power Co	American Electric Power Co Inc	Y	0.0326
Louisville Gas & Electric Co	LG&E Energy Corporation	Y	0.0339
Kentucky Utilities Co	LG&E Energy Corporation	Y	0.0360
Southwestern Public Service Co	Xcel Energy	Y	0.0363

$$\text{ROM} = \frac{\text{Total O\&M Costs from All Electric Utility Operations}}{\text{Total Electricity Generation}} \quad (\$ \ / \ \text{Kwh})$$

Table 3b: Top 10 Highest ROM			
Investor-owned Utility	Parent Company	IPP	ROM
Commonwealth Electric Co	NSTAR	N	81.3661
Maine Public Service Co	Maine Public Service Co	N	3.3997
Cambridge Electric Light Co	NSTAR	N	1.1632
Central Vermont Pub Serv Corp	CVPS	Y	0.8787
Green Mountain Power Corp	Green Mountain Power Corp	N	0.7830
Bangor Hydro-Electric Co	Emera	N	0.6946
Fitchburg Gas & Elec Light Co	UNITIL Corporation	N	0.4914
Citizens Utilities Co	Citizens Communications	N	0.4555
Western Massachusetts Elec Co	Northeast Utilities	Y	0.3923
Connecticut Light & Power Co	Northeast Utilities	Y	0.3487

$$\text{ROM} = \frac{\text{Total O\&M Costs from All Electric Utility Operations}}{\text{Total Electricity Generation}} \quad (\$ \ / \ \text{Kwh})$$

Tables 3a and 3b report the average overall utility O&M costs (ROM), calculated by dividing total overall utility O&M costs by total electricity generation. ROM captures the O&M costs stemming from all aspects of a vertically integrated electric utility's service; it includes O&M costs from the transmission, distribution, and sale of electricity - not just generation.[9] We examine this "overall" figure first, instead of just focusing on generation O&M costs, because there are some potentially important cost complementarities between electricity transmission & distribution and generation. Consequently, a cost minimizing vertically integrated electric utility may take on more

[9]However, generation accounts for the lion's share of total utility cost, over 75% for many IOUs.

generation cost in order to avoid even more sizable T&D costs, and vice versa. Examining the relationship between ROM and IPP participation reveals the degree to which overall more efficient (in terms of short-run variable cost) utilities are more likely to participate in IPP.

Table 3a lists the 10 major investor owned utilities with the lowest overall utility operation and maintenance (O&M) costs per unit of electricity generation (ROM) in 1996. With the exception of SCANA owned South Carolina Generating, all of the top 10 IOUs are owned by parent companies that participate in U.S. IPP activity.[10] In fact, even if we expand the list to the top 20, we would find only two more IOUs owned by parent companies not active in U.S. IPP: Western Resources at number 11 and Indianapolis Power & Light at number 16.[11] On the other hand, very few IOUs in the bottom of the list are affiliated with parent companies active in U.S. IPP. Table 3b shows that of the 10 major IOUs with the highest ROM, only three are owned by parent companies affiliated with U.S. IPP activity. This difference between table 3a and table 3b is consistent with the idea that parent companies affiliated with more overall efficient IOUs are more likely to participate in U.S. IPP activities. Furthermore, the Pearson correlation coefficient between ROM and a dummy for whether the IOU parent company is active in IPP is -0.11683. However, the standard error for the coefficient is 0.1789 and, thus, the correlation coefficient is not statistically different from 0. We might conclude that examining ROM provides a suggestive pattern but nothing statistically conclusive.

Table 4a: Top 10 Lowest SROM

Investor-owned Utility	Parent Company	IPP	SROM
Western Massachusetts Elec Co	Northeast Utilities	Y	-0.0262
MidAmerican Energy Co	MidAmerican Energy	Y	0.0127
Electric Energy Inc	LG&E Energy Corporation	Y	0.0130
Northwestern Public Service Co	Northwestern Corp	N	0.0133
Black Hills Corporation	Black Hills Corporation	Y	0.0137
PacifiCorp	PacifiCorp	Y	0.0137
Kansas City Power & Light Co	KCPL	N	0.0141
Puget Sound Power & Light Co	Puget Sound Energy	N	0.0144
Indiana-Kentucky Electric Corp	American Electric Power Co Inc	Y	0.0148
Public Service Co of Colorado	Xcel Energy	Y	0.0151

$$\text{SROM} = \frac{\text{Total O\&M Costs from Electric Utility Steam Power Generation}}{\text{Total Steam Power Generation}} \quad (\$ / \text{Kwh})$$

[10] South Carolina Generating is a non-traditional utility that operates a single plant, Williams Station, which sells electricity to SCANA owned SCG&E.

[11] IPL, owned by Ipalco, was recently bought by the major IPP firm AES Corp

Table 4b: Top 10 Highest SROM			
Investor-owned Utility	Parent Company	IPP	SROM
Cambridge Electric Light Co	NSTAR	N	0.0851
Maine Public Service Co	Maine Public Service Co	N	0.0763
Central Vermont Pub Serv Corp	CVPS	Y	0.0590
Maui Electric Co Ltd	HEI	N	0.0583
Central Maine Power Co	EnergyEast	Y	0.0575
Bangor Hydro-Electric Co	Emera	N	0.0571
Green Mountain Power Corp	Green Mountain Power Corp	N	0.0505
Consolidated Edison Co-NY Inc	ConEd	Y	0.0492
Commonwealth Electric Co	NSTAR	N	0.0471
Public Service Co of NH	Northeast Utilities	Y	0.0463

$$\text{SROM} = \frac{\text{Total O\&M Costs from Electric Utility Steam Power Generation}}{\text{Total Steam Power Generation}} \quad (\$ \,/\, \text{Kwh})$$

A similar pattern can be found even if we narrow our search to just the average O&M costs stemming from generating electricity (excluding O&M costs from the transmission, distribution and sales of electricity). More specifically, the search is narrowed to O&M costs stemming from steam-powered electricity generation. This latter criterion is added in recognition of the fact that most merchant power plants run by IPPs domestically and abroad are steam-powered.[12] Therefore the average O&M costs from steam-powered generation perhaps best reflect the total O&M costs that IOU-affiliated IPPs may have to face while running and maintaining merchant power plants. Table 4a and 4b list the major IOUs with the 10 highest and 10 lowest O&M cost for steam powered electricity generation (SROM), respectively. Comparing table 4a to 4b, there seems to be a relationship between IOUs with lower SROM and their parent companies participating in U.S. IPP, though weaker than the comparison of table 3a and table 3b. The Pearson correlation coefficient between SROM and whether the IOU's parent company participates in IPP is -0.15403, which is statistically negative given the standard error of 0.0756. It appears that the elimination of some of the non-generation costs has revealed a more precise relationship between utility O&M costs and IPP participation, with IOUs facing lower steam power generation O&M costs more likely to participate in IPP.

[12] FERC and EIA classify generation as steam power, nuclear, hydraulic, or other. Steam power captures the vast majority of the fossil-fuel based generation. There may be some fossil-fuel based generation (small combustion turbines) in the "other" category.

Table 5a: Top 10 Lowest SRNF			
Investor-owned Utility	Parent Company	IPP	SRNF
Cambridge Electric Light Co	NSTAR	N	-.0036
South Carolina Generg Co Inc	SCANA Corp	N	0.0012
Oklahoma Gas & Electric Co	OGE Energy Corp	N	0.0019
Central Power & Light Co	American Electric Power Co Inc	Y	0.0020
Public Service Co of Oklahoma	American Electric Power Co Inc	Y	0.0021
St Joseph Light & Power Co	UtiliCorp United	Y	0.0022
Southwestern Public Service Co	Xcel Energy	Y	0.0022
Southwestern Electric Power Co	American Electric Power Co Inc	Y	0.0023
Texas-New Mexico Power Co	TNP Enterprises Inc	N	0.0025
West Texas Utilities Co	American Electric Power Co Inc	Y	0.0025

$$\text{SRNF} = \frac{\text{Total Non-fuel O\&M Costs from Electric Utility Steam Power Generation}}{\text{Total Steam Power Generation}} \quad (\$ \ / \ \text{Kwh})$$

Table 5b: Top 10 Highest SRNF			
Investor-owned Utility	Parent Company	IPP	SRNF
Maine Public Service Co	Maine Public Service Co	N	0.0396
Central Maine Power Co	EnergyEast	Y	0.0243
Commonwealth Electric Co	NSTAR	N	0.0236
Bangor Hydro-Electric Co	Emera	N	0.0225
Citizens Utilities Co	Citizens Communications	N	0.0207
Northern States Pwr Co-WI	Xcel Energy	Y	0.0202
Central Vermont Pub Serv Corp	CVPS	Y	0.0193
Western Massachusetts Elec Co	Northeast Utilities	Y	0.0187
Green Mountain Power Corp	Green Mountain Power Corp	N	0.0170
Consolidated Edison Co-NY Inc	ConEd	Y	0.0168

$$\text{SRNF} = \frac{\text{Total Non-fuel O\&M Costs from Electric Utility Steam Power Generation}}{\text{Total Steam Power Generation}} \quad (\$ \ / \ \text{Kwh})$$

Lastly, we consider average O&M costs from steam-power generation excluding fuel costs (SRNF). One possible concern to using SROM is that SROM incorporates regional differences in both fuel mix and fuel prices. Thus, an IOU that can operate and maintain a given power plant better than any other IOU may still exhibit a relatively high SROM value if it operates in a state such as California where fuel prices are high and the use of coal (the least expensive of the fossil fuels) is prohibited. In order to make the O&M generation cost figures more comparable across utilities located in different states, we might consider excluding fuel costs. Table 5a and 5b address this concern. After excluding fuel costs, there is no real discernible relationship between IOUs with the top 10 lowest/highest SRNF values and the decision to participate in IPP activities by their parent companies. However, the Pearson correlation coefficient is still statistically negative and of similar magnitude: -0.15254 with a standard error of 0.0785. Therefore, even after eliminating fuel costs, there seems to be some significantly negative correlation between steam power generation O&M costs and IPP participation.

In none of the three O&M figures does the relationship between O&M costs and IPP activity appear very strong. There are good reasons to expect this, apart from any conclusion about the role of O&M costs in an IOU's IPP participation decision. First, these cost data are the values reported by the IOU to a regulatory commission. In so far as an IOU has an incentive to misreport its cost (and in so far as the regulatory commission cannot completely monitor the utility), these variables may be distorted reflections of the true underlying cost of generation. However, this may not be as significant a problem because generation cost are, perhaps, the aspect of utility cost that can be best monitored; regulators can use engineering information and fuel receipts to arrive at good bounds for generation cost. The more troubling factor is the fact that these variables capture average generation cost for a given amount of generation; they provide us with a single point of observation for an IOU's generation cost function. Therefore, ROM, SROM, and SRNF are only truly comparable across firms if either all firms produce similar amounts of generation or the average cost of generation is roughly constant for a firm. Neither assumption holds outright as IOUs are observed providing varied amounts of generation and electricity generation is usually understood to involve some sizable fixed cost (e.g. ramping). Consequently, even if (in reality) more generation cost efficient utilities are more likely to be involved in IPP activities, it may not be perfectly borne out by the average cost measures ROM, SROM, SRNF. Ideally, we would like to observe the O&M costs for IOUs for comparable levels of generation. However, such data is generally not available. We proceed with the belief that while these variables may not be perfect reflections of an IOU's generation cost (dis)advantages, they are still most likely correlated with the "ideal" measures and serve as good proxies.[13]

The three O&M costs provide some suggestive evidence that IOUs who can seemingly best operate and maintain steam-based power plants are the ones more likely to participate in independent power production. However, O&M costs only make up one aspect of a firm's overall independent power production cost. An IPP also incurs costs associated with developing new and acquiring existing power plant projects. An important component of the cost of developing and acquiring

[13]In the appendix, we consider a possible "fix" for this problem based on strong assumptions.

power plants is the cost of capital. The FERC Form 1 Report does report utility capital costs. However, such reported capital cost is likely not comparable across IOUs nor the relevant capital cost for IPP power plant projects. This is because the regulated retail electricity price that an IOU can charge is largely set such that the IOU has the opportunity to earn a regulated rate of return on its reported capital investment. Depending on the diligence of the local regulators, an IOU has a weak incentive[14] to keep capital costs down. Instead of using reported capital costs, we infer an IOU's capital cost from its observed utility financial characteristics. With imperfect capital markets (due to asymmetric information between IPP and outside lender about the profitability of a power plant project) the outside cost of capital faced by an IPP will be greater than the opportunity cost for internal capital owned by the IPP. We use measures of an IOU's access to internal capital to capture its potential relative capital cost for IPP projects. In particular, we look at how an IOU's reported 1996 net income and total revenue are correlated with the decision of its parent company to expand into IPP.

Table 6a: Top 10 Highest NETY

Investor-owned Utility	Parent Company	IPP	NETY
Texas Utilities Electric Co	Texas Utilities Company	N	862695
Pacific Gas & Electric Co	PG&E	Y	755210
Commonwealth Edison Co	Exelon	Y	743368
Duke Power Co	Duke Energy	Y	729966
Consolidated Edison Co-NY Inc	ConEd	Y	694085
Southern California Edison Co	Edison International	Y	655395
Georgia Power Co	The Southern Company	Y	625353
Florida Power & Light Co	FPL Group Inc	Y	614895
Public Service Electric & Gas Co	Public Serv Enterprise Group	Y	535071
PECO Energy Co	Exelon	Y	517204

NETY = Electric Utility Net Income ($1000)

[14] Possibly disincentive, as hypothesized under Averch & Johnson (1962) and subsequent literature

Table 6b: Top 10 Lowest NETY			
Investor-owned Utility	Parent Company	IPP	NETY
Connecticut Light & Power Co	Northeast Utilities	Y	-78561
Entergy Gulf States Inc	Entergy Corporation	Y	-4209
Holyoke Water Power Co	Northeast Utilities	Y	-772
Indiana-Kentucky Electric Corp	American Electric Power Co Inc	Y	0
Maine Public Service Co	Maine Public Service Co	N	2111
Ohio Valley Electric Corp	American Electric Power Co Inc	Y	2315
Western Massachusetts Elec Co	Northeast Utilities	Y	4205
South Carolina Generg Co Inc	SCANA Corp	N	4611
Cambridge Electric Light Co	NSTAR	N	5121
Commonwealth Edison Co Ind Inc	Exelon	Y	5991
NETY = Electric Utility Net Income ($1000)			

Table 6a and 6b list the top 10 major IOUs with the highest and lowest 1996 net income (NETY), respectively. An IOU parent company with an utility earning greater net income is presumably one who has access to greater internal capital in the form of retained earnings and thus lower capital cost.[15] Table 6a is practically a list of who's who among IOU parent companies in U.S. IPP. All of the parent companies represented in table 6a are significant players in the U.S. independent power market except Texas Utilities Company (TXU). And even the exclusion of TXU is an exception that proves the rule: although TXU has, as of 2000, remained inactive in the U.S. IPP market, TXU is a major player internationally, especially in the deregulated markets of Australia and United Kingdom. An expansion of table 6a to include the major IOUs with the top 20 highest net income would include the parent companies that own major IPP firms Constellation Energy, PPL Energy, and Reliant Energy. There is clearly a relationship with the amount of net income an IOU receives and the likelihood of an IOU parent company to enter U.S. independent power production.[16] But this apparent relationship, though consistent with the argument that IOU parent companies use their regulated utilities to help finance IPP power plant projects, could be explained by other factors. For example, net income may also reflect the cost efficiency of the IOU.[17] Furthermore, being an accounting measure, net income may not reflect the economic

[15] Under the standard model of corporate finance, we would expect an IOU parent company's cost of capital to rise as it uses up cheaper sources of capital (retained earnings) and moves onto more expensive forms of capital (high priced corporate bonds). So greater retained earnings means that a firm can invest more at the lower capital cost.

[16] The Pearson correlation coefficient between net income and IPP participation is 0.20478 with a standard error of 0.0176.

[17] Note that higher reported net income does not necessarily indicate a better run utility. As found in Berndt, Epstein, & Doane (1996), the effective rate of return faced by a firm can be significantly affected by factors outside the control of the managers of the firm.

variable of interest: the retained earnings of the IOU. Due to such factors as taxes, firms do have an incentive to "play with the numbers" and report a net income different from its economic value. The analysis on net income is *caveat* the usual criticisms associated with using accounting financial measures.

Table 6c: Top 10 Highest NRVSE			
Investor-owned Utility	Parent Company	IPP	NRVSE
Pacific Gas & Electric Co	PG&E	Y	7432952
Southern California Edison Co	Edison International	Y	7362431
Commonwealth Edison Co	Exelon	Y	6868993
Florida Power & Light Co	FPL Group Inc	Y	5872088
Texas Utilities Electric Co	Texas Utilities Company	N	5867619
Consolidated Edison Co-NY Inc	ConEd	Y	5220209
Georgia Power Co	The Southern Company	Y	4340778
Virginia Electric & Power Co	Dominion Resources Inc	Y	4300152
Duke Power Co	Duke Energy	Y	4246556
Public Service Electric&Gas Co	Public Serv Enterprise Group	Y	3854423
NRVSE = Revenue from Sale of Electricity ($1000)			

Table 6d: Top 10 Lowest NRVSE			
Investor-owned Utility	Parent Company	IPP	NETY
Fitchburg Gas & Elec Light Co	UNITIL Corporation	N	51034
Maine Public Service Co	Maine Public Service Co	N	54194
Holyoke Water Power Co	Northeast Utilities	Y	63500
Northwestern Public Service Co	Northwestern Corp	N	72652
St Joseph Light & Power Co	UtiliCorp United	Y	82470
Commonwealth Edison Co Ind Inc	Exelon	Y	94137
South Carolina Generg Co Inc	SCANA Corp	N	95344
Black Hills Corporation	Black Hills Corporation	Y	114596
Cambridge Electric Light Co	NSTAR	N	118261
MDU Resources Group Inc	MDU Resources Group	N	135045
NRVSE = Revenue from Sale of Electricity ($1000)			

In addition to net income, we also consider the revenue an IOU earns from the sale of electricity (NRVSE). For an IOU parent company considering making large IPP capital investments, the relevant financial information may not be so much retained earnings as it is cash flow. Moreover, revenue is a figure that may be less prone to accounting manipulation than net income as retail electricity prices are set by the regulators. Not too surprisingly, the results for revenue are similar to the results for net income, with Tables 6c and 6d including most of the same IOUs as for net income.[18] There is clearly a strong positive correlation between net income and revenue, based primarily on the scale of utility operation: an IOU serving a larger franchise area will face a larger revenue stream and have the opportunity to earn a greater level of net income. This raises another concern in that it is difficult to tell whether the significant correlation we observe between net income / revenue and IPP participation is due to greater access to capital (as argued) or to other benefits of scale, such as more experience from operating more generation capacity. Further complicating the analysis is the idea that scale may be endogenous; IOUs with greater scale of operation may be the ones with greater (unobserved) advantages. Unfortunately, there are no simple fixes for these complications. Some of these complications are dealt with explicitly later in the paper.

Table 7a: Top 10 Highest ATOL			
Electric Energy Inc	LG&E Energy Corporation	Y	2.148
Indiana-Kentucky Electric Corp	American Electric Power Co Inc	Y	2.142
Commonwealth Edison Co Ind Inc	Exelon	Y	2.049
Southern Electric Generatg Co	The Southern Company	Y	1.876
Kentucky Utilities Co	LG&E Energy Corporation	Y	1.482
Ohio Valley Electric Corp	American Electric Power Co Inc	Y	1.471
Public Service Co of Oklahoma	American Electric Power Co Inc	Y	1.468
Oklahoma Gas & Electric Co	OGE Energy Corp	N	1.416
South Carolina Generg Co Inc	SCANA Corp	N	1.366
Interstate Power Co	Alliant Energy	Y	1.339
ATOL = Electric Utility Assets-to-Liabilities Ratio			

Table 7b: Top 10 Lowest ATOL			
Citizens Utilities Co	Citizens Communications	N	0.168
Public Service Co of NH	Northeast Utilities	Y	0.406
Western Resources Inc	Western Resources	N	0.453
UtiliCorp United Inc	UtiliCorp United	Y	0.497
Fitchburg Gas & Elec Light Co	UNITIL Corporation	N	0.565
Bangor Hydro-Electric Co	Emera	N	0.569
Minnesota Power & Light Co	Allete	N	0.638
Northwestern Public Service Co	Northwestern Corp	N	0.667
Montana Power Co	Montana Power Co	N	0.701
Orange & Rockland Utils Inc	ConEd	Y	0.711
ATOL = Electric Utility Assets-to-Liabilities Ratio			

[18]The Pearson correlation coefficient is similar as well, 0.23095 with a standard error of 0.0073

In addition to net income and revenue from sale of electricity, we examine one last financial characteristic of an IOU: its assets-to-liabilities ratio (ATOL). We use the reported assets-to-liabilities ratio to arrive at a more direct inference of an IOU's capital cost, especially with respect to outside sources of capital. The idea here is that an IOU with a lower assets-to-liabilities ratio is one that faces greater borrowing constraints (less collateral, more leveraged) and greater capital costs from outside lendors. Tables 7a and 7b appear consistent with this conjecture as 8 of the major IOUs with high ATOL values are owned by parent companies active in U.S. IPP, compared to just 3 among the major IOUs with low ATOL values.[19] Again, like the case for net income, this result is *caveat* the usual criticisms surrounding the use of accounting measures, with the chosen accounting definition of assets and liabilities possibly different from their relevant economic definitions. However, while the observed significant correlation between the financial variables (NETY,NRVSE,ATOL) and IPP participation may not necessarily reflect the intended capital cost argument, it is difficult to think that the correlations are purely spurious. There is most likely some economic story underlying these observed correlations.

Tables 1 through 7 provide some descriptive support for the idea that the characteristics of the IOUs bear some influence on the decision of the IOU parent companies to participate in U.S. IPP activities. Table 1 and 2 show that both the main buyers and sellers of divested utility power plants are IOUs owned by parent companies active in U.S. IPP. Combined with the results from tables 6 and 7, these tables paint a suggestive story that an IOU's financial situation, especially with regards to its ability to provide cash-flow to finance other projects, may help explain the significant presence of IOU parent companies in U.S. IPP activities. At the same time Tables 3 through 5, using data from FERC Form 1 reports, provide some evidence that parent companies affiliated with IOUs with lower reported O&M costs are more likely to participate in U.S. IPP. Both of these findings are consistent (though not exclusively) with the argument that the IPP participation decision of IOU parent companies is driven by relative cost considerations, with more efficient IOUs entering the newly restructured wholesale electricity markets. The descriptive information analyzed above, while not conclusive, does motivate a closer examination of the relationship between these utility characteristics and the IPP participation decision.

[19] The Pearson correlation coefficient is 0.29613 with a standard error of 0.0005

3 An Entry Model for IPP Generation Capacity

In the previous section, we examine how different individual characteristics of the IOUs seem to correlate with the decision of the parent company to expand into U.S. independent power production. Here, we examine these factors jointly within the framework of an entry model. By imposing the constraints implied by an entry model that reasonably approximates reality on the data, we can estimate an IPP capacity cost function explicitly. This in turn will enable us to consider the relative importance of each observed utility characteristic on the observed level of IPP activity engaged by the IOU parent company. The market the IOU parent companies are considering entering is defined in the following two manners. First, geographically, the market definition follows the North American Electricity Reliability Council (NERC)'s 13 U.S. major subregion definition. NERC is the industry governing body for the North American electricity transmission and distribution entities. Each of these subregions, spanning the continental U.S., is based on existing transmission and distribution capabilities and helps take into consideration the fact that a power plant located in one state may actually provide much of its generation to end consumers located in a neighboring state. Thus, NERC subregions provide the closest geographic definition based on location of actual demand.

Second, the product sold in the market is not generation services per se but rather generation capacity. The wholesale electricity market actually consists of two vertically integrated markets. The downstream "spot" market is the market where actual generation (in terms of Kwh) are traded between energy traders and retail marketers who represent the end consumers. This is the market that has been the focus of much of the current research, including the various market power studies such as BBW. However, the market that drives much of the entry decision for IPPs is the upstream market for new generation capacity. This is the market where IPPs sell options for the rights to their generation output for some time period (often 5-10 years) to an energy trader. These power purchase agreements are usually negotiated before the commercial start and sometimes even before the construction of the power plant.[20] For many IPPs, the decision to go forward with a merchant power plant project hinges crucially on the price it expects to earn from its power purchase agreements. In California, examples of these upstream "capacity" transaction include the power purchase agreements negotiated by IPPs AES and Calpine with energy traders Williams and Enron, respectively. Williams and Enron use the options they purchased from AES and Calpine to sell electricity in the spot market. Although some firms, such as Reliant and Dynegy in California,

[20]These agreements should not be confused with the "secondary" power purchase agreements negotiated by California Governor Gray Davis with energy traders to bypass the spot market during the winter of 2000-01.

choose both to own power plants and trade generation output in the spot market, these can be considered cases where the IPPs choose to sell their capacity to their own internal energy trader.[21]

In this paper, we assume that IOU parent companies (through their subsidiaries) invest in new IPP capacity based on the price they expect to earn from making this capacity available in the upstream generation market. Thus, entry in the market is signified by the parent company acquiring or building a positive amount of IPP generation capacity in the NERC subregion.[22] Unfortunately, identifying the exact timing of entry is complicated by the fact that the exact year in which an IPP capacity was built/acquired is not readily available for some IOU affiliated IPPs.[23] Consequently, we consider entry during a period of time. We consider 1996 to mid-2000 as the initial entry period. An IOU parent company is assumed to have entered a market if it acquired and/or successfully constructed a positive amount of IPP generation capacity between 1996 and 2000 in that NERC subregion. The main drawback to studying entry during a period of time as opposed to a single year is that prices and other market conditions may vary within that period. Of particular concern is the impact that observed ongoing effects of restructuring may have on firm expectations about the profitability of IPP activities. Some of this concern is mitigated by the choice of mid-2000 as the end of the period, which allows us to avoid possible distortions from the California Power Crisis.[24] Moreover, a review of the industry press does not raise any significant concern about changes in the prices for power purchase agreements negotiated between IPPs and energy traders between 1997 and 1999.[25]

The level of IPP capacity with which an IOU parent company decides to enter a market is determined by the market price for capacity and the cost function for developing and operating IPP capacity faced by the parent company. The cost function is modeled as an exogenous function of observed utility characteristics. Both the characteristics raised earlier as reflecting an IOU parent company's costs for operating and maintaining power plants and those believed to reflect the company's capital costs are included. In order to account for the fact that some IOU parent companies own multiple IOUs, two methods of aggregating utility information to the level of parent company are considered. The first method is simply using the characteristics of the "largest" owned

[21] This difference in chosen level of integration might be an interesting focus for a separate paper.

[22] We exclude any transfers of generation capacity from the utility subsidiary to the IPP subsidiary of the same parent company.

[23] What we observe for all firms is the generation portfolio of the IPP as of mid-2000. For some power plants in the portfolio, investment date is neither observed nor can be inferred.

[24] With power plant acquisitions and construction taking no less than a year, power plants that become commercially available in mid-2000 were developed by IPPs based on information no more current than mid-1999.

[25] Although the period covers 1996-2000, most of the new capacity became commercially online from 1998 to 2000, implying that much of the power purchase agreements were probably signed between 1997 and 1999.

IOU as defined by the amount of 1996 steam power generation.[26] The second is using a weighted average of all owned major IOUs, with weights calculated by taking the ratio of the utility's 1996 steam power generation over the sum of 1996 steam power generation by all owned major IOUs.

Table 8: IOU Parent Company Characteristics

Variable	Mean	Std Dev	Min	Max
Owned IPP U.S. Capacity (IPPUSN)	0.96185	2.50588	0.00000	13.18277
Divested Utility Capacity (DIVTOT)	1.59649	3.12699	0.00000	12.69900
"Largest Utility" Specification				
Non-fuel O&M Cost (SRNF)	0.00656	0.00549	0.00191	0.03960
Net Income (NETY)	0.19953	0.20780	-0.00421	0.86270
Revenue from Elec Sale (NRVSE)	1.63047	1.75148	0.05103	7.43300
Assets-to-Liabilities (ATOL)	0.98420	0.23265	0.16782	1.48192
"Weighted Average" Specification				
Non-fuel O&M Cost (SRNF)	0.00663	0.00544	0.00191	0.03960
Net Income (NETY)	0.18932	0.19622	0.00211	0.86270
Revenue from Elec Sale (NRVSE)	1.55860	1.67034	0.05103	7.43300
Assets-to-Liabilities (ATOL)	0.99335	0.21642	0.16782	1.46687

$N = 81$
IPPUSN, DIVTOT are in thousand MWs
NETY, NRVSE are in billion dollars
SRNF is in dollars / KWh

As the summary statistics above reveal, the variables do not differ much between the two methods. This is primarily because most IOU parent companies own only one IOU or own one that simply dwarfs all others in scale of operation. Consequently, the paper adopts the simpler specification of "largest utility" in determining the observed utility characteristics assigned to each IOU parent company. Therefore, the IPP capacity cost function for an IOU parent company will primarily be a function of the utility characteristics of the "largest" IOU it owns. However, we make one exception: we model cost as being a function of the total amount of utility generation capacity divested by all major IOUs owned by the parent company. This is because divestiture is an one-time event (for each utility) whose timing is erratic. Therefore, it does not make sense to use a "representative" utility approach for the divestiture characteristic. Additionally, we choose to use only one of the utility O&M costs as ROM, SROM, and SRNF are highly correlated with each other. The non-fuel,

[26] Again, steam power is used as a criterion as most merchant power generation is steam powered. Therefore the utility with the greatest steam power generation seems the most relevant for inferring potential IPP costs

steam powered O&M cost (SRNF) is adopted because it is the most comparable across utilities operating in different geographic regions.

The price for capacity is modeled as being uniform for all IPPs in a market. Although power purchase agreements are negotiated bilaterally between IPP and energy trader, there are good reasons to believe that these negotiated prices converge for a market. First, while details of a power purchase agreement are not published, there is sufficient evidence in industry press to suggest that industry agents do know the agreed price and quantity. Second, given that there are relatively few energy traders and IPPs active in a market, the transaction costs are low for both IPPs and energy traders to "shop around." Therefore, we would not expect differential prices to survive long for similar types of capacity.[27] Assuming uniform market prices seems fairly reasonable. However, what is unclear about market prices is the process by which they are determined. The market price for any good is determined in large part by the nature of competition in the market. In a purely competitive market, the price is determined by the intersection between the aggregate demand curve and the system-wide marginal cost curve. But in the presence of market power for either buyer or seller, the price can stray from this competitive value. Much of the current research on electricity restructuring has focused on establishing empirical evidence of market power (for energy traders) in the downstream spot market. The results of this literature would seem to suggest that the market for power purchase agreements would similarly be distorted by the presence of market power.

However, there are key differences between the two generation markets that would suggest otherwise. First, the ability of energy traders to exercise market power in the spot market depends greatly on real-time fluctuations in market conditions that cannot easily be forecasted. For example, in California, much of the ability of energy traders to charge high prices have been linked to abnormally high summer temperatures and abnormally low rainfall that limited the amount of available (cheap) hydroelectric power.[28] While spot market prices can change to reflect these unexpected changes in current market conditions, the price for capacity cannot, in general, because it has been agreed upon ahead of time, with a price schedule determined and fixed for several years based on *expected* market conditions.[29] Furthermore, we would expect the energy trader to get most

[27] A *caveat* is that not all capacity are the same. Due to transmission constraints, the location of a power plant may make it more or less valuable, especially in the ancillary services markets for generation. However, for many restructured wholesale electricity markets, such as California, the main "generation" spot market values electricity from all locations equally. For now, we ignore the location dimension of generation capacity.

[28] See Borenstein & Bushnell (1999) for an analysis of factors contributing to market power in California.

[29] In theory, the agents could draw up a contingent claims contract. But this is not the general practice in the industry.

of the surplus from beneficial turns in the market as they incur almost all of the market risk when they sign a power purchase agreement. Therefore, it is not clear that greater surplus in the spot market due to unexpectedly favorable market fluctuations would lead to greater surplus for the IPP in the capacity market. Second, favorable changes in market conditions can lead to market power (in the short-run) for energy traders in the spot market because there are sizable entry barriers; it is difficult for firms outside of the spot market to take advantage of unexpected shocks (e.g. heat wave or an emergency shutdown of a large existing power plant) because new power plants cannot be constructed quickly nor can electricity from a different market be exported economically to the desired market.[30] But this is not necessarily true for the capacity market. Given the fact that many of these power purchase agreements are negotiated well before the commercial start of the new power plant, both IPPs inside and outside the market have much more time to adjust their supply capability. Consequently, sudden shifts in expectations about current and future value of generation can elicit suitable supply reactions from both current and potential entrants, leading to much of the benefits from the market shift being competed away.

Based on these two key differences between the spot and capacity markets, it is not clear that (apparent) market power in the spot market naturally indicates market power in the upstream capacity market. In fact, it is arguable that IPPs are actually price-takers in the capacity market, given the credible threat of entry. Furthermore, we would expect the price that an energy trader is willing to pay for capacity would depend principally on expected prices in the spot market. So modeling market price as a function of observed market characteristics that govern an energy trader's expectations about spot generation prices would be a reasonable approximation. Accordingly, the entry model considered in this paper assumes that IPPs are price-takers in the capacity market and that the equilibrium market prices are a function of observed market characteristics that indicate expected spot market prices.

3.1 Empirical Framework

We consider the standard linear-quadratic framework for our entry model: the price for capacity is constant per unit of capacity while the cost of developing and operating the capacity over the horizon of the power purchase agreement is quadratic with respect to the size of capacity. The assumption of a constant per unit price can be rationalized by thinking that for N power plants

[30] This is given inter-NERC region transmission constraints and losses.

providing generation at the same price, the utilization rate of each of the power plant is the same.[31]

$$
\begin{aligned}
P_{\text{capacity}} &= \sum_{t=1}^{T}\sum_{h=1}^{24} \beta^t \; P_{th} \; u_{th} && (1)\\
&\text{where} \\
P_{th} &= \text{Unit price for generation for year t, hour h} \\
u_{th} &= \text{Utilization rate for year t, hour h}
\end{aligned}
$$

The quadratic cost function can be rationalized in several manners. Perhaps the most reasonable is to think that while initial increases in the capacity decreases overall cost due to scale benefits in operations and maintenance costs,[32] overall costs eventually rise with capacity due to larger capital costs, as cheaper internal sources of capital get depleted.

$$
\begin{aligned}
C(q) &= \alpha_{0f} + \alpha_{1f} \; q + \alpha_{2f} \; q^2 && (2)\\
&\text{where} \\
(\alpha_{0f}, \alpha_{2f}) &\geq 0 \\
\alpha_{0f} &\equiv \alpha_0(X_{0f} : \theta_0) \\
\alpha_{1f} &\equiv \alpha_1(X_{1f} : \theta_1) \\
\alpha_{2f} &\equiv \alpha_2(X_{2f} : \theta_2)
\end{aligned}
$$

Given the market price and a cost function, an IOU parent company f enters market g only if a firm can earn non-negative nominal profits for some positive amount of capacity q_{fg}. A necessary and sufficient condition for this profit condition given the linear-quadratic framework is for market price to be greater than or equal to minimum scale cost. Moreover, conditional on a firm entering, a price-taking firm will provide capacity until the marginal cost of providing the q^{th} unit of capacity equals the market price. Recall that in an industry without fixed costs, this "P=MC" condition is sufficient to ensure the non-negative profit constraint as well. However, in the presence of fixed cost, the two constraints need to be imposed individually.[33]

[31] This is true for the CalPX market. If firm A bids 200 MW at $30/Mwh and firm B bids 300 MW at $30/Mwh and only 100 MW is needed to clear the market, then the market takes 40 MW from firm A and 60 MW from firm B, leaving each firm with an utilization rate of 20%.

[32] These scale benefits include bulk purchasing of fuel and the sharing of equipment and labor (repair crews) among many power plants

[33] Furthermore, neither the existence nor uniqueness of a competitive equilibrium in general can be proven in a market with fixed costs. Therefore, the analysis starts from the working assumption that a unique competitive equilibrium exists for the market.

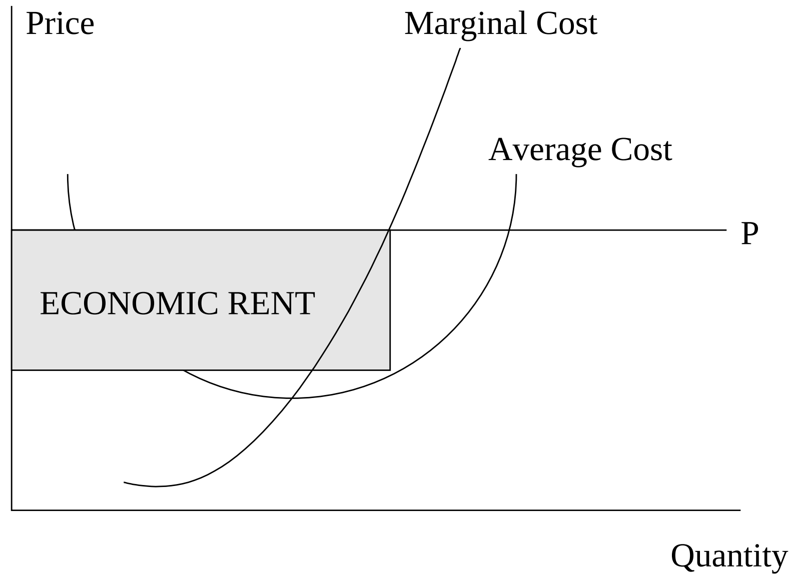

Figure 1: Case of an Entrant IOU Parent Company

In this model, it is possible for a firm to earn positive nominal profits. This is because they are earning economic rents for their cost advantages compared to the marginal entrant firm. In the long-run, we would expect these rents to disappear as production technology and skills diffuse in the industry. But during the relevant, shorter time horizon of the power purchase agreement, the technology and skill set of a firm are presumably fixed. So, for a given uniform market price, some firms will earn more nominal profits. To some extent, the entry model explains the difference in the level of IPP activities among IOU parent companies through the difference in economic rent they can potentially earn.

Conditional on a firm entering the market, the linear revenue function and globally convex cost function ensures that the "P=MC" condition inverts for a unique value of capacity (q^*_{fg}). Also, in order for a firm to enter, both this derived q^*_{fg} and nominal profits at this q^*_{fg} must be non-negative.

$$q^*_{fg} = \frac{P_g - \alpha_{1f}}{2\alpha_{2f}} \tag{3}$$

$$\begin{aligned} \Pi^*_{fg} &= P_g q^*_{fg} - C(q^*_{fg}) \\ &= (P_g - \alpha_{1f}) q^*_{fg} - \alpha_{0f} - \alpha_{2f}(q^*_{fg})^2 \\ &= \frac{(P_g - \alpha_{1f})^2}{4\alpha_{2f}} - \alpha_{0f} \end{aligned} \tag{4}$$

To capture the econometrician's ignorance, we propose that we observe the difference between market price and the linear cost term ($P_g - \alpha_{fg}$) up to some additive error term (ν_{fg}) which is distributed *i.i.d.* Normal across (firm,market) observations. This term is meant to capture the fact that there are some components of the firm negotiated price and cost that are not completely captured by the model.[34]

$$
\begin{aligned}
q^*_{fg} &= \frac{P_g - \alpha_{1f} - \nu_{fg}}{2\alpha_{2f}} && (5)\\
\Pi^*_{fg} &= \frac{(P_g - \alpha_{1f} - \nu_{fg})^2}{4\alpha_{2f}} - \alpha_{0f} && (6)\\
\nu_{fg} &\overset{i.i.d.}{\sim} N(0, \sigma^2_\nu) && (7)
\end{aligned}
$$

Accordingly, a likelihood function can be derived for the observed q_{fg}. Recall that a firm enters ($q_{fg} > 0$) only if $q^*_{fg} > 0$ and $\Pi^*_{fg} \geq 0$. This implies a range of values for ν_{fg} such that a firm with characteristics (X_{0f}, X_{1f}, X_{2f}) facing market price P_g will enter.

$$
\begin{aligned}
q^*_{fg} > 0 \ &\rightarrow \ \nu_{fg} < P_g - \alpha_{1f}\\
\Pi^*_{fg} \geq 0 \ &\rightarrow \ \nu_{fg} \leq P_g - \alpha_{1f} - 2\sqrt{\alpha_{0f}\alpha_{2f}} \ \text{ or } \ \nu_{fg} \geq P_g - \alpha_{1f} + 2\sqrt{\alpha_{0f}\alpha_{2f}}
\end{aligned}
$$

Combining the two constraints, we find that an observation of $q_{fg} > 0$ is associated with $\nu_{fg} \leq P_g - \alpha_{1f} - 2\sqrt{\alpha_{0f}\alpha_{2f}}$. Similarly, observations where firm f has not entered market g ($q_{fg} = 0$) are associated with $\nu_{fg} > P_g - \alpha_{1f} - 2\sqrt{\alpha_{0f}\alpha_{2f}}$. This yields us the following explicit likelihood function

$$
(\theta_0, \theta_1, \theta_2) \equiv \operatorname{argmax} \sum_{f=1}^{81}\sum_{g=1}^{13} \log \, l_{fg} \qquad (8)
$$

where

$$
\begin{aligned}
l_{fg} &= \left[\phi\Big(\frac{P_g - \alpha_{1f} - 2\alpha_{2f}\, q_{fg}}{\sigma_\nu}\Big) \, \frac{2\alpha_{2f}}{\sigma_\nu} \right]^{\delta_{fg}} \left[1 - \Phi\Big(\frac{\nu^*_{fg}}{\sigma_\nu}\Big) \right]^{1-\delta_{fg}} && (9)\\
\alpha_{0f} &\leq \alpha_{2f} \times (\, q_{fg}\,)^2\\
\nu^*_{fg} &= P_g - \alpha_{1f} - 2\sqrt{\alpha_{0f}\alpha_{2f}}\\
\delta_{fg} &= \begin{cases} 0 & \text{if } q_{fg} = 0 \\ 1 & \text{if } q_{fg} > 0 \end{cases}
\end{aligned}
$$

The constraint on the relative values of α_{0f}, α_{2f} is necessary in order to ensure that the likelihood has full parameter support. With the presence of fixed costs, it is possible for the value of q_{fg} obtained from inverting the "P=MC" condition (q^*_{fg}) to imply a value $\nu_{fg} > \nu^*_{fg}$. The above constraint on α_{0f}, α_{2f} ensures that this does not happen.[35] Note that an alternative to this constraint

[34] An alternative framework would have been to assume a separate error for price (ϵ_g) and linear cost (η_f) such that $\nu_{fg} = \epsilon_g - \eta_f$. This implies a serial correlation structure across observations for the same market g or same firm f. For simplicity, we first the *i.i.d* ν_{fg} specification.

[35] One can think of this constraint being yet another derived from the data. Here, the minimum amount of positive investment made by an IOU parent company in a market provides information on the upper bound of the fixed cost.

is to introduce an additional error term, such as in the level of profit (perhaps an unobserved component of fixed cost). With two errors, one error would fit the observed entry decision and the second error would fit the observed amount of q_{fg}. But this likelihood would require the use of simulated maximum likelihood as it requires numerical integration to evaluate part of the likelihood. Furthermore, the constraint can also be avoided by estimating the model using Generalized Method of Moments. The appendix provides a derivation of such a GMM model based on the first two conditional moments.

Finally, it is important to point out a key assumption underlying this empirical model: market price P_g is assumed not only to be observable to all firms but also (at least indirectly) to the econometrician. In the empirical exercise undertaken in this paper, P_g is modeled as a function of observed, exogenous market characteristics: $P_g = f(X_g : \theta_p)$. Without an explicit price error, this implies that P_g can be recovered fully from the model. This assumption can be relaxed with the introduction of an explicit price error ϵ_g but would require the model to stray from the simple *i.i.d.* framework.

3.2 Model Specification

In order to keep the model parsimonious, we model observed differences in the cost function across IOU parent companies as being exclusively in the quadratic term ν_{fg}.[36] This specification takes an explicit stance on what we believe the data can explain: for a quadratic cost curve and a given price, it is the linear cost term that determines whether a firm enters and the quadratic cost term that largely determines the amount by which a firm enters. Consequently, putting the observed explanatory variables exclusively in the quadratic term makes the stance that what can be best explained by the data is not the (0-1) decision of whether an IOU parent company enters the generation capacity market but the level of capacity associated with an entrant IOU parent company. Therefore, the empirical estimates seek mainly to explain the observed differences in the level of IPP activities among entrants. However, the model does not completely abandon the goal of using observed utility characteristics to explain the IOU parent company (0-1) entry decision: the fixed cost α_{0f} is modeled as an increasing function of α_{2f}.

[36]Efforts to estimate models where utility characteristics were included in both the linear and quadratic term have so far failed to converge to reasonable estimates.

$$
\begin{aligned}
C(q) &= \alpha_{0f} + \alpha_{1f}\ q + \alpha_{2f}\ q^2 \\
\alpha_{2f} &= \exp\{\alpha_{20} + \alpha_{21}\ \mathrm{ATOL}_f + \alpha_{22}\ \mathrm{LNETY}_f + \alpha_{23}\ \mathrm{LNRVSE}_f \\
&\quad +\alpha_{23}\ \mathrm{DIVTOT}_f + \alpha_{24}\ \mathrm{SRNF}_f + \alpha_{25}\ \mathrm{FOSCAP}_f \\
&\quad +\alpha_{26}\ \mathrm{LFOSYR}_f + \alpha_{27}\ \mathrm{NEWCAP}_f\} \\
\alpha_{0f} &= \Phi(\alpha_{01})\ \alpha_{2f}\ (\ \min\{\ q_{fg} | q_{fg} > 0\ \}_{(f,g)}\ )^2 \\
\alpha_{1f} &= \alpha_{11} \\
\sigma_\nu &= \exp\{\ \mathrm{VSIGMA}\ \} \\
\mathrm{LNETY} &\equiv \log(\ 1 + \max\{\ 0, \mathrm{NETY}\ \}\ ) \\
\mathrm{LNRVSE} &\equiv \log(\ \mathrm{NRVSE}\ ) \\
\mathrm{LFOSYR} &\equiv \log(\ \mathrm{FOSYR}\ )
\end{aligned}
$$

In addition to the utility characteristics we considered in the earlier descriptive analysis, we consider three additional variables: FOSCAP, FOSYR, and NEWCAP. One of the concerns raised in the analysis of the correlation between observed IPP participation and the utility characteristics net income (NETY) and revenue from sales of electricity (NRVSE) is that these latter utility variables may not be reflecting capital cost advantages as much as the scale of operation of the utility. An alternative reason why scale might matter other than access to greater retained earnings / cash-flow is that IOUs with greater generation operations would have more opportunities to learn and benefit from the experience of running power plants. In order to help alleviate this concern, FOSCAP is included in the specification. FOSCAP is simply the total (nameplate) capacity of fossil-fuel burning power plants operated by the "largest" owned utility in 1996.[37] By including FOSCAP, we hope to separate the two scale effects: larger internal sources of capital and greater operational experience. We also include the 1996 average age of the fossil-fuel burning capacity (FOSYR) and the amount of utility generation capacity developed between 1985 and 1995. Both are used to capture the vintage of the power plants the IOU parent company is used to operating and maintaining. Furthermore, it is important to note that the specification of α_{0f} ensures that the fixed cost is non-negative and bounded above appropriately.[38]

The price for capacity (P_g) is modeled around the 1996 retail electricity price ($/Kwh) for the market. This is a confession that not all relevant variation in market characteristics is observed in the model. It is hoped that differences in the 1996 retail electricity price will capture much of this

[37] Again, "largest" refers to most steam-powered generation in 1996.

[38] The specification ensures full parameter support as it guarantees that $q_{fg} \geq \sqrt{\alpha_{0f}/\alpha_{2f}}$ for all (f,g) where $q_{fg} > 0$

unobserved variation.

$$P_g \;=\; P_{1996}^{\mathrm{retail}} \; \exp\{\, \gamma_1 \; \mathrm{LOAD96}_g + \gamma_2 \; \mathrm{RM96}_g \; + \gamma_3 \; \mathrm{LDFACT96}_f \,\}$$

In terms of observed market variation, we include two terms (RM, LDFACT) we believe provide a strong indication of the spot price of generation an energy trader expects to earn in the market. RM is the 1996 reserve margin for the market, calculated as the ratio between peak demand and existing generation capacity in the market. This market characteristic captures the general tightness of supply. A market with a low reserve margin is one that is susceptible to supply shortages, whether due to unexpected demand / supply shocks or strategic withholding of capacity. Thus, energy traders may expect a larger price for generation in such markets and be willing to pay more for capacity. LDFACT is a measure of the load factor for the market and is calculated as the ratio between peak and average generation demand. LDFACT captures the tightness in supply during peak periods as a high load factor implies that a large amount of generation capacity is needed just for the peak period. Lastly, the demand for the market in 1996 is included as well. This is to account for a direct consequence of the assumption of a competitive market. A market with a greater level of demand *ceteras paribus* will face a higher price because the market will need to resort to the entry and greater participation of less efficient firms in order to satisfy demand ("climbing up" the system marginal cost curve).

3.3 Results

In the estimates reported below, the parameter for the fixed cost α_{01} was fixed to be 0. In theory, the parameter is identified. However, in practice, it is difficult to estimate it with any precision. Furthermore, it hampers the ability to obtain precise estimates for other parameters. Note that the only feature in the model that helps pin down the units for the level of profits is the retail price. Thus, the identification of α_{01} is tenuous at best. The maximum likelihood estimates reported below should therefore be interpreted as the parameters for the cost and price functions normalized by the unobserved level of each IOU parent company's fixed cost. Along with the ML estimates, the OLS estimates from regressing q_{fg} against the chosen market and utility characteristics are reported for contrast.[39]

[39] Keep in mind that the sign expectations are "flipped" for the cost parameters in the OLS regression.

Table 9a: Estimates for Full Observations				
Parameter	OLS		ML	
	Estimate	Std Error	Estimate	Std Error
PRICE PARAMETERS				
Retail Price (P96)	.03225	.01371		
Load (LOAD96)	.01222	.02089	-.01965	.09960
Reserve Margin (RM96)	.16846	.25226	-2.42291	2.04881
Load Factor (LDFACT96)	-.00443	.19871	-3.36370	1.95257
LINEAR COST PARAMETERS				
Constant (α_{11})			.00316	.01816
VSIGMA			-6.44980	5.6690
QUADRATIC COST PARAMETERS				
Constant (α_{21})			7.28723	6.55183
Assets-to-Liab (ATOL)	.08556	.12625	.84501	.32570
Net Income (LNETY)	.53833	.35674	4.15416	1.68024
Revenue (LNRVSE)	-.04703	.04123	-.98716	.39978
Divestiture (DIVTOT)	.03129	.00897	-.16975	.02991
Non-fuel O&M (SRNF)	-2.98007	5.46886	242.019	46.9908
Fossil-Fuel Cap (FOSCAP)	.00876	.01405	-.01978	.05733
Fossil-Fuel Age (LFOSYR)	.00870	.09140	-1.05097	.69170
New Capacity (NEWCAP)	.05820	.03588	-.98716	.10117
Log Likelihood	-1211.57		-447.147	
N = 1053, R^2 for OLS = .054593				

The maximum likelihood estimates, for the most part, provide precise estimates for the cost parameters. With the exception of the two utility fossil-fuel burning power plant statistics (FOSCAP, LFOSYR), the coefficients for the utility characteristics are significant around the 1% level. For the characteristics that capture the IOU parent company's skills in operating and maintaining power plants, the coefficients are consistent with prior belief. An IOU parent company with utilities reporting larger non-fuel O&M costs (SRNF) face a larger cost in the IPP capacity market. Similarly, IOU parent companies with utilities that have extensive fossil-fuel burning operations face a lower cost, though not statistically significant. The ML estimates also provide an interesting dichotomy: the coefficients before the level of new utility capacity (NEWCAP) and the average age of the utility fossil-fuel burning power plants are both negative.[40] This would imply that an IOU parent company has a possible advantage operating both old and new power plants. This is

[40] Only NEWCAP is statistically significant by convention, although the P-value for LFOSYR is 0.129

most likely a result of the fact that the two primary ways to acquire IPP capacity in a market is to build a new power plant or buy an old existing power plant from the incumbent utility. Hence, familiarity with both new and old power plants can translate into lower cost for operating IPP merchant power plants. Although the earlier descriptive analysis found only weak evidence for the role of variation in reported O&M costs in explaining different IPP participation decisions, the ML estimates appear to indicate that both reported and inferred O&M costs have a significant bearing on an IOU parent company's decision to enter and invest in an IPP capacity market.

Furthermore, the ML estimates find much weaker evidence for the earlier "capital cost" story that seemed so compelling in the descriptive analysis. The coefficients before net income (LNETY) and assets-to-liabilities (ATOL) are statistically significant but positive. According to the capital cost argument, this would imply that a parent company with greater access to internal capital would face larger (not smaller) capacity costs.[41] This would appear to confirm the earlier concern that the correlation between these reported financial measures and IPP participation is reflecting not the capital cost advantage but the scale of operation. In fact, further confirming this suspicion is the result that eliminating net income and revenue from the model yields estimates that do not qualitatively differ except for the the coefficients before FOSCAP and LFOSYR, which "become" more substantial and statistically significant.[42] However, it is difficult to tell whether this disappearance of the net income and revenue effects is an invalidation of the capital cost story or an unfortunate consequence of using accounting measures which can be substantially distorted from their "true" economic values. One thing that points to the answer being the latter is the significant, negative coefficient on the level of utility divestiture. As argued earlier, proceeds from utility divestiture can be used by the parent company to finance the generation investment of their IPP subsidiary. In all of the different models estimated during the course of this research, a significant, negative coefficient on divestiture has been a consistent result. Moreover, it should be pointed out that the divestiture is one of the few coefficients significant in the Least Squares estimates as well. The fact that divestiture has such a robust negative effect on cost (and positive effect on IPP capacity investment) would seem to argue that capital cost considerations do appear to matter.

A possible concern about these results is that the underlying model does not distinguish between entering a market and entering the IPP industry in general. There may be sizable costs to entering the industry that are separate from entering any individual market. In order to explore this concern, the model is re-estimated based on a limited sample. The full dataset was pruned

[41] However, the coefficient before revenue is negative and significant near the 1% level.

[42] See Appendix for these alternate estimates. The likelihood ratio test on the null hypothesis that the coefficients for LNETY and LNRVSE are jointly zero (test statistic = 3.214) cannot be rejected at the 10% significance level

to include only firms that have entered at least one of the markets during the sample period and only markets where at least one state has enacted substantial restructuring legislation. The latter criterion eliminated the NERC regions FRCC (Florida), MAPP (South Dakota, Nebraska area), and WSCC-NWP (Pacific Northwest). As the estimates reported in the Appendix demonstrate, the results hardly change. Of course, working with such a limited sample only partially accounts for this difference between entering the industry and entering a market. A more comprehensive study would require modeling the two decisions separately. One could imagine capital costs playing a significant role in the decision to enter the industry (as setting up IPP operations may require sizable up-front investments) but O&M costs playing the deciding factor in the decision over which and how many markets to enter.

Table 10: Counterfactual

Market	$\hat{P}_g$	% Δ $E(\sum_f q_{fg})$	
		$0.9 \times \hat{p}_g$	$1.1 \times \hat{p}_g$
California (WSCC-CNV)	0.00144	-14.05	14.05
East North Central (ECAR)	0.00143	-14.01	14.08
East South Central (SPP)	0.00144	-8.23	8.63
Florida (FRCC)	0.00099	-11.58	13.37
Midwest (MAIN)	0.00077	-8.52	9.27
Mountain / Midwest (MAPP)	0.00075	-9.46	10.81
New England (NPCC-NE)	0.00183	-12.71	12.71
New York (NPCC-NY)	0.00156	-14.86	14.86
Northwest (WSCC-NWP)	0.00097	-10.58	11.90
Pennsylvania-New Jersey-Maryland (MAAC)	0.00147	-13.96	13.96
Southeast (SERC)	0.00145	-13.78	15.07
Southwest (WSCC-RA)	0.00119	-13.34	13.71
Texas (ERCOT)	0.00063	-9.44	9.68

Lastly, we consider the price sensitivity of IPP capacity supply provided by IOU parent companies. One of the main policy issues debated during the California Power Crisis is the price that the market (or the state, in the case of California) would have to set in order to ensure adequate capacity. While several IPPs and energy traders have been quoted in the public press as requiring substantially higher prices in order for them to develop new power plant project, the estimates above suggest otherwise. For each firm and market, the expected capacity response was calculated for a given market price.[43] The calculations reveal that for a 10% change in the market price,

[43] Expectation was calculated using simulation methods. ν_{fg} was drawn 50 times from the estimated distribution N(0,EXP(-6.4498)) for each (f,g). $E(\sum_f q_{fg})$ was then calculated using standard Monte Carlo methods.

expected capacity changes between 9 and 15%. This suggests that the IPP capacity supplied by an IOU parent company is fairly price elastic and that even reasonable changes in price can lead to significant changes in the supply reaction. Of course, a major *caveat* to this result is the assumption of price-taking, which imposes a degree of price sensitivity.

4 Conclusion

The recent state level experiments with electricity restructuring have opened up many new research opportunities for regulatory economists. Much of the current work has focused on the behavior of the independent power producers, abstracting away from their identity. In this paper, we examine the identity of a major subset of the IPPs: IPPs who are owned by parent companies who also own investor-owned electric utilities. By exploring the firm characteristics of these IOU-owned IPPs, we are able to shed some light on the behavior of these firms. Specifically, we are able to ask the question: why do some IOUs participate in U.S. independent power production but not others? The conjecture raised in the paper is that IOU parent companies differ along two dimensions, their relative ability to run and maintain power plants and their relative capital access. Thus, IOU parent companies that decide to participate in the restructured wholesale electricity markets may be the ones that can leverage one or both of these competitive advantages. By combining reported utility data from FERC with IPP activity data from various trade sources, the empirical linkage between utility characteristics and IOU parent company IPP activity can be used to examine this conjecture.

The results of the empirical exercise suggest that among the observed utility characteristics, those that reflect the ability of an IOU parent company to run and maintain power plants similar to those used as merchant power plants by IPPs seem to be key. The average non-fuel O&M cost for steam power generation, the amount of fossil-fuel burning capacity, the amount of new capacity (built between 1995 and 1996), and even familiarity with aging, utility fossil-fuel burning power plants (similar to power plants sold in divestiture auctions) all figure prominently as important factors that reduce an IOU parent company's merchant power costs and increase the likelihood of significant IPP participation. On the other hand, the impact of financial characteristics such as assets-to-liabilities, net income, and revenue do not seem to be robust. Much of the observed correlation between big "rich" IOU parent companies and IPP participation appear to stem from scale benefits other than access to cheaper sources of capital.[44] Furthermore, the significant and

[44]Of course, this is *caveat* the unreliability of accounting measures. Retained earnings and cash flow may matter but not reported net income and revenue.

robust estimates for an IOU parent company's divested utility capacity suggests that the "swapping" of generation assets among IOU parent company is a real phenomenon and one that has a substantial impact on the U.S. IPP industry. This potential, unintended effect of divestiture clearly merits more attention in the coming years, especially as other states design their own restructuring programs.

The analysis above provides some hope for the long-run viability of electricity restructuring. A major motivation for electricity restructuring is the belief that opening up the generation sector to competition will lead to the exit of inefficient, incumbent generators and the entry of more efficient out-of-state electricity producers. Although the estimated model does not completely explain the different levels of IPP participation chosen by the IOU parent companies, it is encouraging to see that the observed ability of these IOU parent companies to operate and maintain utility power plants do appear to play an important factor in the parent company's IPP participation decision. Moreover, the admittedly simple model proposed in this paper may be expanded; many of the econometric (and associated economic) assumptions of the model – with the notable exception of price taking – can be relaxed if one is willing to use more sophsiticated and computationally taxing estimation methods. For example, simulation methods may allow the introduction of separate error terms (ϵ_g, η_f) in the price and linear cost terms respectively which would allow for correlation across observations with the same firm or market. This improved correlation structure may help extract even more information from the existing data. The results from the simple model do, however, demonstrate how the basic descriptive analysis can be misleading, especially with regards to utility financial health measures.

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Appendix: Average Generation Cost

One possible exercise that might be considered to address the "average generation cost problem" is to run a regression of these average cost variables against a function of the amount of generation provided by the IOU. If one is willing to take a strong stance on the form of firm heterogeneity in generation cost then the difference between predicted average cost (from the regression) and reported average cost might capture firm specific relative cost (dis)advantages, controlling for differences in amount of generation. (Alternatively, if a sufficiently rich panel of cost data can be constructed, then firm-specific fixed effects can be estimated and used as a measure of a firm's generation O&M cost (dis)advantage.) Consider a simple quadratic cost function for the non-fuel O&M costs associated with steam power. Suppose that the parameters of the cost function are common among all firms except the parameter for the linear term.

$$\begin{aligned} SRNF_f &= \frac{1}{q_f}[\ \alpha_0 + \alpha_{1f}q_f + \alpha_2(q_f)^2\ ] \\ &= \alpha_0\ \frac{1}{q_f} + \alpha_2\ q_f + \alpha_{1f} \\ &= \alpha_1 + \alpha_0\ \frac{1}{q_f} + \alpha_2\ q_f + \epsilon_f \end{aligned}$$

If we assume that each firm f gets an *i.i.d.* draw for α_{1f} from a distribution with mean α_1, then we can use the estimated residuals from the above regression of SRNF to estimate the unobserved α_{1f}. Note that under these assumptions, α_{1f} provides a method of comparing generation cost functions across firms producing different levels of q_f: firms with lower estimated residuals (SRNF - predicted SRNF) are presumed to be more generation efficient (in terms of non-fuel steam power generation costs). SRNF is used as the object of the regression because the exclusion of non-generation, non-steam power, and fuel costs helps control for regional cost differences that are not firm-specific.

Table 5c

Parameter	Estimate	Std Error	P-value
α_0	0.000132	0.00001796	0.0001
α_1	0.007432	0.00054531	0.0001
α_2	-0.000110	0.00003148	0.0006

$N = 134, R^2 = 0.3705$
$q_f \in [0.0045, 72.6169]$ with mean 11.8661, std dev 12.2933 (10^6 MWh)
SRNF $\in [-0.0036, 0.0396]$ with mean 0.0066, std dev 0.0055 ($/KWh)
Residual $\in [-0.0129, 0.0193]$

According to the estimates above, a firm would face a reduction of approximately 1.1 cents per KWh in SRNF if it produced 10 million more MWh of steam powered electricity generation. This is roughly double the standard deviation of SRNF in the data. Therefore, a comparison of average cost among firms with different amount of generation may be very distorted. However, it should be noted that the estimated residuals are only clearly a better measure than SRNF for a given cost function. Absent knowledge about a firm's cost function, it is not clear whether an estimated residual calculated based on an arbitrary cost regression is better than the dependent variable SRNF (or ROM, SROM). The estimated residual may be capturing pure noise rather than unobserved firm heterogeneity. Consequently, the research continues using (ROM, SROM, SRNF) as the primary measures for an IOU's O&M costs while acknowledging the limitations of such measures.

Data Appendix

There are three main categories of data used in this analysis: electric utility characteristics, independent power production investments made by electric utility parent companies, and market characteristics. The data on utility characteristics are obtained from the Federal Energy Regulatory Commission (FERC)'s Form 1 reports for 1996. More precisely, the data was gathered from the summary tables of the 1996 FERC Form 1, tabulated by the Energy Information Administration (EIA). The summary tables are available on the Internet at

http://www.eia.doe.gov/cneaf/electricity/page/at_a_glance/fi_tabs.html

The tables list the financial characteristics of major private electric utilities, with the "major" status determined by EIA. For the purposes of the paper, the pool of utilities were further whittled down. Cooperatives were excluded as many of them are non-profit and not candidate for expansion into nation-wide IPP activity. Furthermore, utilities whose generation needs were satisfied with less than 10% of own fossil-fuel burning units were excluded as well. This excluded a few utilities that were either strictly transmission & distribution companies (imported most of their electricity) or generated most of their electricity using an existing hydro system. The remaining utilities were then classified by the parent company that owned the utility. The 1996 Major Parent Company List (also available from the same EIA source) was used as a template, though substantial updating was done via Internet sources (mostly company web sites). For some utilities, their parent company changed during the interim between 1996 and 2000.[45] In those cases, the most recent ownership status was used.[46] A total of 81 parent companies were arrived at through this process.

[45]This is due to mergers and acquisitions among electric utilities and their parent companies

[46]Three of the utilities were bought out by major independent power producers, AES and Enron. Those utilities

Information on the IPP activities of the 81 electric utility parent companies were obtained using various industry resources. The majority of the data was obtained from the annual McGraw-Hill publication "210 Independent Power Companies: Profiles of Industry Players and Projects." The publication provides data (as of first half 2000) on many of the major electric utility affiliated independent power producers. Data on the smaller electric utility affiliated IPPs as well as second half 2000 updates on the activities of the larger ones were obtained from the various industry publications and the company web sites. The collected variables of interest are whether the electric utility parent company has a subsidiary for domestic independent power production and how much domestic merchant power plant (operational) capacity they owned as of the end of 2000 in each state.

Lastly, information on market characteristics are obtained from the North American Electricity Reliability Council (NERC)'s *Electricity Supply & Demand* (ES&D) database. NERC is the private, industry-organized governing body for North American electricity transmission & distribution operators. The 1996 actual values for load (electricity demand), reserve margin, and load factor for 13 major NERC regions were obtained.[47] In this study, a market is defined as one of the 13 major NERC regions, most of which span across several state lines. More precisely, a market is defined as the wholly included set of states that span the NERC region. For a state at the intersection of multiple NERC regions, the state is assigned to the NERC region that captures most of the state's urban population. In most cases, the assignment of a state is very clear.

NERC Subregions and Corresponding States			
Region	States	Region	States
ECAR	IN, KY, MI, OH, WV	ERCOT	TX
FRCC	FL	MAAC	DE, MD, NJ, PA
MAIN	IL, WI	MAPP	IA, MN, ND, NE, SD
NPCC-NE	CT, MA, ME, NH, RI, VT	NPCC-NY	NY
SERC	AL, GA, MS, NC, SC, TN, VA	SPP	AR, KS, LA, MO, OK
WSCC-CNV	CA	WSCC-NWP	ID, MT, NV, OR, UT, WA
WSCC-RA	AZ, CO, NM, WY		

were dropped from the analysis.

[47]However, the 1996 retail electricity price is calculated using state-level information obtained from the Energy Information Administration's *Electric Power Annual*. The price is aggregated to the NERC region level by weighted average, where the weight is the ratio of the state's 1996 generation and the total amount of 1996 generation in the region.

The NERC definition was used as it largely accounts for imports and exports of electricity across state borders: a merchant power plant in one state may actually have been built with the intent of exporting electricity to a neighboring state. Moreover, IPPs are often quoted as saying that they are building a power plant to serve a particular NERC region. Additional information on NERC regions can be found at the NERC web site (www.nerc.com)

Appendix: GMM Estimation of the Entry Model

In this appendix, we consider estimating the entry model using GMM. The moment conditions we wish to impose are simply the first two conditional moments. As will be apparent soon, estimating the model based on $N > 2$ conditional moments is also feasible and derived in a similar manner.

$$\begin{aligned} E[E(q|X) - q] &= 0 \\ E[E(q^2|X) - q^2] &= 0 \end{aligned}$$

Derivation of the conditional moments $E(q^k|X)$ is based on the constraints on ν_{fg} that we derived earlier for the maximum likelihood model. So for observed $q_{fg} > 0$ we know that $\nu_{fg} \geq \nu^*_{fg}$. Similarly, for $q_{fg} = 0$ we know that $\nu_{fg} < \nu^*_{fg}$.

$$\begin{aligned}
E(q|X) &= \int_{-\infty}^{\nu^*_{fg}} (\frac{P_g - \alpha_1 - \nu}{2\alpha_{2f}}) \frac{1}{\sqrt{2\pi}\ \sigma_{nu}} e^{-\frac{1}{2}(\frac{\nu}{\sigma_{nu}})^2} d\nu \\
&= (\frac{P_g - \alpha_1}{2\alpha_2})\Phi(\frac{\nu^*_{fg}}{\sigma_\nu}) - \Phi(\frac{\nu^*_{fg}}{\sigma_\nu})\ E(\nu|\nu \leq \nu^*_{fg}) \\
&= (\frac{P_g - \alpha_1}{2\alpha_2})\Phi(\frac{\nu^*_{fg}}{\sigma_\nu}) + \frac{\sigma_\nu}{2\alpha_{2f}\ \sqrt{2\pi}} e^{-\frac{1}{2}(\nu^*_{fg})^2} \\
E(q^2|X_{fg}) &= \int_{-\infty}^{\nu^*_{fg}} (\frac{P_g - \alpha_1 - \nu}{2\alpha_{2f}})^2 \frac{1}{\sqrt{2\pi}\ \sigma_\nu} e^{-\frac{1}{2}(\frac{\nu}{\sigma_\nu})^2} d\nu \\
&= \frac{1}{4\alpha_{2f}^2} \int_{-\infty}^{\nu^*_{fg}} [\ (P_g - \alpha_1)^2 - 2(P_g - \alpha_1)\nu + \nu^2\ ] \frac{1}{\sqrt{2\pi}\ \sigma_\nu} e^{-\frac{1}{2}(\frac{\nu}{\sigma_\nu})^2} d\nu \\
&= \frac{1}{4\alpha_{2f}^2} [\ (P_g - \alpha_1)^2 \Phi(\frac{\nu^*_{fg}}{\sigma_\nu}) - 2(P_g - \alpha_1)\ \Phi(\frac{\nu^*_{fg}}{\sigma_\nu}) E(\nu|\nu \leq \nu^*_{fg}) \\
&\quad + \Phi(\frac{\nu^*_{fg}}{\sigma_\nu}) E(\nu^2|\nu \leq \nu^*_{fg})\ ] \\
&\text{where} \\
E(\nu|\nu \leq \nu^*_{fg}) &= \int_{-\infty}^{\nu^*_{fg}} \nu \frac{1}{\sqrt{2\pi}\ \sigma_\nu} e^{-\frac{1}{2}(\frac{\nu}{\sigma_\nu})^2} d\nu \left(\frac{1}{\Phi(\frac{\nu^*_{fg}}{\sigma_\nu})} \right) \\
&= \frac{-\sigma_\nu}{\sqrt{2\pi}}\ e^{-\frac{1}{2}(\frac{\nu^*_{fg}}{\sigma_\nu})^2} \left(\frac{1}{\Phi(\frac{\nu^*_{fg}}{\sigma_\nu})} \right)
\end{aligned}$$

$$
\begin{aligned}
E(\nu^2|\nu \leq \nu^*_{fg}) &= \int_{-\infty}^{\nu^*_{fg}} \nu^2 \frac{1}{\sqrt{2\pi}\ \sigma_\nu} e^{-\frac{1}{2}(\frac{\nu}{\sigma_\nu})^2} d\nu \ \left(\frac{1}{\Phi(\frac{\nu^*_{fg}}{\sigma_\nu})} \right) \\
&= \nu^*_{fg}\ E(\nu|\nu \leq \nu^*_{fg}) + \sigma^2_\nu \\
&= \left[\nu^*_{fg} \frac{-\sigma_\nu}{\sqrt{2\pi}}\ e^{-\frac{1}{2}(\frac{\nu^*_{fg}}{\sigma_\nu})^2} + \sigma^2_\nu \Phi(\frac{\nu^*_{fg}}{\sigma_\nu}) \right] \ \left(\frac{1}{\Phi(\frac{\nu^*_{fg}}{\sigma_\nu})} \right)
\end{aligned}
$$

Given the linear-quadratic framework, the other N-2 conditional moments can similarly be derived analytically by judicious use of the "UV" integration method. GMM can be run based on the orthogonality conditions implied by these two conditional moments to estimate a maximum of $2 \times r(Z)$ parameters, where Z is the set of instruments. The natural set of instruments is $(\ 1, \{X_{fg}\}^{F,G}_{f=1,g=1} \ )$ - the difference between the observed quantity and its conditional moment should in expectations be orthogonal to its conditioning variables.

$$
\min_\theta \underbrace{\left(\begin{array}{c} \frac{1}{FG} \sum_{f=1}^F \sum_{g=1}^G Z'(q_{fg} - E(q|X_{fg})) \\ \frac{1}{FG} \sum_{f=1}^F \sum_{g=1}^G Z'(q^2_{fg} - E(q^2|X_{fg})) \end{array} \right)' W \left(\begin{array}{c} \frac{1}{FG} \sum_{f=1}^F \sum_{g=1}^G Z'(q_{fg} - E(q|X_{fg})) \\ \frac{1}{FG} \sum_{f=1}^F \sum_{g=1}^G Z'(q^2_{fg} - E(q^2|X_{fg})) \end{array} \right)}_{M'\ W\ M}
$$

Estimation can then be obtained by the standard Hansen two-step method.[48] It should be noted that all else equal we would expect the maximum likelihood estimates to have more desirable properties as it imposes all of the conditional moments, not just a handful. Also, under the usual conditions, the ML estimator achieves the Cramer-Rao lower bound while the GMM estimator in general does not.

[48]Hansen (1982)

Appendix: Alternative Estimates

Table 9b: Excluding NETY, NRVSE		
Parameter	ML	
	Estimate	Std Error
PRICE PARAMETERS		
Load (LOAD96)	-.02022	.098628
Reserve Margin (RM96)	-2.36890	1.97153
Load Factor (LDFACT96)	-3.33891	1.88080
LINEAR COST PARAMETERS		
Constant (α_{11})	.00351	.019395
VSIGMA	-6.34822	5.45208
QUADRATIC COST PARAMETERS		
Constant (α_{21})	-1.70621	5.53286
Assets-to-Liab (ATOL)	1.22723	.30113
Divestiture (DIVTOT)	-.18341	.02934
Non-fuel O&M (SRNF)	308.946	35.1039
Fossil-Fuel Cap (FOSCAP)	-.07358	.03497
Fossil-Fuel Age (LFOSCAP)	-2.46053	.516767
New Capacity (NEWCAP)	-.177651	.100063
Log Likelihood	-448.754	
N = 1053		

Table 9c: Estimates for Limited Observations				
Parameter	OLS		ML	
	Estimate	Std Error	Estimate	Std Error
PRICE PARAMETERS				
Retail Price (P96)	.06729	.03998		
Load (LOAD96)	-.01476	.07283	-.11972	.16255
Reserve Margin (RM96)	-.30544	1.15355	-4.24813	3.23968
Load Factor (LDFACT96)	.39778	.73950	-3.87068	2.74456
LINEAR COST PARAMETERS				
Constant (α_{11})			.00007	.00060
VSIGMA			-9.91305	8.50472
QUADRATIC COST PARAMETERS				
Constant (α_{21})			3.22885	8.90267
Assets-to-Liab (ATOL)	.08255	.39073	.99879	.34009
Net Income (LNETY)	.23307	1.31420	3.97784	1.75611
Revenue (LNRVSE)	-.17028	.24280	-.91691	.41020
Divestiture (DIVTOT)	.04864	.02170	-.16090	.02840
Non-fuel O&M (SRNF)	-34.3694	28.1415	242.128	47.7407
Fossil-Fuel Cap (FOSCAP)	.06383	.04911	-.03971	.06030
Fossil-Fuel Age (LFOSYR)	.49518	.51235	-1.15393	.70875
New Capacity (NEWCAP)	.08674	.10243	-.20134	.09992
Log Likelihood	-313.212		-447.147	
N = 352, R^2 for OLS = .072511				
Include only firms that have entered some market as of mid-2000				
Excluded observations from markets FRCC, MAPP, WSCC-NWP				
(largely unrestructured markets)				