# Carbon Price Pass-Through in Electricity Markets*

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**Abstract**

This paper evaluates the response of wholesale power market participants in Alberta to a series of changes in greenhouse gas (GHG) emissions policies. Between 2015 and 2024, legislative and regulatory changes have affected carbon price levels, the rates of output-based allocations of emissions credits, and the coverage of carbon pricing across facilities of different sizes, creating variation in average and marginal carbon prices both across and within facility types and across and within portfolios held by major players in Alberta's wholesale power market. I exploit this variation in treatment to provide unique evidence of carbon price pass-through in power markets. I show lower rates of pass-through of carbon prices to offers than generally seen in the literature. My analysis suggest that no more than 60% of the changes in carbon policy costs were reflected in shifts in the merit order of electricity offers in Alberta. Importantly, the pass-through that does occur — only in the middle of the merit order — is symmetric between carbon pricing and allocations of emissions credits, and these results are generally robust to changes in market conditions or time periods. I test these results by looking at supply curves by plant fuel, plant type, and plant owner and, while in some cases individual supply curves by plant type or by owner reflect a full-cost pass-through, these are the exception not the rule.

Keywords: climate change, carbon pricing, electricity, coal
JEL classification: Q3, Q4, Q54

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# 1 Introduction

This paper evaluates the response of wholesale power market participants in Alberta to a series of changes in greenhouse gas (GHG) emissions policies. Between 2015 and 2024, legislative and regulatory changes have affected carbon price levels, the rates of output-based allocations of emissions credits, and the coverage of carbon pricing across facilities of different sizes, creating variation in average and marginal carbon prices both across and within facility types and across and within portfolios held by major players in Alberta's wholesale power market. I exploit this variation in treatment to provide unique evidence of carbon price pass-through in power markets and show lower rates of pass-through of carbon prices to offers than generally seen in the literature. My analysis suggest that less than half of the changes in carbon policy costs was reflected in shifts in the merit order of electricity price offers in Alberta. Importantly, the pass-through that does occur — approximately 60% in the middle of the merit order — is symmetric between carbon pricing and allocations of emissions credits, and that these results are generally robust to changes in market conditions or time periods. I also show lower and even in some cases negative pass-through of costs from combined-cycle natural gas generators, which likely accelerated the phase-out of coal-fired power in the province.

The traditional view of competitive firm response to carbon pricing would be an upward shift in each firm's supply function of an amount equal to the net, incremental costs imposed by the policy. For some facilities, there may be dynamic gains to participating in the market in a given hour (for example, if shutdown implies multi-hour restarts, as can be the case for coal- or gas-fired steam generators), in which case the supply curve may lie below zero up to some positive quantity supplied in each hour, even if carbon prices are high. For these facilities, especially if they are inframarginal, one might not expect to see a carbon price change their bidding behaviour up to some threshold quantity. However, above such a threshold, one should expect to see carbon price pass-through into power offers. My results in the Alberta context suggest less than perfect pass-through, even for units likely to be on the margin in the market in a given hour, although I find far-above perfect pass-through for natural gas simple-cycle plants which respond to market prices more than other generators.

The degree to which carbon prices are passed-through to wholesale electricity markets has been extensively investigated. The studies of Fabra and Reguant (2014) and Hintermann (2016) are most closely related to the present analysis, and both find that carbon costs imposed in the European Union emissions trading system are almost completely passed-through to market prices. In the case of Fabra and Reguant, they find more-than-complete (110%) pass-through of carbon costs in peak hours, and less-than-complete (60%) pass-through in off-peak hours. Similarly, Hintermann finds pass-through rates of 81-111% depending on the hour of the day, and also finds that costs are fully passed-through on average. Kara et al. (2008) find pass-through of 74% in annual electricity prices in the Nordic area. Nazifi (2016) finds near-complete pass-through of Australian emissions prices to wholesale power prices, as does Maryniak et al. (2019) although the latter projects a wider range of pass-through of 67-150%. An examination of the Greek electricity market in Dagoumas and Polemis (2020) also suggests near-complete (86%) long-run pass-through of emissions costs to electricity prices. Using regional data, Nazifi et al. (2021) show greater pass-through in less emissions-intensive regions and vice-versa, with a range of pass-through rates from 97-290%. Guo and Gissey (2021) also shows a wide range of pass-through rates in a paper where, like my work, they examine impacts by generation fuel showing higher pass-through rates for coal than for gas. Conversely, Jouvet and Solier (2013) argues that there is incomplete and frequently not-statistically-significant pass-through in the European Union.

My analysis is unique in that I can measure facility-specific carbon policy costs (both costs of carbon prices and the value of output-based allocations of emissions credits) precisely for long periods of time, which allows the separate identification of changes due to carbon pricing from changes due to other coincident market or climate factors. Furthermore, the changes in Alberta's climate change policies were such that the average and net marginal costs of carbon pricing policies changed across facilities for the same time periods. For example, in 2018, the marginal carbon price did not change from 2017, but there were substantial changes in output-based allocations of emissions credits such that marginal net carbon costs went up for some facilities and down for others. I use this variation to identify pass-through more precisely than is possible with daily market fluctuations in a cap-and-trade market such as that of the European Union. My results estimate much lower pass-through of carbon prices to electricity offers and thus to market prices than the papers cited above.

Average carbon policy costs have varied over time and between fuel types in Alberta as a result of various changes to emissions policies since 2015. This links the present study and Cullen and Mansur (2017) which uses variations in fuel costs (coal vs. natural gas) to identify impacts on emissions. They find substantial impacts from small changes in fuel costs which make natural-gas-fired plants more competitive relative to coal plants. The policy changes I study in Alberta, both the changes in output-based allocations and the carbon price increases, have had a similar effect on the coal-to-gas cost ratio as a reduction in natural gas prices, although there was also a coincident reduction in gas prices during my study. I adjust for these impacts by including spot prices of natural gas as a variable in my regressions.

The Alberta electricity market is highly-concentrated, which links this paper to the literature following from the seminal paper of Buchanan (1969) on externalities and related policies in the presence of market power, as well as to myriad studies of market power in electricity, e.g. Borenstein et al. (2002). For example, Fowlie et al. (2016) study the interaction of market structure in the cement industry and greenhouse gas mitigation policies. Miller et al. (2017), also looking at the cement industry, shows that fuel cost changes were more-than-fully reflected in downstream pricing. And, as in Holland (2012), incomplete regulation or regulations which provide competing incentives will distort price-pass through. The latter also applies in the present study since there are changes in market structure coincident with the policy changes I study and which I account for through the inclusion of concentration ratios of major firms in my analysis.

Another unique attribute of the present study is that the policy variation over time and across facilities in Alberta also allows me to directly identify the pass-through of changes in output-based allocations of emissions credits (see Fischer and Fox (2007) and Fischer and Fox (2012)) to wholesale prices, as allocation rates did not vary systematically with changes in carbon prices. The analysis cannot directly speak to the optimal allocations of emissions credits as in Burtraw and Palmer (2008), but my results suggest that there is symmetric and incomplete pass-through of the marginal value of output-based allocations and carbon prices. No decreases in carbon prices occurred over the sample period, but there are plants which see the value of their output-based-allocations increase, decrease, and then increase again through the sample period. To my knowledge, the pass-through of carbon credit allocation value has not been confirmed in any other studies of carbon price pass-through. There are limits to this result as well, since the changes in output-based allocations systematically disadvantaged coal plants relative to other fuel sources, and were coincident with substantial declines in natural gas prices. This implies that Alberta's coal plants were already at a substantial competitive disadvantage, and thus unable to pass through higher net carbon policy costs associated with reduced output-based allocations of emissions credits.

The Alberta wholesale power market provides an excellent quasi-laboratory for this study because it is small, isolated, and the market is settled on a real-time, energy-only basis. The downside to this isolation is that Alberta, a major oil-producing jurisdiction, was hit with a major, oil-price-induced recession contemporaneously with some of the changes in carbon policies, and this economic downturn led to a period of low prices in the power market. Alberta's generation mix is also somewhat unique, with a significant portion of internal load served by combined heat and power (or co-generation) plants associated with industrial facilities, primarily located in the oil sands region in Northern Alberta. Despite these anomalies, the transparency and isolation of Alberta's market provide us with a unique opportunity to study carbon price pass-through to prices as well as the induced changes in market participation. The analysis in this paper is based on more than 14 years of hourly data describing market offer behaviour and a wide range of relevant characteristics. I combine individual firm offer behaviour with detailed plant characteristics compiled from regulatory filings under Alberta's and Canada's air emissions reporting programs, aggregate power market data including hourly renewable generation, imports and exports, import and export capabilities, actual and forecast prices and internal loads, weather data, and commodity price information. I add carbon policy costs and the value of output-based allocations at the facility level to these market and environmental variables to build a large dataset covering all relevant aspects of firm behaviour and market conditions.

I derive my results through a unique empirical strategy based on merit order sampling. For each of three different aggregation levels (market, plant type or fuel, and controlling entity), I build hourly merit orders of offered generation. I then sample these merit orders at various support points which allows me to build a synthetic merit order with substantially-reduced dimensionality, and also to make the data comparable across time periods with different total market and/or plant sizes. I match these with measured marginal carbon emissions policy costs along the merit order. My results show that firms pass through carbon policy costs in part as standard economic models would predict, although with less complete pass-through than previous papers have shown. Carbon prices changes are passed-through in the mid-merit at a maximum of 0.6:1 at the 60th percentile of offered power with smaller pass-through values at higher and lower points in the merit order. The impact of carbon pricing in the upper merit is smaller, and measured with less precision in part due to the censoring of the offers by a $1000/MWh offer limit in the market. This effect is replicated when carbon pricing net revenues are decomposed into carbon price and output-based allocation values, and across peak and off-peak hours. Results by plant type are somewhat counter-intuitive, with small and sometimes negative pass-through for natural gas combined cycle plants with higher pass-through for coal plants. This is likely a combined effect of a strategic interaction with coal plants whereby the higher carbon prices increased costs more for coal plants than for gas plants, giving the gas plants the potential to shift coal higher up the merit order with shaded offers. Results obtained by controlling entity show two interesting results. Beyond the interesting result that the only government-owned entity in the sector acted almost exactly as the theory would predict, there was no obvious consistent pass-through behaviour among generators.

These results suggest that traditional models of marginal cost pass-through may be subject to substantial revision with respect to strategic incentives, portfolio optimization, and other impacts. My results suggest that the market price impacts of Alberta's carbon pricing changes may have been substantially lower than would have been forecast by an assumed marginal net-cost pass-through, even though such an assumption would have been reasonable based on the evidence in the literature to date.

The paper proceeds as follows. In Section 2, I build some notation for a power plant facing environmental policy. In 3, I detail Alberta's greenhouse gas policy history. In Sections 4 and 5, I detail the data set used in the paper and provide a statistical portrait of Alberta's power market. In Section 6, I detail the empirical strategy. Section 7 summarizes the results. Section 8 concludes.

## 2 Power Plant Optimization Problem

To introduce the firm behaviour I have in mind, and to inform the discussion of changes in GHG policies, I begin with a simple model of an electricity generator facing carbon pricing and benefitting from output-based allocations. Here, I borrow from the notation of Brown et al. (2018). Each individual generator $i \in I$ faces a carbon pricing program with two relevant policy variables: price, and output-based allocation rate. The policy also applies to generator $i$ from year $y^*$ onward if emissions from the generator in year $y^*$ exceed a threshold $\bar{E}$. If the policy applies, the generator pays an annual, fixed price on emissions (in $\$/\mathrm{t}_{\mathrm{CO_2e}}$) denoted $\tau_t$ for a given time period $t$. The firm also receives an output-based allocation of emissions credits, $\Omega_{i,t}$ which are assumed to have a value equal to the carbon price. As such, the net compliance cost in a period $t$ for a generator $i$ with emissions $E_{i,t} > \bar{E}$ and production $q_{i,t}$ is given by:

$$C_{E,i,t} = \tau_t E_{i,t} - \Omega_{i,t} q_{i,t} \tau_t. \tag{1}$$

Given that the output-based allocations are assumed to be marketable at the carbon price or have an equivalent value within the firm, this reduces to:

$$C_{E,i,t} = \tau_t \left( E_{i,t} - \Omega_{i,t} q_{i,t} \right). \tag{2}$$

This structure also reduces, for $\Omega_{i,t} = 0$, to a pure carbon tax at rate $\tau_t$. This also implies that, within the standard optimization problem for a facility with a fixed emissions intensity $\xi_i$, measured in $tCO_2e/MWh$, the emissions policy contribution to the marginal cost of electricity production is:

$$MC_{E,i,t} = \tau_t \left( \xi_i - \Omega_{i,t} \right). \tag{3}$$

Therefore, if market or individual firm or generator supply curves reflect marginal emissions policy costs systematically, even if there are additional mark-ups, other sources of variation, or partial pass-through, we should be able to identify the pass through of these costs using variability in carbon pricing costs $\tau$ and output-based allocation rates $\Omega$ over time and across firms, so long as data on emissions intensity $\xi$ are completed and we can account for other sources of variation in marginal costs or rents from electricity production.

Unlike previous studies which exploit high-frequency variation in emissions prices in the EU-ETS, the present analysis uses longer-term variability in annually-fixed emissions prices in Alberta to identify carbon price pass-through, and also exploits the fact that carbon prices vary across generators as well as over time in ways that can be readily observed.

# 3 Alberta's GHG Policy Changes

Alberta has had carbon pricing in place since the *Specified Gas Emitters Regulation* (*SGER*) took effect on July 1, 2007.[1] That regulation, the first industrial carbon price in North America, implemented a price of \$15/tonne, and allocated emissions credits to covered facilities at a rate equal to 88% of an individual facility's historic (2003-2005) emissions intensity ($\tau_{2007-2015} = \$15$, and $\Omega = 0.88 * \xi_i$). Facilities were covered if their annual emissions were over 100,000 $tCO_2e$($\bar{E} = 100,000$) between 2003 and 2005. New facilities built after 2005 meeting the 100,000 $tCO_2e/yr$ threshold were allocated emissions credits per unit output at a rate equal to 88% of their average year 3 emissions intensity and had to comply from that point forward. Once a facility crossed the 100,000 $tCO_2e/yr$ threshold in any year, they

[1] *Specified Gas Emitters Regulation*, Alta Reg 139/2007, <canlii.ca/t/52x2q>.

would remain covered by the policy. In addition to carbon pricing on industrial emissions, the *SGER* also included an offset protocol which provided emissions credits for deemed emissions reductions due to certain activities including some types of power generation. In the case of combined heat and power plants, facilities received an allocation of credits at a rate of 0.418t/MWh for net-to-grid electricity. New renewable power facilities were also eligible for offset credits under the SGER, with a deemed emissions reduction rate of 0.65t/MWh.[2] Combined, these measures meant that all large power generators were covered with a consistent emissions priding regime from 2007 onward. I the analysis in this paper, offsets and output-based allocations of emissions credits are treated as equivalent.

This system remained unchanged until June, 2015 when the government of Premier Rachel Notley introduced a series of changes to the existing regulation.[3] The first set of changes increased the carbon price to \$20/tonne for 2016 and to \$30/tonne for 2017 ($\tau_{2016} = 20$, $\tau_{2017} = 30$), while also reducing the benchmarks for the output-based allocation of emissions credits to 85% and 80% of historic facility level emissions intensity for 2016 and 2017 respectively ($\Omega_{i,2016} = 0.85\xi_i$, and $\Omega_{i,2017} = 0.8\xi_i$). Combined, these changes implied a material increase in the average cost of carbon in each of the years 2016 and 2017 for all generators covered by the regulation, with the increase in costs being proportional to their emissions intensity.

The Notley government subsequently adopted, in November of 2015, a more comprehensive change to GHG emissions policies. Two changes in this iteration of policies affected power markets. Most importantly, the *Carbon Competitiveness Incentive Regulation (CCIR)* replaced the *SGER* and these regulations leveled the output-based allocation of emissions credits offered to all power generators at 0.37t/MWh ($\Omega_{i,2018-2022} = 0.37\,\forall\, i$), the emissions intensity of the best-in-class combined cycle natural gas generation facility in the province.[4] This implied that coal producers saw a steep increase in their average costs of carbon and a decrease in their marginal effective output subsidy, while impacts on gas power plants varied depending on the heat rates of the facility. The second important change was that an economy-wide carbon price was introduced for facilities not covered under the *CCIR* — those without emissions in any previous year greater than 100,000 $tCO_2e$. These facilities did not, by default, receive output-based allocations of emissions credits to offset the cost of the carbon price ($\Omega_{i,2018-...} = 0 \forall i \mid E_{i,\tilde{t}} < 100,000t\,\forall\,\tilde{t} <= t$),so their average costs of car-

[2]These values were subsequently reduced to 0.59t/MWh (2015), 0.53t/MWh (2019), 0.52t/MWh (2020), and 0.4901t/MWh (2024).

[3]*Specified Gas Emitters Amendment Regulation*, Alta O.C. 105/2015, <perma.cc/Z2ZM-WDWP>.

[4]*Carbon Competitiveness Incentive Regulation*, Alta Reg 255/2017, <canlii.ca/t/53h9v>.

bon could be much higher than their larger competitors. An opt-in provision allowing these smaller firms to be covered under the *CCIR* was available, for facilities willing to undertake the comprehensive emissions reporting required. Finally, the government also announced an accelerated coal phase-out which would see all coal-fired generation shut-down, equipped with carbon capture and storage, or re-fired with natural gas by December 31, 2030. No regulations to enforce this announcement were enacted in Alberta, and federal regulation did not bind explicitly on any facilties. Coal was, eventually, phased-out in Alberta in 2024 with several facilities converting to gas-fired steam generation.

The *CCIR* remained in place until it was replaced by the *Technology Innovation and Emissions Reduction Regulation* (*TIER*) which took effect on January 1, 2020.[5] While *TIER* altered the design of output-based allocations in most sectors, it did not impose material changes in the electricity industry and so no changes should be expected to result directly from its implementation. *TIER* remains in place as of this writing and so covers the balance of the sample period, with the price on carbon having increased to \$40 per tonne for 2021, \$50 per tonne for 2022, and then in \$15/tonne increments in 2023, 2024, and 2025 ($\tau_{2021} = 40$, $\tau_{2022} = 50$, $\tau_{2023} = 65$, $\tau_{2024} = 80$).[6] Output-based allocations remained consistent with *CCIR* levels until 2023, after which the allocation rate began to decline ($\Omega_{i,2023} = 0.3626$, $\Omega_{i,2024} = 0.3552$, and $\Omega_{i,2025} = 0.3478$.)

Alberta's three carbon pricing regimes each affected generating facilities through two channels. First, each of the three (*SGER*, *CCIR*, and *TIER*) regimes imposes a price on emissions. Second, each regime allocated emissions credits based on output or deemed avoided emissions. The net effects of these policies create variation within and across facilities and facility types and over time. Figure 1 shows the mean value and range of annual compliance costs for larger generators in Alberta's fleet over the sample period.[7]

As Figure 1 shows, changes in facility compliance costs were not all coincident with increased marginal carbon prices. In fact, the compliance cost changes are mostly determined by the changes in output-based allocations which occurred subsequent to the adoption of the *CCIR* in 2018 rather than the initial increase carbon prices from \$15 to \$30 per tonne $CO_2$ein 2016 and 2017 or from \$40 to \$65 later in the sample period. The largest cost increases were

[5] *Technology Innovation and Emissions Reduction Regulation*, Alta Reg 133/2019, <canlii.ca/t/54qgg>.

[6] See Alberta Environment and Parks Ministerial Order 87-2021 under the *Emissions Management and Climate Resilience Act*, SA 2003, c. E-7.8, <perma.cc/3HN3-H9RC>.

[7] Plants were only included in the sample for this figure if we had facility-specific compliance cost data. For the estimation results, I impute compliance costs for a wider set of facilities using emissions intensities from the compliance cost data.

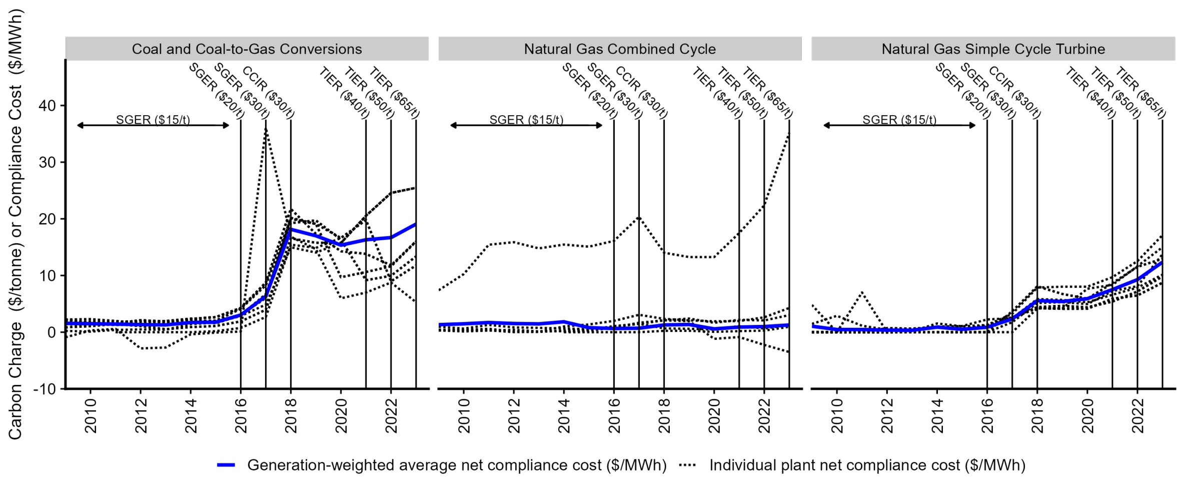


Figure 1: Generation-weighted annual average compliance cost (solid blue lines) and individual plant realizations (lighter dotted lines) by plant type ($/MWh). Coal plants include plants converted to natural gas over time. Natural gas simple-cycle turbines (SC) with more than 20MW installed capacity are included in this figure. The outlier NGCC plant is the Fort Nelson facility which is subject to BC's carbon tax but is connected to the Alberta electricity grid. Source: Government of Canada and Government of Alberta emissions reporting data combined with AESO generation data provided by NRGStream.

experienced by coal-fired power plants and some simple-cycle generators through to 2018, while limited effects were felt by combined heat and power plants (not shown), while compliance costs for natural gas combined-cycle plants dropped between 2017 and 2019 as a result of a change in the formula by which output-based allocations were calculated, and did not change monotonically thereafter as a result of changes in operating behaviour and efficiency. Several coal-fired units converted to gas generation after 2018, which lead to decreasing compliance costs. These changes in compliance costs, across and within generators, provide the variation through which I identify pass-through of these costs to offer prices.

# 4 Alberta's Power Market

Alberta's wholesale market is a single price, energy-only market. There is no day-ahead energy market, but there is a separate ancillary services market not addressed beyond a couple of tangential references in this paper. Alberta's power market is structured similarly to the Energy Reliability Council of Texas (ERCOT) market, but is much smaller. Alberta's record peak load of 12,384MW, reached in 2024, is less than one sixth of ERCOT's 85,931 MW record load. Alberta has seen significant growth in average and peak loads, as shown in Figure 2, although growth has been substantially slower since 2014 due to the effects, initially, of depressed oil prices on the Alberta economy discussed further below. There was also a major, short-term market event with a wildfire in Fort McMurray in 2016 which took a lot of oil sands generation and load off-line, leading to the markedly-lower spring trough in that year's load profile. Similarly, the 2020-22 COVID-19 demand shock is evident in Figure 2.

Consumption in Alberta is relatively stable on daily and annual bases, due to the large industrial base. Figure 3 compares Alberta's hourly load pattern to ERCOT and MISO equivalents, showing both that there is less variability through the day and seasonal patterns are less pronounced in Alberta. Alberta also exhibits a Winter peak, compared to the summer-peaking ERCOT and MISO systems.

The sample period studied in this paper saw no major regulatory changes in the power market design. Alberta briefly considered an addition of a capacity market between 2016 and 2019, but this was never implemented. However, market conditions and the generation mix have varied substantially over the sample period. There are three distinct periods in the sample: relatively high load growth and tight market conditions from 2009 through 2013, followed by sharply constrained growth and high reserve margins after 2014 through most of 2018, with slightly tighter market conditions through COVID, followed by a tight market from 2021-2024. These conditions are reflected in peak and off-peak prices shown in Figure 2. Some of these market changes coincide with policy changes of interest in this paper, in particular the changes to the *SGER* introduced in June of 2015 which took effect in January of 2016 and 2017 respectively and are coincidental with a period of over-supply. Similarly, the introduction of the *CCIR* in 2018 occurred during a period of tightening reserve margins and lingering uncertainty over market structure. As the economic restrictions relating to the COVID pandemic waned at the end of 2020, both GHG policy and the wholesale electricity market were tightening, and care is required to disentangle these impacts.

Alberta's generation mix is dominated by fossil fuels although, as shown in Figure 4, the dominant fossil fuel has changed from coal to natural gas. Within natural gas generation, the mix of plant types is also relevant to this study. During the sample period, a significant increase in generating capacity from combined cycle (NGCC) plants and combined heat and power (COGEN) facilities occurred. Combined heat and power plants tend to operate with high capacity factors but also tend to be price-takers in the market, with very little flexibility at the margin since the industrial processes with which they are associated rely on them for

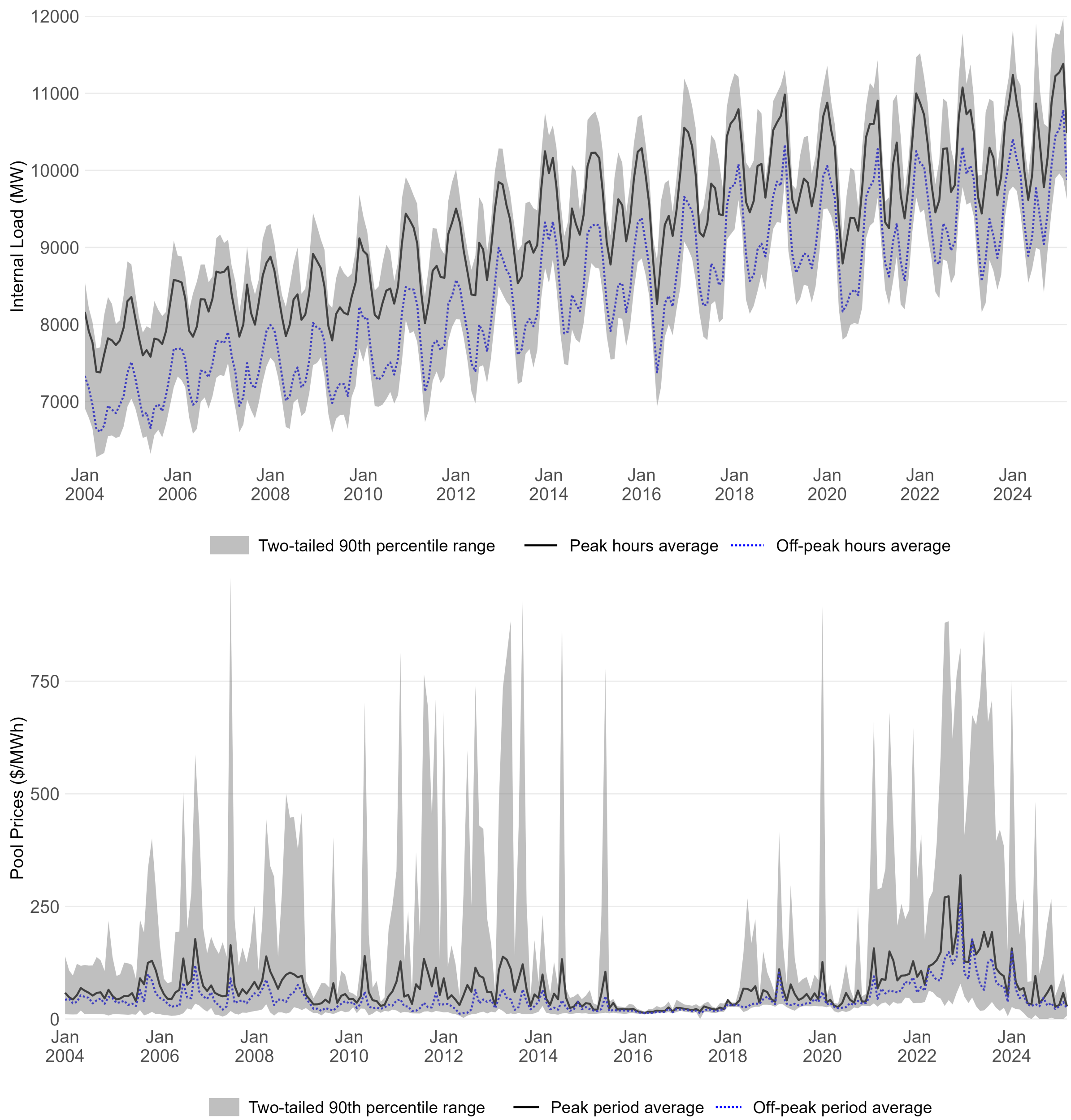


Figure 2: Alberta internal load (top) and wholesale power prices, peak and off-peak hours (bottom). Peak hours are 8am to 11pm other than on statutory holidays or Sundays. Source: AESO data, authors' graph.

process heat.[8] NGCC plants, on the other hand, provide more flexible generation on the margin. Peaking capacity in the market during the sample period was largely met through

[8]As will be discussed below, net-to-grid power from COGEN facilities is primarily offered into the market at a $0 offer and accepts market price, and so limited evidence of carbon price pass-through is found for most of the power offered by these facilities.

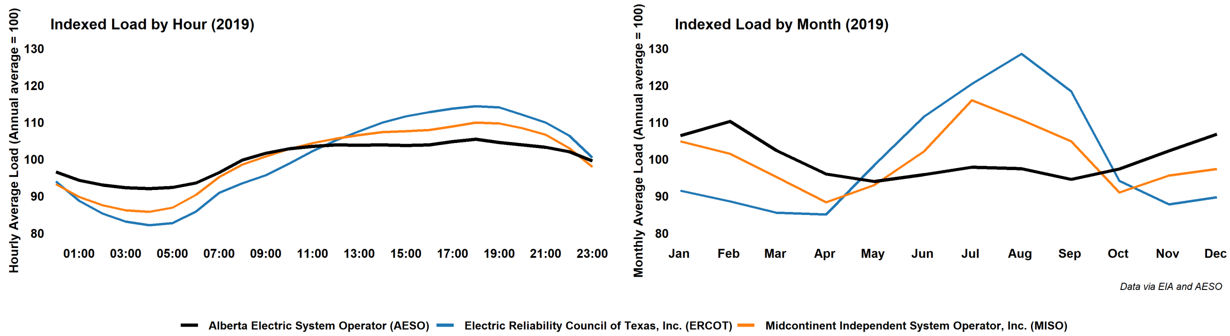


Figure 3: Monthly and hourly load patterns in Alberta compared to ERCOT and MISO.

ramping of coal and simple- and combined-cycle natural gas plants. Each of these would be exposed to carbon pricing, and so one should expect to see pass through affect offers of power from these facilities into the market.

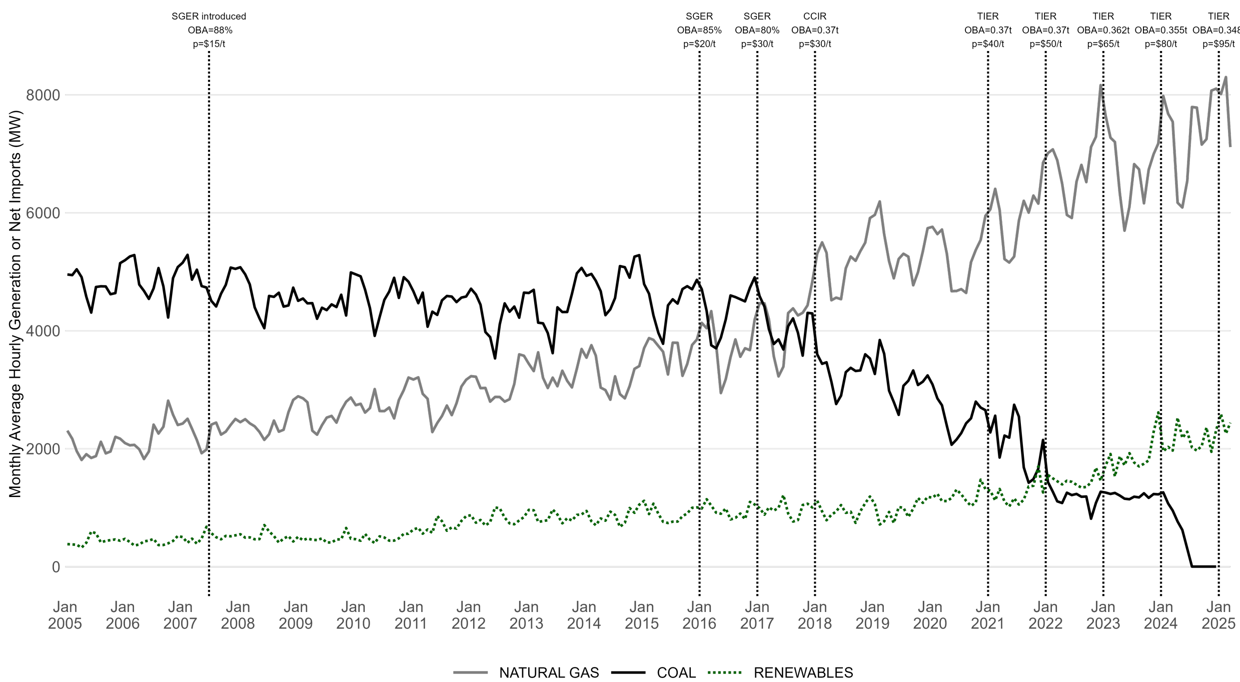


Figure 4: Generation mix in Alberta. Source: AESO data provided by NRGStream, authors' graph.

Finally, Alberta's market is highly-concentrated, with a market structure that has evolved in ways relevant to the analysis during the sample period. When the market was restructured in 2000, a system of power purchase arrangements (PPAs) were used as an alternative to divestment (Daniel et al., 2007). Large coal-fired plants owned by legacy generators were covered by these PPAs which approximated the conditions which had been present under regulation for plant owners, while auctioning off the rights to offer control over these facilities

Table 1: Alberta coal-fired plant Power Purchase Arrangement (PPA) expiry dates and dates of return to the Balancing Pool

| Facility | Plant Owner | Unit ID | Capacity (MW) | End of PPA Term | Returned to Balancing Pool | Conversion to gas-fired steam or retirement |
|---|---|---|---|---|---|---|
| Battle River | ATCO | BR3 | 147 | Dec 31, 2013 | NA | NA |
| | | BR4 | 147 | Dec 31, 2013 | NA | Mar 8, 2022 |
| | | BR5 | 368 | Dec 31, 2020 | Jan 1, 2016 | Nov 19, 2021 |
| Genesee | Capital Power | GN1 | 381 | Dec 31, 2020 | NA | May 1, 2024* |
| | | GN2 | 381 | Dec 31, 2020 | NA | July 1, 2024* |
| | | GN3 | 466 | NA | NA | July 12, 2024* |
| HR Milner | ATCO | HRM | 144 | Jan 01, 2013 | NA | May 8, 2020 |
| Keephills | TransAlta | KH1 | 383 | Dec 31, 2020 | May 5, 2016 | Jan 11, 2022 |
| | | KH2 | 383 | Dec 31, 2020 | May 5, 2016 | July 21, 2021 |
| | | KH3 | 466 | NA | NA | Jan 11, 2022* |
| Sheerness | ATCO (50%) | SH1 | 378 | Dec 31, 2020 | Mar 7, 2016 | July 30, 2021 |
| | TransAlta (50%) | SH2 | 378 | Dec 31, 2020 | Mar 7, 2016 | July 30, 2021 |
| Sundance A | TransAlta | SD1 | 280 | Dec 31, 2020 | Mar 7, 2016 | Jan 1, 2018* |
| | | SD2 | 280 | Dec 31, 2020 | Mar 7, 2016 | July 31, 2018* |
| Sundance B | TransAlta | SD3 | 353 | Dec 31, 2020 | Mar 7, 2016 | July 31, 2020* |
| | | SD4 | 353 | Dec 31, 2020 | Mar 7, 2016 | Apr 1, 2022* |
| Sundance C | TransAlta | SD5 | 353 | Dec 31, 2020 | Mar 24, 2016 | Nov 1, 2021* |
| | | SD6 | 357 | Dec 31, 2020 | Mar 7, 2016 | Feb 1, 2021 |

Note: * denotes a retirement as opposed to a conversion. Supercritical coal units at Keephills (KH3, 466MW, converted to gas Jan 11, 2022) and Genesee (GN3, 466 MW, converted to gas July 12, 2024) were never part of the PPA system, as they were built as merchant generators. A more extensive re-power of the Genesee 1 and 2 units saw them reclassified as natural gas combined-cycle plants after the retirements listed above.

to other entities. PPAs not sold in the auction were held by an entity known as the Balancing Pool. A substantial amount of Alberta's generating capacity (5066 MW) was offered into the market under these PPAs during the study period. The PPAs included a cumbersomely-worded change-of-law clause which was interpreted to imply an option for PPA owners to exit these arrangements should they become "unprofitable or more unprofitable" due to a change in law. In response to the changes in carbon pricing policy announced in June of 2015, all private PPA owners exercised rights of return (Bankes, 2016), and offer control over all of the legacy plants (3866 MW) reverted to the Balancing Pool between January 1, 2016 and May 5, 2016 (see Table 1). As detailed in Leach and Tombe (2016), this was caused nominally by the increase in stringency of the *SGER*, but the adoption of the Climate Leadership Plan and the *CCIR* meant that the expected value of the PPAs was negative for their owners. The fact that these changes in offer control, and implied changes in market power shown in Figure 5, happened coincidentally with changes in carbon pricing in 2016 and 2017 have the potential to confound inference. I discuss this in the results section.

A second major market evolution with respect to the PPAs during the sample period happened at the end of 2020, when the remaining PPAs issued upon the restructuring of Alberta's market in the early 2000s expired. The expiry saw offer control for over 2000 MW of dispatchable generation revert from the provincially-owned Balancing Pool to merchant generators. This had a substantial impact on prices: Brown et al. (2023) find evidence of an average effect of over \$70/MWh on prices due to this change. I test the robustness of the results to including data from this and the COVID era because of the large changes that occurred in the market at the time.

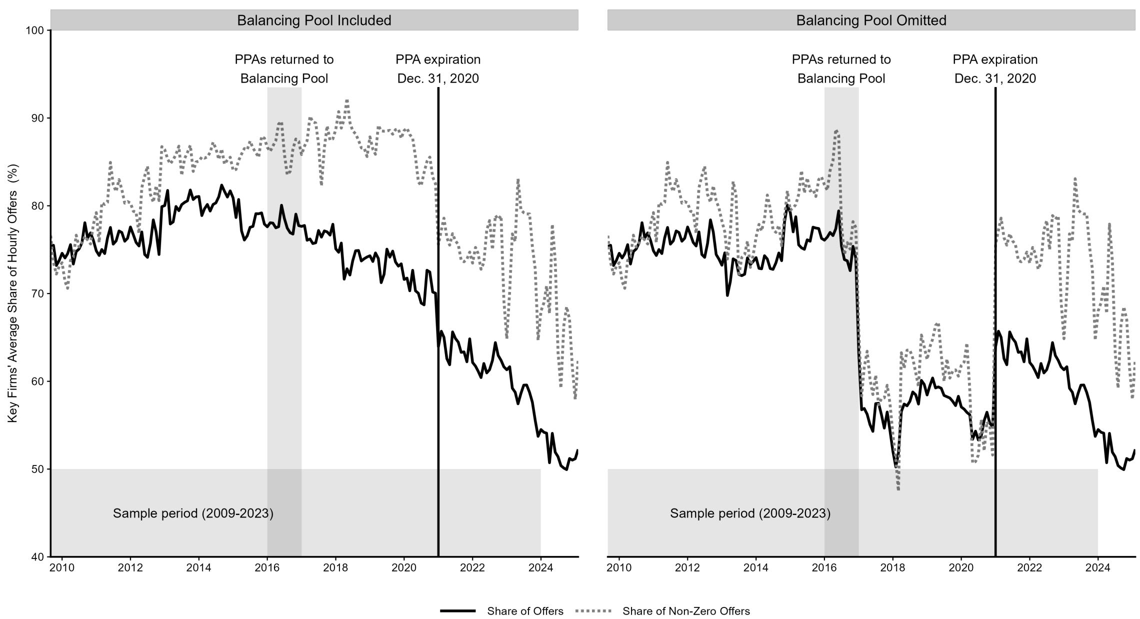


Figure 5: Share of offer control and share of non-zero offers from key firms including and not including the Balancing Pool government-owned corporation. Key firms include TransAlta, Capital Power, ENMAX, ATCO, Heartland Generation, and TransCanada, with the addition of the Balancing Pool in the left-hand panel.

# 5 Data

The majority of data for this paper comes from the Alberta Electricity System Operator (AESO). The AESO provides, with a 60-day lag, information on the offers made by power plant owners or controlling entities into the wholesale power pool on an hourly basis. Facilities offer their power in up to 7 increasing-price blocks, with a price cap of $1000/MWh and a floor of $0/MWh. Plants are dispatched according the merit order derived from a horizontal summation of these firm supply offers, from lowest to highest offered prices.[9] The data set used in this analysis includes hourly merit order and dispatch data from September 1, 2009 through December 31, 2024. For some of the analysis, I truncate the data at December 31, 2019 to test the confounding impacts of the COVID-19 pandemic and changes in the market discussed above.[10] The data also allows us to identify, by block, which entity had offer control in the market for that block of power in each hour.[11]

Three other AESO data sets complete the electricity market data. First, the AESO issues hourly price and load data, including 3-hour ahead forecast and actual prices and day-ahead forecast and actual internal loads, which are merged with merit order data. Next, intertie capability ratings show hours of limited import or export capacity which can affect prices in Alberta. Finally, and most importantly, metered volumes data at the facility level allow the incorporations of renewable generation into the merit order. The AESO treats non-dispatchable renewables (wind and solar power in this case) as negative load, but lists them in the merit order data as $0 offers at full nameplate capacity. For each facility-hour pair in the data, actual metered generation is substituted into the merit order so as to treat renewable generators as having offered exactly their metered volumes each hour, still at a $0/MWh offer price. These data also support the inclusion of total renewable generation in the market by hour in the sample.

I supplement these data with a variety of other information. Most importantly, facility-level compliance data from Alberta's greenhouse gas emissions pricing policies, the *SGER* (2009-2017) and the *CCIR* (2018-2019) provide the most detailed emissions intensity and compliance cost information available. These data were provided for this analysis by the

[9] Blocks may be either flexible or not, and non-flexible blocks will only be dispatched when demand allows the entire block to be used for the hour. If what would otherwise be the marginal block is not a flexible block, the next-highest-priced offer block will be dispatched.

[10] For a discussion of Alberta market responses to the COVID-19 pandemic, see Leach et al. (2020).

[11] The offer control identifiers are only published after 2013, so my analysis based on these data takes place over a smaller sample period.

Government of Alberta, with some portions of the data also available publicly. I supplement these data with information from the Federal Greenhouse Gas Emissions Reporting Program (2004-2023) to provide, where available, emissions intensity data for smaller facilities.[12] Because the emissions data reported in 2025 extend only to 2023 emissions, I restrict my sample period to this timeframe as well.

There are three sources of incompleteness in the emissions data used in this paper. First, no emissions data exist for smaller facilities, since provincial and federal reporting is not required below a minimum threshold. The data covers all facilities that fell under Alberta's industrial carbon pricing programs, but for smaller facilities which would have been subject only to the economy-wide carbon pricing program imposed in 2018, limited information is available. Federal reporting thresholds decreased to 10,000 tonnes per year which translates to an exemption from reporting for most natural gas generators with installed capacity of less than 20MW. Because reporting thresholds have changed over time, in some cases, partial information is available on emissions intensities for smaller facilities, while in other cases no information at all is on offer. I use emissions-intensities from provincial reporting data as the preferred option. Where provincial data on emissions intensities are missing, I use generation data aggregated by facility and federally-reported emissions to calculate an emissions intensity value. Where only partial information exists, I complete the dataset by filling first backward in time and then forward in time by facility or generating unit by year such that, for example, a plant for which we only have 2019 data would see their 2019 emissions intensity used for every previous and subsequent year. Where we have no information at all, we assume an emissions-intensity of 0.55 tonnes per MWh for simple cycle natural gas plants, the only type of plant for which information of this type is unavailable. This value was chosen based on facilities for which information was present in provincial and federal data.

The second source of incompleteness comes from the fact that emissions are reported annually at the facility level, not by generating unit. As a result, the same emissions intensity applies to multiple generating units within a facility.[13] Since we have only annual data at the facility level, we do not allow emissions intensity to vary with the intensity of use of a particular unit within a facility, nor do we allow emissions intensities to vary with

[12] The federal data are useful since the reporting threshold of 10kt $CO_2$eper annum is lower than the provincial threshold for coverage under the emissions pricing policies of 100kt$CO_2$eper annum. This is tempered by the fact that federal reporting is at the facility, not the generating unit level.

[13] There are two exceptions to this. The Keephills 3 and Genessee 3 coal-fired generating units report separately from other units at the same site, and so we have separate emissions-intensity data for them.

ramping of units nor with the capacity factor at any point in time. This will lead to under-reporting of emissions-intensity when units are ramping up or generating below their average efficiency, and over-reporting of emissions-intensity for units operating above their annual average operating efficiency. This is analogous to an assumption that operators do not account for variations in emissions intensity in making operating or offer decisions at the facility level, or that they account only for the average emissions intensity in calculating marginal costs.

Finally, combined heat and power units present a challenge since emissions are reported for the entire production facility, not simply for the power plant, in many cases. There are some stand-alone units which supply both heat and power to adjacent industrial facilities, but these also vary in terms of the emissions-intensity of net-to-grid electricity depending on the design of the specific unit and what share of the produced heat is used to generate electricity versus process steam. The Alberta emissions reporting data tell us the total electricity and heat produced in these facilities, and the emissions attributed to them, but do not tell us what the emissions intensity of an incremental unit of electricity would be. The output-based allocations for these facilities are determined by carbon pricing policies, so we know the value of these for each regulated entity. For the purposes of this analysis, we adopt an assumed emissions intensity of electricity of 0.418 tonnes per MWh for combined heat and power units. Biomass plants, as well as wind, solar and hydroelectric plants are assigned a deemed emissions intensity of zero.

The compliance data also identifies two other attributes of importance to this analysis. Under both *SGER* and *CCIR* , facilities only faced compliance costs after their third full year of operations. Under the TIER Regulation (2020-present), electricity generating facilities are covered from their initial year of operations (s. 12(3)). Because facilities had to report federally during these periods, we can identify emissions intensities and match these to offers for some large facilities for 3 or 4 years before they face carbon pricing, and then for the remaining years in the sample when they are subject to carbon pricing. Until 2018, the rate of allocations is also endogenous to historic emissions due to the design of Alberta's policies. We implicitly assume that facilities did not take account of this in their initial years operations. We account for facilities in their pre-compliance period with an indicator variable in this analysis which provides a partial test of this assumption.

Weather data from Environment Canada weather stations in Edmonton, Fort McMurray, and Calgary were added to the data set, covering the major demand centers in Alberta. I use the average of available measurements in each area in order to maximize the number of hours covered with weather data, and drop observations for which no weather data are available in any region. This leads to a small number of omitted hours from the overall data set, and there is no reason to suspect any correlation between omitted weather data and carbon pricing changes. Temperature data were converted to heating and cooling degree days for each region, and these measures were used in the model estimation.

Finally, I supplement these publicly-available data with several series from NRGStream, a commercial data aggregation service. Most importantly, this service provides daily natural gas prices for the Nova Inventory Transfer (NIT) system which are a better proxy for Alberta natural gas prices than publicly-available series for Henry Hub. NRGStream also scrapes the real-time data from the AESO, and thus provides a second source for the aggregate, publicly-available historic metered volumes provided by the grid operator. We use NRGStream data to compile real-time trade flows between Alberta and British Columbia, Saskatchewan, and Montana and to source real-time generation (as opposed to net-to-grid metered volumes) from all generating units in the province where needed.[14]

All data save the natural gas prices and NRGStream generation and trade data which we are not authorized to redistribute are available DATA LINK TO BE ADDED and the results in the paper can be replicated using code available at GITHUB LINK TO BE ADDED. For the publicly available code, we substitute Henry Hub gas prices as a placeholder, to which we apply the average discount observed between Henry Hub and NIT to adjust the values so that regression results may be more closely replicated.

# 6 Estimation Strategy

The focus of my estimation strategy is to identify the magnitude of the vertical shift in the electricity supply curves for individual large generators, for the market as a whole, and for the supply curves aggregated by plant type or controlling entity, each in response to changes in the individual or net marginal effects of carbon pricing policies.

There are multiple factors which confound the ability to draw inference from the merit order data. The first is that plants of the same type (e.g. coal or combined-cycle natural

[14]The generation data are generally the same as metered volumes with the exception of cases where an industrial production facility is co-located with the power generation facility, in which case only the net-to-grid volumes from the facility are measured in the metered volumes data while the NRGStream scraped data captures actual production by hour for the generating facility.

gas plants) may be of different sizes (e.g. a 350MW plant vs a 200MW plant) while facing similar optimization constraints, and they may be jointly dispatched by the same operator. In particular for coal plants, plant-level minimum-must-run constraints imply that facilities will always offer some portion of their generation into the market at a \$0/MWh price, effectively acting as price takers for an endogenously-determined share of their generation. Given that shutting down in any given hour would imply multiple hours out of the market, the true marginal opportunity cost of this power is negative but plants are constrained to offer at $p \geq 0$ for all blocks. They may offer marginal blocks of power, for capacity above their minimum-must-run level, at higher prices. However, given that plants are of different sizes, and blocks are endogenously determined, it's challenging to identify a change in offers looking only at blocks offered into the market. The second issue is that the strategy space for each facility is very large, given that they may decide both on the break-points for each of up to 7 blocks of power, and then decide on a price for the first block and an adder for each subsequent block offered into the market. For each hour, then, the optimization problem consists of 12 choice variables and we have data on these choices for almost 30 million facility-hour-block combinations. Finally, since multiple plants may be controlled by a single entity, the observed data are the product of a complex portfolio optimization problem and the offers of any individual plant may not reveal an overall portfolio-level attempt to pass through the costs of carbon prices to wholesale prices. We avoid these problems to the degree possible by constructing synthetic offer curves either by plant-type and by controlling entity, or for the market as a whole, thus estimating the impact of policy changes on the supply behaviour of the aggregate fleet rather than on any individual plant. We then use the synthetic merit order data to examine how power has been offered into the system over time as climate policies have varied at consistent sampling points in the merit order. I use the same method to look at offers from some of the largest plants in the market as well.

To understand the approach, consider the traditional textbook treatment of carbon pricing with output-based allocations, which would imply a vertical shift in the supply curve corresponding to the increased marginal cost or the carbon tax, with a negative shift in the case of output-based allocations which reduce net costs of generation. The horizontal summation of all of the individual firm supply curves should imply that, all else equal, the vertical shift in the market supply curve at any point is equal to the marginal cost impact of the carbon policy on the firm which would supply that particular marginal unit of power. We have data on these horizontally-summed supply curves and, by sampling specific points on the supply curve over time, and identifying the carbon price and other policy variables

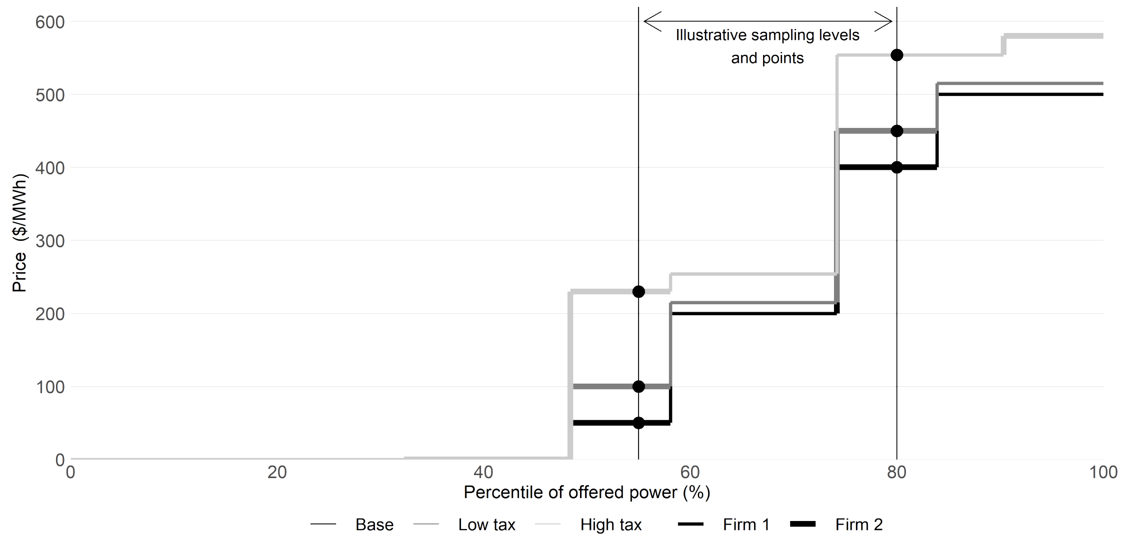


Figure 6: Illustration of two firms' (thicker and thinner lines) offers of power in no-, high-, and low-carbon-tax scenarios, with lighter grey lines indicating a higher carbon price.

applying to the facility at that sampling point, we identify the magnitude of pass-through.

Consider the illustrative example in Figure 6 which shows shifts in a hypothetical two-firm supply curve in response to increasing carbon prices. At the 55th percentile, the first sampling point shown, the vertical shift is driven entirely by pass-through from Firm 2 of their marginal carbon costs over-and-above the base case. At the 80th percentile, the second sampling point shown, the increase under the low-tax scenario is caused by the pass-through from Firm 2, but in the higher carbon tax scenario, the vertical shift is a smaller than would be the case for a pure pass-through by Firm 2 since there is also a shift in the ordering of offered blocks such that a different firm is providing the 80th percentile supply into the market with the high carbon tax. Using this method, we can identify which facility is offering each block at a particular sampling point, and then use the historic data to identify the price at which this facility would have been likely to offer that same block into the market under different carbon prices.

To show what this implies for actual data, consider Figure 7. In the left-hand panel, we show the merit order for one hour for all of the coal-powered facilities in the province, with offers from multi-unit facilities combined for ease of visualization. We see facilities bidding some of their power at $0, ensuring they are in the market, with marginal generation blocks offered at increasing marginal prices. In this particular hour, the price was such that most of the offered coal generation was dispatched, with only blocks offered above the $802/MWh

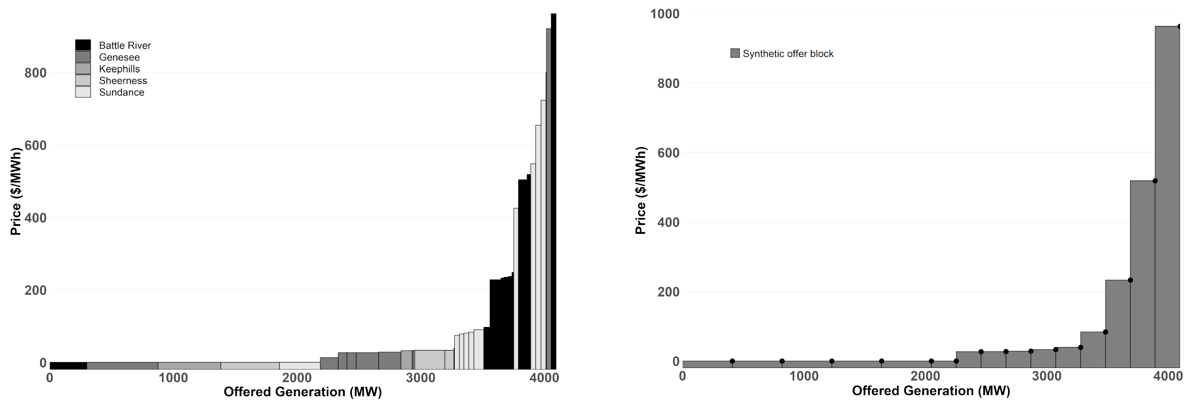


Figure 7: Observed coal facility merit order (left panel) and synthetic coal merit order (right panel) for February 4, 2019 at 7pm. For each hour, we convert the empirical merit order to a step function, and then extract the y-intercept as at 14 unique percentiles of total offered power in that hour, using 5% increments in the upper half of the merit order.

market clearing price not being dispatched. In the right hand panel, I show the sampling of the merit order which summarizes all of the coal power offered into the market in a given hour using the 15 points shown in the Figure, which correspond to the value of the merit order at prescribed percentiles of the total offered power in that hour.[15] Summarizing the data this way reduces stored information by a factor of three, but more importantly it allows us to answer the relevant question at issue - by how much did the supply curve shift in response to changes in the value of carbon pricing costs and output-based allocation revenue - by looking at changes in the value of sampling points across the portfolio of offered power. Or, visually, we want to ask how, on average, each of the points in the right-hand panel of Figure 7 change when carbon prices are increased or when output-based allocations of emissions credits change. For each of these sampled points, we include relevant facility- and market-level data as well as carbon tax compliance costs for that facility on that date. The data included for each sample point would include the facility, which firm has offer control, facility emissions intensity in that year, and the carbon pricing parameters that apply to that firm in that year. These data are then augmented with hourly or daily data on the electricity market, weather, and commodity prices.

There is a lot of day-to-day and hour-to-hour variability in how coal units are offered into the market. Figure 8, which shows all of the 7pm merit orders (left panel) and their synthetic equivalents based only on the sample points, along with the average synthetic merit order for the last year of the sample (right panel), provides a sense of the variability in the

[15]We store the 10th through 40th percentiles in 10% intervals and the 50th percentile and above in 5% intervals to better capture the curvature of the merit order.

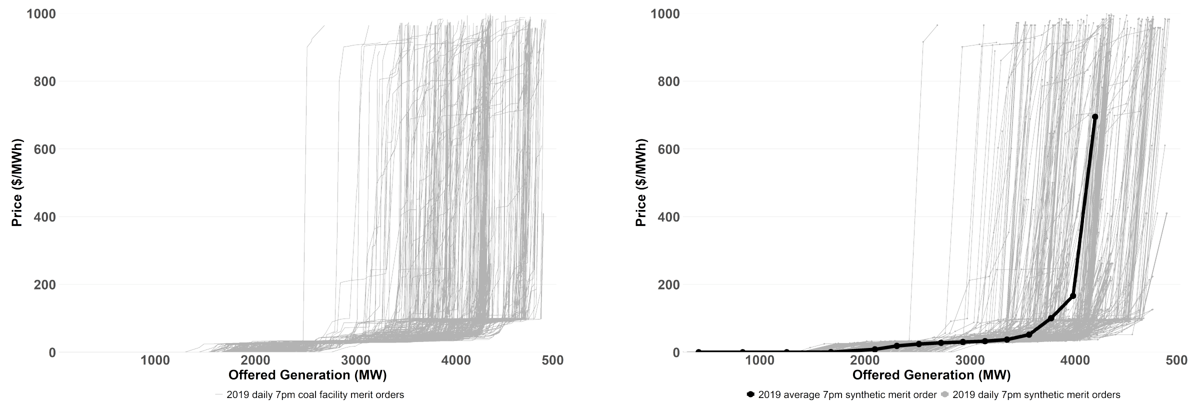


Figure 8: Observed coal facility merit order (left panel) and synthetic coal merit order (right panel) for all of the 7pm hours of 2019.

sample. Similar variability exists in the offers of generation from other dispatchable sources. Figure 8 shows the degree to which changes in total offered capacity would skew the results if I attempted to base the analysis on offered megawatts. Instead, by using percentiles of offered capacity as units of measure, I can more cleanly ask how different segments of the supply curve shift vertically in response to different events, while implicitly assuming that the total offered power available in the market in a given hour is independent of the carbon pricing policy on offer at the time.

Four types of synthetic merit orders inform the analysis. First, for very general results, we characterize the entire merit order using the methodology outlined above. Next, we decompose the results for dispatchable generation types (coal and natural gas plants). We also use the fact that, from 2013 through 2025, the AESO provides offer control by unit as part of their merit order releases. We use this information to construct synthetic supply curves for each of the major participants in the Alberta power market. We also look at the behaviour of some of the largest facilities in the province. This means that we have facility-level, firm- or portfolio-level and market-level synthetic merit orders to analyze.

The variation in carbon pricing over time, as well as variation in which firms are participating in the market, and which facilities' offers are present at a sampling point in the merit order at different times all allow us to identify the impact of carbon costs on offer values. For each sampled point in the synthetic merit order, we identify facility ($F$) and market conditions ($M$), as well as carbon policy compliance costs, which we use to explain changes

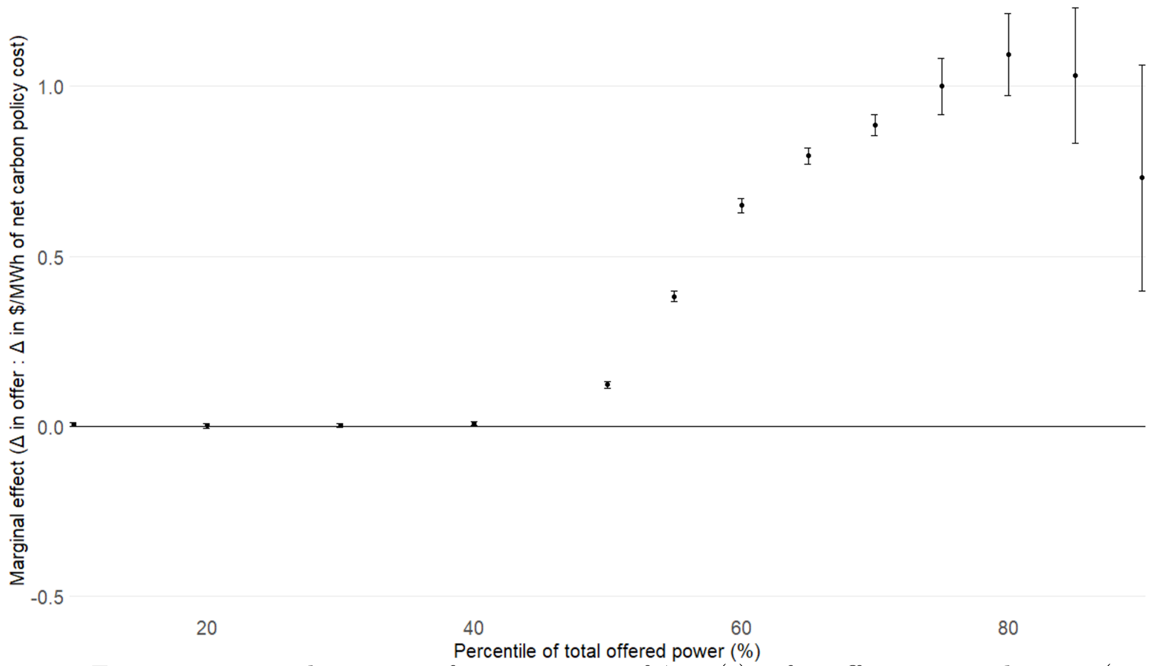


Figure 9: *Ex ante* expected outcome for estimates of $\zeta$ or (-) $\kappa$ for offer percentiles $j \in (0, 100)$ in (4).

in the level offer levels over time. The regression equation is given by:

$$\underbrace{P_{j,t}}_{\substack{\text{Offer value}\\ \text{at percentile } j\\ \text{at time } t}} = \underbrace{\alpha_j}_{\substack{\text{Constant for}\\ \text{percentile } j}} + \underbrace{\beta_j M_t}_{\substack{\text{Market, policy, and}\\ \text{climate variables}\\ \text{at time } t}} + \underbrace{\delta_j F_{j,t}}_{\substack{\text{Facility}\\ \text{characteristics}\\ \text{at percentile } j\\ \text{at time } t}} + \underbrace{\zeta_j t_{j,t}}_{\substack{\text{Carbon cost}\\ \text{at percentile j}\\ \text{at time } t}} + \underbrace{\kappa_j O_{j,t}}_{\substack{\text{OBA value}\\ \text{at percentile j}\\ \text{at time } t}} + \underbrace{\epsilon_{j,t}.}_{\text{Error term}} \tag{4}$$

We estimate this equation for each level of aggregation that we consider: for the full market, for portfolios merit orders by fuel, and for portfolios by offer control. By construction, if there is full net carbon price pass-through, the coefficients $\zeta$ and $\kappa$ should be equal to 1 and the estimates of these coefficients are the focus of the balance of the paper. In setting up the analysis in this way, we take advantage of the fact that the specific facility' offer which occupies a particular sampling point is random, and firms would have no information (until hours after the fact) with respect to their exact position in the merit order, nor do they know the degree to which a particular percentile offer is assured to be infra- or extra-marginal in a given hour. Of course, firms do have information and expectations about demand and will estimate their likely position in the merit order in calculating their offers.

If there is complete pass-through, at least at the margin and during peak hours as seen in Fabra and Reguant (2014) and Hintermann (2016), we would expect the estimates to look like those shown in Figure 9 in which some offers are constrained by considerations like minimum stable generation or contractual heat supply agreements, but that offers close to the margin reflect complete, near-complete, or more-than-complete pass-through of carbon policy costs to offers. While we do find this in some cases, this is not the case systematically through the analysis.

For parts of the sample, censoring is an issue. In the Alberta market, negative price offers are not allowed, and offers are capped at \$1000/MWh. As such, for some percentiles $j$, the values of $P_{j,t}$ may be censored from below, as negative opportunity costs of power do not show up in the data, or they may be censored from above where a firm would offer higher than \$1000/MWh if that were allowed. This implies that we may under-estimate pass-through where either power offers have a less negative implied value below zero or where the carbon tax leads to a higher true costs of offer above \$1000, as we would not observe either of these effects. To correct for this, I augment the ordinary least squares estimates of pass-through with Tobit estimates with two-sided censoring, estimated via maximum likelihood. As discussed further below, censoring does not appear to have a marked effect on the estimates.[16]

# 7 Results and Discussion

## 7.1 Market-wide impacts

The most general results derive from the analysis of the market as a whole. Here, we are calculating, for each hour of the sample, based on sampling the complete supply curve of power offered into the market at 15 points of support, the impact of the marginal carbon pricing cost and marginal output-based allocation value along with other market and environmental variables. Considering first the impact of the net marginal cost of carbon pricing (the hourly carbon charge net the hourly output-based allocation of credits), a pattern that will be familiar through the remainder of the results in this paper emerges. As shown in Figure 10, there is no impact of carbon pricing on offers at the low end of the merit, as this range is characterized by zero dollar offers in all hours of the year. Complete regression results, ex fixed effects are presented in Table A1. The mid-merit range is where we see most of the impacts, and these are intuitive although smaller than might be expected. The

[16] Tobits aren't done for updated data.

present study design is such that, if the costs of carbon pricing were fully passed-through to offers, and if we measured we would expect to see an estimated coefficient exactly equal to 1 on the impact of carbon pricing. The maximum carbon price pass-through appears at the 60th through 80th percentile of offered power, with the maximum share of net carbon costs passed through to offered prices at just over 60%. In this formulation, there is no statistical support for the contention that carbon prices are, on average, fully passed-through at the margin in electricity markets. At the upper-ends of the merit order, there is essentially no material pass-through of carbon pricing costs. This is, when one considers the functioning of the market, perhaps not surprising. At these points, firms are engaged in economic withholding and/or reflecting, as would be the case for hydro power and storage assets, the future opportunity cost of stored energy or water. The fact that offers are constrained to a maximum of \$1000/MWh also influences the results at this point in the merit order.

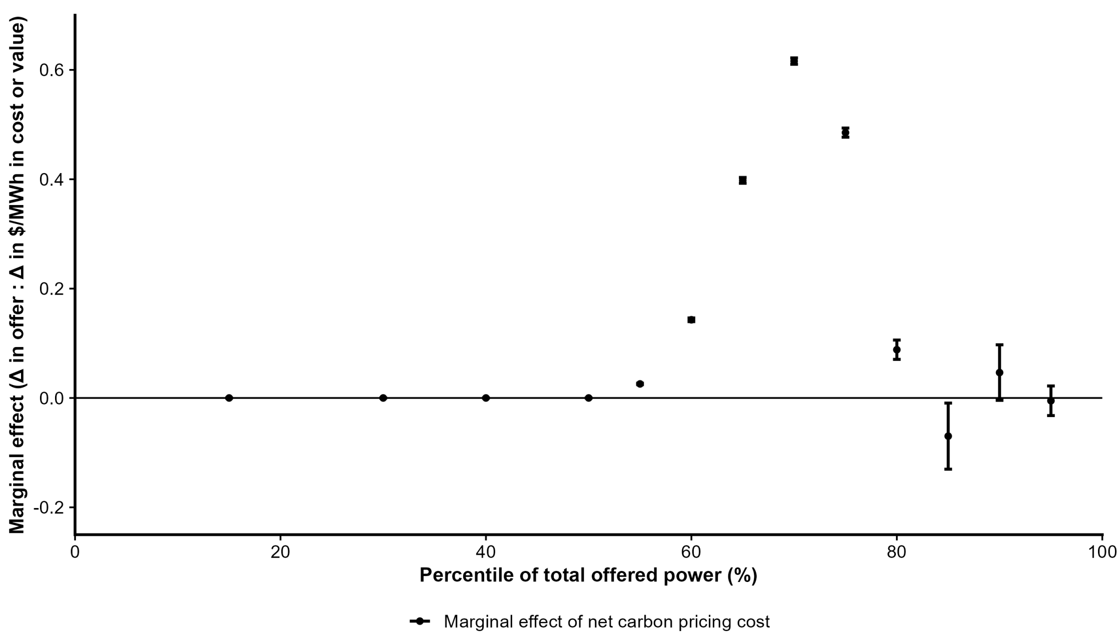


Figure 10: Estimated marginal effect of net carbon charges on power offers, all plant types and all hours. Error bars denote 95% confidence intervals

Since the marginal cost of offered power becomes less elastic (the slope of the merit order increases) at higher levels of offered power, it's reasonable to expect that the pass-through would be altered at peak hours when demand for power is higher, as was found in Fabra and Reguant (2014) and Hintermann (2016). In the base regression shown above, we include a peak-hours factor within the regression, but do not interact that term with carbon costs. In

Figure 11, we re-calculate the regression results separately for peak hours (as defined by the AESO) and non-peak hours.Complete regression results, again ex fixed effects are presented in Tables A2 and A3. We do find intuitive although quantitatively unimportant changes in results. The net effect of the carbon pricing cost is positive across all but the 80th percentile sampling point, and we see significant effects occurring slightly lower in the merit order in peak hours, but we continue to see no statistically significant pass-through of net carbon costs at the upper end of the merit order.

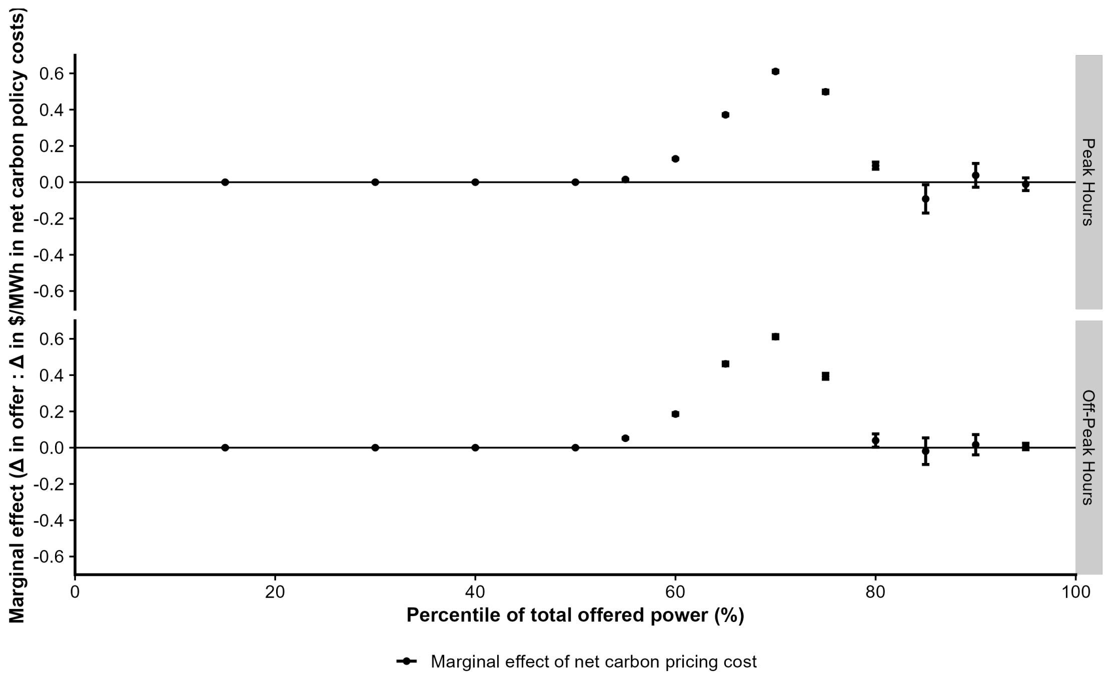


Figure 11: Estimated marginal effect of net carbon charges on power offers, all plant types for peak and off-peak hours. Error bars denote 95% confidence intervals

The data allow a decomposition of the net effect of carbon pricing into a carbon tax and an OBA effect, although with some important caveats. Recall that what we are calling a carbon tax effect in any given hour is the average annual carbon tax per MWh of generation, and so we will miss impacts that occur as a result of hourly ramping or other intensive margin conditions. Also, for some facilities, we have emissions-intensity data at the aggregate level, and in some cases a facility may include as many as six generating units. Where the average emissions intensity varies across units within the facility, the data contain imprecise measures of individual unit intensities. As such, the marginal effective costs of carbon pricing are measured imprecisely. The output-based allocations are consistent through the year on a per-MWh basis, and are determined at the facility level, so we have more accurate measures of these values in the data. Again, my estimation strategy is such that a coefficient with an absolute value of 1 indicates perfect pass-through has occurred, with a value of negative 1 for the full pass through of an output-based allocation to lower offers and a value of 1 for the full pass-through of carbon taxes to power offers.

The results, shown in Figure 12 and provided in full in Table A4, mostly reflect an intuitive decomposition of earlier results derived based on net values, with a few exceptions. Again, we see no impact below the 50th percentile of offered power, and in the mid-merit, an increase (decrease) in offered prices as marginal carbon prices (output-based allocation values) increase (decrease), but with less than full pass through. In the upper merit, it's clear that factors other than carbon prices are driving offers, and we see a slightly negative impact of carbon prices at the 85th percentile, with varied but non-statistically significant impacts of output-based allocations, with all effects estimated much less precisely than the mid-merit impacts.

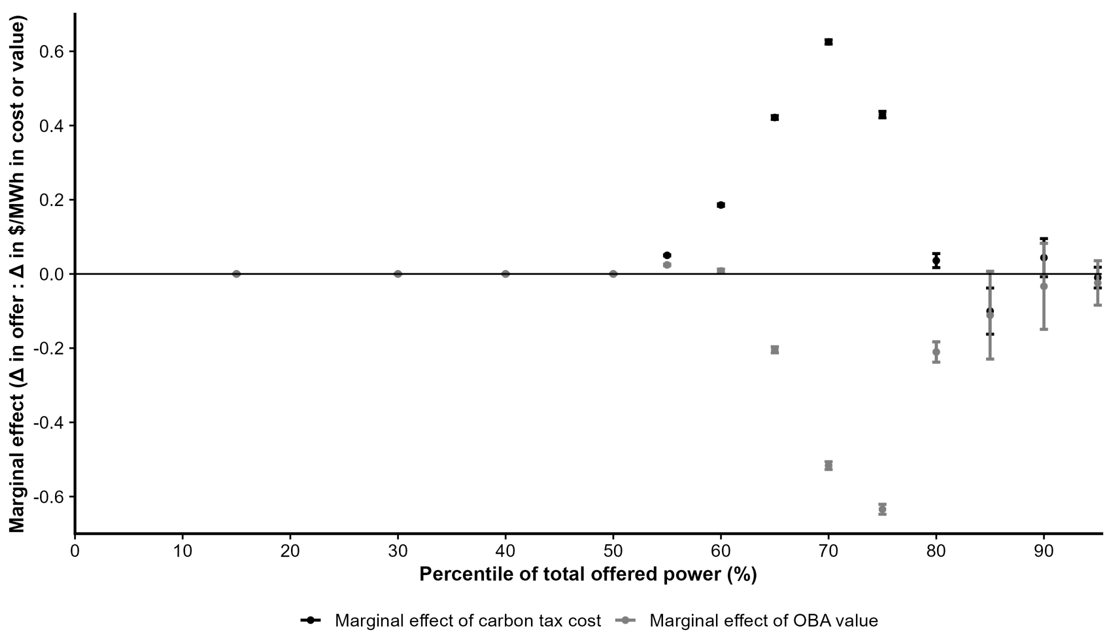


Figure 12: Estimated marginal effect of net carbon charges on power offers, all plant types and all hours. Error bars denote 95% confidence intervals

These results are consistent across peak- and off-peak hours, as shown in Figure 13. The impact of carbon pricing is always statistically greater than or equal to zero, with a maximum pass-through of approximately 60% of carbon costs in the mid-merit, and less

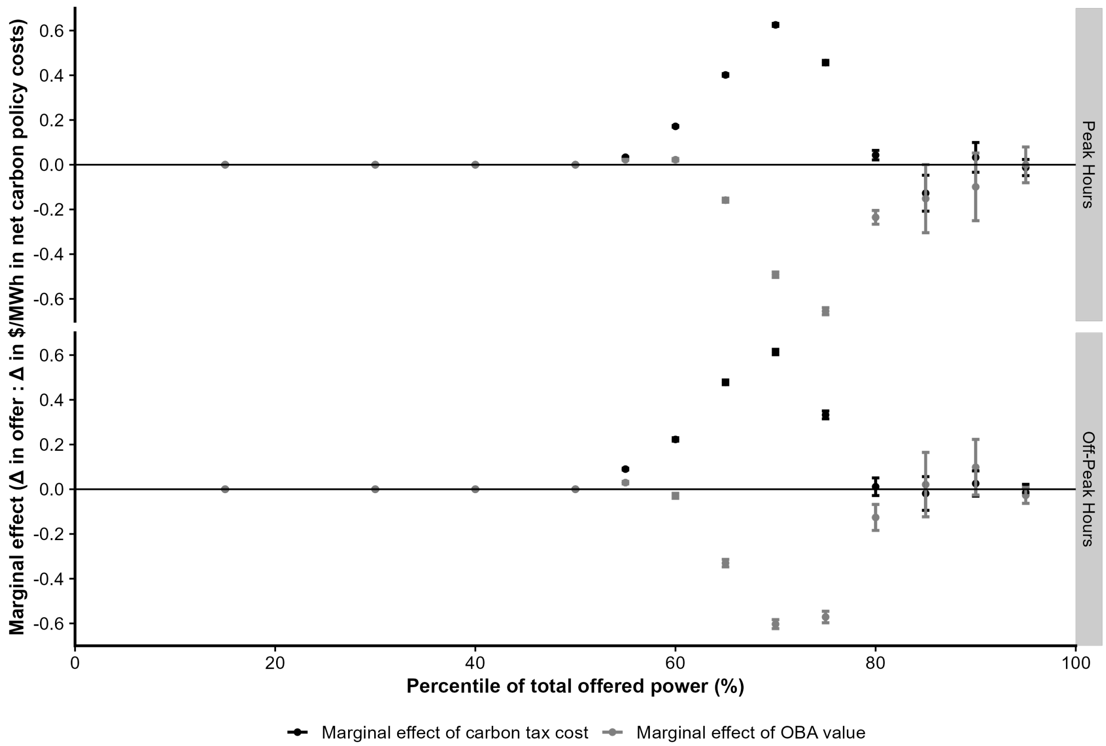


Figure 13: Estimated marginal effect of net carbon charges on power offers, all plant types. Error bars denote 95% confidence intervals

elsewhere. There is no material difference once the results are decomposed across peak and non-peak hours.

Instead of the system operator definition of peak hours based on time of day and day of the week, I recalculate effects based on an endogenously determined *tight* market condition variable, which is true when there is less than 500MW of supply available over-and-above internal load. Results are reported in full in Table A5. Recall that, per Alberta market rules, there is a must-offer requirement for all generators, although generators may withhold economically by offering their blocks at high prices. When the market is *tight*, we would expect there to be more competition within these high-priced blocks as opposed to them being out-of-the-market power. In Figure 14, some of this effect is evident through much more noise in the estimate of the effect of carbon pricing in *tight* hours, but it remains clear that at these points in the merit order, other factors are driving offers, not carbon pricing.

Throughout these results, I find no evidence of full cost pass-through of carbon pricing charges anywhere in the market merit order, with partial pass-through seen in the mid-merit

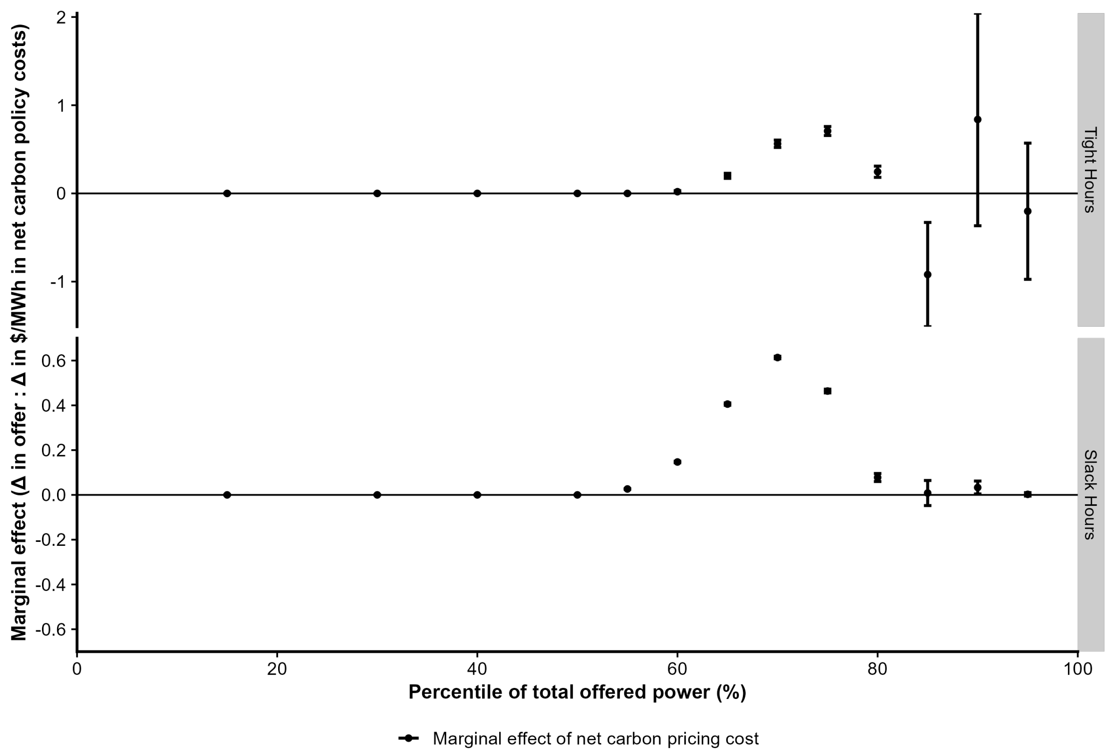


Figure 14: Estimated marginal effect of net carbon charges on power offers, all plant types. Error bars denote 95% confidence intervals

and then only to a maximum of 60% of carbon pricing marginal costs.

## 7.2 Impacts By Generator Type

Different generator types tend to offer their power into the market in different ways, and so decomposing the key results by plant type may yield additional insight. For this section, the results are focused on fossil fuel generators, although to the exclusion of combined heat and power plants for whom we do not observe external drivers for power offers. The results by plant type are, as seen in Figure 15, counter-intuitive in many cases and clarify that the pre-COVID period and the full sample results do differ significantly. In the top panel of Figure 15, coal-fired steam plants act very similarly to what we would predict from the theory. They do not consistently pass-through carbon costs to their offers at all points, but their mid-merit offers (above minimum stable generation, but below the point of economic witholding) show pass-through close to one. The combined cycle gas plants in the data is where the behaviour is most interesting and counter-intuitive: in the mid-merit, combined cycle plants exhibit negative pass-through. This is likely as a result, in part, of their direct competition with coal-fired power plants which have higher emissions-intensity. It's also likely a function of the addition of a lot more gas capacity later in the sample coincident with increasing carbon prices. Simple-cycle gas plants exhibit more time-dependent behaviour, with pass-through rates as high as 4:1 in the full sample, but estimated at -4:1 in the pre-2020 sample at the upper reaches of the supply curve.

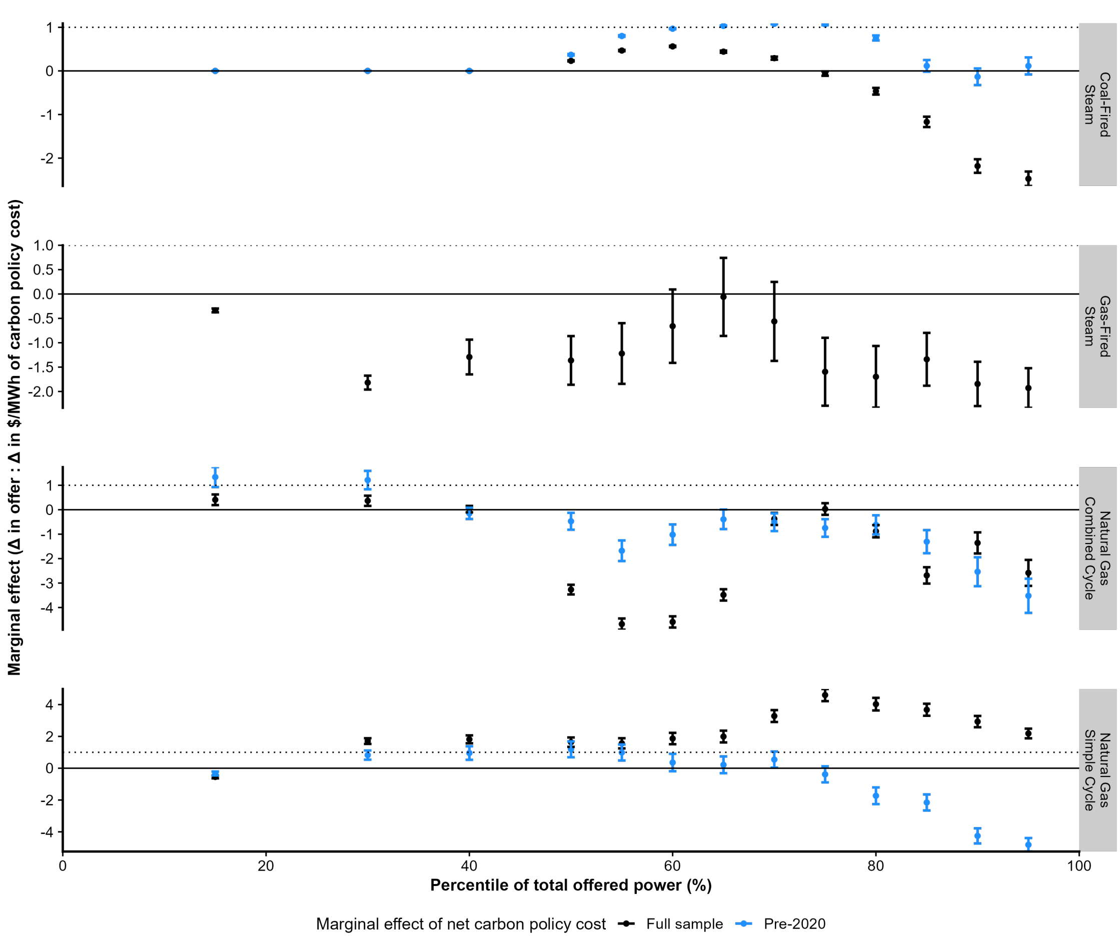


Figure 15: Estimated marginal effect of net carbon charges on power offers, dispatchable fossil fuel generators. Error bars denote 95% confidence intervals.

There are a few factors that may explain these counter-intuitive results: first, some of the simple-cycle gas turbines are relatively new, so we do not observe all plants over the entire sample space. In and of itself, this would not be important given the sampling technique employed, but many of the newer simple-cycle plants have been added as a consequence of emissions policies, as alternatives to venting or flaring of methane from oil field operations. Additionally, many simple-cycle plants operated historically in the ancillary services market, capturing value as spinning reserves rather than when generating, but they have been largely displaced in this space by batteries meaning that more of them are seeking to earn returns directly from generation in the latter part of the sample. These plants will also be most sensitive to the hourly opportunity costs of natural gas and, while we observe hourly spot prices, individual entities may face different gas costs on an hourly basis than what we observe, in particular if facilities have long-term contracts for delivery in place.

These caveats notwithstanding, the results provide no consistent support for full-cost pass-through of net marginal carbon pricing costs, nor of full pass-through of the costs of carbon pricing components in offers by plant type. The closest to a theoretical response to carbon pricing are the coal-fired steam plants which exhibit behaviour similar to that hypothesized in Figure 9, although with limited or even perhaps negative pass-through in the upper reaches of their supply curve.

## 7.3 Impacts By Offer Control

The Alberta market has been and remains highly concentrated, with offer control spread among 5 or 6 key entities in all years. From 2013 onwards, the AESO provides detailed information on offer control (i.e. which entity is offering the generator's power into the market). Prior to 2013, the AESO did not provide offer control records along with their merit order data. To test offer control impacts, we use only the post-2013 data, which remains a sufficient sample, since we have three full years of data (2013-2015) in the initial *SGER* pricing program, along with at least one full year under each of the altered policy regimes over which to assess changed in offers by different market participants. Where there are missing records for any plants in the sample, we impute offer control by filling backwards and then forwards from available data on the same plants.[17]

Before turning to the results, there are a couple of potential endogeneity issues with respect to offer control that may affect the results. When the PPAs discussed in Section 4 were returned to the Balancing Pool in 2016, this was a result of changes to carbon pricing regimes Leach and Tombe (2016). As such, some observed changes in offer control occured a function of the variables of interest over the sample period. This affects offer control from

[17]The Alberta Power 2000 Ltd. holding company was affiliated with ATCO prior to its sale to Heartland in 2019, and so we assign Alberta Power 2000 Ltd offer controls to ATCO/Heartland in the analysis.

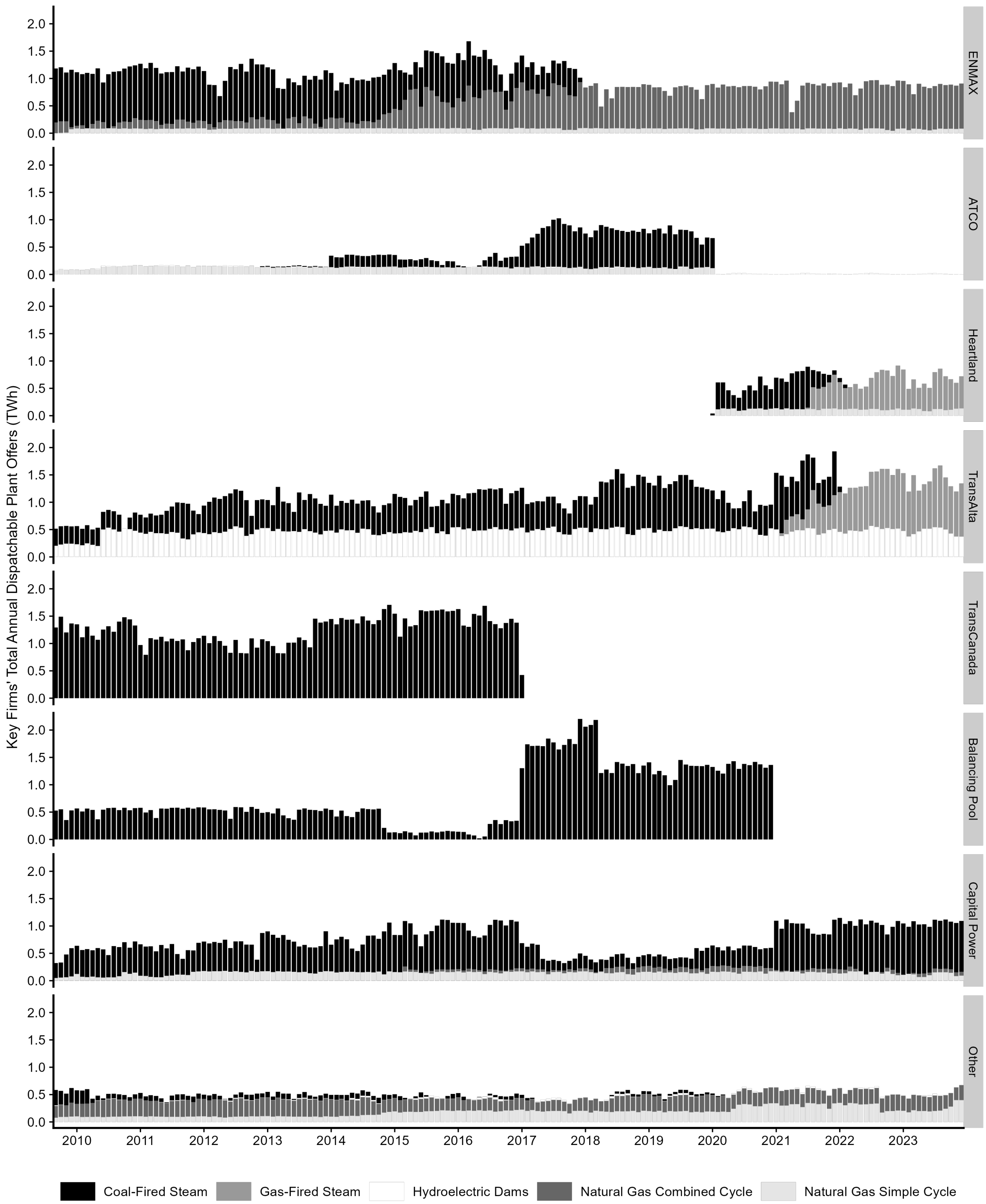


Figure 16: Monthly offers by controlling entity, including dispatchable plants (gas- and coal-fired steam, simple- and combined-cycle natural gas turbines, and hydroelectric power.

the entities holding those PPAs (ENMAX, Capital Power, TransCanada) and the Balancing Pool to which the PPAs were returned. And since TransCanada held no other dispatchable assets other than their PPAs, their history in the data ends when their PPAs were returned in 2016. The second event is the sale of ATCO's fossil fuel assets to Heartland in 2019. While there is no documented causal relationship between the sale and carbon pricing, it occurred subsequent to the 2019 federal election and the announcement of the TIER regulations in Alberta, each of which would have impacted the value of the assets in question and so may have influenced the sale. For this analysis, we treat the ATCO and Heartland assets as a single portfolio. Figure 16 shows the evolution of offer control in the Alberta market for dispatchable assets.

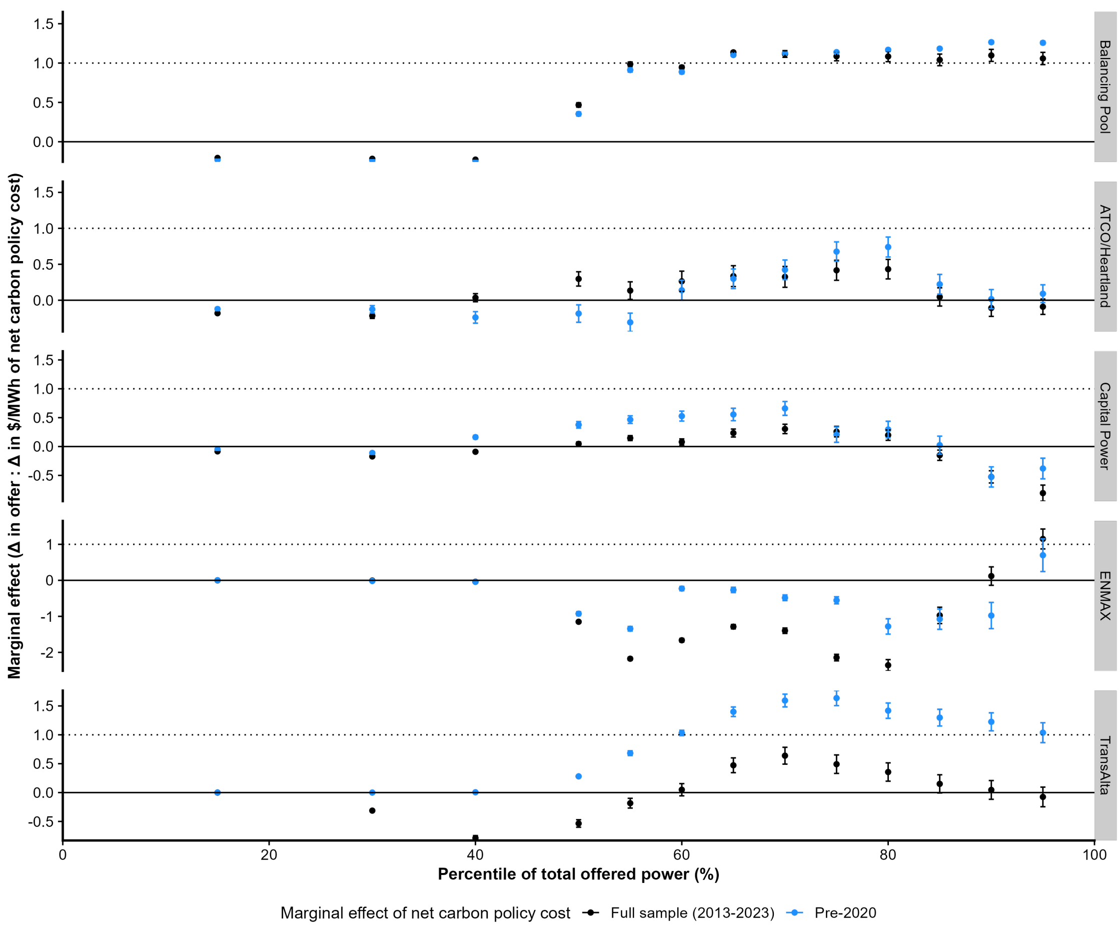


Figure 17: Estimated marginal effect of net carbon charges on power offers by offer-controlling entity. Error bars denote 95% confidence intervals

The results by offer control are noisy but, with the exception of ENMAX, reflect many of the same trends as seen in the market-wide data. The government-owned Balancing Pool replicates the results we might have expected from the theory, both over the full 2013-2023 sample and in the 2013-2019 truncated sample. ATCO/Heartland, TransAlta, and Capital Power show partial mid-portfolio pass-through with limited and/or noisy pass-through in the upper reaches of their firm-level supply curves. TransAlta is more variable over time, likely because of the conversion from coal-fired to gas-fired steam later in the sample as well as they fact that they have hydro plants which are used strategically in certain seasons but are also constrained by environmental factors at other points during the year. ENMAX and Capital Power each saw substantial changes in the makeup of its portfolio over time, both due to the PPA returns in 2016 and due to the construction of new or refurbished generation during the sample period.

With the exception of the 50th percentile and above for TransAlta and the Balancing Pool, we see no evidence of consistent, full-cost pass-through of marginal net carbon pricing costs in firm portfolios.

# 8 Conclusion

To be written, but thus far the the results suggest that:

- No evidence of full-cost pass-through to offers;
- Clear evidence of structural change in pass-through drivers in the market;
- Constraints on offers low in merit (\$0) and in the upper reaches (\$1000) limit inference on those points (Tobits with robust standard errors to be completed once specifications finalized);
- First results to show symmetric pass-through of OBAs and carbon prices;
- Substantial sensitivity to sample period selection remains, as a result of limited variation in carbon price and other contemporaneous events.

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Table A1: All Plants, Net Carbon Pricing Effect Regression Coefficients by Percentile. Standard errors in parentheses, ** $p<0.01$, * $p<0.05$

| term | P15 | P30 | P40 | P50 | P55 | P60 | P65 | P70 | P75 | P80 | P85 | P90 | P95 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| INTERCEPT | -0.000 | -0.000 | -0.000 | 0.022 | -10.472** | -38.843** | -34.139** | -16.577** | -24.577** | -37.314** | -230.677** | -258.010** | -71.926** |
| | (0.000) | (0.000) | (0.000) | (0.013) | (0.536) | (1.263) | (1.779) | (2.188) | (2.658) | (5.611) | (24.628) | (23.523) | (11.009) |
| CR KEY | 0.000 | 0.000 | 0.000 | -0.001 | 3.461** | 18.239** | 7.878** | -23.734** | -48.225** | -109.455** | -154.530** | -57.034** | -0.017 |
| | (0.000) | (0.000) | (0.000) | (0.003) | (0.135) | (0.314) | (0.488) | (0.548) | (0.664) | (1.447) | (6.328) | (6.177) | (2.688) |
| CR NBP | -0.000 | 0.000 | -0.000 | 0.004 | 0.023 | -6.401** | -20.753** | -17.125** | -15.570** | -2.738* | 22.503** | 21.887** | 12.598** |
| | (0.000) | (0.000) | (0.000) | (0.002) | (0.090) | (0.211) | (0.304) | (0.375) | (0.486) | (1.104) | (4.479) | (4.018) | (1.935) |
| HOURLY RENEWABLES | 0.000 | 0.000 | 0.000 | -0.000 | -0.001** | -0.002** | -0.003** | -0.003** | -0.001** | -0.002** | -0.018** | -0.009** | 0.000 |
| | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.001) | (0.001) | (0.001) |
| HOURLY RENEWABLES SQUARED | -0.000 | -0.000 | -0.000 | 0.000 | 0.000** | 0.000** | 0.000** | 0.000** | -0.000** | -0.000** | 0.000 | -0.000 | -0.000** |
| | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) |
| OUT MKT | NA | NA | NA | NA | NA | 1.217* | 0.389* | 0.481** | 0.503** | 1.165** | 1.187** | 1.094** | 1.075** |
| | (NA) | (NA) | (NA) | (NA) | (NA) | (0.499) | (0.161) | (0.068) | (0.019) | (0.008) | (0.007) | (0.003) | (0.002) |
| OUT MKT SQUARED | NA | NA | NA | NA | NA | -0.060 | -0.017 | -0.017** | 0.002** | -0.000** | -0.000** | -0.000** | -0.000** |
| | (NA) | (NA) | (NA) | (NA) | (NA) | (0.047) | (0.010) | (0.004) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) |
| FORECAST POOL PRICE | -0.000 | 0.000 | 0.000 | 0.000 | -0.000 | -0.001** | -0.000** | 0.001** | 0.004** | 0.021** | 0.299** | 0.809** | 0.979** |
| | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.002) | (0.002) | (0.001) |
| DAY AHEAD FORECASTED AIL | 0.000 | 0.000 | 0.000 | -0.000* | 0.002** | 0.006** | 0.009** | 0.009** | 0.012** | 0.020** | 0.058** | 0.051** | 0.006** |
| | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.001) | (0.001) | (0.005) | (0.005) | (0.002) |
| DAY AHEAD FORECASTED AIL SQUARED | -0.000 | -0.000 | -0.000 | 0.000* | -0.000** | -0.000** | -0.000** | -0.000** | -0.000** | -0.000** | -0.000** | -0.000** | -0.000 |
| | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) |
| NIT SETTLE CAD GJ | 0.000 | 0.000 | 0.000 | -0.000* | -0.019** | 0.060** | 0.345** | 1.505** | 3.313** | 4.913** | 4.742** | 0.461* | -0.139 |
| | (0.000) | (0.000) | (0.000) | (0.000) | (0.005) | (0.011) | (0.016) | (0.019) | (0.023) | (0.051) | (0.221) | (0.212) | (0.098) |
| TOTAL IMPORT CAPABILITY | 0.000 | 0.000 | 0.000 | -0.000 | -0.001** | -0.002** | -0.002** | -0.003** | -0.002** | -0.002** | -0.005** | -0.013** | -0.003** |
| | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.001) | (0.001) | (0.001) |
| TOTAL EXPORT CAPABILITY | 0.000 | 0.000 | 0.000 | 0.000 | 0.001** | 0.003** | 0.003** | 0.003** | 0.003** | 0.002** | 0.003** | 0.005** | 0.002** |
| | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.001) | (0.001) | (0.000) |
| HDD YEG | 0.000 | 0.000 | 0.000 | -0.001 | -0.245** | -1.138** | -1.385** | -2.440** | -2.516** | -2.790** | -1.661 | 3.077 | 1.904 |
| | (0.000) | (0.000) | (0.000) | (0.001) | (0.050) | (0.119) | (0.167) | (0.204) | (0.250) | (0.533) | (2.327) | (2.232) | (1.030) |
| HDD YYC | -0.000 | -0.000 | 0.000 | 0.001 | 0.205** | 1.286** | 0.992** | 0.386* | -0.355 | -0.989* | -5.102** | -0.885 | 0.234 |
| | (0.000) | (0.000) | (0.000) | (0.001) | (0.039) | (0.092) | (0.129) | (0.157) | (0.193) | (0.412) | (1.798) | (1.725) | (0.796) |
| HDD YMM | -0.000 | 0.000 | 0.000 | 0.000 | 0.041 | 0.080 | 0.103 | 0.315* | 0.215 | -0.636 | -2.436 | -0.858 | 0.025 |
| | (0.000) | (0.000) | (0.000) | (0.001) | (0.038) | (0.091) | (0.127) | (0.155) | (0.190) | (0.406) | (1.774) | (1.704) | (0.785) |
| CDD YEG | -0.000 | -0.000 | -0.000 | -0.002 | 0.057 | 0.102 | -0.331 | -2.633** | -5.018** | -2.288 | -12.153 | -53.147** | -42.589** |
| | (0.000) | (0.000) | (0.000) | (0.004) | (0.146) | (0.344) | (0.482) | (0.589) | (0.721) | (1.541) | (6.731) | (6.461) | (2.979) |
| CDD YMM | 0.000 | -0.000 | -0.000 | -0.000 | -0.274* | -0.452 | -1.004* | -2.581** | -4.123** | -4.766** | 39.317** | 36.004** | 23.332** |
| | (0.000) | (0.000) | (0.000) | (0.003) | (0.121) | (0.286) | (0.400) | (0.489) | (0.599) | (1.279) | (5.588) | (5.363) | (2.474) |
| CDD YYC | 0.000 | 0.000 | 0.000 | 0.001 | -0.163 | -0.995** | -2.315** | -4.023** | -2.239** | -5.190** | -17.444** | 29.298** | 8.813** |
| | (0.000) | (0.000) | (0.000) | (0.003) | (0.117) | (0.277) | (0.388) | (0.474) | (0.580) | (1.240) | (5.415) | (5.200) | (2.397) |
| PEAK HOURS | 0.000 | 0.000 | -0.000 | 0.002 | 0.185** | 0.521** | -0.153 | -0.963** | -1.102** | -12.836** | -78.270** | -68.496** | -19.850** |
| | (0.000) | (0.000) | (0.000) | (0.002) | (0.067) | (0.158) | (0.223) | (0.271) | (0.331) | (0.709) | (3.086) | (2.963) | (1.366) |
| CARBON PRICING NET | 0.000 | 0.000 | -0.000 | 0.000 | 0.026** | 0.143** | 0.398** | 0.616** | 0.485** | 0.088** | -0.070* | 0.046 | -0.005 |
| | (0.000) | (0.000) | (0.000) | (0.000) | (0.001) | (0.002) | (0.003) | (0.003) | (0.004) | (0.009) | (0.031) | (0.026) | (0.014) |
| OFF-PEAK HOURS * SUPPLY CUSHION | -0.000 | -0.000 | -0.000 | 0.000 | 0.001** | 0.003** | 0.005** | 0.007** | 0.011** | 0.014** | 0.042** | 0.027** | 0.002 |
| | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.001) | (0.003) | (0.003) | (0.001) |
| PEAK HOURS * SUPPLY CUSHION | -0.000 | -0.000 | -0.000 | 0.000 | 0.001** | 0.002** | 0.004** | 0.006** | 0.010** | 0.027** | 0.150** | 0.118** | 0.026** |
| | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.002) | (0.002) | (0.001) |
| OFF-PEAK HOURS * SUPPLY CUSHION SQUARED | 0.000 | 0.000 | 0.000 | -0.000 | -0.000* | -0.000** | -0.000** | -0.000** | -0.000** | -0.000** | -0.000** | -0.000** | -0.000 |
| | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) |
| PEAK HOURS * SUPPLY CUSHION SQUARED | -0.000 | 0.000 | 0.000 | -0.000 | -0.000** | -0.000** | -0.000** | -0.000** | -0.000** | -0.000** | -0.000** | -0.000** | -0.000** |
| | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) |

Note: Regressions also include offer control, monthly, and hourly fixed effects.

Table A2: All Plants, Net Carbon Pricing Effect Regression Coefficients by Percentile for Peak Hours. Standard errors in parentheses, ** p<0.01, * p<0.05

| term | P15 | P30 | P40 | P50 | P55 | P60 | P65 | P70 | P75 | P80 | P85 | P90 | P95 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| INTERCEPT | -0.000 | -0.000 | -0.000 | -0.000 | -6.256** | -34.640** | -39.213** | -23.444** | -23.370** | 16.273* | -272.067** | -533.527** | -197.710** |
| | (0.000) | (0.000) | (0.000) | (0.000) | (0.637) | (1.751) | (2.528) | (3.173) | (3.812) | (7.903) | (39.949) | (38.570) | (18.653) |
| CR KEY | 0.000 | 0.000 | 0.000 | 0.000 | 2.402** | 17.507** | 12.839** | -21.639** | -44.261** | -108.170** | -154.348** | -67.772** | -0.061 |
| | (0.000) | (0.000) | (0.000) | (0.000) | (0.127) | (0.344) | (0.553) | (0.632) | (0.759) | (1.614) | (8.140) | (8.082) | (3.603) |
| CR NBP | -0.000 | 0.000 | -0.000 | -0.000 | 0.282** | -4.411** | -18.972** | -15.990** | -14.719** | -1.591 | 22.320** | 28.972** | 16.694** |
| | (0.000) | (0.000) | (0.000) | (0.000) | (0.084) | (0.230) | (0.342) | (0.431) | (0.552) | (1.236) | (5.778) | (5.222) | (2.580) |
| HOURLY RENEWABLES | 0.000 | 0.000 | 0.000 | 0.000 | -0.001** | -0.002** | -0.003** | -0.003** | -0.001** | -0.002** | -0.023** | -0.011** | 0.000 |
| | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.002) | (0.002) | (0.001) |
| HOURLY RENEWABLES SQUARED | -0.000 | -0.000 | -0.000 | -0.000 | 0.000** | 0.000** | 0.000** | 0.000** | -0.000** | -0.000** | 0.000 | 0.000 | -0.000** |
| | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) |
| OUT MKT | NA | NA | NA | NA | NA | NA | 0.285 | 0.397* | 0.698** | 1.320** | 1.233** | 1.117** | 1.086** |
| | (NA) | (NA) | (NA) | (NA) | (NA) | (NA) | (0.404) | (0.175) | (0.075) | (0.015) | (0.010) | (0.004) | (0.003) |
| OUT MKT SQUARED | NA | NA | NA | NA | NA | NA | -0.014 | -0.022 | -0.023** | -0.000** | -0.000** | -0.000** | -0.000** |
| | (NA) | (NA) | (NA) | (NA) | (NA) | (NA) | (0.026) | (0.011) | (0.005) | (0.000) | (0.000) | (0.000) | (0.000) |
| FORECAST POOL PRICE | -0.000 | -0.000 | -0.000 | -0.000 | -0.000 | -0.001** | -0.001** | 0.000 | 0.003** | 0.017** | 0.298** | 0.805** | 0.978** |
| | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.002) | (0.002) | (0.001) |
| DAY AHEAD FORECASTED AIL | 0.000 | -0.000 | 0.000 | 0.000 | 0.001** | 0.005** | 0.008** | 0.009** | 0.010** | 0.005** | 0.050** | 0.093** | 0.027** |
| | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.001) | (0.001) | (0.001) | (0.002) | (0.008) | (0.008) | (0.004) |
| DAY AHEAD FORECASTED AIL SQUARED | 0.000 | 0.000 | 0.000 | 0.000 | -0.000** | -0.000** | -0.000** | -0.000** | -0.000** | 0.000 | -0.000** | -0.000** | -0.000** |
| | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) |
| NIT SETTLE CAD GJ | 0.000 | 0.000 | 0.000 | 0.000 | -0.009* | 0.059** | 0.295** | 1.418** | 3.286** | 4.898** | 5.241** | 0.519 | -0.145 |
| | (0.000) | (0.000) | (0.000) | (0.000) | (0.004) | (0.012) | (0.018) | (0.022) | (0.026) | (0.055) | (0.279) | (0.271) | (0.129) |
| TOTAL IMPORT CAPABILITY | -0.000 | 0.000 | 0.000 | 0.000 | -0.000** | -0.002** | -0.002** | -0.002** | -0.002** | -0.001** | -0.007** | -0.017** | -0.004** |
| | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.002) | (0.001) | (0.001) |
| TOTAL EXPORT CAPABILITY | 0.000 | 0.000 | 0.000 | 0.000 | 0.001** | 0.003** | 0.003** | 0.003** | 0.003** | 0.001** | 0.004** | 0.007** | 0.002** |
| | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.001) | (0.001) | (0.001) |
| HDD YEG | 0.000 | 0.000 | 0.000 | 0.000 | -0.128** | -1.318** | -1.457** | -2.703** | -2.748** | -2.434** | -0.766 | 5.660 | 2.542 |
| | (0.000) | (0.000) | (0.000) | (0.000) | (0.049) | (0.134) | (0.194) | (0.241) | (0.292) | (0.612) | (3.073) | (2.987) | (1.420) |
| HDD YYC | 0.000 | -0.000 | -0.000 | -0.000 | 0.109** | 1.110** | 0.383** | -0.500** | -1.576** | -3.388** | -9.282** | -0.668 | 0.680 |
| | (0.000) | (0.000) | (0.000) | (0.000) | (0.037) | (0.103) | (0.148) | (0.185) | (0.224) | (0.469) | (2.356) | (2.289) | (1.088) |
| HDD YMM | 0.000 | 0.000 | 0.000 | 0.000 | -0.040 | -0.051 | -0.235 | -0.076 | -0.570* | -1.858** | -3.351 | -3.560 | -0.546 |
| | (0.000) | (0.000) | (0.000) | (0.000) | (0.037) | (0.103) | (0.148) | (0.184) | (0.223) | (0.467) | (2.348) | (2.282) | (1.084) |
| CDD YEG | 0.000 | 0.000 | 0.000 | 0.000 | 0.196 | -0.128 | -0.727 | -3.402** | -5.802** | -2.331 | -12.853 | -61.335** | -50.021** |
| | (0.000) | (0.000) | (0.000) | (0.000) | (0.128) | (0.354) | (0.510) | (0.635) | (0.769) | (1.609) | (8.089) | (7.859) | (3.734) |
| CDD YMM | -0.000 | -0.000 | -0.000 | -0.000 | -0.255* | -0.103 | -0.732 | -2.497** | -3.731** | -4.831** | 43.561** | 38.366** | 25.152** |
| | (0.000) | (0.000) | (0.000) | (0.000) | (0.106) | (0.294) | (0.423) | (0.527) | (0.638) | (1.335) | (6.712) | (6.523) | (3.101) |
| CDD YYC | -0.000 | -0.000 | -0.000 | -0.000 | -0.106 | -0.855** | -1.897** | -3.505** | -2.545** | -5.498** | -26.572** | 29.635** | 11.117** |
| | (0.000) | (0.000) | (0.000) | (0.000) | (0.102) | (0.284) | (0.408) | (0.509) | (0.616) | (1.289) | (6.479) | (6.303) | (2.992) |
| SUPPLY CUSHION | -0.000 | -0.000 | -0.000 | -0.000 | 0.000** | 0.002** | 0.004** | 0.005** | 0.009** | 0.024** | 0.148** | 0.116** | 0.025** |
| | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.002) | (0.002) | (0.001) |
| SUPPLY CUSHION SQUARED | -0.000 | -0.000 | -0.000 | 0.000 | -0.000** | -0.000** | -0.000** | -0.000** | -0.000** | -0.000** | -0.000** | -0.000** | -0.000** |
| | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) |
| CARBON PRICING NET | -0.000 | 0.000 | -0.000 | 0.000 | 0.015** | 0.129** | 0.371** | 0.610** | 0.498** | 0.091** | -0.092* | 0.038 | -0.011 |
| | (0.000) | (0.000) | (0.000) | (0.000) | (0.001) | (0.002) | (0.003) | (0.003) | (0.005) | (0.010) | (0.040) | (0.033) | (0.018) |

Note: Regressions also include offer control, monthly, and hourly fixed effects.

Table A3: All Plants, Net Carbon Pricing Effect Regression Coefficients by Percentile for Off-Peak Hours. Standard errors in parentheses, ** p<0.01, * p<0.05

| term | P15 | P30 | P40 | P50 | P55 | P60 | P65 | P70 | P75 | P80 | P85 | P90 | P95 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| INTERCEPT | -0.000 | -0.000 | -0.000 | 0.046 | -16.667** | -47.957** | -43.122** | -38.273** | -56.703** | -141.061** | -225.030** | -68.350** | -12.241* |
| | (0.000) | (0.000) | (0.000) | (0.048) | (1.322) | (2.520) | (3.271) | (3.766) | (4.660) | (10.872) | (28.242) | (23.481) | (6.018) |
| CR KEY | 0.000 | 0.000 | 0.000 | -0.004 | 5.985** | 22.330** | 0.548 | -22.743** | -56.173** | -107.350** | -158.937** | -53.198** | -5.304** |
| | (0.000) | (0.000) | (0.000) | (0.013) | (0.365) | (0.700) | (0.981) | (1.041) | (1.283) | (3.085) | (7.932) | (6.765) | (1.619) |
| CR NBP | -0.000 | -0.000 | -0.000 | 0.016 | -0.032 | -8.914** | -19.026** | -11.381** | -5.221** | 7.101** | 27.101** | 12.035** | 4.233** |
| | (0.000) | (0.000) | (0.000) | (0.009) | (0.249) | (0.479) | (0.635) | (0.743) | (0.979) | (2.366) | (5.719) | (4.591) | (1.206) |
| HOURLY RENEWABLES | 0.000 | 0.000 | 0.000 | -0.000 | -0.001** | -0.003** | -0.004** | -0.003** | -0.000 | -0.002** | -0.006** | -0.004** | 0.001* |
| | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.001) | (0.002) | (0.001) | (0.000) |
| HOURLY RENEWABLES SQUARED | 0.000 | 0.000 | 0.000 | 0.000 | 0.000** | 0.000** | 0.000** | 0.000** | -0.000** | -0.000** | -0.000** | -0.000 | -0.000** |
| | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) |
| OUT MKT | NA | NA | NA | NA | NA | 1.235* | 0.346* | 0.360** | 0.427** | 1.021** | 1.099** | 1.048** | 1.021** |
| | (NA) | (NA) | (NA) | (NA) | (NA) | (0.543) | (0.176) | (0.070) | (0.021) | (0.011) | (0.008) | (0.003) | (0.002) |
| OUT MKT SQUARED | NA | NA | NA | NA | NA | -0.065 | -0.015 | -0.009* | 0.002** | -0.000 | -0.000** | -0.000** | -0.000** |
| | (NA) | (NA) | (NA) | (NA) | (NA) | (0.051) | (0.011) | (0.004) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) |
| FORECAST POOL PRICE | 0.000 | 0.000 | 0.000 | 0.000 | -0.000 | -0.001* | -0.001 | 0.001* | 0.006** | 0.044** | 0.290** | 0.820** | 0.989** |
| | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.001) | (0.001) | (0.003) | (0.003) | (0.001) |
| DAY AHEAD FORECASTED AIL | 0.000 | 0.000 | 0.000 | -0.000 | 0.002** | 0.007** | 0.012** | 0.012** | 0.018** | 0.040** | 0.058** | 0.013** | 0.001 |
| | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.001) | (0.001) | (0.001) | (0.001) | (0.002) | (0.006) | (0.005) | (0.001) |
| DAY AHEAD FORECASTED AIL SQUARED | -0.000 | -0.000 | -0.000 | 0.000 | -0.000** | -0.000** | -0.000** | -0.000** | -0.000** | -0.000** | -0.000** | -0.000 | -0.000 |
| | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) |
| NIT SETTLE CAD GJ | 0.000 | 0.000 | 0.000 | -0.001* | -0.062** | 0.070** | 0.474** | 1.752** | 3.289** | 4.781** | 3.405** | 0.031 | -0.106 |
| | (0.000) | (0.000) | (0.000) | (0.000) | (0.013) | (0.026) | (0.033) | (0.038) | (0.047) | (0.112) | (0.288) | (0.244) | (0.060) |
| TOTAL IMPORT CAPABILITY | 0.000 | 0.000 | 0.000 | -0.000 | -0.001** | -0.002** | -0.002** | -0.002** | -0.001** | -0.002** | 0.001 | -0.002 | 0.000 |
| | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.001) | (0.001) | (0.001) | (0.000) |
| TOTAL EXPORT CAPABILITY | 0.000 | 0.000 | 0.000 | 0.000 | 0.001** | 0.002** | 0.002** | 0.002** | 0.002** | 0.002** | -0.001 | -0.000 | -0.001* |
| | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.001) | (0.001) | (0.000) |
| HDD YEG | 0.000 | 0.000 | 0.000 | -0.003 | -0.570** | -0.970** | -1.633** | -2.486** | -2.414** | -3.893** | -3.754 | -2.819 | -0.189 |
| | (0.000) | (0.000) | (0.000) | (0.004) | (0.124) | (0.236) | (0.306) | (0.352) | (0.441) | (1.031) | (2.663) | (2.232) | (0.561) |
| HDD YYC | -0.000 | -0.000 | -0.000 | 0.004 | 0.364** | 0.691** | 0.349 | -0.251 | -1.041** | -0.611 | 1.423 | 0.752 | 0.433 |
| | (0.000) | (0.000) | (0.000) | (0.004) | (0.101) | (0.191) | (0.248) | (0.286) | (0.358) | (0.837) | (2.163) | (1.813) | (0.455) |
| HDD YMM | -0.000 | -0.000 | -0.000 | 0.000 | 0.104 | -0.387* | -0.765** | -1.231** | -1.463** | -1.471 | -2.418 | 2.228 | 0.082 |
| | (0.000) | (0.000) | (0.000) | (0.003) | (0.096) | (0.183) | (0.238) | (0.274) | (0.343) | (0.801) | (2.068) | (1.738) | (0.435) |
| CDD YEG | 0.000 | 0.000 | 0.000 | -0.005 | -0.316 | 0.238 | -1.071 | -3.175* | -7.029** | -8.779* | -15.349 | -17.570 | -5.391* |
| | (0.000) | (0.000) | (0.000) | (0.018) | (0.499) | (0.948) | (1.229) | (1.414) | (1.770) | (4.140) | (10.689) | (8.976) | (2.253) |
| CDD YMM | 0.000 | 0.000 | -0.000 | -0.001 | 0.064 | -1.120 | 1.131 | 0.548 | -3.083* | 2.587 | 9.654 | 3.477 | 4.775* |
| | (0.000) | (0.000) | (0.000) | (0.015) | (0.430) | (0.816) | (1.059) | (1.218) | (1.525) | (3.567) | (9.212) | (7.729) | (1.941) |
| CDD YYC | 0.000 | 0.000 | 0.000 | 0.008 | -0.386 | -0.775 | -4.687** | -6.543** | -1.322 | -7.507* | 34.558** | 29.405** | -2.283 |
| | (0.000) | (0.000) | (0.000) | (0.015) | (0.422) | (0.802) | (1.039) | (1.195) | (1.498) | (3.503) | (9.044) | (7.585) | (1.903) |
| SUPPLY CUSHION | -0.000 | -0.000 | -0.000 | 0.000 | 0.001** | 0.003** | 0.004** | 0.005** | 0.010** | 0.017** | 0.041** | 0.024** | 0.002** |
| | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.001) | (0.002) | (0.002) | (0.000) |
| SUPPLY CUSHION SQUARED | -0.000 | -0.000 | -0.000 | -0.000 | -0.000** | -0.000** | -0.000** | -0.000** | -0.000** | -0.000** | -0.000** | -0.000** | -0.000** |
| | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) |
| CARBON PRICING NET | -0.000 | 0.000 | 0.000 | 0.000 | 0.052** | 0.185** | 0.462** | 0.612** | 0.393** | 0.039* | -0.019 | 0.016 | 0.006 |
| | (0.000) | (0.000) | (0.000) | (0.000) | (0.002) | (0.004) | (0.005) | (0.006) | (0.008) | (0.019) | (0.037) | (0.028) | (0.009) |

Note: Regressions also include offer control, monthly, and hourly fixed effects.

Table A4: All Plants, Carbon Pricing Effects Regression Coefficients by Percentile. Standard errors in parentheses, ** p<0.01, * p<0.05

| term | P15 | P30 | P40 | P50 | P55 | P60 | P65 | P70 | P75 | P80 | P85 | P90 | P95 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| INTERCEPT | -0.000 | -0.000 | -0.000 | 0.031* | -11.063** | -46.830** | -43.184** | -27.348** | -31.153** | -38.987** | -230.871** | -275.869** | -81.856** |
| | (0.000) | (0.000) | (0.000) | (0.014) | (0.541) | (1.251) | (1.771) | (2.213) | (2.672) | (5.760) | (25.454) | (24.242) | (11.383) |
| CR KEY | 0.000 | 0.000 | 0.000 | 0.001 | 6.818** | 25.934** | 16.660** | -18.393** | -54.523** | -113.595** | -162.043** | -58.607** | -2.480 |
| | (0.000) | (0.000) | (0.000) | (0.004) | (0.144) | (0.318) | (0.490) | (0.574) | (0.690) | (1.496) | (6.675) | (6.544) | (3.202) |
| CR NBP | -0.000 | 0.000 | -0.000 | 0.004 | 0.710** | -3.984** | -17.657** | -14.202** | -14.851** | -2.231* | 22.075** | 24.844** | 13.205** |
| | (0.000) | (0.000) | (0.000) | (0.002) | (0.089) | (0.205) | (0.297) | (0.373) | (0.483) | (1.123) | (4.592) | (4.109) | (1.964) |
| HOURLY RENEWABLES | 0.000 | 0.000 | 0.000 | -0.000 | -0.001** | -0.002** | -0.003** | -0.003** | -0.001** | -0.002** | -0.018** | -0.009** | 0.001 |
| | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.001) | (0.001) | (0.001) |
| HOURLY RENEWABLES SQUARED | -0.000 | -0.000 | -0.000 | 0.000 | 0.000** | 0.000** | 0.000** | 0.000** | -0.000** | -0.000** | 0.000 | -0.000 | -0.000** |
| | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) |
| OUT MKT | NA | NA | NA | NA | NA | 1.365** | 0.290 | 0.390** | 0.397** | 1.140** | 1.184** | 1.093** | 1.075** |
| | (NA) | (NA) | (NA) | (NA) | (NA) | (0.478) | (0.155) | (0.067) | (0.019) | (0.008) | (0.007) | (0.003) | (0.002) |
| OUT MKT SQUARED | NA | NA | NA | NA | NA | -0.075 | -0.011 | -0.012** | 0.002** | -0.000** | -0.000** | -0.000** | -0.000** |
| | (NA) | (NA) | (NA) | (NA) | (NA) | (0.045) | (0.010) | (0.004) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) |
| FORECAST POOL PRICE | -0.000 | 0.000 | 0.000 | 0.000 | -0.000** | -0.001** | -0.001** | 0.000 | 0.003** | 0.020** | 0.298** | 0.809** | 0.979** |
| | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.002) | (0.002) | (0.001) |
| DAY AHEAD FORECASTED AIL | 0.000 | 0.000 | 0.000 | -0.000** | 0.001** | 0.007** | 0.009** | 0.010** | 0.015** | 0.022** | 0.060** | 0.056** | 0.009** |
| | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.001) | (0.001) | (0.005) | (0.005) | (0.002) |
| DAY AHEAD FORECASTED AIL SQUARED | -0.000 | -0.000 | -0.000 | 0.000** | -0.000** | -0.000** | -0.000** | -0.000** | -0.000** | -0.000** | -0.000** | -0.000** | -0.000** |
| | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) |
| NIT SETTLE CAD GJ | 0.000 | 0.000 | 0.000 | -0.000* | -0.043** | 0.042** | 0.324** | 1.474** | 3.393** | 4.956** | 4.766** | 0.401 | -0.153 |
| | (0.000) | (0.000) | (0.000) | (0.000) | (0.005) | (0.011) | (0.015) | (0.019) | (0.023) | (0.050) | (0.221) | (0.213) | (0.098) |
| TOTAL IMPORT CAPABILITY | 0.000 | 0.000 | 0.000 | 0.000 | -0.000** | -0.002** | -0.002** | -0.002** | -0.002** | -0.002** | -0.005** | -0.013** | -0.003** |
| | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.001) | (0.001) | (0.001) |
| TOTAL EXPORT CAPABILITY | 0.000 | 0.000 | 0.000 | 0.000 | 0.001** | 0.002** | 0.002** | 0.002** | 0.003** | 0.002** | 0.003** | 0.005** | 0.001** |
| | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.001) | (0.001) | (0.000) |
| HDD YEG | 0.000 | 0.000 | 0.000 | -0.001 | -0.101* | -0.981** | -1.213** | -2.488** | -2.860** | -3.159** | -2.059 | 3.311 | 1.933 |
| | (0.000) | (0.000) | (0.000) | (0.001) | (0.049) | (0.114) | (0.161) | (0.200) | (0.244) | (0.530) | (2.329) | (2.235) | (1.031) |
| HDD YYC | -0.000 | -0.000 | 0.000 | 0.001 | 0.119** | 0.916** | 0.159 | -0.494** | -1.235** | -2.093** | -5.822** | -0.966 | 0.253 |
| | (0.000) | (0.000) | (0.000) | (0.001) | (0.038) | (0.089) | (0.125) | (0.155) | (0.189) | (0.412) | (1.812) | (1.738) | (0.802) |
| HDD YMM | -0.000 | 0.000 | 0.000 | 0.000 | 0.054 | 0.081 | -0.151 | -0.316* | -0.810** | -1.706** | -3.059 | -1.572 | -0.205 |
| | (0.000) | (0.000) | (0.000) | (0.001) | (0.038) | (0.088) | (0.123) | (0.153) | (0.187) | (0.406) | (1.786) | (1.715) | (0.791) |
| CDD YEG | -0.000 | -0.000 | -0.000 | -0.001 | -0.082 | -0.235 | -0.999* | -3.417** | -5.592** | -3.269* | -12.821 | -53.969** | -42.901** |
| | (0.000) | (0.000) | (0.000) | (0.004) | (0.142) | (0.330) | (0.465) | (0.578) | (0.704) | (1.532) | (6.735) | (6.462) | (2.981) |
| CDD YMM | 0.000 | -0.000 | -0.000 | 0.000 | -0.062 | 0.031 | -0.213 | -1.904** | -3.625** | -3.934** | 40.102** | 35.304** | 22.956** |
| | (0.000) | (0.000) | (0.000) | (0.003) | (0.118) | (0.274) | (0.386) | (0.480) | (0.585) | (1.272) | (5.593) | (5.370) | (2.477) |
| CDD YYC | 0.000 | 0.000 | 0.000 | 0.002 | 0.134 | -0.671* | -2.043** | -4.002** | -2.553** | -5.291** | -17.318** | 27.947** | 8.480** |
| | (0.000) | (0.000) | (0.000) | (0.003) | (0.115) | (0.266) | (0.375) | (0.465) | (0.567) | (1.234) | (5.425) | (5.212) | (2.402) |
| PEAK HOURS | 0.000 | 0.000 | -0.000 | 0.002 | 0.321** | 0.612** | -0.657** | -1.912** | -2.747** | -14.595** | -79.424** | -69.765** | -20.291** |
| | (0.000) | (0.000) | (0.000) | (0.002) | (0.066) | (0.152) | (0.216) | (0.268) | (0.325) | (0.709) | (3.107) | (2.984) | (1.377) |
| CARBON TAX | -0.000 | 0.000 | 0.000 | 0.000 | 0.050** | 0.186** | 0.422** | 0.625** | 0.429** | 0.036** | -0.100** | 0.044 | -0.010 |
| | (0.000) | (0.000) | (0.000) | (0.000) | (0.001) | (0.002) | (0.003) | (0.003) | (0.004) | (0.010) | (0.032) | (0.026) | (0.014) |
| OUTPUT-BASED ALLOCATION | -0.000 | -0.000 | 0.000 | 0.000 | 0.024** | 0.008** | -0.205** | -0.516** | -0.634** | -0.210** | -0.111 | -0.033 | -0.024 |
| | (0.000) | (0.000) | (0.000) | (0.000) | (0.001) | (0.003) | (0.004) | (0.005) | (0.007) | (0.014) | (0.060) | (0.059) | (0.031) |
| OFF-PEAK HOURS * SUPPLY CUSHION | -0.000 | 0.000 | 0.000 | 0.000 | 0.001** | 0.002** | 0.004** | 0.005** | 0.009** | 0.011** | 0.041** | 0.025** | 0.001 |
| | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.001) | (0.003) | (0.003) | (0.001) |
| PEAK HOURS * SUPPLY CUSHION | -0.000 | -0.000 | -0.000 | 0.000 | 0.000** | 0.001** | 0.003** | 0.005** | 0.009** | 0.026** | 0.150** | 0.117** | 0.026** |
| | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.002) | (0.002) | (0.001) |
| OFF-PEAK HOURS * SUPPLY CUSHION SQUARED | 0.000 | -0.000 | -0.000 | -0.000 | -0.000 | -0.000** | -0.000** | -0.000** | -0.000** | -0.000** | -0.000** | -0.000** | -0.000 |
| | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) |
| PEAK HOURS * SUPPLY CUSHION SQUARED | -0.000 | -0.000 | -0.000 | -0.000 | -0.000** | -0.000** | -0.000** | -0.000** | -0.000** | -0.000** | -0.000** | -0.000** | -0.000** |
| | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) |

Note: Regressions also include offer control, monthly, and hourly fixed effects.

Table A5: All Plants, Net Carbon Pricing Effect Regression Coefficients by Percentile for Tight Market Conditions. Standard errors in parentheses, ** p<0.01, * p<0.05

| term | P15 | P30 | P40 | P50 | P55 | P60 | P65 | P70 | P75 | P80 | P85 | P90 | P95 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| INTERCEPT | -0.000 | -0.000 | -0.000 | -0.000 | -0.000 | -13.712* | -29.909* | -58.876** | -100.483** | -74.536** | -766.412** | -4045.795** | -2018.433** |
| | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (5.426) | (12.724) | (17.205) | (19.754) | (21.747) | (236.840) | (581.131) | (372.148) |
| CR KEY | 0.000 | -0.000 | -0.000 | 0.000 | 0.000 | 8.795** | 19.858** | -15.548** | -24.127** | -41.014** | -137.468* | 352.253* | 350.644** |
| | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (1.325) | (3.110) | (4.290) | (4.793) | (5.534) | (60.015) | (144.580) | (93.025) |
| CR NBP | -0.000 | -0.000 | -0.000 | -0.000 | -0.000 | -3.149* | -21.773** | -23.501** | -19.577** | -27.499** | 213.778** | 760.756** | 160.583 |
| | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (1.261) | (2.958) | (4.010) | (4.636) | (5.383) | (57.479) | (138.878) | (91.160) |
| HOURLY RENEWABLES | 0.000 | 0.000 | -0.000 | 0.000 | -0.000 | -0.000 | -0.001 | -0.002 | -0.004** | -0.001 | -0.001 | 0.064 | 0.075** |
| | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.001) | (0.001) | (0.001) | (0.001) | (0.015) | (0.037) | (0.023) |
| HOURLY RENEWABLES SQUARED | -0.000 | -0.000 | -0.000 | -0.000 | 0.000 | 0.000 | 0.000 | 0.000 | -0.000 | -0.000** | -0.000 | -0.000 | -0.000** |
| | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) |
| OUT MKT | NA | NA | NA | NA | NA | NA | NA | NA | NA | 4.013 | -3.809 | 1.645** | 1.206** |
| | (NA) | (NA) | (NA) | (NA) | (NA) | (NA) | (NA) | (NA) | (NA) | (2.404) | (17.469) | (0.182) | (0.041) |
| OUT MKT SQUARED | NA | NA | NA | NA | NA | NA | NA | NA | NA | NA | 0.319 | -0.001** | -0.000** |
| | (NA) | (NA) | (NA) | (NA) | (NA) | (NA) | (NA) | (NA) | (NA) | (NA) | (0.982) | (0.000) | (0.000) |
| FORECAST POOL PRICE | 0.000 | 0.000 | -0.000 | 0.000 | 0.000 | -0.000 | -0.001* | 0.001* | 0.002** | 0.005** | 0.064** | 0.540** | 0.921** |
| | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.001) | (0.001) | (0.007) | (0.017) | (0.015) |
| DAY AHEAD FORECASTED AIL | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.003* | 0.006* | 0.017** | 0.024** | 0.017** | 0.100* | 0.580** | 0.281** |
| | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.001) | (0.002) | (0.003) | (0.004) | (0.004) | (0.045) | (0.110) | (0.070) |
| DAY AHEAD FORECASTED AIL SQUARED | -0.000 | -0.000 | 0.000 | -0.000 | -0.000 | -0.000* | -0.000 | -0.000** | -0.000** | -0.000 | -0.000 | -0.000** | -0.000** |
| | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) |
| NIT SETTLE CAD GJ | -0.000 | -0.000 | -0.000 | -0.000 | -0.000 | 0.088 | 0.598** | 1.916** | 4.257** | 6.455** | 10.770** | 10.835* | 5.375 |
| | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.051) | (0.117) | (0.161) | (0.186) | (0.207) | (2.264) | (5.468) | (3.450) |
| TOTAL IMPORT CAPABILITY | -0.000 | -0.000 | -0.000 | -0.000 | -0.000 | -0.000 | -0.001* | -0.003** | -0.004** | -0.005** | -0.002 | -0.163** | -0.109** |
| | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.001) | (0.001) | (0.001) | (0.001) | (0.010) | (0.025) | (0.016) |
| TOTAL EXPORT CAPABILITY | -0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.001** | 0.001** | 0.002** | 0.003** | 0.003** | 0.024** | -0.007 | 0.022 |
| | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.001) | (0.001) | (0.001) | (0.009) | (0.022) | (0.014) |
| HDD YEG | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.836 | 1.836 | -5.146* | -6.538** | -4.736 | -6.948 | 50.861 | 19.205 |
| | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.643) | (1.498) | (2.031) | (2.336) | (2.615) | (28.453) | (69.704) | (43.546) |
| HDD YYC | -0.000 | 0.000 | -0.000 | 0.000 | -0.000 | -1.724** | -3.117** | 1.967 | 2.140 | 3.555 | -27.843 | -1.224 | 22.325 |
| | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.509) | (1.181) | (1.601) | (1.843) | (2.065) | (22.410) | (54.998) | (34.298) |
| HDD YMM | -0.000 | -0.000 | 0.000 | -0.000 | -0.000 | 0.986* | 0.016 | -1.195 | -4.735** | -8.026** | 15.847 | -9.426 | -33.917 |
| | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.480) | (1.118) | (1.520) | (1.744) | (1.948) | (21.277) | (52.032) | (32.781) |
| CDD YEG | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | -0.052 | -2.301 | -6.458* | -3.360 | -2.057 | 21.173 | -241.133** | -253.881** |
| | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.794) | (1.867) | (2.527) | (2.901) | (3.256) | (35.307) | (86.665) | (54.623) |
| CDD YMM | -0.000 | -0.000 | -0.000 | -0.000 | -0.000 | 0.624 | 0.517 | -2.083 | -5.992* | -9.333** | -17.413 | 80.098 | 119.000** |
| | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.665) | (1.549) | (2.103) | (2.419) | (2.691) | (29.360) | (71.750) | (44.955) |
| CDD YYC | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | -1.175 | -2.195 | -0.354 | -5.213* | -6.529* | -35.830 | -104.803 | 2.789 |
| | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.662) | (1.543) | (2.093) | (2.411) | (2.709) | (29.166) | (71.791) | (45.108) |
| PEAK HOURS | -0.000 | -0.000 | -0.000 | -0.000 | -0.000 | -2.268** | -0.649 | -2.950 | -2.080 | 0.681 | 13.242 | -321.413** | -128.912** |
| | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.617) | (1.439) | (1.954) | (2.249) | (2.517) | (27.423) | (66.947) | (41.844) |
| CARBON PRICING NET | -0.000 | -0.000 | 0.000 | 0.000 | -0.000 | 0.019** | 0.199** | 0.563** | 0.707** | 0.246** | -0.920** | 0.838 | -0.202 |
| | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.006) | (0.015) | (0.021) | (0.026) | (0.033) | (0.301) | (0.614) | (0.394) |
| OFF-PEAK HOURS * SUPPLY CUSHION | -0.000 | -0.000 | 0.000 | -0.000 | 0.000 | -0.011* | 0.011 | -0.006 | 0.018 | 0.049** | 0.226 | -0.757 | -0.085 |
| | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.004) | (0.010) | (0.014) | (0.016) | (0.018) | (0.195) | (0.476) | (0.297) |
| PEAK HOURS * SUPPLY CUSHION | 0.000 | 0.000 | -0.000 | 0.000 | -0.000 | -0.002* | -0.004 | 0.004 | 0.005 | 0.015** | 0.112* | 0.400** | 0.306** |
| | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.001) | (0.003) | (0.004) | (0.004) | (0.005) | (0.049) | (0.121) | (0.077) |
| OFF-PEAK HOURS * SUPPLY CUSHION SQUARED | -0.000 | -0.000 | 0.000 | -0.000 | 0.000 | 0.000* | -0.000 | 0.000 | -0.000 | -0.000* | -0.000 | 0.001 | 0.000 |
| | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.001) | (0.001) |
| PEAK HOURS * SUPPLY CUSHION SQUARED | -0.000 | 0.000 | -0.000 | 0.000 | -0.000 | 0.000** | 0.000* | 0.000 | 0.000 | -0.000 | -0.000 | -0.000 | -0.000* |
| | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) |

Note: Regressions also include offer control, monthly, and hourly fixed effects.

Table A6: Balancing Pool, Net Carbon Pricing Effect Regression Coefficients by Percentile. Standard errors in parentheses, ** $p<0.01$, * $p<0.05$

| term | P15 | P30 | P40 | P50 | P55 | P60 | P65 | P70 | P75 | P80 | P85 | P90 | P95 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| INTERCEPT | -26.177** | -27.760** | -28.482** | -48.932** | -26.364** | -28.881** | -41.118** | -8.922** | 6.391** | 36.251** | 56.645** | 61.099** | 63.402** |
| | (1.408) | (1.411) | (1.411) | (4.144) | (4.148) | (3.634) | (2.522) | (1.945) | (1.887) | (2.131) | (2.380) | (2.841) | (2.983) |
| CR KEY | -70.558** | -69.170** | -70.950** | -57.036** | -47.651** | -3.103 | -7.696** | -13.096** | -18.594** | -8.396** | -14.458** | -22.837** | -20.797** |
| | (0.635) | (0.634) | (0.643) | (1.910) | (1.900) | (1.652) | (1.138) | (0.874) | (0.849) | (0.966) | (1.075) | (1.281) | (1.343) |
| CR NBP | 50.951** | 51.209** | 53.088** | 42.621** | 33.656** | 4.434** | 3.452** | 5.164** | 5.140** | 2.009** | 3.993** | 8.312** | 5.571** |
| | (0.239) | (0.240) | (0.227) | (0.618) | (0.619) | (0.547) | (0.383) | (0.304) | (0.304) | (0.343) | (0.390) | (0.472) | (0.502) |
| HOURLY RENEWABLES | -0.002** | -0.002** | -0.002** | -0.002** | -0.004** | -0.000 | -0.001** | 0.000 | 0.001** | 0.001** | 0.001** | 0.000 | 0.000 |
| | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) |
| HOURLY RENEWABLES SQUARED | 0.000** | 0.000** | 0.000** | 0.000** | 0.000** | -0.000 | 0.000 | -0.000** | -0.000** | -0.000** | -0.000** | -0.000** | -0.000** |
| | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) |
| OUT MKT | 4.571** | 4.591** | 4.581** | 3.554** | 1.901** | 1.668** | 1.001** | 0.853** | 0.259** | 0.366** | 0.601** | 0.664** | 0.666** |
| | (0.084) | (0.085) | (0.085) | (0.121) | (0.059) | (0.047) | (0.030) | (0.020) | (0.011) | (0.011) | (0.010) | (0.011) | (0.011) |
| OUT MKT SQUARED | -0.436** | -0.438** | -0.437** | -0.223** | -0.077** | -0.073** | -0.045** | -0.037** | 0.011** | 0.006** | 0.003** | 0.003** | 0.002** |
| | (0.013) | (0.013) | (0.013) | (0.015) | (0.004) | (0.003) | (0.002) | (0.001) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) |
| FORECAST POOL PRICE | -0.002** | -0.003** | -0.003** | -0.001* | -0.001** | -0.002** | -0.003** | -0.000* | -0.000 | -0.000 | -0.000 | 0.001** | 0.001** |
| | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) |
| DAY AHEAD FORECASTED AIL | 0.008** | 0.008** | 0.008** | 0.012** | 0.006** | 0.006** | 0.010** | 0.005** | 0.002** | -0.005** | -0.008** | -0.008** | -0.009** |
| | (0.000) | (0.000) | (0.000) | (0.001) | (0.001) | (0.001) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.001) | (0.001) |
| DAY AHEAD FORECASTED AIL SQUARED | -0.000** | -0.000** | -0.000** | -0.000** | -0.000** | -0.000** | -0.000** | -0.000** | -0.000** | 0.000** | 0.000** | 0.000** | 0.000** |
| | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) |
| NIT SETTLE CAD GJ | -0.612** | -0.608** | -0.581** | -0.436** | -0.803** | -1.211** | -0.754** | -0.530** | -0.422** | 0.089** | 0.168** | 0.238** | 0.168** |
| | (0.013) | (0.013) | (0.013) | (0.037) | (0.037) | (0.033) | (0.023) | (0.018) | (0.017) | (0.019) | (0.022) | (0.026) | (0.027) |
| TOTAL IMPORT CAPABILITY | -0.003** | -0.003** | -0.003** | -0.004** | -0.003** | 0.002** | 0.002** | 0.001** | 0.001** | 0.000** | 0.000** | 0.000 | -0.000 |
| | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) |
| TOTAL EXPORT CAPABILITY | 0.005** | 0.006** | 0.006** | 0.004** | 0.004** | 0.001** | 0.002** | 0.002** | 0.002** | 0.001** | 0.001** | 0.001** | 0.001** |
| | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) |
| HDD YEG | -0.770** | -0.709** | -0.723** | -0.112 | 0.202 | 1.731** | 0.980** | 0.806** | 0.740** | -0.279 | -0.453* | -0.674** | -0.763** |
| | (0.109) | (0.110) | (0.110) | (0.322) | (0.322) | (0.283) | (0.196) | (0.151) | (0.147) | (0.166) | (0.185) | (0.221) | (0.232) |
| HDD YYC | 1.536** | 1.502** | 1.474** | 0.547* | 1.070** | 0.198 | 0.109 | -0.421** | -0.566** | -0.354** | -0.037 | -0.146 | -0.275 |
| | (0.089) | (0.089) | (0.089) | (0.260) | (0.261) | (0.229) | (0.159) | (0.122) | (0.119) | (0.134) | (0.150) | (0.179) | (0.188) |
| HDD YMM | -0.759** | -0.767** | -0.757** | 0.322 | -0.128 | 0.793** | 0.447** | 0.107 | -0.020 | -0.240* | -0.458** | -0.541** | -0.508** |
| | (0.080) | (0.080) | (0.081) | (0.235) | (0.236) | (0.207) | (0.143) | (0.111) | (0.107) | (0.121) | (0.135) | (0.162) | (0.170) |
| CDD YEG | 3.167** | 3.391** | 3.031** | -3.435** | 1.836 | 0.649 | 1.458 | 1.118 | 1.055 | 1.894** | 0.371 | 0.344 | 0.594 |
| | (0.420) | (0.422) | (0.422) | (1.234) | (1.237) | (1.084) | (0.752) | (0.580) | (0.563) | (0.636) | (0.710) | (0.847) | (0.889) |
| CDD YMM | -0.601 | -0.679* | -0.417 | 0.837 | 2.441* | 1.692 | -2.909** | -3.783** | -1.734** | -1.438** | 1.268* | 0.613 | -0.390 |
| | (0.341) | (0.343) | (0.343) | (1.002) | (1.005) | (0.881) | (0.610) | (0.471) | (0.457) | (0.517) | (0.577) | (0.688) | (0.722) |
| CDD YYC | -2.770** | -2.827** | -2.643** | 1.544 | -1.817 | 0.201 | -0.064 | 0.305 | -2.016** | -2.556** | -3.498** | -3.211** | -2.982** |
| | (0.342) | (0.344) | (0.344) | (1.005) | (1.008) | (0.884) | (0.613) | (0.472) | (0.459) | (0.518) | (0.579) | (0.690) | (0.724) |
| PEAK HOURS | 1.011** | 1.066** | 1.099** | -0.689 | -0.589 | 0.232 | -0.158 | 0.636** | 0.915** | 0.293 | -0.246 | 0.271 | 0.125 |
| | (0.150) | (0.151) | (0.151) | (0.441) | (0.442) | (0.387) | (0.268) | (0.207) | (0.201) | (0.227) | (0.253) | (0.302) | (0.317) |
| CARBON PRICING NET | -0.229** | -0.238** | -0.246** | 0.418** | 0.950** | 0.915** | 1.090** | 1.116** | 1.136** | 1.164** | 1.164** | 1.245** | 1.235** |
| | (0.003) | (0.003) | (0.003) | (0.009) | (0.009) | (0.008) | (0.006) | (0.004) | (0.004) | (0.005) | (0.005) | (0.006) | (0.007) |
| OFF-PEAK HOURS * SUPPLY CUSHION | 0.002** | 0.002** | 0.002** | 0.004** | 0.006** | 0.003** | 0.001** | -0.000** | -0.001** | -0.000 | -0.001** | -0.001** | -0.001** |
| | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) |
| PEAK HOURS * SUPPLY CUSHION | 0.001** | 0.001** | 0.001** | 0.004** | 0.006** | 0.004** | 0.002** | -0.001** | -0.001** | -0.000 | -0.000* | -0.001** | -0.001** |
| | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) |
| OFF-PEAK HOURS * SUPPLY CUSHION SQUARED | -0.000** | -0.000* | -0.000 | -0.000** | -0.000** | -0.000** | -0.000** | 0.000 | 0.000* | -0.000 | -0.000 | 0.000 | 0.000 |
| | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) |
| PEAK HOURS * SUPPLY CUSHION SQUARED | 0.000** | 0.000** | 0.000** | -0.000** | -0.000** | -0.000** | -0.000** | 0.000 | 0.000** | 0.000 | -0.000* | -0.000 | -0.000 |
| | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) | (0.000) |

Note: Regressions also include offer control, monthly, and hourly fixed effects.