Measuring Market Power and the Efficiency of Alberta's Restructured Electricity Market: An Energy-Only Market Design

by

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Abstract

We measure the degree of market power execution and inefficiencies in Alberta's restructured electricity market. Using hourly wholesale market data from 2008 to 2014, we find that firms exercise substantial market power in the highest demand hours with limited excess production capacity. The degree of market power execution in all other hours is low. Market inefficiencies are larger in the high demand hours and elevate production costs by 14% - 19% above the competitive benchmark. This reflects 2.35% of the average market price across all hours. A recent regulatory policy clarifies that certain types of unilateral market power execution is permitted in Alberta. We find evidence that suggests that strategic behavior changed after this announcement. Market power execution increased. We illustrate that the observed earnings are often sufficient to promote investment in natural gas based technologies. However, the rents from market power execution can exceed the estimated capacity costs for certain generation technologies. We demonstrate that the energy market profits in the presence of no market power execution are generally insufficient to promote investment in new generation capacity. This stresses the importance of considering both short-run and long-run performance measures.

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1 Introduction

Traditionally, electricity markets are served by large vertically integrated utilities that own and operate all sectors of the electricity industry. These regulated monopolies recovered their costs through a cost-of-service regulatory regime. Concerns over the performance of these markets led to market restructuring which converted regulated monopolies into a disintegrated market-based design. Electricity market restructuring has become pervasive worldwide. These markets aim to use market-oriented mechanisms to induce competition, improve efficiency, and promote adequate amounts of generation capacity investment.

There has been substantial controversy over the performance of these markets. In particular, there are concerns over firms' abilities to exercise market power and of the ability of these markets to promote sufficient investment to ensure a reliable supply of electricity.[1] There is a large diversity in the market design and regulatory policy in these restructured markets. This has led to a debate over the appropriate restructured electricity market design (Cramton et al., 2013; Kleit and Michaels, 2013). The objective of this paper is to evaluate the efficiency and degree of market power execution in Alberta's restructured wholesale electricity market. Alberta's market design provides insight into the performance of a largely debated restructured electricity market design.

Alberta's electricity market has several important components that make evaluating its performance interesting. Unlike many restructured markets worldwide, firms do not receive supplementary payments to promote investment. Rather, Alberta is an energy-only market design. Firms rely solely on the revenues from energy markets to drive new capacity investments. Similar energy-only market designs exist in Texas, Australia's National Electricity Market, New Zealand, Germany, and Northern Europe's Nord Pool (Pfeifenberger et al., 2009). Further, unlike other restructured wholesale markets, there are no formal bid mitigation mechanisms in Alberta to restrict firms' abilities to exercise market power.[2] In fact, in 2011 Alberta's Market Surveillance Administrator (MSA) released the Offer Behavior Enforcement Guidelines (OBEGs) that clarified that market participants are able to engage in unilateral market conduct that does not impede or weaken market competition (MSA, 2011).[3] The market relies on entry of new generation capacity to moderate long-run market prices. The heavy weight placed on market-based mechanisms in such an energy-only market designs has garnered support from energy economists (Hogan, 2005). However,

[1] Joskow (2008b) and Borenstein and Bushnell (2015) summarize the performance of and challenges in restructured markets.

[2] While there are no mechanisms to restrict bids to reflect estimates of marginal cost, Alberta has a price-cap at $1,000.

[3] Prior to the OBEGs, existing legislation was not transparent regarding the types of market power execution that would lead to investigation and enforcement actions. The OBEGs clarify that firms are not permitted to engage in coordinated behavior or behavior that weakens or prevents competition (MSA, 2011). Rather, market power conduct by a firm that captures surplus from what the firm has established independent of the conduct's effect on rival firms is permitted (see "extractive" conduct in Carlton and Heyer (2008)).

the performance of these market designs has been the subject of heated debate due to price volatility and concerns over the degree of market power execution and anti-competitive behavior (Pfeifenberger et al., 2009). Alberta's market has also been subject to this controversy (Woo et al., 2003; MSA, 2013).

There is a growing literature that empirically estimates the degree of market power execution and inefficiencies in restructured electricity markets. The most widely used method establishes a competitive benchmark to reflect the market outcome that would arise if firms behaved as price-takers. The seminal work by Wolfram (1999) uses this approach to analyze the degree of market power in the England and Wales electricity market. This approach was then extended to analyze the degree of market power and inefficiencies during California's electricity crisis (Borenstein et al., 2002; Joskow and Kahn, 2002).[4] These analyses find that firms often exercise substantial market power in these electricity markets and this can lead to sizable market inefficiencies. We employ this approach to estimate the degree of market power execution and inefficiencies in Alberta. Unlike the prior literature, we have detailed demand-side data for a set of large industrial consumers. Our approach extends this literature by establishing a methodology to account for these price-responsive consumers in our assessment of market performance.

Another strand of literature measures the degree of market power execution in electricity markets by using a structural approach that compares a firm's optimal bid function to observed bids (Wolak, 2000, 2003a,b; Sweeting, 2007; Puller, 2007; Hortacsu and Puller, 2008; Kendall-Smith, 2013). These analyses test if observed offer behavior is consistent with short-run profit maximization. These studies often find sizable bid mark ups above estimated marginal costs. In particular, in an analysis of Alberta's electricity market, Kendall-Smith (2013) uses this structural approach to illustrate that firms exercise substantial market power. However, these analyses rely on various structural assumptions of profit maximization and focus solely on market power measures. Alternatively, we use a competitive benchmark approach to compute the degree of market power execution, market inefficiencies, and the distribution of rents. This allows us to provide a broader assessment of Alberta's electricity market design.

In addition to concerns over short-run market power execution, promoting investment has been a primary concern in restructured markets. Many of these markets have adopted capacity payment mechanisms to provide revenues in addition to those earned in energy markets to drive investment. Proponents argue that these markets are necessary to ensure resource adequacy and correct for a market failure that arises because regulatory policies put in place to limit market power execution also restrict firms' abilities to earn sufficient revenues to cover the cost of investment (Joskow, 2008a; Cramton et al., 2013). Critics

[4] This method was also used to analyze various other electricity markets including New England (Bushnell and Saravia, 2002), England and Wales (Sweeting, 2007), and PJM (Mansur, 2008).

claim that these capacity payment mechanisms are costly to operate, based upon controversial administrative parameters, and lead to excessive rents being distributed to firms (Kleit and Michaels, 2013; APPA, 2014). While energy-only market designs have been viewed favorably from a theoretical standpoint due to their reliance on market-forces and relative simplicity, there are growing concerns that these market designs are unable to promote sufficient capacity investment in practice (Pfeifenberger et al., 2009).[5,6] Our study contributes to this debate by providing a detailed look at Alberta's energy-only market design.

We utilize detailed data on generator's bids and unit characteristics from 2008 to 2014 to construct a competitive counterfactual benchmark. This allows us to measure the degree of market power execution, market inefficiencies, and the distribution of rents. Further, we use this methodology to investigate whether there was a change in strategic behavior after the MSA released the OBEGs clarifying the regulatory policy on market power execution. Lastly, to assess if Alberta's energy-only market provides sufficient revenues to promote investment, we compare the observed and competitive benchmark energy market profits to estimates on the annual capacity cost for various generation technologies.

We find that firms exercise substantial market power in the high demand hours with limited excess production capacity. This can yield a sizable amount of rents transfered to firms. The market power measures in the highest demand hours correspond with estimates from the prior literature in California, Germany, and England and Wales (Borenstein et al., 2002; Musgens, 2006; Sweeting, 2007). The degree of market power is limited in all other hours. However, looking across all hours, our quantity-weighted market power measure illustrates that there is a sizable amount of strategic behavior. Market inefficiencies are also larger in the high demand hours. These inefficiencies elevate production costs by 14% - 19% above the competitive benchmark. While this is a non-trivial amount, these inefficiencies reflect 0.9% - 6.35% of the observed market prices with a point estimate of 2.35% of the market price across all hours.[7]

We find that the degree of strategic behavior changed in the post-2010 period of our sample. In particular, we observe higher market power estimates and oligopoly rents that cannot be explained by higher industry production costs due to the outage of two large coal units during this period. Further, we show that the higher market power measures persist even after these units come back online. This

[5] For example, in Texas there has been growing concern over promoting investment and resource adequacy due to shrinking capacity reserve margins. There has been substantial debate over the adoption of capacity payments in Texas (Kleit and Michaels, 2013). Similarly, Capacity Market designs are currently being considered in various countries in Europe. Most notably, the United Kingdom recently approved a capacity payment mechanism (U.K. DOECC, 2014).

[6] To moderate market power and price volatility, regulatory mechanisms such as bid mitigation and price-caps are place on energy-only market designs. This drives concerns that these markets are unable to promote investment (Joskow, 2008a).

[7] These estimates are similar to those identified for the PJM region (Mansur, 2008). Mansur illustrates that these inefficiencies may largely overestimate the true market inefficiencies once ramping and production constraints are considered. Hence, our approach provides a conservative estimate of the market inefficiencies in Alberta.

suggests that the degree of strategic behavior changed after the announcement of the OBEGs in 2011.[8]

We compare the observed and competitive market profits to estimates on the annual cost of capacity investment by generation technologies. We find that the earnings from the competitive benchmark are systematically insufficient to cover the fixed capacity costs. However, the observed energy market profits are often sufficient to cover the estimated fixed cost of investment for the natural gas and cogeneration technologies. This supports the observed entry of natural gas based technologies in Alberta (Pfeifenberger et al., 2013). These findings cumulatively suggest that Alberta's wholesale electricity market has sizable market power execution, inefficiencies, and rent transfers in the high demand hours. These effects are limited in all other hours. The magnitude of these market inefficiencies are small as a proportion of the market price. However, policies that increase consumers' price-responsiveness in the high demand hours have the opportunity to lead to improvements in market efficiencies. In Alberta's energy-only market, the market rents may be at least in part necessary to promote capacity investment. These findings stress the importance of evaluating both measures of short-run and long-run market efficiency when evaluating any electricity market design.

We develop these findings as follows. Section 2 provides an overview of Alberta's electricity market. Section 3 characterizes our empirical methodology, describes the data used, and estimates various preliminary components that will be the foundation of our analysis. Section 4 presents the market power, inefficiency, and rent division estimates, highlighting how these measures vary by year and the level of demand. Section 5 compares the energy profits for various generation technologies to estimates of capacity investment costs. Section 6 provides conclusions, policy suggestions, and directions for future research.

2 The Alberta Electricity Market

Prior to 2001, Alberta's electricity market consisted of several large vertically integrated providers that were regulated under a cost-of-service regime. The three largest firms had control of over 85 percent of the market's generation capacity (MSA, 2012b). A movement towards market restructuring began in 1996 and retail and wholesale market-based competition was established in 2001, while transmission and distribution remained as regulated monopolies (Olmstead and Ayres, 2014). In Alberta's energy-only market design, generation units rely solely on short-run markets for electricity and ancillary services to cover the fixed cost of capacity investment. The Alberta Electric System Operator (AESO) is mandated

[8]Kendall-Smith (2013) uses a structural approach and illustrates that the firms' bid functions changed after the announcement of the OBEGs in Alberta. This provides additional support that there was a change in offer behavior in the post-2010 period.

to design and operate Alberta's wholesale electricity market.

The AESO organizes a single real-time wholesale electricity market that takes the form of a uniform-priced procurement auction.[9] Suppliers are required to offer (bid) in their total available generation capacity for each hour of the day. The generators can offer electricity at prices between \$0 and \$999.99 per megawatt hour (MWh). Generation units are called upon to supply electricity in order of their offer prices until sufficient generation is called upon to meet electricity demand. The real-time system marginal price (SMP) is effectively determined every minute and equals the highest offer price accepted to supply electricity. The pool price is calculated as the time-weighted average SMP for each hour. The pool price is paid to all generation units that supply electricity within that hour.

Table 1: Alberta Market and Firm Characteristics

Panel A: Market Shares of Generation Capacity by Firm and Year (%)							
	2008	2009	2010	2011	2012	2013	2014
TransCanada	21.7	21.0	20.0	19.0	18.4	18.1	17.9
TransAlta	16.9	16.6	18.2	19.1	19.9	15.8	15.6
ENMAX	16.9	17.2	16.4	15.6	15.1	14.9	12.7
ATCO	9.3	9.2	11.1	10.6	10.3	9.8	11.8
Capital Power	8.7	10.5	9.3	10.6	10.5	11.5	11.3
Fringe	26.5	25.5	25.0	25.1	25.8	29.9	30.7
Panel B: Market Shares of Generation Capacity by Fuel Type and Year (%)							
	2008	2009	2010	2011	2012	2013	2014
Coal	50.7	49.4	48.7	46.9	45.1	47.2	44.7
Natural Gas	33.8	35.6	35.5	36.0	37.3	36.9	37.6
Wind	4.1	4.4	5.1	6.1	7.0	7.2	9.0
Hydro	6.9	6.5	6.0	6.1	6.3	6.2	6.1
Other	4.4	4.1	4.6	4.9	4.2	2.4	2.6

Notes: For each year, the generation capacity by firm and fuel type is based on the maximum generation capacity that a firm has the ability to offer into the wholesale market, divided by the total available generation capacity. Fringe contains over 20 small firms. The Other generation category consists largely of biomass units.

While restructuring reduced concentration, supply remains relatively concentrated with the largest five firms having control of approximately 70 percent of the generation capacity (see Table 1). Despite the relatively high concentration, the Alberta market does not impose regulatory bid mitigation mechanisms on the firms' offers in the energy market to limit the degree at which bids exceed a firm's (estimated) marginal cost (Olmstead and Ayres, 2014). In 2011, the MSA released the Offer Behavior Enforcement Guidelines (OBEGs) that stated that unilateral market conduct that does not create, maintain, or enhance

[9] In addition to the wholesale energy market, the AESO operates various ancillary service markets. The focus of the current analysis will be on the wholesale energy market. Unlike other markets, Alberta does not have a day-ahead energy market.

market power is permitted (MSA, 2011).[10] While firms are not restricted in their offers, there are explicit rules that prohibit a firm from withholding available physical generation capacity from the market (FEOC, 2009) and from engaging in coordinated strategic behavior (MSA, 2011).

Table 1 summarizes characteristics of Alberta's market concentration and electricity production capacity by fuel source. The generation capacity is concentrated within the five largest firms, while a fringe of over 20 firms own the residual capacity. The largest share of generation capacity is coal-fired. However, coal generation capacity has been declining over our sample period and has primarily been replaced by natural gas generation capacity. There has been an increase in wind generation capacity.

3 Empirical Methodology

We use an approach similar to that established in Wolfram (1999) and Borenstein et al. (2002). We measure the degree of market power and inefficiencies by comparing the observed market outcome to a competitive counterfactual benchmark. This benchmark reflects the outcome that would arise if firms behaved as price-takers and submitted offers into the spot market equivalent to their marginal cost of production. The competitive benchmark price reflects the marginal cost of the highest cost generation unit needed to meet the electricity demanded. The aim of the analysis is to use the competitive benchmark to measure the severity of market power and inefficiencies in Alberta's restructured electricity market.[11]

The approach used to measure market power and inefficiencies is as follows. First, we estimate the market-level marginal cost curve using unit-specific thermal efficiencies, capacities, input (fuel) prices, environmental regulation costs, variable operating and maintenance costs, and offer behavior. Second, we formulate a downward sloping residual market demand curve by estimating import supply and a price-responsive demand function for a subset of large consumers. Residual demand reflects the amount of demand that needs to be served by units within Alberta, net of imports. Third, we use an algorithm to find the highest marginal cost unit that is required to meet this demand. This unit sets the competitive benchmark price. All available units whose estimated marginal costs are at or below the competitive price are called upon to meet supply under the benchmark outcome. Fourth, we compare the observed and competitive counterfactual outcomes to compute the degree of market inefficiencies, market power

[10] Alberta's Market Surveillance Administrator (MSA) is an independent entity that monitors the electricity market. For more details on the OBEGs, see Footnote 3.

[11] The counterfactual approach used in this analysis attributes all prices and costs that exceed the competitive benchmark to market power and inefficiencies. The higher prices and production costs could be due to ramping costs and constraints associated with turning on and off generation units (Mansur, 2008). Therefore, the results of this study can be viewed as a conservative upper bound on the market power and inefficiency estimates in Alberta.

execution, and decompose the payments and rents to firms. Below we describe the essential features of the data and procedure used in this study.

3.1 Data Description

We use available data from the AESO from January 11, 2008 to December 31, 2014.[12] This data set includes observed hourly price and quantity offers for all generation firms in Alberta, unit-level production, natural gas prices from Alberta's Natural Gas Exchange, import and export supply, transmission capacity limits, market level demand, price-responsive demand, and the identity and ownership of the assets.[13] Further, we gather hourly weather data for British Columbia (BC), Alberta (AB), and Saskatchewan (SK) from Environment Canada: Weather Information. We acquired data on the thermal heat rates of natural gas generation technologies from the MSA and AESO. Our sample includes $60,597$ hours.

Table 2 presents the summary statistics of several market characteristics over our sample period. There is substantial variance in the pool price. Further, the mean pool price substantially exceeds its median value. This reflects the presence of periodic price-spikes. The limited variance in the level of market demand arises because industrial demand makes up the majority of overall electricity demand in Alberta (over 70%). Alberta is systematically a net importer of electricity from the neighboring provinces British Columbia and Saskatchewan with median import capacities of 500 MW and 153 MW, respectively.

Table 2: Summary Statistics of the Observed Outcome

	Units	Mean	Std. Dev.	Min	Median	Max	N
Quantity Demanded	MWh	7,800.70	783.85	6,213.10	7,793.20	10,475.40	60,597
Prices and Net Imports							
System Marginal Price	$/MWh	65.94	138.61	0.00	32.24	999.99	60,597
Natural Gas Price	$/GJ	4.02	1.89	1.43	3.52	24.82	60,597
Net Imports	MWh	257.10	265.58	-826.00	256.00	1,022.00	60,597

3.2 Marginal Cost Estimation

Estimating the competitive supply curve requires us to estimate the marginal cost of each generation unit. There are two types of generation units in our analysis: those units whose marginal costs can be modeled and those that cannot due to data availability or technology characteristics.[14]

[12] Data availability limits our ability to use market data prior to hour 18 of January 11, 2008.

[13] Recall, the real-time price is set every minute and equals the offer price of the last unit called upon to meet demand. Our data set includes the market-clearing price from the AESO's market snapshots taken at a particular minute in each hour.

[14] Electricity generation technologies are well understood. The cost imputation used in this study uses detailed unit information and an established empirical methodology (e.g., Wolfram (1999); Borenstein et al. (2002); Mansur (2007)).

We explicitly model marginal costs for natural gas units in Alberta. We calculate the cost of natural gas units using hourly natural gas price data (p_t^{NG}), unit-specific thermal efficiencies measured by the heat rate (HR_i), estimates on the variable operation and maintenance (O&M) costs, and environmental regulation compliance cost data.[15] We estimate the marginal cost of a modeled generation unit as the summation of its fuel costs ($p_t^{NG} \times HR_i$), the environmental compliance costs, and estimated variable O&M costs per MWh.

There are several types of units whose marginal cost cannot be explicitly modeled. In particular, due to data limitations we cannot formally model the marginal cost of coal generation technologies. In Alberta, coal is purchased through (unobservable) long-term contracts. We use the energy market bids of these coal units during hours where there is a large amount of generation production capacity that is not being utilized to meet demand as a proxy for the marginal cost.[16] Generation capacity that is not utilized will be referred to as the supply cushion throughout the analysis. In hours where there is a large supply cushion, market power execution is less likely to be profitable (e.g., see Crawford et al. (2007)). By analyzing these hours, it is more likely a generator's offer reflects its marginal cost. To ensure that our results are robust to the energy market bids selected, we create a year and unit-specific empirical offer distribution that reflects the annual distribution of bids for each coal unit during hours with a large supply cushion.[17] Then, for each year in our sample, we undertake a Monte Carlo simulation by drawing an offer for each coal unit from its year-specific empirical offer distribution to proxy for its marginal cost.[18] The entire analysis is then computed, given this draw for each coal unit. This numerical approach is performed repeatedly ($N = 100$), yielding a distribution of market power and inefficiency estimates.

A growing share of electricity generation in Alberta is coming from cogeneration technologies. Cogeneration units produce both steam and electricity for industrial use on-site using natural gas. These units sell all excess electricity not consumed on-site. We assume that cogeneration has a marginal cost of zero. In practice, these units submit bids of zero into the energy markets for this output. Several cogeneration units systematically produce electricity output beyond their on-site industrial energy needs and submit non-zero bids for this output. For these units, we explicitly model the marginal cost of this output using unit-specific heat rates and the natural gas methodology specified above.

[15] Thermal efficiencies measure the rate at which a plant converts a unit of fuel to a unit of electricity. Appendix A provides additional details on the data sources used.

[16] We focus on hours where the quantity of undispatched supply exceeds 1500 MWhs. The key conclusions of the analysis are robust to the consideration of alternative supply cushion thresholds.

[17] We establish a year-specific offer distribution for each unit to capture variation in the underlying long-term coal contracts.

[18] Formally, we use a uniform distribution to randomly draw a number $z \in [0, 1]$. Then, for each asset j and year y, we select the highest bid $\widetilde{b}_{jy}$ on the asset and year-specific empirical cumulative offer curve $F_{jy}(b_{jy})$ where $F_{jy}(b_{jy} \leq \widetilde{b}_{jy}) \leq z$.

There are several small hydro units in Alberta. Unlike most generation technologies, a hydro unit can store its electricity generation potential. Hence, the unit-specific bids do not reflect production costs, but rather the opportunity cost of using the energy at some other time. Further, the offers of these units provide little information about their opportunity cost of energy because the underlying opportunity cost depends upon expectations of future market prices. Thus, analogous to Borenstein et al. (2002), Bushnell and Saravia (2002), and Mansur (2007), we assume that the output produced by these units is equal to the amount that would be produced by a price-taking firm.[19]

There has been substantial growth in wind generation capacity in Alberta. We set the marginal cost of the observed wind generation equal to zero. There are several small Biomass units (categorized as Other in Table 1). Similar to the cogeneration technologies, these units are often associated with on-site industrial processes. We assume that these units have a marginal cost of zero. In practice, these units systematically submit bids of zero.[20] Figure 1 provides an illustration of a typical estimated hourly marginal cost supply curve, highlighting the types of generation technologies and their estimated marginal production costs.

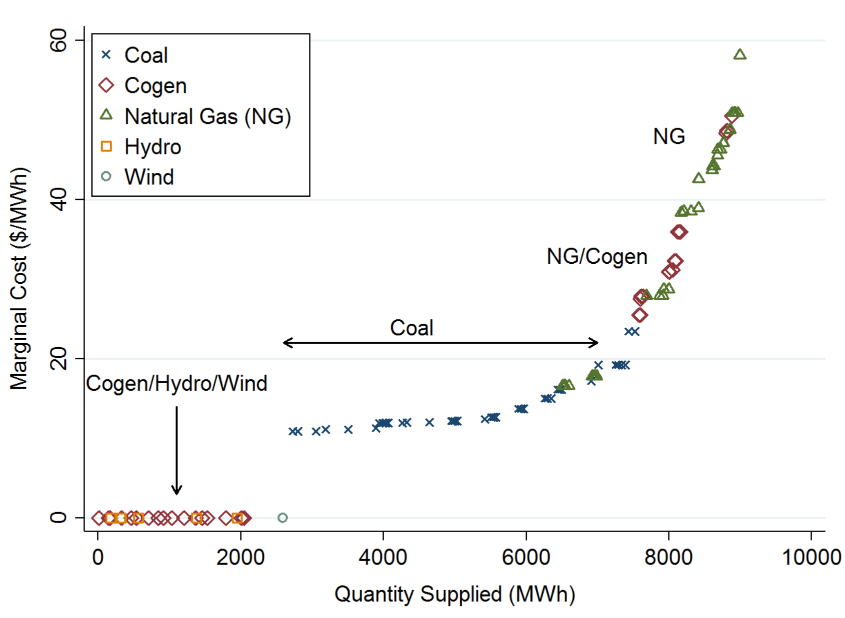


Figure 1: Alberta Supply Curve November 12, 2011 Hour 16

[19]This implies that we apply the observed output of hydro for each hour and investigate the non-hydro units needed to satisfy the remaining demand. For more details, see Borenstein et al. (2002) and Bushnell and Saravia (2002). The potential biases from this assumption are likely to be small in Alberta due to the limited Hydro generation. Hydro makes up 6 - 7 % of generation capacity (Table 1) and 2 - 3% of annual generation output in Alberta.

[20]There are three biomass units that submit non-zero offers. For these units, we replicate the coal marginal cost imputation.

3.3 Import Supply Function Estimation

Firms outside of Alberta will choose to supply (import) output into Alberta based upon the relative electricity market prices. To account for the price-responsive nature of import supply, we estimate an import supply function for each of the neighboring provinces: BC and SK.[21,22]

For each hour t, the following province-specific import supply functions are estimated using a linear-log function of observed Alberta market price p_t:[23]

$$\begin{aligned} Q_{jt}^{IM} = \beta_{0j} + \beta_{1j}\ln(p_t) + \beta_{2j} Weekday_t + \beta_{3j} Holiday_t + \alpha_j\, h(Temp_{jt}) + \sum_{h=1}^{24} \omega_{hj} Hour_{ht} \\ + \sum_{m=1}^{12} \gamma_{mj} Month_{mt} + \sum_{y=2008}^{2014} \psi_{yj} Year_{yj} + \epsilon_{jt} \qquad \forall \quad j \in \{BC, SK\} \end{aligned} \tag{1}$$

where $h(Temp_{jt})$ is a non-linear function of the temperature variables in province j, $Weekday_t$ is an indicator for weekdays, and $Holiday_t$, $Hour_{ht}$, $Month_{mt}$, and $Year_{yj}$ are indicator variables for each provincial holiday in Alberta, hour, month, and year in our sample, respectively.[24] These calendar fixed-effects are included to address systematic demand variation and input supply shocks. Alberta energy prices are endogenous to the degree of net imports. To address the endogeneity in price, we use a Instrumental Variable (IV) approach where the exclusive instruments are hourly temperature variables in Alberta. Temperature in Alberta is a vaild instrument because it affects the prevailing demand conditions in Alberta and so, it impacts the market price in Alberta (p_t). However, temperature variation in Alberta only impacts the import quantity through its impact on p_t.

Table 3 illustrates the key results from the IV estimation that accounts for heteroskedasticity and autocorrelation.[25] Table 3 illustrates that import supply is price-responsive. The coefficients imply a price-elasticity of imports of 0.64 and 0.55 for BC and SK, respectively.[26]

Once the import supply functions are estimated, we assume that the import supply curve represents the

[21] In 2013, a transmission interconnection between Alberta and Montana was added. The Montana line did not increase transmission capacity into Alberta because of its interaction with the BC interconnection (MSA, 2012c). The limited Montana imports are included in the British Columbia import supply estimation.

[22] A similar approach is undertaken by Bushnell et al. (2008) and Mansur (2007, 2008).

[23] The linear-log specification is chosen for computational ease. The results are robust to the consideration of the commonly used log-log functional form.

[24] The temperature variables used in the analysis for AB, BC, and SK are modeled as quadratics for hourly cooling degrees (hourly mean degrees above 65^o F) and hourly heating degrees (hourly mean degrees below 65^o F). The cities considered in AB, BC, and SK are Calgary, Edmonton, Vancouver, and Saskatoon, respectively. This data is accessed through Environment Canada: Weather Information. The results of the analysis are robust to the consideration of higher degree polynomials on the temperature variables and alternative large cities in each province.

[25] While computing Newey-West heteroskedastic and autocorrelation robust standard errors, the number of autocorrelated lags are chosen using the Bartlett's approximation $N^{\frac{1}{3}}$ where N is the sample size. The Kleibergen-Paap Wald F statistic strongly rejects the null hypothesis that our instruments are weak. For detailed output of the first- and second-stage regressions, see Appendix B.

[26] Elasticity estimates equal $\widehat{\beta}_{1j}/\overline{Q}_{tj}^{IM}$ where $\overline{Q}_{tj}^{IM}$ is averaged imports in province j for both $j \in \{SK, BC\}$.

Table 3: IV Estimation of Hourly Import Supply:
Second-Stage Price-Responsiveness

Variable	British Columbia Import Supply		Saskatchewan Import Supply	
ln(price)	147.51***	(11.15)	29.11***	(4.02)
R^2	0.66		0.58	
N	60,597		60,597	

Notes: IV estimates with heteroskedastic and autocorrelation robust standard errors are presented in the parentheses.
*** Statistical significance at the 1% level.

marginal cost curve of suppliers outside of Alberta (net of their native load obligations).[27] When market power in Alberta is being exercised, some firms in Alberta have raised their offers above marginal costs. This creates the opportunity for more expensive imported generation from the neighboring provinces to supply power in Alberta. This implies that in the presence of market power execution, import supply is (weakly) higher reflecting an inefficient substitution of more expensive imports for production by more efficient units in Alberta. This external import inefficiency will be measured in the subsequent analysis.

3.4 Price-Responsive Demand Estimation

In Alberta, a subset of large industrial consumers face time-varying wholesale electricity prices. Prior literature has taken the level of observable market demand as given and perfectly price-inelastic (e.g., Borenstein et al. (2002)). In our analysis, we have detailed demand data for various large industrial consumers in Alberta that represent up to eight percent of hourly load. These customers are firms primarily in the pulp, paper, forestry, and petrochemical sectors. Unlike prior studies, this data allows us to estimate the degree of price-responsiveness for a subset of consumers in Alberta. For each hour t, we estimate the quantity demanded for these industrial consumers as a linear-log function of the observed Alberta energy market price p_t:[28]

$$Q_t = \theta_0 + \theta_1 \ln(p_t) + \theta_2 \ln(p_t^{NG}) + \theta_3 Weekday_t + \theta_4 Holiday_t + \phi\, h(Temp_{AB,t})$$
$$+ \sum_{h=1}^{24} \omega_h Hour_{ht} + \sum_{m=1}^{12} \gamma_m Month_{mt} + \sum_{y=2008}^{2014} \psi_y Year_y + \eta_t \qquad (2)$$

where p_t^{NG} is the price of natural gas, $h(Temp_{AB,t})$ is a non-linear function of the temperature variables in Alberta, $Weekday_t$ is an indicator for weekdays, and $Holiday_t$, $Hour_{ht}$, $Month_{mt}$, and $Year_y$ are indicator

[27] A similar approach is used in Borenstein et al. (2002) and Mansur (2007, 2008). If the neighboring provinces exercise market power in their offers to supply imports, then we are overestimating the degree of import supply, lowering the competitive benchmark price. For more details, see Borenstein et al. (2002).

[28] The qualitative conclusions are robust to the functional form specification. For more details, see Footnote 23.

variables for each provincial holiday in Alberta, hour, month, and year in our sample, respectively.[29] The covariates contain various demand shifters to account for non-price related demand factors. Further, natural gas prices are included to control for fuel substitution.[30] Estimating the relationship between electricity price and quantity demanded is difficult because demand is impacted by various factors other than price, shifting the demand curve along the supply curve. This creates potential correlation between the price variable and the error term. This common endogeneity concern is alleviated by finding IVs for the price of electricity. First, we adopt the common approach of using lagged prices as the exclusive IVs (e.g., see Lijesen (2007); Aroonruengsawat et al. (2012)). Second, we use supply shifters as IVs that impact demand only through their impact on the electricity price. The exclusive instruments in this setting are observed imports, temperature variables from the neighboring provinces, and capacity supply availability that reflects the sum of the available electricity generation capacity within Alberta and the import transmission capacity limits for each hour.[31]

Table 4: IV Estimation of Industrial Demand: Second-Stage Regression Price-Responsiveness

	Lagged Price IVs		Supply Shifter IVs	
Variable	Industrial Demand		Industrial Demand	
ln(price)	-35.61***	(0.889)	-37.74***	(1.553)
R^2	0.487		0.484	
N	60,597		60,597	

Notes: IV estimates with heteroskedastic and autocorrelation robust standard errors are presented in the parentheses.
*** Statistical significance at the 1% level.

Table 4 illustrates the IV estimates that account for heteroskedasticity and autocorrelation.[32] Table 4 shows that industrial demand is price-responsive. The coefficients imply price-elasticities of demand of -0.147 and -0.155 for the lagged price and supply shifter IVs, respectively.[33] It is without loss of generality to focus on the results from the lagged price IV model in the subsequent analysis.[34]

[29] The Alberta temperature variables used are analogous to those defined in the import supply estimation above.

[30] We use hourly data on natural gas prices from Alberta's Natural Gas Exchange (NGX). To alleviate concerns over the endogeneity of regional natural gas prices, we also used monthly natural gas prices from Henry Hub converted to Canadian Dollars using monthly USD to CAD exchange rates from the Bank of Canada. Henry Hub prices provide a reflection of the overall natural gas market conditions in North America. Because of Alberta's small size, the demand of the price-responsive industrial consumers will have no impact on the Henry Hub gas prices. These prices are strongly correlated with the NGX prices ($\rho = 0.92$). Our IV estimation results and subsequent analyses are robust to the use of Henry Hub prices.

[31] The temperature variables in neighboring provinces (BC and SK) are analogous to those detailed in Footnote 24.

[32] The IV solution methodology is analogous to that in the Import Supply Function estimation detailed in Footnote 25. The Kleibergen-Paap Wald F statistic strongly rejects the null hypothesis that our instruments are weak. For detailed output of the first- and second-stage regressions, see Appendix B.

[33] Elasticity estimates equal $\widehat{\theta}_1/\overline{Q}_t$ where $\overline{Q}_t$ is average industrial demand. These estimates fall in-line with the literature (e.g., see Lijesen (2007)).

[34] The conclusions remain unchanged if the supply shifter IV results are used to estimate the industrial demand function.

3.5 Market Power and Production Inefficiency Measures

Having established the marginal cost, import supply function, and price-elastic industrial demand estimates, we estimate the equilibrium market price and quantity and identify the units called upon (dispatched) to supply electricity in both the competitive benchmark and observed market outcomes. The competitive benchmark price is the marginal cost of the highest cost generation unit dispatched to meet the residual demand, where residual demand is estimated to be the market demand net of imports.

We are interested in measuring the loss in economic efficiency from the observed offer behavior. In particular, we measure the degree of productive inefficiencies that arise when firms in Alberta are bidding above their marginal costs. Two types of production inefficiencies arise in our analysis. First, internal production inefficiencies reflect the degree to which available least-cost generation resources within Alberta are not called upon to meet the electricity demanded, holding the energy supplied by units in Alberta constant. Second, external production inefficiencies arise because of a misallocation of production from units within Alberta to power imported from neighboring provinces. That is, when the observed market price exceeds the competitive market price, we have an inefficiently high level of imports. In this setting, lower cost generation in Alberta is substituted by higher cost imports.

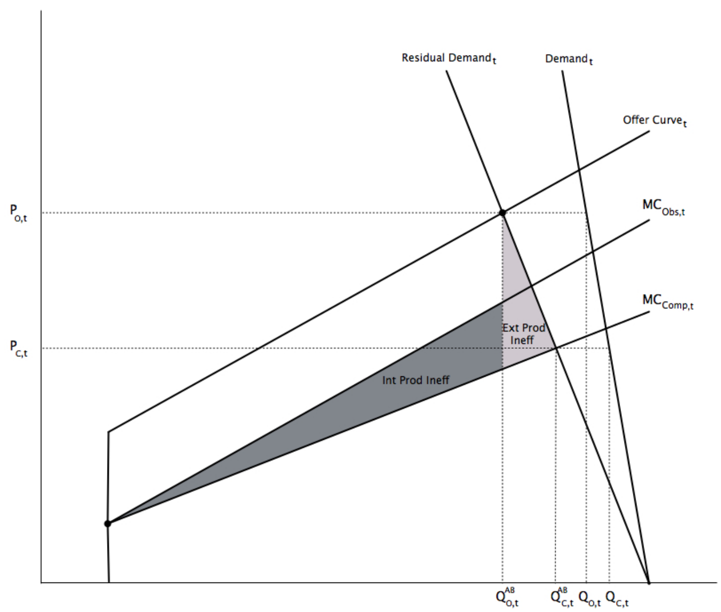


Figure 2: Internal and External Productive Inefficiencies

Figure 2 illustrates both types of production inefficiencies. The intersection of the residual demand curve and the observed offer curve yields the observed market equilibrium price. Further, the observed marginal cost of the Alberta generation units dispatched is represented by the curve $MC_{obs,t}$. Alternatively, the intersection of the residual demand curve and the competitive marginal cost curve ($MC_{comp,t}$) yields the competitive market equilibrium price. Denote $P_{O,t}, Q_{O,t}$, and $Q^{AB}_{O,t}$ to be the observed market price, total level of output, and output served by generation units in Alberta in period t, respectively. Similarly, denote $P_{C,t}, Q_{C,t}$, and $Q^{AB}_{C,t}$ to be the competitive benchmark market price, total level of output, and output served by generation units in Alberta in period t, respectively. The internal production inefficiencies is reflected by the area between the observed and competitive benchmark marginal cost curves, holding the internal observed supply in Alberta ($Q^{AB}_{O,t}$) constant. The external production inefficiencies is reflected by the additional costs associated with dispatching more expensive imports, displacing the more efficient internal production ($Q^{AB}_{C,t} - Q^{AB}_{O,t}$) in Alberta.

We employ the method established by Borenstein et al. (2002) to calculate the degree of market power execution and the additional wholesale costs incurred due to departures from marginal cost bidding. In each period $t \in l$, for a subset of hours l, we compute the quantity-weighted Lerner Index as follows:

$$MP(l) = \frac{\sum_{t \in l} \Delta TC_t}{\sum_{t \in l} TC_t} = \frac{\sum_{t \in l} P_{O,t}\, Q_{O,t} - P_{C,t}\, Q_{C,t}}{\sum_{t \in l} P_{O,t}\, Q_{O,t}} \tag{3}$$

where $\sum_{t \in l} TC_t$ and $\sum_{t \in l} \Delta TC_t$ reflects the total wholesale costs and the additional wholesale cost due to departures from the competitive benchmark for the set of l hours, respectively.[35] This represents the proportional increase in wholesale procurement costs caused by firms' abilities to exercise market power in the set of hours l.

4 Main Findings

In this section, we highlight our main findings. We compute the levels of market inefficiencies and market power measure for each iteration of our Monte Carlo coal cost simulation. Further, for each iteration we numerically decompose the distribution of rents and payments under the observed and competitive benchmark settings. We take the average over the resulting distribution of estimates from this Monte Carlo simulation. Throughout the analysis, we will present the results based upon a subset of hours determined by the level of the supply cushion that reflects the amount of available generation capacity that is not being utilized to meet demand. In particular, we consider the Bottom 5%, Bottom 25%, the Inner Quartile Range (IQR) representing the 25th to 75th percentiles of the supply cushion, Top 25%, Top 5%, and Total representing all hours. A lower supply cushion is associated with higher market demand.

[35] Unlike the prior literature, we account for the price-elasticity of large industrial consumers and so, the market demand function is price-responsive. In this setting, $Q_{O,t} \neq Q_{C,t}$ for each period t. This leads to adjustments in our definition of $MP(l)$ compared to Borenstein et al. (2002) because ΔTC_t in (3) does not simplify to $(P_{O,t} - P_{C,t})Q_{O,t}$.

All currency values are in Canadian Dollars throughout the analysis.

4.1 Market Power Measures and Productive Inefficiencies

Table 5 presents the mean hourly observed and competitive outcomes (prices and quantities) and the market power measure as the supply cushion varies. The observed and competitive prices and the market power measures vary substantially by supply cushion. For the hours at the bottom 25th percentile of the supply cushion (i.e., high demand hours), we observe large increases in the market price. The higher competitive price in these hours reflects the tight supply conditions. The observed output is below the output implied by the competitive benchmark. These differences are driven by the subset of price-responsive consumers. The market power measure ($MP(l)$) varies substantially by the supply cushion. These market power estimates are in-line with what the economic theory predicts. In hours with limited excess available generation capacity to meet demand (i.e., lower competition on the margin), we observe market power estimates that reflect a sizable execution of market power.

Table 5: Observed and Competitive Outcomes and Market Power Measures by Supply Cushion

	Supply Cushion					
	Bottom 5 %	Bottom 25 %	IQR	Top 25 %	Top 5%	Total
Observed Price ($/MWh)	399.69	161.21	36.59	19.10	14.18	65.94
Observed Output (MWh)	8,189	8,128	7,800	7,421	7,345	7,800
Competitive Price ($/MWh)	154.61	68.22	30.09	20.03	17.02	37.99
Competitive Output (MWh)	8,368	8,179	7,832	7,488	7,452	7,837
$MP(l)$ (percent)	60.1	57.4	17.6	-2.3	-18.5	42.7

In the hours with a supply cushion in interquartile range (IQR) or higher, the observed and competitive benchmark prices are substantially lower. Further, there is limited market power execution in these hours. In fact, the market power measure is often negative.[36] Looking at all hours in our sample, we find that the higher weight placed on the hours with a low supply cushion (higher demand) in our quantity-weighted market power measure elevates the overall (total) market power measure. These findings suggest that there is a sizeable amount of additional wholesale electricity procurement costs due to departures from the competitive benchmark, largely being driven by a subset of hours with a low supply cushion.

[36] In hours with a large supply cushion, dispatched units' bids often are below their estimated marginal cost. In Alberta, some firms enter into forward contracts that specify a fixed volume of electricity to be traded at a specified time. This determines if a firm is a net buyer or seller. Firms that are net buyers aim to reduce the market price. During hours with a large supply cushion, these firms can be the firms that set the market price (e.g., Green (1999); Hortacsu and Puller (2008)). Alternatively, the negative market power measures could arise because we are not accounting for ramping constraints of the coal generation technologies that often set the pool price during these hours. Rather than ramping down a unit, these units may operate at prices below our static estimates of marginal cost to avoid costly ramping (Mansur, 2008).

Table 6: Observed and Competitive Outcomes and Market Power by Supply Cushion and Year

Year	Supply Cushion	Observed Price ($/MWh)	Observed Output (MWh)	Competitive Price ($/MWh)	Competitive Output (MWh)	$MP(l)$ (percent)
2008	Bottom 5%	460.17	7,862.84	242.30	7,937.59	46.2
	Bottom 25%	197.92	7,769.72	112.55	7,781.21	42.5
	IQR	65.07	7,465.04	51.77	7,538.71	19.5
	Top 25%	30.08	6,936.60	26.41	6,955.07	12.0
	Top 5%	19.11	6,695.10	18.74	6,659.14	2.9
	Total	91.18	7,416.71	61.46	7,460.88	32.2
2009	Bottom 5%	242.88	8,095.04	100.36	8,136.26	57.6
	Bottom 25%	96.87	7,910.02	49.88	7,891.80	48.1
	IQR	37.05	7,397.33	28.23	7,484.33	23.1
	Top 25%	19.17	6,734.97	19.45	6,790.94	-1.7
	Top 5%	13.04	6,410.24	16.80	6,411.63	-28.5
	Total	48.09	7,368.42	31.66	7,420.84	34.4
2010	Bottom 5%	276.43	7,796.43	119.09	7,958.38	55.1
	Bottom 25%	109.74	7,899.85	57.68	7,917.74	46.7
	IQR	35.95	7,623.96	31.95	7,680.12	10.6
	Top 25%	21.56	7,039.83	23.04	7,118.23	-7.9
	Top 5%	15.89	6,850.58	20.03	6,879.21	-26.5
	Total	51.44	7,551.39	36.40	7,603.15	29.2
2011	Bottom 5%	519.32	8,599.86	185.52	8,890.45	62.2
	Bottom 25%	216.50	8,368.41	72.61	8,478.59	65.2
	IQR	34.23	7,787.76	28.60	7,810.12	16.3
	Top 25%	17.75	6,990.98	20.02	7,062.94	-14.3
	Top 5%	13.97	6,763.63	17.60	6,833.84	-27.7
	Total	76.16	7,737.96	37.59	7,794.70	50.8
2012	Bottom 5%	448.23	8,547.42	136.01	8,823.01	68.1
	Bottom 25%	182.94	8,436.87	52.43	8,5551.46	64.3
	IQR	27.46	7,967.61	21.34	7,994.08	21.9
	Top 25%	13.88	7,220.58	15.74	7,263.94	-14.3
	Top 5%	9.28	6,967.57	13.12	6,886.46	-29.0
	Total	64.02	7,906.81	27.95	7,959.95	56.4
2013	Bottom 5%	584.11	8,262.37	211.66	8,616.80	63.4
	Bottom 25%	219.49	8,369.24	78.64	8,443.67	61.7
	IQR	35.71	8,235.90	30.02	8,230.71	16.2
	Top 25%	18.97	7,710.96	21.71	7,777.25	-15.7
	Top 5%	14.70	7,748.05	18.93	7,797.01	-30.1
	Total	80.72	8,148.14	41.02	8,180.93	48.7
2014	Bottom 5%	289.50	9,092.74	71.40	9,150.72	73.2
	Bottom 25%	111.26	8,945.44	67.12	8,896.89	58.8
	IQR	33.05	8,524.11	27.51	8,499.15	17.1
	Top 25%	18.09	7,937.25	18.39	7,889.79	-0.9
	Top 5%	12.87	7,723.65	15.36	7,612.04	-18.0
	Total	50.04	8,492.77	30.23	8,456.13	40.8

Table 6 takes a detailed look at the observed and competitive outcomes and market power measures by supply cushion and year. This captures changes in market trends over our period of study. In particular, we are interested in identifying if there was a change in market behavior in 2011 corresponding with the passing of the OBEGs and the anticipated long-term outage of two coal units.

The trend that we observed in Table 5 persists in the annual analysis. In the bottom 25th percentile of the supply cushion, we observe a large degree of market power execution. However, in the hours with the highest supply cushion (above the 25th percentile), the degree of market power execution is largely limited. Further, we observe negative market power measures for hours with the highest supply cushion. The larger demand and market power execution in the bottom portion of the supply cushion elevates our quantity-weighted market power measure when looking across all hours (Total).

In the post-2010 period, we observe higher average prices in the hours at the Bottom 25% of the supply cushion compared to those in 2009 and 2010.[37] The market power measure across all hours (Total) is considerably higher in the post-2010 period. This is primarily being driven by the higher market power measures in the hours at the Bottom 5% and 25% of the supply cushion. These findings suggest that there was a change in the degree of strategic behavior in the post-2010 period.[38] We observe a smaller decrease in the market power execution measures as we move away from the hours at the Bottom 5% of the supply cushion in the post-2010 period. This illustrates that there is a higher persistence of market power execution beyond the highest demand hours in the post-2010 period.

Table 7 details the hourly internal and external production inefficiency estimates by the supply cushion. Similar to our market power measure, we observe lower levels of production inefficiencies in periods with a higher supply cushion (i.e., lower demand). The external inefficiencies rise dramatically at the bottom 25% of the supply cushion, while the internal production inefficiencies increase more gradually.

Table 7: Hourly Production Inefficiencies by Supply Cushion

	Supply Cushion					
Production Inefficiencies	Bottom 5 %	Bottom 25 %	IQR	Top 25 %	Top 5%	Total
Internal ($/hr)	18,366	12,981	10,011	8,974	6,671	10,246
Internal Per-Unit ($/MWh)	2.42	1.75	1.29	1.11	0.82	1.34
External ($/hr)	9,997	1,910	915	715	648	1,006
External Per-Unit ($/MWh)	1.23	0.24	0.12	0.10	0.08	0.21

The hourly total (sum of internal and external) production inefficiency estimates range from $7,319 to

[37] In 2008, we observe the highest average observed and competitive benchmark prices across all hours. This is primarily driven by the high natural gas prices in 2008. This is supported by the lower market power measures in 2008.

[38] It is difficult to deterministically disentangle if the change in offer behavior arises due to the OBEGs or coal unit outages. However, in 2014 these two large coal units were operational and market power measures remained higher than the pre-2010 period. Further, Kendall-Smith (2013) uses a structural approach established by (Wolak, 2000, 2003a,b) and finds that firms altered their offer behavior in the post-2010 period in Alberta.

\$28,363 or \$0.90 to \$3.65 per-MWh of electricity generation. This elevates the production costs by 14% - 19% above the competitive benchmark. Comparing these numbers to the observed market price by supply cushion, the total inefficiencies per-unit ranges from 0.9% - 6.35% of the observed market price. Across our entire sample, the average observed market price is \$65.94/MWh and the average total production inefficiencies per-unit (\$/MWh) is \$1.55/MWh, which is approximately 2.35% of the pool price. Therefore, while we see a large amount of market power execution in low supply cushion (high demand) hours, we find that the degree of production inefficiencies are limited as a fraction of the observed market price.

4.2 Rent Decomposition

Using the observed bids and the estimated price-responsive market demand, residual demand, and competitive cost function, we can numerically integrate to compute the observed and competitive benchmark payments, production costs, and rents. Further, we can compute the degree of deadweight loss (i.e., allocative inefficiency) that illustrates the degree of losses in economic efficiency when aggregate electricity production deviates from the competitive benchmark level.

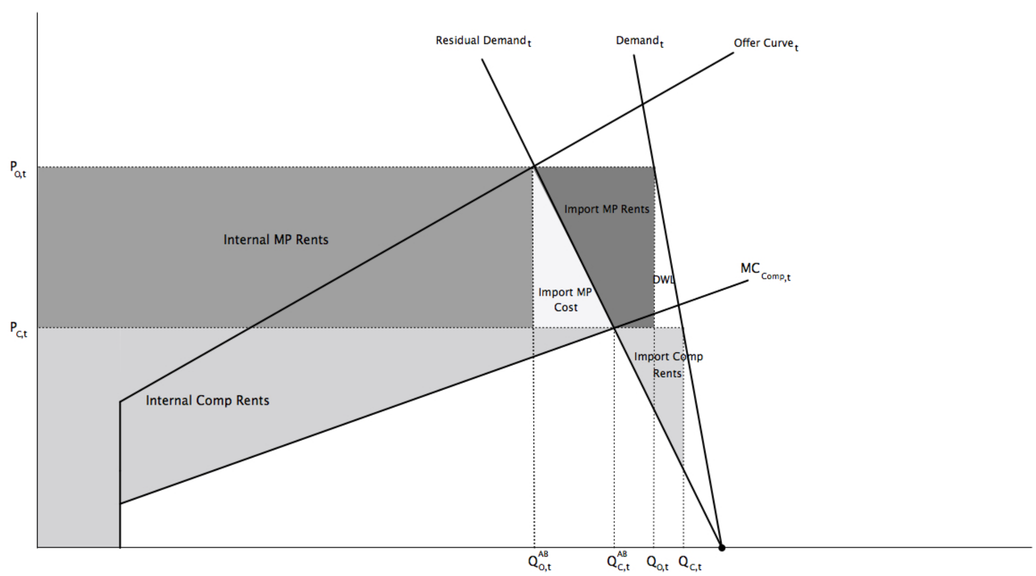


Figure 3: Rent Division and Payments

Figure 3 illustrates several of these components.[39] *Internal and Import Comp Rents* reflect the payments above production costs to firms operating in Alberta and to importers in the competitive bench-

[39] For illustrative purposes, this figure assumes that the least cost firms are being dispatched, i.e., the competitive benchmark and observed cost functions are analogous. The most efficient units may not be dispatched because they are exercising market power. The numerical computation of rents, payments, and costs accounts for this in the observed outcome. Accounting for such productive inefficiencies removes some of the internal market power rents illustrated in this figure.

mark, respectively. *Internal and Import MP Rents* represent additional payments to firms operating in Alberta and importing in the observed outcome because of market power execution, respectively. *Import MP costs* represent the cost of procuring additional imports because excess imports are attracted due to the higher observed price compared to the competitive benchmark. *DWL* reflects the deadweight loss (allocative inefficiency) associated with lower total electricity output due to market power execution.

Table 8 provides the mean hourly payments, costs, rents, and deadweight loss in the observed and competitive benchmark for various measures of the supply cushion. Similar to our market power measures, the observed and competitive payments and oligopoly (observed) and competitive rents increase as the supply cushion decreases.

Table 8: Mean Hourly Payments, Costs, Rents, and Deadweight Losses by Supply Cushion

	Supply Cushion					
Measure	Bottom 5 %	Bottom 25 %	IQR	Top 25 %	Top 5%	Total
Observed Payment	3,315,141	1,333,392	289,068	144,584	109,002	535,569
Competitive Payment	1,323,763	568,757	237,756	151,340	129,385	305,989
Oligopoly (Obs) Rent	3,137,450	1,205,606	198,529	67,342	34,882	436,165
Competitive Rent	1,178,704	465,402	164,182	87,139	78,849	228,009
Production Costs - Obs	177,691	127,786	90,539	77,242	74,120	99,404
Production Cost - Comp	145,059	103,355	73,574	64,201	50,536	77,980
Deadweight Loss	15,417	1,348	1,057	734	508	1,004

The observed payments and oligopoly rents diverge substantially from the competitive benchmark payments and rents in hours with a supply cushion below the 25th percentile. For example, in the hours at the bottom 5% of the supply cushion, the mean hourly oligopoly rents exceed the competitive rents by approximately 166%. The divergence in payments reflects both additional rents and increased production inefficiencies in low supply cushion (higher demand) hours. In hours where the supply cushion is large (i.e., low demand), we see that the competitive benchmark payments and rents exceed the observed outcomes.[40] These findings are driven by the strategic bidding behavior detailed in Table 5.

The deadweight loss is small for the majority of hours. However, in low supply cushion hours the deadweight loss can be substantial because of the exercise of market power. From Table 5 we can see that in the hours with a supply cushion in the Bottom 5%, the mean hourly competitive output exceeds the observed aggregate output by 189 MWs. This drives the higher allocative inefficiencies in these hours.

To understand how the strategic behavior changes over time, Table 9 presents the observed and competitive payments, rents, and production costs by year. In particular, it provides additional evidence

[40] At the top 25% of the supply cushion, we find that the mean observed payments are below the competitive benchmark. This corresponds to the negative market power measures in Table 5 in these hours. For more intuition see Footnote 36.

Table 9: Mean Hourly Payments, Costs and Rents by Year

Measure	2008	2009	2010	2011	2012	2013	2014
Observed Payment	698,183	371,275	399,566	627,562	535,400	674,458	443,540
Competitive Payment	471,120	242,044	282,345	308,720	233,834	347,874	261,448
Oligopoly (Obs) Rent	604,154	288,666	304,763	523,229	450,827	556,404	337,958
Competitive Rent	386,146	167,657	201,914	225,872	168,109	267,750	186,602
Production Costs - Obs	93,779	82,427	94,959	103,265	84,362	108,688	104,609
Production Cost - Comp	84,802	74,491	80,778	83,496	66,378	80,369	75,211

to determine if the increase in prices in the post-2010 period are driven by higher cost due to the long-term outage of baseload coal units or due to changes in strategic behavior. We see an increase in the observed production costs in the post-2010 period. However, these costs are not sufficient to fully explain the higher payments during this period. This is illustrated by the sizable increase in oligopoly rents in the post-2010 period.[41] This provides further evidence to suggest that there was a change in the degree of market power execution after the establishment of the OBEGs. This supports the higher market power measures found in Table 6 in the post-2010 period.

In addition to our main analysis, we perform various sensitivity analyses. In particular, built into our research methodology is the Monte Carlo simulation used to construct marginal costs for coal units. For each iteration, the analysis estimated market power, market inefficiencies, and the distribution of rents. While this yields a distribution of estimates for each of these measures, these distributions are compact and the qualitative conclusions are robust. For a detailed output on the distribution of estimates from the Monte Carlo simulation, see Table A4 in the Appendix. In addition, throughout the analysis we abstracted away from import constraints. Accounting for transmission constraints limits the imports in the hours with a high market price when transmission constraints are binding, creating a kink in the residual demand curve that increases its slope. Accounting for import constraints increases the market power measures in our analysis slightly. However, the conclusions remain.

5 Energy Market Profits and Capacity Investment

Next, we compute the level of the observed and competitive wholesale energy market profits for each year in our sample and compare them to estimates of the fixed cost of generation capacity in Alberta. This allows us to assess if the rents accrued from the exercise of market power are sufficient to cover

[41] In 2008, that natural gas fuel input prices reached their peak. Table 6 illustrates that the market power measures in 2008 are some of the lowest in our sample. In the high demand hours, these natural gas units set high market-clearing prices yielding large payments to the dispatched low-cost baseload coal units in Alberta. This explains the abnormally high payments and rents observed in 2008 in the presence of the lower market power measures illustrated in Table 6.

the fixed costs associated with capacity investment, or if they substantially exceed estimates of the cost of capacity investment. Further, we can assess if the rents implied by the competitive benchmark are sufficient to cover these large fixed cost of capacity. Estimates of the cost of capacity investment by generation technology in Alberta are obtained from Pfeifenberger et al. (2013).[42] These capacity costs represent the annualized capacity costs per MW of generation capacity by technology in Alberta.

While generation investment decisions are complex long-run processes, this analysis provides insight into the ability of Alberta's energy-only market design to promote and sustain investment. We anticipate the retirement of significant coal generation capacity in the future and have observed significant investment in natural gas generation capacity (Pfeifenberger et al., 2013). We aim to assess the overall attractiveness of investment by comparing the annualized variable profits from the energy market to the fixed capacity cost estimates by year and technology.

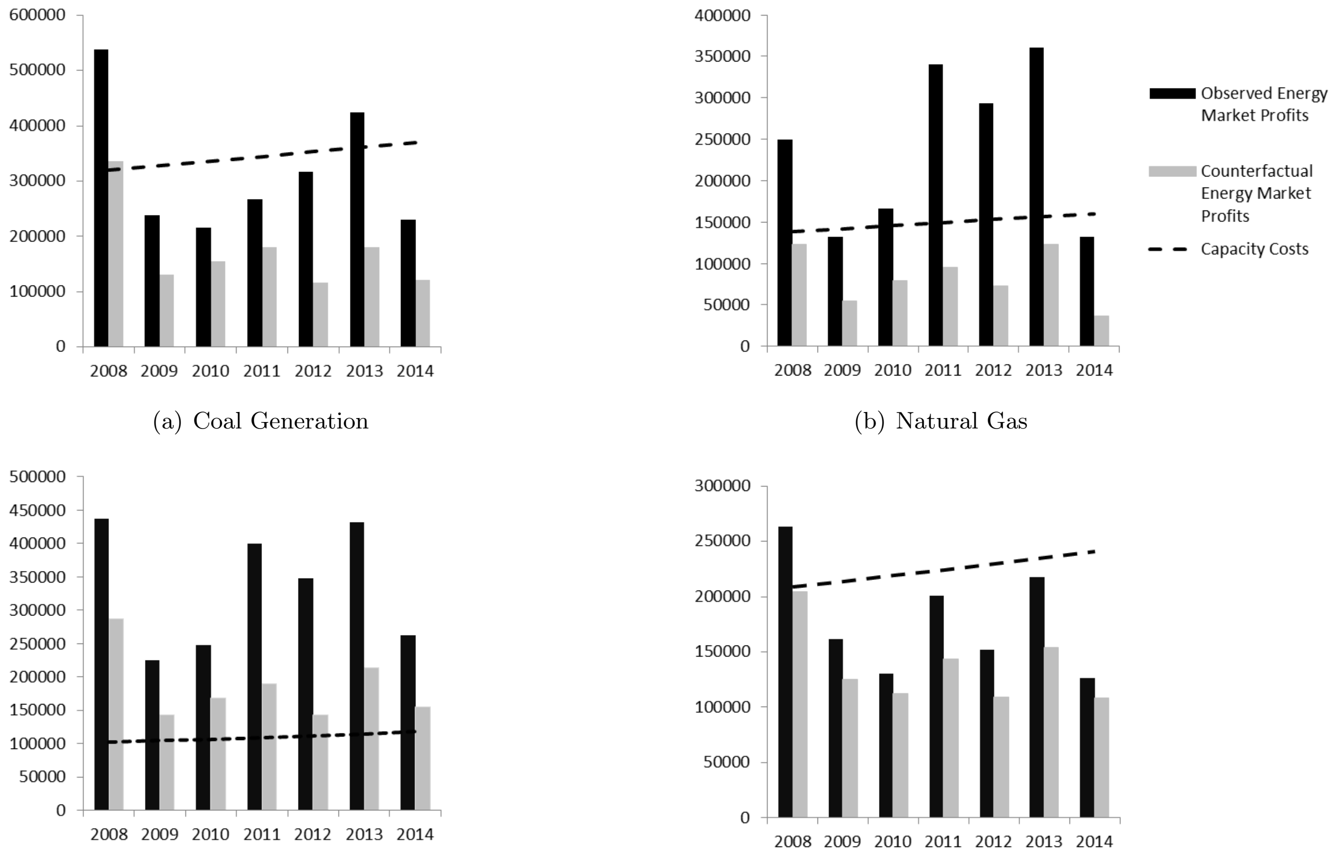
Figure 4 compares the observed and competitive counterfactual wholesale energy market profits to estimates of the cost of capacity investment across four technologies: coal, natural gas, cogeneration, and wind.[43] These comparisons vary substantially by generation technology and year. For cogeneration units, both the observed and counterfactual energy market profits exceed the estimates of the fixed cost of capacity investment. For the natural gas units, the observed energy market profits exceed capacity costs for several years in our sample. Alternatively, the observed energy market profits for coal and wind are systematically below the cost of capacity investment. Consequently, counterfactual energy market profits are systematically insufficient to cover the fixed cost of capacity for all technologies except for cogeneration.

Figure 4 also illustrates that there is a sizable increase in the observed energy market profits in 2011, 2012, and 2013, while the competitive counterfactual earnings only increased slightly. This is most pronounced for the natural gas and cogeneration units. This result, coupled with the finding that the market power measures (Table 6) and observed rents (Table 9) increased in this period, provides further evidence that the energy market behavior changed in 2011.

It is important to recognize that generation capacity investment decisions are long-run forward-looking decisions. Using our calculations, we are unable to address if the observed variable profits above fixed cost of capacity investment are in excess of those necessary to promote capacity investment to ensure

[42] These estimates compare closely to other studies on the cost of capacity investment in other markets (e.g., Monitoring Analytics (2014) and EIA (2015)). For additional details on the cost of capacity, see Appendix C.

[43] We focus on wholesale market profits which represents the primary source of firms' profits in Alberta. Firms earn additional revenues from ancillary service markets. These profits are excluded because we do not model the counterfactual of the ancillary service markets. However, when observed ancillary service profits are included, the qualitative conclusions hold.



(a) Coal Generation

(b) Natural Gas

(c) Cogeneration

(d) Wind

Figure 4: Comparison of Mean Energy Market Profits and Capacity Cost ($/MW-year) by Technology.

long-run market reliability. However, the current analysis does illustrate that the competitive counterfactual payments are often too low to cover the estimated cost of capacity. The observed variable profits are systematically sufficient to cover the cost of capacity investment for natural gas and cogeneration technologies. These findings support the observed pattern of investment in natural gas and cogeneration in Alberta (Pfeifenberger and Spees, 2011; Pfeifenberger et al., 2013).[44]

6 Conclusion

We use a competitive benchmark approach and detailed bid and marginal cost data from 2008 to 2014 to evaluate the divergence of Alberta's restructured wholesale electricity market from one where all firms behave as price-takers. We demonstrate that firms exercise substantial market power in the hours with

[44]The large observed rents in 2011 to 2013 start to dissipate in 2014. This corresponds with an increase in available generation capacity because of new capacity investment and the end of the long-run outages of the two large coal plants.

a low supply cushion (i.e., high demand), while limited market power execution arises in all other hours. Using a quantity-weighted market power measure, aggregating across all hours illustrates that firms exercise a significant amount of market power during our period of study. We also find evidence that the firms' strategic behavior changed in 2011 after the passing of a regulatory policy (OBEGs), which clarified that the exercise of certain types of unilateral market power is permissible (MSA, 2011). In particular, we observe higher market power measures and an increase in the observed payments that cannot be explained by higher production costs.

We find that productive and allocative market inefficiencies increase as the supply cushion decreases (demand rises). Productive inefficiencies increase production costs 14% - 19% above the competitive benchmark. While sizable, these inefficiencies reflect 0.9% - 6.35% of the observed market prices, with a point estimate of 2.35% of the average market price across all hours. Because of the limited number of consumers exposed to wholesale prices, allocative inefficiencies remain small.

Using estimates on the cost of capacity investment in Alberta for various generation technologies, we demonstrate that the energy market profits are systematically too low to cover the estimated fixed cost of capacity in the competitive benchmark. However, the observed energy market profits are often sufficient to promote and sustain investment in natural gas based technologies.[45] Further, the rents from market power execution can exceed the estimated capacity costs for certain technologies. This is most pronounced in the post-2010 period.

This study provides detailed insight into the performance of an energy-only electricity market design. Our findings suggest that Alberta's wholesale electricity market has sizable market power execution, inefficiencies, and rent transfers in the highest demand hours. However, the magnitude of the production inefficiencies are small as a proportion of the market price. In Alberta's energy-only market, the observed rents may be at least in part necessary to promote and sustain investment. These findings stress the importance of evaluating both short-run and long-run market efficiency when evaluating a market design.

Our findings also provide important policy implications for Alberta's wholesale market. In particular, an increase in the price-responsiveness of consumers in the highest demand hours has the potential to limit the degree of market power, price spikes, and inefficiencies. This may be achieved by establishing a market-based time-varying pricing program such as time-of-use, critical peak pricing, or real-time pricing. Similarly, many wholesale markets worldwide have established incentive-based demand response mechanisms that provide payments to consumers for reducing demand when called upon by the System

[45] These findings support recent studies that find that Alberta's energy-only market design is able to promote capacity investment; primarily in natural gas based technologies (Pfeifenberger and Spees, 2011; Pfeifenberger et al., 2013).

Operator during periods of high demand (and/or scarce supply) (Albadi and El-Saadany, 2008). While an evaluation and comparison of the performance of an incentive-based demand response and/or time-varying pricing program in Alberta is out of the scope of the current analysis, our findings illustrate that sizable static (short-run) welfare gains could be achieved by increasing consumers' price-responsiveness in the highest demand hours. The value of increased price-responsiveness may be magnified in the future as concerns of market power execution rise due to the expiration of several virtual divestitures established to reduce market concentration during the initial phase of electricity market restructuring in Alberta.[46] Further, while we provide evidence that Alberta's market is able to promote investment in natural gas technologies, it is important to continue to evaluate the ability of Alberta's market to attract investment.

In concluding, we note several directions for future research. First, the value and impact of time-varying pricing and/or incentive-based demand response programs in Alberta's wholesale electricity market should be considered. In particular, a detailed analysis of the impact that increased price-responsiveness has on market prices, efficiency, and strategic behavior is warranted.[47] Second, we focus solely on static market power execution through firms' offer behavior. An analysis that considers potential intertemporal (dynamic) collusive-like market power execution is a fruitful area of research.[48] Third, ensuring there are sufficient investment incentives to promote investment in Alberta's energy-only market is essential. A detailed and ongoing analysis of firms' investment incentives in Alberta awaits formal investigation. Fourth, a continued assessment of other electricity markets is critical to evaluate the performance of the large array of diverse restructured electricity market designs worldwide.

[46] These virtual divestitures (called power purchase arrangements) relinquished the offer control of several large coal units from the large incumbent utilities to other smaller firms. A large array of these arrangements are set to retire before 2020, leading to a potential increase in market concentration.

[47] In 2008, the AESO formed a working group to analyze the potential benefits of demand response. This brief study identified that there are sizable potential benefits to demand response in Alberta and discussed various barriers to its adoption (AESO, 2008).

[48] For example, the large degree of transparency of firms' hourly offers in Alberta has raised concerns over firms' abilities to coordinate across hours (Baziliauskas et al., 2011). This led to adjustments on how firms' offers are published (MSA, 2013).

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Appendix

A Marginal Cost Estimation

Data on the unit-specific heat rates for the natural gas (including cogeneration) units were obtained from the MSA (MSA, 2012a), the Alberta Utility Commission, and the Alberta Electric System Operator. Data on the technology-specific variable O&M rates were obtained from the U.S. Energy Information Administration (EIA, 2013). In Alberta, the Specified Gas Emitter Regulation (SGER) imposes a requirement that fossil fuel generators pay a \$15/tCO2e or buy offsets (SGER, 2007). This results in a compliance cost of approximately \$1.80/tCO2e resulting in an estimated compliance cost of \$1.35/MWh for natural gas combustion turbines and \$0.79/MWh for a natural gas combined cycle (Pfeifenberger and Spees, 2011). For cogeneration units, SGER treats the high energy efficiency of these units as an environmental benefit. This results in cogeneration facilities receiving an environmental credit (payment). Using data on operating and baseline greenhouse gas emission intensities, the estimated average environmental credit for cogeneration facilities in 2009 equals \$1.28/MWh (AESRD, 2009). We assume that the O&M and the environmental compliance cost (payment) grows at the average inflation rate in Alberta over our sample. The key qualitative conclusions are robust to the consideration of alternative growth rates.

B Hourly Import Supply and Demand Functions

In Tables A1 - A3, we provide the output of the first- and second-stage IV regressions for the import supply and industrial demand function estimations. The regressions are estimated using IV with Newey-West robust standard errors (in parentheses). The number of autocorrelated lags are chosen by Bartlett's Approximation $N^{\frac{1}{3}}$ where N is the sample size. The Kleibergen-Paap Wald F-Stat test for the weakness of the exclusive IVs with the null hypothesis that the exclusive instruments are weak.

C Cost of Capacity Investment

We use estimates on the cost of capacity investment in Alberta by generation technology from Pfeifenberger et al. (2013). Similar to their study, we assume a growth rate of 2.4% per-year for each generation technology. The qualitative conclusions are robust to alternative growth rates. In Alberta, renewable generation resources receive an emissions reduction credit (SGER, 2007). The Renewable Energy Credit of approximately \$15/MWh is included in the wind energy market revenues.

Table A1: Hourly Import Supply Function IV Estimation

	Saskatchewan		British Columbia	
	First Stage $\ln(p_t)$	Second Stage $Q^{IM}_{SK,t}$	First Stage $\ln(p_t)$	Second Stage $Q^{IM}_{BC,t}$
$\ln(p_t)$	—	29.11***	—	147.51***
		(4.02)		(11.15)
HDD_j	0.01**	0.418	-0.033***	15.42***
	(0.004)	(0.276)	(0.008)	(2.26)
HDD^2_j	-0.0002**	-0.012**	0.001***	-0.52***
	(0.00007)	(0.005)	(0.0003)	(0.095)
CDD_j	-0.018	-2.208**	0.002	-5.68
	(0.017)	(0.973)	(0.019)	(4.45)
CDD^2_j	0.006**	-0.074	-0.001	0.665
	(0.002)	(0.107)	(0.002)	(0.488)
Weekday	0.203***	-5.63***	0.206***	14.22**
	(0.002)	(1.91)	(0.019)	(5.82)
Holiday	-0.28***	5.25	-0.28***	-4.74
	(0.05)	(4.37)	(0.05)	(14.08)
HDD_{Edm}	-0.002	—	0.008	—
	(0.006)		(0.003)	
$\text{HDD}^2{}_{Edm}$	0.0002	—	-0.00009	—
	(0.0001)		(0.0001)	
HDD_{Cal}	-0.016***	—	-0.11**	—
	(0.005)		(0.005)	
$\text{HDD}^2{}_{Cal}$	0.0008***	—	0.0007***	—
	(0.0001)		(0.0001)	
CDD_{Edm}	0.09***	—	0.088***	—
	(0.019)		(0.02)	
$\text{CDD}^2{}_{Edm}$	-0.002	—	-0.0002	—
	(0.002)		(0.003)	
CDD_{Cal}	0.012	—	0.016	—
	(0.022)		(0.022)	
$\text{CDD}^2{}_{Cal}$	0.005*	—	0.006**	—
	(0.002)		(0.002)	
Constant	3.34***	-44.47***	3.57***	-622.43***
	(0.08)	(14.96)	(0.088)	(47.85)
R^2	0.378	0.58	0.377	0.66
Kleibergen-Paap Wald F-Stat	40.27***	—	53.35***	—
Sample Size	60,597	60,597	60,597	60,597
Hour-Month-Year Indicators	Y	Y	Y	Y

Notes: Each regression includes hour, month, and year covariates. The temperature variables contain heating degree days (HDD) and cooling degree days (CDD) for two cities in Alberta (Edmonton (Edm) and Calgary (Cal)), Vancouver in BC (denoted BC), and Saskatoon (denoted SK). HHD_j and CDD_j denotes the temperature variables for the province whose import function is being estimated (i.e., $j \in \{BC, SK\}$). These cities represent the major load centers in each province. ***, ** and * indicate statistically significant coefficients at the 1%, 5%, and 10% percent levels, respectively.

Table A2: Hourly Industrial Demand IV Estimation

	Lagged Price IV		Supply Shifters IV	
	First Stage $\ln(p_t)$	Second Stage Q_t	First Stage $\ln(p_t)$	Second Stage Q_t
$\ln(p_t)$	—	-35.61***	—	-37.74***
		(0.89)		(1.55)
HDD_{Edm}	0.0001	-0.398	0.007*	-0.59*
	(0.0005)	(0.358)	(0.004)	(0.35)
${\text{HDD}^2}_{Edm}$	0.00003	0.008	0.00003	0.01
	(0.0001)	(0.008)	(0.00009)	(0.008)
CDD_{Edm}	0.004**	-0.15	0.08***	0.19
	(0.002)	(0.809)	(0.015)	(0.80)
${\text{CDD}^2}_{Edm}$	-0.00007	0.21**	-0.001	-0.22**
	(0.0002)	(0.09)	(0.002)	(0.087)
HDD_{Cal}	0.0002	0.96***	-0.12***	0.98***
	(0.0005)	(0.339)	(0.004)	(0.33)
${\text{HDD}^2}_{Cal}$	0.00002	-0.019**	0.0006***	-0.18**
	(0.00001)	(0.008)	(0.00009)	(0.008)
CDD_{Cal}	0.002	1.31	0.009	1.04
	(0.003)	(0.856)	(0.017)	(0.84)
${\text{CDD}^2}_{Cal}$	0.0003	-0.152	0.004	-0.12
	(0.0003)	(0.098)	(0.002)	(0.096)
Weekday	0.01***	-17.05***	0.359***	-16.38***
	(0.002)	(1.20)	(0.015)	(1.22)
Holiday	-0.01**	2.09	-0.369***	1.59
	(0.004)	(3.13)	(0.039)	(3.17)
$\ln(p_t^{NG})$	0.002**	5.54***	0.057***	6.89***
	(0.001)	(1.49)	(0.009)	(1.35)
$\ln(p_{t-24})$	0.955***	—	—	—
	(0.002)			
Capacity Avail	—	—	-0.0007***	—
			(0.00002)	
$Q^{IM}_{SK,t}$	—	—	0.0004***	—
			(0.00002)	
$Q^{IM}_{BC,t}$	—	—	-0.0004***	—
			(0.00005)	
HDD_{SK}	—	—	0.009***	—
			(0.003)	
HDD^2_{SK}	—	—	-0.00003	—
			(0.00006)	
CDD_{SK}	—	—	0.004	—
			(0.014)	
CDD^2_{SK}	—	—	0.004**	—
			(0.002)	

Table A3: Hourly Industrial Demand IV Estimation Continued

	Lagged Price IV		Supply Shifters IV	
	First Stage	Second Stage	First Stage	Second Stage
	$\ln(p_t)$	Q_t	$\ln(p_t)$	Q_t
HDD_{BC}	—	—	-0.16**	—
			(0.007)	
HDD^2_{BC}	—	—	0.0007***	—
			(0.0003)	
CDD_{BC}	—	—	-0.009	—
			(0.016)	
CDD^2_{BC}	—	—	0.0004	—
			(0.002)	
Constant	0.091***	395.83***	9.91***	393.53***
	(0.013)	(12.99)	(0.22)	(12.34)
R^2	0.952	0.49	0.54	0.48
Kleibergen-Paap Wald F-Stat	140.72***	—	133.99***	—
Sample Size	60,597	60,597	60,597	60,597
Hour-Month-Year Indicators	Y	Y	Y	Y

Notes: Each regression includes hour, month, and year covariates. Capacity Availability is defined as the available capacity of generation units within Alberta and the transmission capacity limits of the BC/MT and SK transmission interties for each hour. The temperature variables contain heating degree days (HDD) and cooling degree days (CDD) for two cities in Alberta (Edmonton (Edm) and Calgary (Cal)), Vancouver in BC (denoted BC), and Saskatoon (denoted SK). These cities represent the major load centers in each province. The results are robust to higher order polynomials for each temperature variable and the choice of alternative large cities in BC and SK. $Q^{IM}_{j,t}$ denotes the import quantity from province $j \in \{SK, BC\}$. ***, ** and * indicate statistically significant coefficients at the 1%, 5%, and 10% percent levels, respectively.

Table A4: Detailed Distribution of Central Model Estimates by Supply Cushion

	Competitive Price ($)				Observed Price ($)			
	Mean	Std Dev	Min	Max	Mean	Std Dev	Min	Max
Bottom 5%	154.61	14.5	141.67	218.53	399.69	-	-	-
Bottom 25%	68.22	4.2	64.29	88.39	161.21	-	-	-
IQR	30.09	1.9	27.43	37.25	36.59	-	-	-
Top 25%	20.03	1.7	17.22	26.16	19.10	-	-	-
Top 5%	17.02	1.3	14.55	22.04	14.18	-	-	-
Total	37.99	2.2	35.15	46.86	65.94	-	-	-
	$MP(l)$				Deadweight Loss ($/hr)			
	Mean	Std Dev	Min	Max	Mean	Std Dev	Min	Max
Bottom 5%	60.1	3.9	49.7	63.6	15,417	1,023.7	9,387	19,421
Bottom 25%	57.4	2.7	43.7	59.6	1,348	43.9	1,180	1,402
IQR	17.6	4.2	9.5	24.9	1,057	16.1	1,009	1,100
Top 25%	-2.3	7.3	-29.2	10.4	734	26.1	668	796
Top 5%	-18.5	8.1	-44.4	-1.5	508	34.5	432	578
Total	42.7	3.3	29.5	47.1	1,004	13.0	963	1,031
	Internal Ineff ($/hr)				External Ineff ($/hr)			
	Mean	Std Dev	Min	Max	Mean	Std Dev	Min	Max
Bottom 5%	18,366	4,831	9,262	38,959	9,997	547.3	8,435	13,540
Bottom 25%	12,981	3,489	8,496	30,487	1,910	203.3	1,738	2,883
IQR	10,011	2,476	7,174	21,985	915	69.6	797	1,113
Top 25%	8,974	1,571	6,892	16,352	715	76.3	557	967
Top 5%	6,671	966	5,396	11,439	648	82.5	476	885
Total	10,246	2,244	7,573	21,407	1,006	77.1	881	1,264
	Competitive Payment ($/hr)				Observed Payment ($/hr)			
	Mean	Std Dev	Min	Max	Mean	Std Dev	Min	Max
Bottom 5%	1,323,763	129,891	1,205,541	1,997,382	3,315,141	-	-	-
Bottom 25%	568,757	37,084	533,856	750,293	1,333,392	-	-	-
IQR	237,756	15,346	216,940	293,415	289,068	-	-	-
Top 25%	151,340	12,513	130,345	197,885	144,584	-	-	-
Top 5%	129,385	10,056	110,608	168,330	109,002	-	-	-
Total	305,989	17,502	283,514	377,396	535,569	-	-	-
	Competitive Rent ($/hr)				Oligopoly (Obs) Rent ($/hr)			
	Mean	Std Dev	Min	Max	Mean	Std Dev	Min	Max
Bottom 5%	1,178,704	126,336	1,056,459	1,838,857	3,137,450	14,953	3,054,996	3,151,475
Bottom 25%	465,402	34,962	432,571	646,128	1,205,606	14,669	1,116,225	1,219,411
IQR	164,182	12,112	149,326	209,672	198,529	15,134	118,899	213,150
Top 25%	87,139	10,270	77,719	134,883	67,342	12,481	48,505	83,179
Top 5%	78,849	8,446	63,600	114,320	34,882	10,501	15,334	51,892
Total	228,009	14,843	212,563	288,058	436,165	15,295	359,945	452,790

Notes: Each iteration of the Monte Carlo Coal marginal cost analysis yields a value for each of these central measures. This establishes a distribution of estimates. Because Observed Price and Payments represent a deterministic outcome, they do not have a distribution. Alternatively, oligopoly (Observed) Rents vary because the underlying cost structure varies for each iteration of the Monte Carlo Simulation.