Measuring market power and the efficiency of Alberta's restructured electricity market: An energy-only market design

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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 6.7%–19% above the competitive benchmark, with an average of 13%. This reflects 2.1% 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 behaviour 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. The rents from market power execution can exceed the estimated capacity costs for certain generation technologies. However, 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 electricity market performance measures.

Résumê. Mesurer le pouvoir de marché et les inefficacités du marché restructuré pour l'électricité en Alberta: un design de marché pour l'énergie seulement. Les auteurs mesurent le degré de pouvoir de marché effectif en acte et les inefficacités du marché restructuré de l'électricité en Alberta. Utilisant les données par heure sur le marché en gros, on découvre que les firmes exercent un pouvoir de marché substantiel dans les plages horaires de forte demande où il y a excès de capacité de production limité. L'exercice du pouvoir de marché est faible dans les autres plages horaires. Les inefficacités sont plus grandes dans les heures de grande demande et soulèvent les coûts de production de 6,7 % à 19 % au-dessus des coûts concurrentiels de référence – en moyenne de 13 %. Cela se traduit par une augmentation de 2,1% du prix moyen par heure quand c'est reporté sur toutes les heures.

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Un cadre de réglementation récent a clarifié que certains types d'usage de pouvoir de marché sont permis en Alberta. Les auteurs ont observé que le comportement stratégique a changé après ces clarifications. L'exercice du pouvoir de marché s'est accru. On montre que les revenus observés sont souvent suffisants pour promouvoir l'investissement dans des technologies fondées sur le gaz naturel. Les rentes tirées de l'usage du pouvoir de marché peuvent excéder les coûts estimés pour accroître la capacité dans certaines technologies de génération d'énergie. Cependant, on montre que les profits dans le marché de l'énergie en l'absence de l'usage du pouvoir de marché sont insuffisants pour promouvoir l'investissement dans le développement de capacité de génération additionnelle. Cela souligne l'importance de considérer à la fois les mesures à court et à long terme de la performance du marché pour l'électricité.

JEL classification: D44, L13, L50, L94, Q40

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, Newbery and Grubb 2015). 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

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

mechanisms in Alberta to restrict firms' abilities to exercise market power.[2] In fact, in 2011 the Alberta Market Surveillance Administrator (MSA) released the Offer Behaviour Enforcement Guidelines (OBEGs), which 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 these energy-only market designs has garnered support from energy economists (Hogan 2005). However, 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 behaviour (Pfeifenberger et al. 2009). Alberta's market has also been subject to this controversy (Woo et al. 2003, MSA 2013). For example, in a recent ruling an incumbent generator was found to have manipulated prices away from the competitive outcome via strategically timing outages, resulting in a $56 million settlement (AUC 2015).

There is a growing literature that empirically estimates the degree of market power execution and inefficiencies in restructured electricity markets. Several studies analyze the impact of electricity market restructuring on the efficiency of power plants. Fabrizio et al. (2007) find modest efficiency gains in restructured states. Davis and Wolfram (2012) analyze the performance of nuclear plants after restructuring and find a sizable increase in capacity utilization compared to their regulated counterparts. Alternatively, taking market restructuring as given, an array of studies measure the performance of restructured electricity markets by comparing observed outcomes to a competitive benchmark. 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 analyzes market power in electricity markets by using a structural approach that compares a firm's optimal bid function to

2 While there are no mechanisms to restrict bids to reflect estimates of marginal cost, Alberta has a price cap at $999.99.

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 behaviour or behaviour that weakens or prevents competition (MSA 2011).

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).

observed bids (Wolak 2000; 2003a, b; Hortacsu and Puller 2008). These studies focus on estimating firms' abilities to exercise market power and rely on structural assumptions regarding firms' profit-maximizing behaviour. In a related analysis of Alberta's electricity market, Church and Kendall-Smith (2014) use the approach established by Wolak (2000, 2003a) to investigate a firm's ability to exercise market power and how this ability impacts offer behaviour. The authors find that firms have the ability to exercise market power in periods of high demand and this ability impacts firms' incentives to offer units at high prices. Unlike this approach, we use a competitive equilibrium methodology and observed bids to compute the degree of observed market power execution, market inefficiencies and the distribution of rents across all hours. This allows us to provide a broader assessment of Alberta's electricity market design and evaluate observed market power execution.

In addition to concerns over market power execution, promoting investment has been a primary concern in restructured markets, and in energy-only markets in particular.[5] Many electricity markets have adopted capacity payment mechanisms to provide revenues in addition to those earned in energy markets. Proponents argue that capacity markets are necessary to ensure resource adequacy and correct for a market failure that arises because regulatory policies (such as price caps and bid mitigation) 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 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, Newbery and Grubb 2015). 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 benchmark to measure market power execution, inefficiencies and the distribution of rents. Further, we investigate if firms changed their strategic behaviour 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, elevating average hourly wholesale prices by 22% to 157%. This can yield a sizable amount of rents transferred 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,

5 For example, in Texas there has been growing concern over resource adequacy due to shrinking capacity reserve margins (Kleit and Michaels 2013). Similarly, capacity market designs are currently being considered in various countries in Europe. Most notably, the United Kingdom recently implemented a capacity payment mechanism (Newbery and Grubb 2015).

looking across all hours, our market power measure illustrates that there is a sizable amount of strategic behaviour. Market inefficiencies are also larger in the high demand hours. These inefficiencies elevate production costs by 6.7% to 19% above the competitive benchmark, with an average of 13%. These estimates are similar to those identified for the PJM region and California (Borenstein et al. 2002, Mansur 2008). These inefficiencies reflect 0.8% to 6.1% of the observed market prices, with a point estimate of 2.1% of the market price across all hours.[6]

We find that the degree of strategic behaviour changed after the announcement of the OBEGs. 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.

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 and cogeneration technologies in Alberta. 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. 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 static (short-run) and dynamic (long-run) market efficiency measures 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 investigates firms' energy market profits and investment incentives. Various sensitivity analyses are considered in section 6. Section 7 concludes and discusses 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% of the market's generation capacity (MSA 2012b). A movement towards market restructuring began in 1996 and retail and

6 The competitive counterfactual approach attributes all deviations from marginal cost bidding to market inefficiencies. Mansur (2008) illustrates that this approach can overestimate the true market inefficiencies once ramping and start-up costs are considered. Hence, our approach provides a conservative upper bound on the market inefficiencies in Alberta.

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 revenues from short-run markets for electricity and ancillary services to cover the fixed cost of capacity investment. The Alberta Electric System Operator (AESO) is mandated 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.[7] 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.

While restructuring reduced concentration, supply remains relatively concentrated with the largest five firms having control of approximately 70% 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 Behaviour Enforcement Guidelines (OBEGs) that stated that unilateral market conduct that does not create or enhance market power is permitted (MSA 2011). 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 (GOA 2009).

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 benchmark. This

7 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.

TABLE 1
Alberta market and firm characteristics

	2008	2009	2010	2011	2012	2013	2014
Panel A: Market shares of generation capacity by firm and year (%)							
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 (%)							
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.

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 approach used to measure market power, inefficiencies and rents is as follows. First, we estimate the market-level marginal cost curve using unit-specific thermal efficiencies, capacities, fuel prices, environmental costs, variable operating and maintenance costs and offer behaviour. Second, we formulate a residual market demand curve by using reduced-form approaches to separately estimate hourly import electricity supply from neighbouring provinces and price-responsive demand 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 that reflect electricity supplied from neighbouring provinces into Alberta. Third, we identify the highest marginal cost unit that is required to meet residual demand. This unit sets the competitive benchmark price. All available units whose estimated marginal costs are at or below the competitive price are dispatched. Fourth, we compare the observed and competitive outcomes to compute the degree of market inefficiencies, market power execution and decompose the payments and rents to firms.

3.1. Data description

We use publicly available data from the AESO from January 11, 2008, to December 31, 2014.[8] This data set includes observed hourly price and quantity offers for all generation firms in Alberta, unit-level production, natural gas prices from

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

TABLE 2
Summary statistics of the observed outcome

	Units	Mean	Std dev	Min	Median	Max	N
Quantity demanded	MWh	7,800	783	6,213	7,793	10,475	60,597
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	265	−826	256	1,022	60,597

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. Further, we gather hourly weather data for British Columbia (BC), Alberta (AB) and Saskatchewan (SK) from Environment Canada: Weather Information. 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 market price. Further, the mean market 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. Alberta is systematically a net importer of electricity from the neighbouring provinces.

3.2. Marginal cost estimation

We estimate the marginal cost of each generation unit to establish the perfectly competitive supply curve.[9] We explicitly model 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. We estimate the marginal cost of a natural gas 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.

Alberta generates a sizable portion of its electricity from cogeneration units which produce both steam and electricity for industrial use on-site using natural gas. These units sell all excess electricity not consumed on-site. Similarly, there are several small Biomass units that are often associated with on-site industrial processes. We assume that the excess electricity from these cogeneration and biomass units have a marginal cost of zero. These units systematically submit bids of zero.

There are several types of units whose marginal cost cannot be explicitly modelled. In particular, in Alberta coal is purchased through unobservable long-term contracts. For each year, we establish a Monte Carlo algorithm that selects a coal unit's energy market bid during hours where there is a large amount of generation

9 Appendix A1 provides details on the data sources and methodology used to estimate marginal cost by generation technology.

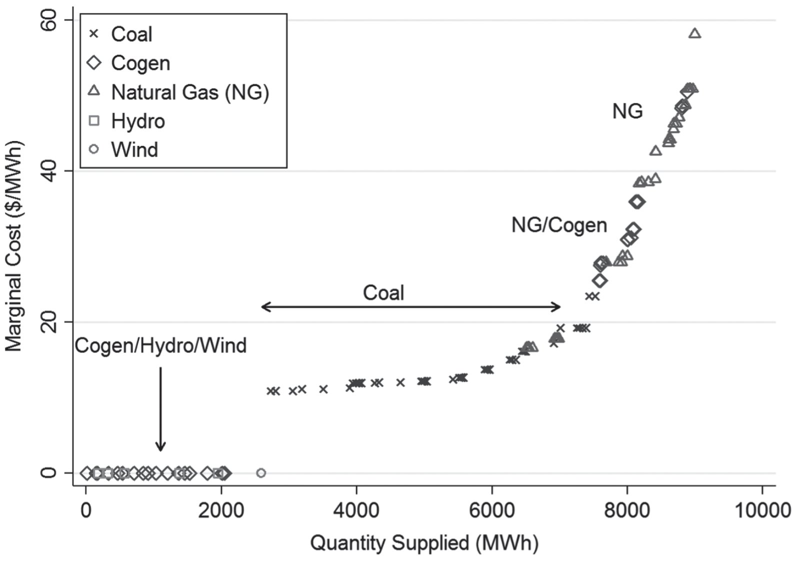

FIGURE 1 Alberta supply curve November 12, 2011, hour 16

capacity that is not being utilized to meet demand as a proxy for marginal cost.[10] Generation capacity that is not utilized will be referred to as the supply cushion throughout the analysis. The entire analysis is then computed, given this draw for each coal unit and year. This numerical approach is performed repeatedly ($N = 100$), yielding a distribution of market power and inefficiency estimates.

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. 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.[11] Lastly, there has been substantial growth in wind generation capacity in Alberta. We set the marginal cost of the observed wind generation equal to zero. Figure 1 provides an illustration of a typical estimated hourly marginal cost supply curve.

10 In these hours, it has been shown that generators' offers often reflect their marginal cost (e.g., see Crawford et al. 2007). Brown and Olmstead (2016) illustrate that our results are robust to the use of Wyoming Powder River Basin coal prices.

11 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. The potential biases from this assumption are likely to be small in Alberta due to the limited Hydro generation. Hydro makes up 6% to 7% of generation capacity and 2% to 3% of annual generation output in Alberta.

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. For each hour t and neighbouring province j, the following province-specific import supply functions are estimated using a linear-log function of observed Alberta price p_t:[12]

$$\begin{aligned} Q_{jt}^{IM} &= \beta_{0j} + \beta_{1j}\ln(p_t) + \beta_{2j}\text{Weekday}_t + \beta_{3j}\text{Holiday}_t + \alpha_j \text{h}(\text{Temp}_{jt}) \\ &+ \sum_{h=1}^{24} \omega_{hj}\text{Hour}_{ht} + \sum_{m=1}^{12} \gamma_{mj}\text{Month}_{mt} + \sum_{y=2008}^{2014} \psi_{yj}\text{Year}_{yj} + \epsilon_{jt} \forall \quad j \in \{BC, SK\}, \end{aligned} \tag{1}$$

where $\text{h}(\text{Temp}_{jt})$ 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.[13] 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. Similar to Mansur (2008), to address the endogeneity in price, we use a Instrumental Variable (IV) approach where the exclusive instruments are the hourly temperature variables in Alberta. Measures of temperatures in Alberta are valid instruments because they affect the prevailing demand conditions in Alberta and so, it impacts the market price in Alberta (p_t). However, the temperature variation in Alberta only impacts the import quantity through its impact on p_t. Table A2 provides detailed results of the import supply function estimation. The import supply function yields average price elasticities of imports of 0.64 and 0.55 for BC and SK, respectively.

Once the import supply functions are estimated, we assume that the import supply curve represents the marginal cost curve of suppliers outside of Alberta (net of their native load obligations). 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 neighbouring 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.[14]

12 For additional details on the import supply function estimation approach, see appendix A2.

13 The temperature variables used in the analysis for AB, BC and SK are modelled as quadratics for hourly cooling degrees (hourly mean degrees above 18.33° Celsius (65° F)) and hourly heating degrees (hourly mean degrees below 18.33° Celsius (65° 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.

14 If the neighbouring provinces exercise market power in their offers to supply imports, then our analysis underestimates the rents paid to neighbouring provinces and overestimates our external production inefficiency measure (for more details, see appendix A3). This contributes to our approach of providing an conservative upper bound on market inefficiencies.

3.4. Price-responsive demand estimation

In Alberta, a subset of large 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 8% of hourly load. These customers are firms primarily in the pulp, paper, forestry and petrochemical sectors. 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:

$$Q_t = \theta_0 + \theta_1 \ln(p_t) + \theta_2 \ln(p_t^{NG}) + \theta_3 \text{Weekday}_t + \theta_4 \text{Holiday}_t + \phi \text{h}(\text{Temp}_{AB,t}) \\ + \sum_{h=1}^{24} \omega_h Hour_{ht} + \sum_{m=1}^{12} \gamma_m \text{Month}_{mt} + \sum_{y=2008}^{2014} \psi_y \text{Year}_y + \eta_t, \tag{2}$$

where p_t^{NG} is the price of natural gas, $\text{h}(\text{Temp}_{AB,t})$ 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 variables for each provincial holiday in Alberta, hour, month and year in our sample, respectively.[15] 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. 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 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 hourly wind production and capacity supply availability that reflects the sum of the available electricity generation capacity within Alberta and the import transmission capacity limits.

Table A3 provides detailed estimates of industrial demand. The coefficients imply average price-elasticities of demand of -0.15 and -0.16 for the lagged price and supply shifter IVs, respectively. It is without loss of generality to focus on the results from the lagged price IV model in the subsequent analysis.

3.5. Market power and production inefficiency measures

Having established the marginal cost, import supply and price-elastic industrial demand estimates, we estimate the equilibrium price and quantity and identify the units called upon to supply electricity in both the competitive and observed market outcomes. Two types of production inefficiencies arise in our analysis.

15 The Alberta temperature variables used are analogous to those defined in the import supply estimation above. For additional details on the industrial demand function estimation approach, see appendix A2

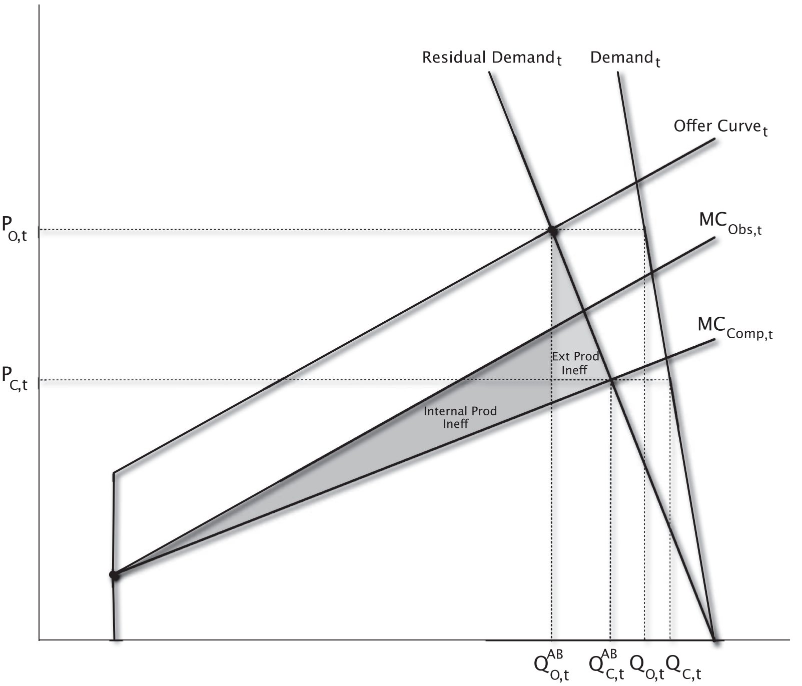

FIGURE 2 Internal and external productive inefficiencies

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 in Alberta constant. These production inefficiencies arise when firms exercise market power by increasing their bids on low-cost efficient units above marginal cost to elevate the market price, resulting in these units being displaced by less efficient resources with lower bids. Second, external production inefficiencies arise because of a misallocation of production from units within Alberta to power imported from neighbouring provinces. When the observed price exceeds the competitive 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 illustrates both types of production inefficiencies. The observed marginal cost of the Alberta units dispatched based on their offers is represented by the curve $MC_{obs,t}$. The intersection of the residual demand curve and the observed offer curve yields the observed equilibrium price. Alternatively, the competitive equilibrium price results from the intersection of the residual demand curve and the competitive marginal cost curve ($MC_{comp,t}$) which represents the least-cost available resources in Alberta. 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 market price, total level of output and output served by generation units in Alberta in period t, respectively. The internal production inefficiencies are reflected by the area between the observed and competitive marginal cost curves, holding the internal observed supply in Alberta ($Q^{AB}_{O,t}$) constant. The external production inefficiencies are reflected by the additional production costs associated with dispatching more expensive imports in place of within Alberta production ($Q^{AB}_{C,t} - Q^{AB}_{O,t}$) that would be served by more efficient Alberta generation units in the competitive equilibrium. Appendix A3 provides additional details into the measurement of internal and external inefficiencies presented in figure 2.

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.[16] This represents the proportional increase in wholesale procurement costs caused by firms' abilities to exercise market power in the set of hours l.

In hours with a large supply cushion, there are cases where market power estimates are negative. Inflexible coal units may operate at prices below our static estimates of marginal cost to avoid costly ramping or start-up costs (Borenstein et al. 2002, Mansur 2008). Our static marginal cost estimates are unable to account for these dynamic cost characteristics and so, this will bias our competitive benchmark outcomes in hours where there is low market demand. Throughout our analysis, we separate our estimates based upon the level of the supply cushion. These dynamic cost factors will have limited impacts on the mark-ups in lower supply cushion hours.[17]

4. Main findings

In this section, we highlight our main findings. We estimate market power execution, production inefficiencies and decompose the distribution of rents and payments for each iteration of our Monte Carlo coal cost simulation. We take the average over the resulting distribution of estimates from this Monte Carlo

16 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 $(P_{O,t} - P_{C,t})Q_{O,t}$.

17 In section 6, we perform sensitivity analyses to check the robustness of our results to our coal cost estimation methodology.

TABLE 3
Average observed and competitive outcomes and market power 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)	155.36	68.36	29.90	19.97	17.01	37.93
Competitive output (MWh)	8,365	8,176	7,832	7,453	7,325	7,837
MP(l) (%)	60.0	57.3	18.0	−2.1	−18.9	42.8

NOTES: For each measure, the values reflect averages across all hours within a particular supply cushion. IQR reflects the interquartile range. Total is the average across all hours. $MP(l)$ represents our market power measure.

simulation. Throughout the analysis, we will present these 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, for each year, 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. All currency values are in Canadian dollars.

4.1. *Market power measures and productive inefficiencies*

Table 3 presents the mean hourly observed and competitive outcomes 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 (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. In hours with a low supply cushion (lower competition on the margin), we observe a sizable execution of market power. At the bottom 5% and 25% of the supply cushion, market power elevates average wholesale prices by 157% and 136%, respectively.

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.[18] Looking at all hours in our sample, we find that the higher weight placed on the hours with a low supply cushion (higher demand)

18 The negative market power measures arise because our static marginal cost estimates do not account for ramping constraints and start-up costs 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 (Mansur 2008). Section 6 considers alternative approaches to measure coal costs and market power in these high supply cushion hours.

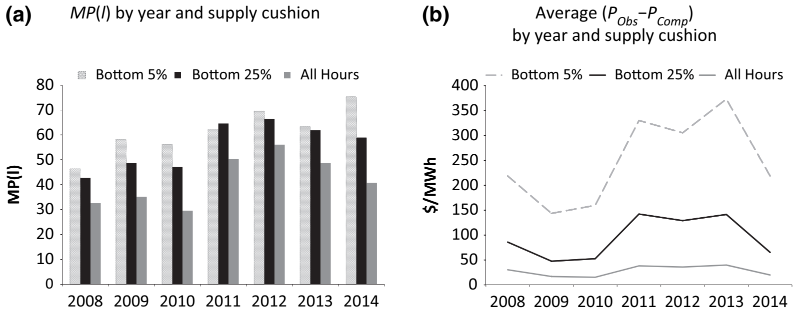

FIGURE 3 Market power and average observed and competitive price differences by year

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. Figure 3 takes a detailed look at the change in market power and observed prices (relative to the competitive price) by year and supply cushion for the bottom 5%, 25% and all hours.[19] Figure 3(a) illustrates that firms exercise a sizable amount of market power in the low supply cushion hours and in aggregate across all years. In particular, the market power measures are considerably higher in the post-2010 period. This is being driven by the higher market power measures in the hours at the bottom 5% and 25% of the supply cushion. Figure 3(b) demonstrates that the average difference between observed and competitive prices increased substantially in the post-2010 period at the lowest supply cushion hours. These findings suggest that there was a change in the degree of strategic behaviour in the post-2010 period.[20] 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 4 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. The hourly total (internal and external) production inefficiency estimates range from \$6,987 to \$25,812 or \$0.86 to \$3.21 per MWh of electricity. Comparing these numbers to the observed market price by supply cushion,

19 Table A1 of the appendix provides detailed data on the observed and competitive equilibrium outcomes and market power measures by year and supply cushion.
20 It is difficult to deterministically disentangle if the change in offer behaviour arises due to the OBEGs or coal unit outages. However, in 2014 these two large coal units were operational and market power remained higher than the pre-2010 period.

TABLE 4
Hourly production inefficiencies by supply cushion

Production inefficiencies	Supply cushion					
	Bottom 5%	Bottom 25%	IQR	Top 25%	Top 5%	Total
Internal ($/hr)	15,831	10,564	9,221	8,509	6,355	9,453
Internal per-unit ($/MWh)	1.97	1.43	1.19	1.06	0.78	1.22
External ($/hr)	9,981	1,829	903	701	632	990
External per-unit ($/MWh)	1.24	0.23	0.12	0.09	0.08	0.17

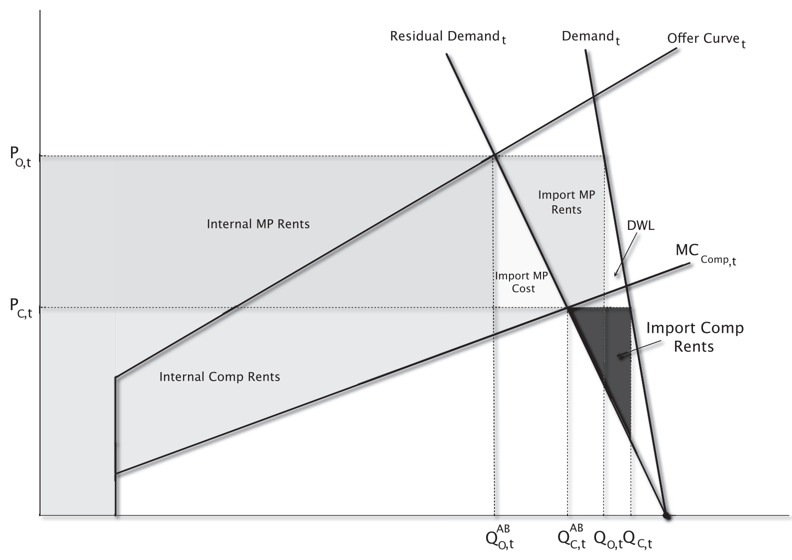

FIGURE 4 Rent division and payments

the total inefficiencies per-unit ranges from 0.8% to 6.1% 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 $1.22/MWh, which is approximately 2.1% of the pool price. Therefore, the production inefficiencies are limited as a fraction of the average observed market price.

4.2. Rent decomposition

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

TABLE 5
Mean hourly payments, costs, rents and deadweight losses by supply cushion

	Supply cushion					
Observed measure	Bottom 5 %	Bottom 25 %	IQR	Top 25 %	Top 5%	Total
Payments ($/hr)	3,315,142	1,333,392	289,068	144,585	109,002	530,214
	[150.6]	[134.8]	[22.8]	[−3.7]	[−15.4]	[73.9]
Rents ($/hr)	3,143,766	1,211,494	204,037	74,774	44,158	438,951
	[166.7]	[164.7]	[31.0]	[−14.8]	[−35.9]	[95.9]
Production costs ($/hr)	171,376	121,898	85,032	69,810	64,844	91,263
	[18.9]	[10.7]	[6.7]	[11.9]	[8.2]	[13.0]
Deadweight loss ($/hr)	14,247	1,333	1,042	720	502	988
Deadweight loss ($/MWh)	1.74	0.16	0.13	0.10	0.07	0.13

NOTES: For each of the observed measures, the values reflect averages across all hours within a particular supply cushion. The numbers in the brackets denote the percentage change in the observed outcome relative to the competitive benchmark.

Figure 4 illustrates several of these components.[21] *Internal* and *Import Comp Rents* reflect the payments above production costs to firms operating in Alberta and to importers in the competitive benchmark, 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* represents the cost of procuring imports in place of more efficient within Alberta production due to the higher observed equilibrium price associated with market power (see appendix A3 for additional details on Import Rents and Costs). *DWL* reflects the deadweight loss associated with lower output.

Table 5 provides the average hourly observed payments, costs, rents and deadweight loss for various measures of the supply cushion. The percentage change from the competitive benchmark is represented in brackets. Similar to our market power measures, the observed payments and oligopoly (observed) rents increase as the supply cushion decreases. 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, at the bottom 5% of the supply cushion, the mean hourly oligopoly rents exceed the competitive rents by approximately 166.7%. Looking across all hours, observed payments and rents exceed the competitive benchmark by 73.9% and 95.9%, respectively. These findings are driven by the strategic bidding behaviour detailed in table 3. 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. This corresponds to the negative market power measures in table 3 in the high supply cushion hours.

21 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.

TABLE 6
Mean hourly payments, costs and rents by year

Observed measure	2008	2009	2010	2011	2012	2013	2014
Payments ($/hr)	698,183	371,276	399,566	627,563	535,401	674,459	443,540
	[49.10]	[54.63]	[42.46]	[100.92]	[128.28]	[97.18]	[70.09]
Rents ($/hr)	607,697	288,931	306,820	529,043	456,106	574,654	352,867
	[57.55]	[74.99]	[55.02]	[132.52]	[173.96]	[121.67]	[92.63]
Production costs ($/hr)	90,486	82,345	92,746	98,519	79,295	99,804	90,674
	[9.59]	[9.79]	[12.36]	[16.16]	[16.53]	[20.51]	[16.86]

NOTES: For each of the observed measures, the values reflect averages across all hours within a particular supply cushion. The numbers in the brackets denote the percentage change in the observed outcome relative to the competitive benchmark.

Table 5 illustrates that observed production costs can exceed the competitive benchmark by 6.7% to 19%, with an average increase of 13%. The higher cost is driven by the internal production inefficiencies due to market power execution (recall table 4). The deadweight loss is small for the majority of hours. In low supply cushion hours the deadweight loss can be substantial because of the exercise of market power.

To understand how the strategic behaviour changes over time, table 6 presents the observed payments, rents and production costs by year. The percentage change from the competitive benchmark is represented in brackets. This analysis provides further evidence that firm behaviour changed after the post-2010 period; payments and rents increased substantially in the post-2010 period relative to the competitive benchmark. While we observe an increase in the production costs in the post-2010 period, these costs are not sufficient to fully explain the higher observed payments.[22] In addition, production costs relative to the benchmark increased in the post-2010 period suggesting that the elevated market power s execution lead to a higher average production inefficiencies. 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 illustrated in figure 3(a) in the post-2010 period.

5. Energy market profits and capacity investment

Next, we compute the level of the observed and competitive wholesale energy market profits for each year and compare them to estimates of the fixed cost of generation capacity in Alberta. While investment decisions are long-run processes, this analysis provides insight into the ability of Alberta's energy-only market design

22 In 2008, that natural gas fuel input prices reached their peak. Table A1 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 A1.

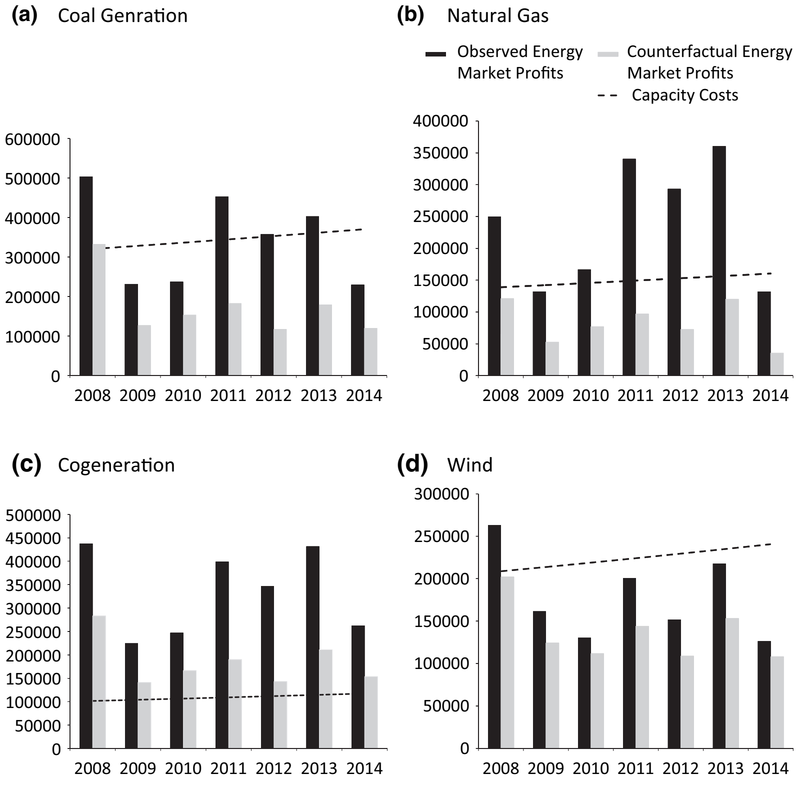

FIGURE 5 Average energy market profits and capacity cost ($/MW-year) by technology

to promote and sustain investment. 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. 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 in Alberta are obtained from Pfeifenberger et al. (2013).[23] These capacity costs represent the annualized capacity costs per MW of generation capacity by technology in Alberta.

Figure 5 compares the observed and competitive wholesale energy market profits to estimates of the cost of capacity investment across four technologies: coal, natural gas, cogeneration and wind.[24] These comparisons vary substantially

23 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 A4.

24 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.

TABLE 7
Utility-scale generation capacity additions (MW) 2004–2021

Year	By technology (MW)							By firm type (MW)	
	Coal	Cogen	Gas	Hydro	Wind	Other	Total	Incumbent	Fringe
2004	0	0	0	7	98	0	105	75	30
2005	450	10	0	0	0	25	485	450	35
2006	0	165	0	0	111	0	276	68	208
2007	53	80	0	0	135	0	268	134	134
2008	0	302	202	0	0	0	504	95	409
2009	53	107	337	0	66	0	563	469	94
2010	115	182	15	10	214	0	536	330	206
2011	469	0	23	0	88	100	680	493	187
2012	34	376	27	15	230	38	720	202	518
2013	13	158	20	0	0	0	191	30	161
2014	0	264	989	0	346	0	1,599	879	720
2015	6	40	53	0	29	0	128	6	122
2016–2021*	0	0	4,530	0	1,182	41	5,753	2,928	2,825

NOTES: Other reflects biomass or solar. We define incumbent as one of the five large generators (ATCO, CP, ENMAX, TA, TC). An asset is assigned to the fringe if the original project developer was not an incumbent; assets can be subsequently purchased by an incumbent. The 2016–2021 projects reflect units that are either under construction or are approved (AESO 2016b). These projects' in-service dates, capacities and overall investment decisions are subject to change.

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 and coal units, the observed energy market profits exceed capacity costs for several years in our sample. Alternatively, the observed energy market profits for wind are systematically below the cost of capacity. Importantly, the competitive energy market profits are systematically insufficient to cover the fixed cost of capacity for all technologies except for cogeneration.

Figure 5 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 result, coupled with the finding that the market power measures (figure 3(a)) and observed rents (table 6) increased in this period, provides further evidence that the energy market behaviour changed in 2011.

Using our calculations, we are unable to address if the observed variable profits above fixed cost of investment are in excess of those necessary to promote capacity investment to ensure long-run market reliability. However, the current analysis does illustrate that the competitive payments are too low to cover the estimated cost of capacity and the observed variable profits are systematically sufficient to cover the cost of capacity investment for natural gas and cogeneration technologies.

Table 7 illustrates observed and anticipated capacity investment in Alberta by technology and firm type. Since 2004, there has been substantial growth in cogeneration and natural gas capacity; 66.9% of all observed capacity additions have been cogeneration and natural gas units. In addition, future expected capacity additions are largely concentrated in natural gas based technologies; 78.7% of projected investments are in natural gas technologies.[25] These observed and anticipated investment trends complement our findings in figure 5. Further, the reduction in energy market profits in 2014 observed throughout our analysis corresponds with a large amount of natural gas capacity investment.[26] Observed and projected capacity investment decisions have been evenly split among the incumbents and fringe; 53.4% of observed capacity investments have been from incumbents. While initial development of assets has been distributed evenly among the incumbents and fringe, the incumbents have often subsequently purchased these assets.

Since 2004, there has been an array of unit retirements concentrated in aging coal (593 MW) and natural gas simple-cycle (859 MW) technologies. Currently, Alberta has sufficient generation capacity with a reserve margin of 33% (AESO 2016b). However, recent market developments in Alberta, such as the passing of a carbon pricing plan and mandated coal unit retirements by 2030 (Alberta Government 2015), has increased the importance of monitoring firms' energy market profits and investment and retirement incentives going forward to ensure resource adequacy is achieved in Alberta's energy-only market design.

6. Sensitivity analyses

We perform various sensitivity analyses to demonstrate the robustness of our findings. Brown and Olmstead (2016) provide a detailed discussion and presentation of these results. First, built into our research methodology is the Monte Carlo simulation used to construct marginal costs for coal units. For each iteration, the analysis estimates market power measures, inefficiencies and decomposes rents. While this yields a distribution of estimates for each of these measures, this distribution is compact and the qualitative conclusions are robust. Second, to test the robustness of our coal cost estimation methodology, we use weekly coal price data from Wyoming's Powder River Basin (PRB) and unit-specific heat rates to estimate the marginal cost of each coal unit in Alberta. The estimated short-run marginal cost of coal ranges from \$10.24 to \$23.29 per MWh and \$8.60 to \$25.06 per MWh using the PRB coal prices and our Monte Carlo simulation method, respectively. When we re-estimate our analysis using PRB estimated coal marginal costs, we get similar market power estimates, an increase in observed rents and lower production inefficiencies. While the precise numerical results differ, the key qualitative results hold.

Third, to ensure that our negative market power estimates in the large supply cushion hours do not bias our aggregated market power measures downward,

25 Wind capacity has also increased substantially and is expected to continue to grow. However, figure 5(d) and Pfeifenberger et al. (2013) demonstrate that wind generation in Alberta is currently not profitable without out-of-market payments.

26 Weaker demand growth and the sizable 2014 capacity investment has coincided with historically low wholesale prices in Alberta in 2015 and the first quarter of 2016 (MSA 2016).

we truncate the market power measures in these hours to zero.[27] Intuitively, this elevates our aggregated market power measures by a few percentage points, emphasizing that firms exercise a sizable amount of market power in the highest demand hours. Fourth, because we want to focus on a short-term price elasticity of industrial demand, we test the robustness of our results to the estimated price elasticity by assuming industrial demand is perfectly price-inelastic. This increases the slope of residual demand and so, provides a conservative upper bound on the estimated market power measure and firm rents. We see a modest increase in the estimated market power measures, production inefficiencies and observed rents. However, the central results of our analysis are unchanged.

Fifth, our analysis has abstracted from transmission congestion from neighbouring provinces and within Alberta. We truncate estimated imports at their capacity intertie limits to investigate the impact of transmission congestion from neighbouring provinces. This creates a kink in the residual demand function, increasing its slope, resulting in a several percentage point increase in market power estimates in the low supply cushion hours. Transmission congestion within Alberta could result in us overestimating inefficiencies because the least-cost resources are not being dispatched due to transmission constraints, not firm behaviour. Using proprietary data on transmission congestion management in Alberta, we identify the hours where some degree of congestion occurred within Alberta and re-estimate our analysis breaking our sample into hours with and without some degree of congestion. Hours with congestion tend to have higher market prices and a lower supply cushion, on average. However, there is not a sizable difference in the estimated production inefficiencies across hours with and without within Alberta congestion.[28]

Sixth, we investigate if the estimated inefficiencies are due to inefficient dispatch decisions within a firm. Using our estimated unit-specific marginal cost, we find that a firm's observed production costs are 2% to 6% larger than its least-cost dispatch. This modest number alleviates concerns that estimated production inefficiencies are being largely driven by measurement error within a firm's marginal cost function. Seventh, throughout our analysis, we decomposed our results by supply cushion percentiles defined separately for each year of our sample. Because these thresholds can vary by year (in MW terms), we also decomposed our results by fixed MW thresholds over our entire sample. The qualitative conclusions of our analysis are insensitive to this alternative supply cushion threshold definition.

7. Conclusion

We use a competitive benchmark approach and detailed data from 2008 to 2014 to evaluate the divergence of Alberta's restructured wholesale electricity market

27 This follows the large empirical and theoretical literature that illustrates that firms behave as price-takers in low demand hours (e.g., see Crawford et al. 2007 and Mansur 2008).

28 MSA (2014) find that only 0.2% of the MWh dispatched in Alberta in 2012 and 2013 were uneconomic due to congestion.

from one where all firms behave as price-takers. We demonstrate that firms exercise substantial market power in the hours with a low supply cushion, 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 behaviour changed in 2011 after the passing of a regulatory policy (the 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 and rents 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 6.7% to 19% above the competitive benchmark, with an average increase of 13%. While sizable, these inefficiencies reflect 0.8% to 6.1% of the observed market prices, with a point estimate of 2.1% of the average market price. 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 and cogeneration technologies. These findings support recent investment trends in Alberta. 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 a large degree of market power execution and rent transfers in the highest demand hours. This market power execution leads to sizable short-run production inefficiencies. However, the magnitude of the production inefficiencies are small as a proportion of the market price in our sample. In Alberta's energy-only market, the observed oligopoly 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 electricity market. While we provide evidence that Alberta's wholesale market has been 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 natural gas and other technologies. Recent market changes such as the introduction of carbon pricing and mandated coal unit phase out (Alberta Government 2015) have the potential to substantially impact firms' investment and retirement incentives and the portfolio of generation technologies in Alberta going forward. The impact of these changes on firms' abilities to exercise market power depends largely on which firms make these generation capacity investments (i.e., incumbents or fringe) and if the capacity reserve margin remains high (AESO 2016b). Our analysis illustrates that a reduction in the supply cushion (e.g., due to coal retirements) can lead to a large increase in market power, holding all else constant.

We demonstrate that there is a trade-off associated with the inefficiencies due to market power execution and providing rents to promote investment in Alberta's energy-only market. Critics of energy-only markets advocate for a market design that imposes regulatory restrictions on firms' bidding behaviour and institutes a capacity payment mechanism to motivate investment and limit the distortions associated with market power (Joskow 2008a, Cramton et al. 2013). However, such capacity payment mechanisms have also been criticized for excessive capacity procurement, providing windfall profits to incumbents and the controversial administrative parameters (Kleit and Michaels 2013, Newbery and Grubb 2015). For each possible market design, it is essential that regulators and policy makers evaluate the market's ability to promote investment, while minimizing short-run distortions associated with market power execution.

In Alberta's current market design, the short-run distortions associated with market power can potentially be alleviated by an increase in the price-responsiveness of consumers in high-demand hours. This may be achieved by establishing a time-varying pricing program (e.g., time-of-use or critical peak pricing) or a demand response mechanism that provide payments to consumers for reducing demand when called upon by the System Operator (Albadi and El-Saadany 2008). Recent proposals have been made to increase the transmission intertie limit to allow for more imports from neighbouring British Columbia (AESO 2015). Our results illustrate that a moderate increase in the supply cushion (e.g., 500 MW in the case of the BC intertie) could result in a large reduction in the execution of market power.[29]

In concluding, we note several directions for future research. First, an analysis of the value and impact of time-varying pricing and demand response on market prices, efficiency and strategic behaviour warrants formal investigation.[30] Second, we focus solely on static market power. An analysis that considers potential dynamic market power execution is a fruitful area of research.[31] Third, additional research that considers start-up costs and ramping constraints when evaluating the performance of electricity markets warrants further consideration. Accounting for such non-convexities will improve researchers' abilities to

29 This is further demonstrated by the low wholesale prices in 2015 and 2016 corresponding to a new 989 MW natural gas facility and low demand (MSA 2016). Moderate changes in supply conditions can have sizable impacts on market power.
30 AESO (2016a) identified that there are sizable potential benefits to demand response.
31 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).

model firm behaviour in oligopolistic electricity markets.[32] Fourth, in the face of a quickly evolving market, ensuring there are sufficient 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. Fifth, a continued assessment of other electricity markets is critical to evaluate the performance and trade-offs associated with the large array of diverse restructured market designs worldwide.

Appendix

Appendix A1. Marginal cost estimation

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 the marginal cost of natural gas units. 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. 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 US 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 (GOA 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.

For the coal units, we undertake the following Monte Carlo simulation. We use the energy market bids of these coal units during hours where the quantity of undispatched supply exceeds 1,500 MWh. To ensure that our results are robust to the energy market bids selected, we create a year and unit-specific empirical offer

32 Recent research has begun to use rich data sources that include complex bidding schedules to incorporate such non-convexities when modelling firm behaviour in electricity markets (e.g., see Reguant 2014).

distribution that reflects the annual distribution of bids for each coal unit during hours with a large supply cushion. We establish a year-specific offer distribution for each unit to capture variation in the underlying long-term coal contracts. 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. 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 $F_{jy}(b_{jy} \leqslant \widetilde{b}_{jy}) \leqslant z$. The entire analysis is then computed, given this draw for each coal unit. This numerical approach is performed repeatedly ($N = 100$). There are three biomass units that submit non-zero offers. For these units, we replicate the coal cost imputation.

Appendix A2. Hourly import supply and industrial demand functions

After the import quantity decisions are made, importers are required to bid into the hourly spot market at a price of \$0, effectively becoming price-takers. While importers become price-takers in the spot market, they make their import supply decisions taking into account the expected uniform spot market price. Table A2 details the province-specific import supply function estimation results. In 2013, a transmission interconnection between Alberta and Montana was added. The

TABLE A1
Observed and competitive prices and market power by supply cushion and year

Supply cushion		2008	2009	2010	2011	2012	2013	2014
Bottom 5%	P_{Obs}	460.17	242.89	276.43	519.32	448.23	584.12	289.51
	P_{Comp}	241.58	99.38	116.83	189.20	142.93	211.05	70.85
	$MP(l)$	46.4	58.1	56.2	62.0	69.5	63.3	75.3
Bottom 25%	P_{Obs}	197.93	96.88	109.74	216.50	182.94	219.50	111.26
	P_{Comp}	112.10	49.38	57.23	74.32	53.96	78.20	46.03
	$MP(l)$	42.8	48.7	47.2	64.6	66.5	61.9	58.9
IQR	P_{Obs}	65.07	37.05	35.95	34.24	27.47	35.72	33.05
	P_{Comp}	51.24	27.86	31.81	28.64	21.14	30.11	27.53
	$MP(l)$	20.1	23.9	10.8	16.3	22.9	16.0	16.7
Top 25%	P_{Obs}	30.08	19.17	21.56	17.76	13.89	18.98	18.10
	P_{Comp}	25.74	19.30	22.90	19.94	15.57	21.87	18.39
	$MP(l)$	13.5	−0.8	−7.3	−13.4	−12.7	−16.4	−1.1
Top 5%	P_{Obs}	19.11	13.04	15.89	13.97	9.28	14.71	12.87
	P_{Comp}	18.13	16.78	20.00	17.57	12.99	18.97	15.36
	$MP(l)$	5.7	−28.1	−26.0	−27.2	−37.6	−30.1	−17.9
Total	P_{Obs}	91.19	48.09	51.45	76.16	64.02	80.72	50.05
	P_{Comp}	60.92	31.32	36.18	38.02	28.20	40.98	30.19
	$MP(l)$	32.6	35.2	29.6	50.4	56.1	48.7	40.8

TABLE A2
Hourly import supply function IV estimation

	Saskatchewan			British Columbia		
	OLS $Q^{IM}_{SK,t}$	First stage $\ln(p_t)$	Second stage $Q^{IM}_{SK,t}$	OLS $Q^{IM}_{BC,t}$	First stage $\ln(p_t)$	Second stage $Q^{IM}_{BC,t}$
$\ln(p_t)$	11.73***	—	29.11***	15.07***	—	147.51***
	(1.03)		(4.02)	(3.27)		(11.15)
HDD_j	0.29	0.01**	0.418	10.94***	−0.032***	15.42***
	(0.29)	(0.004)	(0.276)	(1.95)	(0.008)	(2.26)
HDD^2_j	−0.003	−0.0002***	−0.012**	−0.182**	0.001***	−0.52***
	(0.0005)	(0.00008)	(0.005)	(0.079)	(0.0003)	(0.095)
CDD_j	−1.21	−0.018	−2.218**	12.24***	0.0019	−5.68
	(0.853)	(0.017)	(0.972)	(3.67)	(0.0188)	(4.45)
CDD^2_j	0.016	0.006**	−0.074	−0.32	−0.002	0.665
	(0.08)	(0.002)	(0.107)	(0.43)	(0.002)	(0.489)
Weekday	−2.32	0.203***	−5.63***	38.95***	0.206***	14.22**
	(1.77)	(0.018)	(1.91)	(5.24)	(0.019)	(5.82)
Holiday	0.47	−0.28***	5.25	−41.74***	−0.28***	−4.74
	(4.46)	(0.05)	(4.37)	(12.92)	(0.05)	(14.08)
HDD_{Edm}	—	−0.002	—	—	0.008	—
		(0.005)			(0.005)	
HDD^2_{Edm}	—	0.0002	—	—	−0.0009	—
		(0.0001)			(0.0001)	
HDD_{Cal}	—	−0.016***	—	—	−0.011**	—
		(0.005)			(0.005)	
HDD^2_{Cal}	—	0.0008***	—	—	0.0007***	—
		(0.0001)			(0.0001)	
CDD_{Edm}	—	0.09***	—	—	0.087***	—
		(0.019)			(0.02)	
CDD^2_{Edm}	—	−0.002	—	—	−0.002	—
		(0.003)			(0.002)	
CDD_{Cal}	—	0.012	—	—	0.016	—
		(0.022)			(0.022)	
CDD^2_{Cal}	—	0.005*	—	—	0.006**	—
		(0.003)			(0.0028)	
Constant	14.01*	3.34***	−44.47***	−140.09***	3.57***	−622.43***
	(7.68)	(0.08)	(14.95)	(24.75)	(0.003)	(47.85)
R^2	0.23	—	—	0.43	—	—
K–P Wald F-stat	—	40.27***	—	—	53.35***	—
Hour–month year	Y	Y	Y	Y	Y	Y

NOTES: Sample size $N = 60,597$. ***, ** and * indicate statistically significant coefficients at the 1%, 5% and 10% levels, respectively.

limited Montana imports are included in the British Columbia import supply estimation.

Table A3 provides detailed estimates of the industrial demand function. Alternative supply shifters such as imports and temperature covariates in neighbouring provinces were also used as exclusive IVs. After the inclusion of hourly wind production and generation capacity availability, these IVs are systematically statis-

TABLE A3
Hourly industrial demand IV estimation

		Lagged price IV		Supply shifters IV	
	OLS Q_t	First stage $\ln(p_t)$	Second stage Q_t	First stage $\ln(p_t)$	Second stage Q_t
$\ln(p_t)$	−24.16***	—	−35.89***	—	−37.55***
	(0.25)		(0.89)		(1.60)
HDD_{Edm}	−0.459***	−0.00004	−0.456	0.013***	−0.40
	(0.122)	(0.0005)	(0.358)	(0.004)	(0.36)
HDD^2_{Edm}	0.007***	0.000003	0.007	−0.00006	0.007
	(0.003)	(0.00001)	(0.008)	(0.00009)	(0.008)
CDD_{Edm}	−0.36	0.004*	−0.21	0.08***	−0.26
	(0.42)	(0.002)	(0.80)	(0.016)	(0.80)
CDD^2_{Edm}	−0.21***	−0.0002	−0.21**	0.0009	−0.20**
	(0.05)	(0.003)	(0.09)	(0.002)	(0.086)
HDD_{Cal}	0.93***	−0.0003	0.90***	−0.02***	0.81**
	(0.12)	(0.0006)	(0.336)	(0.004)	(0.34)
HDD^2_{Cal}	−0.019***	0.00003**	−0.017**	0.0006***	−0.15*
	(0.003)	(0.00001)	(0.008)	(0.00009)	(0.008)
CDD_{Cal}	1.31***	−0.0006	1.35	0.023	1.04*
	(0.47)	(0.002)	(0.85)	(0.017)	(0.84)
CDD^2_{Cal}	−0.16***	0.0008***	−0.147	0.004*	−0.14
	(0.052)	(0.0003)	(0.098)	(0.002)	(0.096)
Weekday	−17.40***	0.082***	−17.06***	0.331***	−16.78***
	(0.38)	(0.0017)	(1.20)	(0.015)	(1.23)
Holiday	2.58**	−0.01**	2.10	−0.342***	1.61
	(1.15)	(0.005)	(3.17)	(0.039)	(3.23)
$\ln(p_t^{NG})$	28.46***	0.018***	29.28***	0.419***	29.10***
	(0.98)	(0.005)	(4.09)	(0.044)	(4.14)
$\ln(p_{t-24})$	—	0.958***	—	—	—
		(0.002)			
Capacity avail.	—	—	—	−0.0007***	—
				(0.00002)	
$QWIND_t$	—	—	—	−0.0003***	—
				(0.00002)	
Constant	376.95***	0.073***	381.18***	9.15***	386.86***
	(2.54)	(0.013)	(10.15)	(0.21)	(10.51)
R^2	0.49	—	—	—	—
K–P Wald F-stat	—	530.96***	—	420.11***	—
Hour–month–year controls	Y	Y	Y	Y	Y

NOTES: Sample size $N = 60,597$. 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. ***, ** and * indicate statistically significant coefficients at the 1%, 5% and 10% levels, respectively.

tically insignificant and reduce the first-stage Kleibergen–Paap Wald F-statistic. The results are robust to the inclusion of these IVs. We use hourly 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. 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.

The import supply and industrial demand functions are estimated using an IV approach with Newey–West robust errors. The number of autocorrelated lags are chosen by Bartlett's Approximation $N^{\frac{1}{3}}$. Using the Kleibergen–Paap Wald F-stat test for the weakness of the exclusive IVs, we strongly reject the weak IV null hypothesis in both models. The temperature variables contain heating degree days (HDD) and cooling degree days (CDD) for two cities in Alberta (Edmonton (Edm) and Calgary (Cal)). These cities represent the major load centres in each province. The results are robust to higher order polynomials for each temperature variable. In table A2, HHD_j and CDD_j denotes the temperature variables for the province whose import function is being estimated (i.e., $j \in \{BC, SK\}$). In each province-specific import supply function $j \in \{SK, BC\}$, HDD_i (CDD_i) denotes the HDD (CDD) measure in city i in Alberta for each $i \in \{Edm, Cal\}$.

Tables A2 and A3 provide the OLS estimates of both the import supply and industrial demand function. Because a positive shock to imports will lower the market price, ignoring the endogeneity of price would bias the price coefficient in the import supply functions towards zero. A positive shock to industrial demand will increase the market price. Consequently, a failure to control for this endogeneity issue will yield an upward bias in of the negative price-elasticity coefficient towards zero. Both of the OLS estimates support the anticipated attenuation bias.

For both the import supply and industrial demand function estimations, we use two tests to illustrate that the linear-log model specification provides a systematically better fit than a log-log model specification. Because we are comparing two non-nested models that involve IV estimation, we cannot rely on traditional goodness-of-fit measures. First, we use the PE test established by Mackinnon et al. (1983). For both of the import supply function models, the PE test finds that the linear-log specification is superior. For the industrial demand estimation, the PE finds that the log-log model provides a slightly better fit in the supply-shifter IV model and the linear-log specification provides a better fit in the lagged prices IV model. Second, we use a generalized R-squared (GR2) measure established by Pesaran and Smith (1983). For both of the import supply and industrial demand function models, the GR2 measure finds that the linear-log specification is a better fit than the log-log specification.

Appendix A3. Relationship between residual demand and import supply

Figure A1 presents the detailed relationship between residual demand, import supply and observed and competitive marginal costs. In particular, in figure A1 the import supply curve is represented explicitly and implicitly in our definition of residual demand (market demand, net of imports). It is important to notice that the marginal cost curves have a portion of supply that has zero marginal

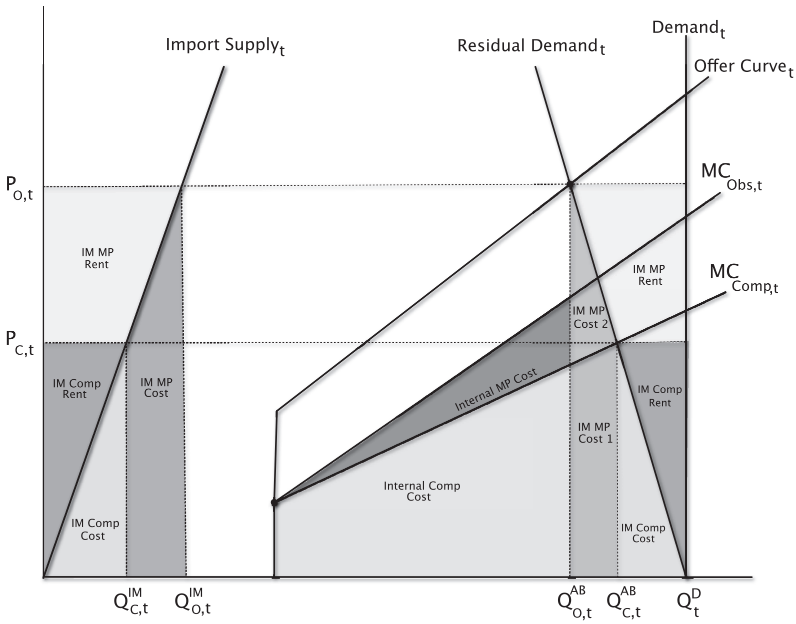

FIGURE A1 Internal and external production inefficiencies – Detailed

costs, representing technologies such as wind and cogeneration. For illustrative purposes, assume that market demand Q_t^D is perfectly price-inelastic. Denote $Q_{j,t}^{IM}$, $Q_{j,t}^{AB}$ and $P_{j,t}$ to be the equilibrium level of imports, production from assets within Alberta and market price in equilibrium $j \in \{$Competitive (C), Observed (O)$\}$. First, *Internal Comp Cost* reflects the cost of supplying output $Q_{O,t}^{AB}$ using the least-cost within Alberta assets. *Internal MP Cost* represents the additional costs associated with procuring units within Alberta based on the order of firms' bids rather than least-cost. *Internal MP Cost* represents the internal productive inefficiencies in figure 2 due to market power.

Second, focus on the import supply curve. Assuming that importers behave as price-takers, the import supply function reflects importers' marginal cost curve. If importers are exercising market power, then we are underestimating importers' rents and overestimating importers' costs and so, we conservatively overestimate external production inefficiencies. *IM Comp Rent* and *IM Comp Cost* reflects the importers' rent and costs under the competitive equilibrium. *IM MP Rent* and *IM MP Cost* represents the additional rents and costs in the observed equilibrium compared to the competitive equilibrium due to the increase in imports ($Q_{O,t}^{IM} - Q_{C,t}^{IM}$) caused by market power execution by firms within Alberta. Third, because residual demand equals market demand minus imports, these regions are inverted around the residual demand curve. The summation of *IM MP Cost 1* and *IM MP Cost 2* equals *IM MP Cost* (i.e., $Q_{O,t}^{IM} - Q_{C,t}^{IM} = Q_{O,t}^{AB} - Q_{C,t}^{AB}$). *IM MP Cost 2* represents the increase in import production costs in the observed outcome due to market power, net of the costs that the more efficient units within Alberta would have incurred in the competitive equilibrium to serve additional output $Q^{AB}_{O,t} - Q^{AB}_{C,t}$ (i.e., this equals the area *IM MP Cost 1*). We define *IM MP Cost 2* as external productive inefficiencies in figure 2.

In the analysis, we account for the fact that a portion of market demand is price-elastic. Figure 4 illustrates how importers' market power rents (*Import MP Rents*) and competitive rents (*Import Comp Rents*) are adjusted to account the addition of market demand price-elasticity. For illustrative purposes, figure 4 assumes there is no within Alberta production inefficiencies (i.e., $MC_{Comp,t}$ and $MC_{Obs,t}$ overlap). The intuition of the regions are unchanged when internal production inefficiencies are considered.

Appendix A4. 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 in 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 (GOA 2007). The Renewable Energy Credit of approximately $15/MWh is included in the wind energy market revenues.

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