Essays on Renewable Energy, Electricity Markets and Local Communities

by

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Abstract

This dissertation consists of three essays spanning various fields, including energy economics, labor economics, development economics, and regulation. As many jurisdictions worldwide shift towards low-carbon energy sources, energy producers, consumers, and policymakers face new challenges. The main objective of this dissertation is to advance our understanding of the effects of this renewable energy transition at different levels, such as energy producers and consumers, as well as policymakers.

Chapter 1 focuses on two commonly used renewable support policies: a fixed-price feed-in tariff (FiT) and a premium-price FiT. The objective is to empirically analyze how these renewable support policies affect wholesale market outcomes like equilibrium prices and quantities and other outcomes of interest such as carbon dioxide emissions and policy costs. Using data from the Alberta wholesale electricity market, a three-stage model simulates a renewable energy procurement auction, a forward contract market, and a spot market competition. The results suggest that a fixed-price FiT increases competition compared to a premium-price FiT through a lower equilibrium price and higher equilibrium output. Further, under a premium-price FiT, the strategic behavior of the firms plays a crucial role in determining the outcomes. This strategic behavior depends heavily on the characteristics of the firms, like the flexibility of their asset portfolio and marginal cost curves. Additionally, due to the lower spot market output, carbon dioxide emissions are lower under a premium-price FiT, while policy costs are lower under a fixed-price FiT. The results highlight the numerous trade-offs associated with these compensation policies and their sensitivity to market and firm characteristics.

Chapter 2 concentrates on an often overlooked effect of renewable energy projects: their impacts on local communities. Policymakers often consider hydroelectric projects as a tool to boost local economies, principally through local job creation and investment inflow. Therefore, using Chilean data from 1990 to 2017, Chapter 2 studies the local effects of hydroelectric projects on salary, employment, the housing market (i.e., probability of owning a house versus renting), and health (i.e., probability of visiting a doctor). The methodology relies on a weighted two-way fixed effect difference-in-differences estimator that accounts for selection into treatment and heterogeneous treatment effects over time. The results show that the measured effects are short-lived, only between 2 and 3 years after project construction starts. The labor market effects primarily manifest as higher salaries in the construction industry with positive spillover effects on the manufacturing and hospitality industries, but these effects do not per-

sist beyond three years. The short-term nature of the results highlights the necessity of understanding the local effects of energy projects, especially as we are increasingly transitioning to renewable energy.

Chapter 3 revisits the role of renewable compensation policies to investigate their interaction with conventional energy capacity investment. In a setting of imperfect competition and uncertain demand, this Chapter develops a two-stage duopoly model where firms have a fixed amount of renewable capacity and can invest in conventional energy capacity. Conventional output is compensated at market prices, but renewable output can be compensated by a fixed-price feed-in tariff or a premium-price FiT. Generally, the pro-competitive effect of a fixed-price FiT is expected to encourage capacity investment to allow the firm to expand its spot market output during peak hours. Nevertheless, the main result shows that modifying the renewable CP has an ambiguous effect on the level of capacity investment, which depends on the relative size of the renewable capacity owned by the firm and its rival. For instance, if a firm owns sufficiently low renewable capacity compared to its rival, a fixed-price FiT encourages it to decrease its conventional capacity investment. This stylized model provides a formal theoretical framework that characterizes the relationship between renewable compensation policies and conventional capacity investment. Understanding this relationship is crucial as we transition towards renewable energy sources while maintaining a reliable supply through conventional generation.

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Chapter 1

Renewable Energy and Compensation Policies in Electricity Markets with Imperfect Competition

Abstract

Renewable compensation policies (CPs) have been successfully employed worldwide to encourage the adoption of renewable energy sources; however, their relative impact on wholesale electricity markets continues to be an open question. In this paper, we use numerical methods to empirically analyze the effects of adding new renewable energy capacity compensated under a fixed-price feed-in tariff (FiT) or a premium-price FiT, two widely used renewable compensation policies. We use data from the Alberta electricity market to develop a three-stage model to simulate the renewable energy procurement auction, the forward contract market, and the spot market. Our main results show that under a fixed-price FiT, the spot price decreases up to 36% during high-demand hours, independent of who owns the new renewable capacity. Under a premium-price FiT, the spot price reduction is more moderated, but total spot market output is lower than under a fixed-price FiT, which indicates increased incentives to exercise market power. Further, under a premium-price FiT, the strategic behavior of the firms determines the outcomes. This strategic behavior depends heavily on the characteristics of the firms, such as their asset portfolios and marginal cost curves. Due to the lower total conventional output, we also find that carbon dioxide emissions are lower under a premium-price FiT, but policy costs are lower for the regulator under a fixed-price FiT. Our results highlight the numerous trade-offs associated with these compensation policies and their sensitivity to market characteristics. In particular, we show that firms' attributes are an especially relevant factor to be considered by policymakers when designing and implementing these types of compensation policies.

1.1 Introduction

In 2021, more than 130 countries relied on market-based procurement auctions to boost the development of renewable energy projects and to encourage open participation and interest from the private sector (REN21, 2022). An important feature of these auctions is the compensation policy (CP) chosen by the energy regulator, such as feed-in tariffs (FiT). These CPs are typically long-term contracts between energy regulators and renewable energy producers in a determined jurisdiction, which specify the electricity price and other conditions for firms to develop renewable energy projects and provide electricity.

There are several types of FiT, such as front-end loaded tariff or spot market gap pricing.[1] Two of the most commonly implemented CPs are fixed-priced FiT and premium-priced FiT. On the one hand, when the auction is designed with a fixed-price FiT, firms bid the fixed dollar amount required to sell each Mega Watt hour (MWh) of renewable output generated. On the other hand, when the auction is designed with a premium-price FiT, firms bid the extra dollar amount per MWh above the spot market price they require to sell their renewable output. These two CPs allow us to capture the essence of renewable compensations that depend on the electricity price and those that are independent. In practice, regulators design auctions with only one FiT at the time in the same jurisdiction, limiting our ability to study them.[2] This is why alternative approaches become helpful to compare the relative effects of these CPs on electricity markets.

In this paper, we use numerical methods (simulation analysis) to empirically analyze the effects of a fixed-price FiT versus a premium-price FiT on wholesale market outcomes,[3] including price, electricity generated, and other relevant variables like carbon dioxide (CO_2) emissions and policy costs. In our simulation analysis, we assume a setting of imperfect competition with two possible renewable energy sources, solar (assumed to be more correlated with electricity demand) and wind (assumed to be less correlated with electricity demand), and we use data to replicate the Alberta electricity market for 2018.[4] We base our analysis on Brown and Eckert (2019), who developed a stylized model that lays the theoretical foundation regarding the interaction between these CPs and market outcomes. Our study extends their theoretical model into an empirical application of an existing market, which allows us to provide more realistic directions and magnitudes of the effects.

[1] Refer to Couture and Gagnon (2010) for a detailed analysis of several FiT.

[2] In general, we do not observe both CPs in the same jurisdiction simultaneously; however, the regulator may change the CPs applied to renewable energy output over a more extended period. Fabra and Imelda (2021) exploit this variation in the Spanish electricity market to show the relative effects of these CPs on market prices.

[3] Fixed-price and premium-price FiT are currently denoted as contracts for differences, but for consistency we refer to them as FiT throughout the paper. Several jurisdictions have used contracts for differences, including the UK in 2013 (Energy Act 2013, Chapter 32) and Alberta in 2018 (AESO, 2016).

[4] We provide details on why we use Alberta in subsection 1.4.1. However, the main reasons are that Alberta is an energy-only market, the exercise of unilateral market power is permitted in 2018, and there is a uniform spot price for all generators each hour.

To better isolate the effects of each CP, we develop a three-stage game. In the first stage of the model, firms simultaneously participate in a winner-take-all first-price auction, where they choose bids and technology (wind or solar). The electricity generated from this new renewable capacity is compensated by either a fixed-price FiT or a premium-price FiT. In the second stage, knowing the auction results, firms decide on their forward positions. We focus on forward contracting for strategic purposes (Allaz and Vila, 1993).[5] In the third stage and once the auction results and forward positions are known, firms engage in Cournot competition to provide electricity at the wholesale spot market.

Our empirical application includes real-world complexities, such as asymmetric marginal costs, heterogeneous firm-level generation portfolios, minimum stable generation (i.e., the necessary lower bound for the safe function of coal plants), and existing renewable capacity. These features are crucial because they may lead us to results that deviate from what Brown and Eckert (2019) have found in their stylized theoretical model. For example, even if firms have similar marginal costs, their asset portfolios might differ, leading to different flexibility in their ability to exercise market power and affecting their incentives to acquire the new renewable capacity.

Our results show that, in equilibrium, under a premium-price FiT, the effects of the new renewable capacity on the spot market depend on the characteristics of the firm that owns the new renewable capacity. For instance, the smallest price reduction arises when the new renewable capacity is allocated to the firm with the lowest marginal cost and its portfolio is based predominantly on natural gas (i.e., relatively more flexibility to exercise market power to keep prices high). In equilibrium, under a premium-price FiT, solar capacity is awarded to the firm with higher marginal costs and relatively less flexible generation (i.e., the firm with a larger share of coal assets). This arises because higher marginal cost and inflexible generation decrease the firm participation on the spot market, leading to relatively lower conventional generation in the spot market for this firm. Therefore, when the firm owns the new capacity, its spot market profits increase relatively more than those with large spot market generation, increasing its incentives to bid aggressively for the new capacity. This result shows that firms will have different incentives to own the new renewable capacity depending on their characteristics.

[5] Risk-averse firms also sign forward contracts for risk-hedging purposes. Eijkel et al. (2016) present evidence in the natural gas industry that firms participate in the forward market for both strategic and risk-hedging purposes. An analysis of forward contracting for risk-hedging purposes is out of the scope of the current analysis.

Further, our results show that, in equilibrium, wind capacity is awarded under a fixed-price FiT, and the firms' characteristics, such as costs and generation portfolio, do not influence the auction result. This arises because of the limited strategic incentives associated with this CP. Additionally, the average spot price decreases up to 36%, relative to a scenario with no new renewable capacity, during high-demand hours independent of who owns the new renewable capacity. Further, we observe a smaller reduction in conventional generation under a fixed-price FiT, which leads to a 3.4% decrease in CO_2 emissions versus a 3.6% reduction under a premium-price FiT. Finally, our results show that, for the Alberta case, a fixed-price FiT costs the regulator 24% less than a premium-price FiT.

In this paper, we highlight the multiple trade-offs associated with these CPs. We demonstrate that the characteristics of the market, like renewable generation productivity and the asset and cost structure of firms, are essential elements that policymakers must consider when deciding what CP to implement. Finally, while we use data of the Alberta wholesale electricity market to test our model, the insights and main conclusions are relevant for any restructured electricity market.

The remainder of the paper proceeds as follows. Section 1.2 presents a review of the relevant literature. Section 1.3 describes the three-stage theoretical model. Section 1.4 details the numerical analysis, starting with a description of the Alberta wholesale electricity market and the data used for our analysis, and followed by the estimation of the main model parameters. Section 1.5 presents the results for each CP in the three stages. This section also shows the results for a setting with increased electricity demand and the effects on CO_2 emissions and policy costs. Finally, Section 1.6 concludes.

1.2 Literature Review

There is extensive literature studying the effects of renewable energy on different levels of electricity markets, such as retail (Trujillo-Baute et al., 2018; Oosthuizen et al., 2022), transmission and distribution (Hitaj, 2015; Navon et al., 2020; Fell et al., 2021), and, the focus of this paper, wholesale electricity generation (Genc and Reynolds, 2019; Bushnell and Novan, 2018). For instance, Genc and Reynolds (2019) and Bahn et al. (2019), using simulation models, show that the effects of adding renewable energy capacity on spot prices and electricity generation are sensitive to the characteristics of the firms that own the new renewable capacity. These studies assume that the new capacity is compensated at market prices and find that firms' asset portfolios and market share determine their ability and incentives to exercise market power. While we also rely on simulation models, our work extends these studies in several ways. First, instead of assuming that new renewable capacity is compensated at market prices, we analyze two commonly used CPs: fixed-price FiT and premium-price FiT. Second, we include forward contracts, a key component of restructured electricity markets. Third, we include the auction stage for heterogeneous new renewable capacities (i.e., wind and solar).[6] Fourth, we use equilibrium outcomes to estimate the cost of each policy and their effects on CO_2 emissions.

As Darudi (2023) points out, the choice of the CP used in auctions is one of the major design challenges regulators face. The author develops a two-stage theoretical model to study the relative effects of a fixed-price FiT versus a premium-price FiT. In the first stage, the regulator auctions out renewable capacity to be compensated by either one of the CPs. In the second stage, firms compete to supply electricity at the wholesale level. Darudi's results show that a fixed-price FiT outperforms a premium-price FiT in several aspects, such as lower spot price and total payment from the regulator to the firms. However, a premium-price FiT may increase social welfare in markets with dirty technologies on the margin. Our study differs from Darudi's in several ways. For example, we model a first-price auction instead of a second price auction. This may have important implication in the bidding behavior and outcome of the procurement auction (Kagel and Levin, 1993). Additionally, Darudi's model considers two bidders, a price-taking entrant with no existing capacity and a strategic firm with existing capacity. We show that the firms' generation portfolio have a crucial role in their incentives to own the new renewable capacity.

Another important difference with Darudi (2023) is that we explicitly model the forward market. Empirical evidence demonstrates that forward contracts influence a firm's behavior (see the seminal work of Allaz and Vila, 1993; for more recent evidence, refer to de Frutos and Fabra, 2012; Eijkel et al., 2016; Brown and Eckert, 2017; 2018). In particular, a strong relationship exists between the incentives to exercise market power and forward contracts (e.g., Wolak, 2000; 2007; Bushnell et al., 2008). Failure to control for this would overestimate the incentives for firms to exercise market power.[7] In addition, studies suggest a negative relationship between forward contracts and renewable energy capacity when renewables

[6] Including heterogeneous renewable energy sources is important because renewables like wind energy tend to displace coal generation, while solar displaces natural gas (Linn and Shih, 2019). Intuitively, solar energy produces more during peak demand hours, while wind energy production peaks at night when demand is relatively lower.

[7] For examples of studies about market power in electricity markets, refer to Borenstein and Bushnell (1999), Borenstein, et al. (1999) and Brown and Olmstead (2017).

are compensated at market prices (Ritz, 2016; Acemoglu et al., 2017). However, Brown and Eckert (2019) have found that renewable output has an ambiguous effect on forward contracts, depending on the CP used.

Oliveira (2015) and Fabra and Imelda (2021) are two other related papers that study the specific cases of fixed-price and premium-price FiTs. Oliveira (2015) develops a two-stage theoretical model, where firms decide whether to invest in new renewable energy capacity and then engage in Cournot competition at the spot market level. While Oliveira's study highlights the theory, we focus on an empirical application using numerical methods to analyze these CPs, including forward markets, which play an important role in firm behavior. Additionally, we model a renewable procurement auction, which is increasingly employed in practice.

Fabra and Imelda (2021), relying on a difference-in-differences approach, assess how changes in CPs in the Spanish electricity market affect the degree of market power exercised by the firms. The authors find that fixed-price CPs directly mitigate market power for dominant firms, while premium-price CPs do so indirectly by increasing the incentives of fringe firms to arbitrage between the day-ahead market and the spot market. Our study focuses on alternative model features, including an auction stage and renewables with different generation profiles. We conduct a simulation exercise to test different hypotheses about fixed-price FiT versus premium-price FiT. The use of a simulation exercise allows us to isolate the effects of the policies in a wide range of scenarios without the influence of confounding factors.

As mentioned earlier, our model and predictions are based on Brown and Eckert (2019). In their paper, the authors derive a theoretical model to determine the effects of additional renewable capacity compensated by a fixed-price FiT or a premium-price FiT. Like Oliveira (2015), they show that the effects of new renewable capacity differ depending on what CP is used. They demonstrate that under a fixed-price FiT, the effects are independent of who owns the new capacity. While under a premium-price FiT, firms have incentives to behave strategically, so the effects depend on who owns the new capacity.

Our study extends the work of Brown and Eckert (2019) in several ways: First, our focus is empirical. We analyze the direction and magnitude of the effects in a real-world setting. Second, we relax numerous assumptions, such as symmetric marginal costs and non-existing renewable capacity, and we allow firms to have heterogeneous asset portfolios. Third, we account for policy costs. As each CP has different payment mechanisms, different situations may arise where even the regulator may get paid by the firms. Fourth, one of the main reasons for the renewable energy transition is to reduce pollution. This is why we include the effects of CPs on carbon dioxide (CO_2) emissions. These extensions aim to provide more realistic estimates of the effects of these CPs on wholesale electricity markets.

1.3 Model

In this section, we describe the theoretical model underlying our analysis. First, we start with a general description of the game, including the characteristics of the procurement auction (first stage). Second, we describe the second- and third-stage equilibrium conditions (forward and spot markets).

To start, consider an oligopoly model with $N \geq 2$ strategic firms plus a price-taking fringe of small firms that produce a homogeneous good (i.e., electricity) in each period $t = 1, 2, ..., T$. We consider a three-stage game where firms make decisions. In the first stage, the regulator organizes a renewable auction to procure a specified amount of renewable capacity $R > 0$. We allow firms to have existing conventional and renewable generation capacities. In the second stage, firms $i = 1, 2, 3, ..., N$ simultaneously choose their forward quantities, q_{it}^{f}, to sell in the forward market at a price, P_{it}^{f}, for each period $t = 1, 2, ..., T$. In the third stage, knowing the outcomes of the previous two stages, the firms compete in the (wholesale) spot market by simultaneously and independently choosing their conventional outputs, q_{it}^{conv}, for each period $t = 1, 2, ..., T$.

The inverse market demand in the spot market is defined as $P_t(Q_t) = a_t - b_t Q_t$, where a_t and b_t are positive constants and $Q_t = \sum_{i=1}^{n} (q_{it}^{conv} + q_{it}^{MR} + \theta_{it} R_i)$ is total spot market output. Total market output is defined as the sum of conventional generation, q_{it}^{conv}, must-run generation, q_{it}^{MR} (i.e., assets with zero marginal cost, such as previously owned renewable energy or cogeneration assets[8]), and the new renewable capacity won by firm i in the auction stage, $R_i \geq 0$, multiplied by the respective renewable capacity factor, $\theta_{it} \in [0, 1]$, which is deterministic and known ex-ante to all firms.[9] The renewable capacity factor refers to the hourly efficiency of the new renewable generation plant. Therefore, $\theta_{it} R_i \geq 0$ can be understood as the realized new renewable energy output for firm i in period t. Must-run generation and new renewable output are assumed to be always called upon to supply

[8]Cogeneration refers to plants (mainly natural gas plants) whose main objective is to generate electricity for on-site industrial purposes and sell the extra generated electricity to the system. These units are systematically bid into the market at \$0/MWh.

[9]Note that we assume deterministic renewable output, but in reality the realization of the capacity factor, θ_{it}, is uncertain. We discuss the potential implications of this assumption in Section 1.6.

electricity.

We define the marginal cost function of conventional energy generation as $C_{it}(q_{it}^{conv}) = x_{it} + y_{it}q_{it}^{conv} + z_{it}(q_{it}^{conv})^2$, for firm i in period t. This function includes all coal and natural gas plants owned by each firm. In reality, a firm's cost function is a discontinuous step function, but we approximate it by a smooth, continuous non-decreasing quadratic function. The fit of this approximation is further discussed in Section 1.4.4. Further, we assume that the new renewable energy generation and must-run generation have zero marginal cost. Cost functions are common knowledge to all firms in every stage of the game.

Conventional generation is compensated at the spot market price, but renewable output is compensated either by a fixed-price FiT, represented by $\overline{P}_i$ per MWh of output, or by a premium-price FiT that pays the firm the market price $P_t(Q_t)$ plus a premium m_i per MWh of output. This means that the total price per MWh of renewable output perceived by the firms under a premium-price FiT is $P_t(Q_t)+m_i$. Additionally, define $\delta \in [0,1]$ as the proportion of renewable output compensated by a fixed-price FiT, and $(1-\delta) \in [0,1]$ the proportion of renewable output compensated by a premium-price FiT. For the purpose of this paper, we assume that all new renewable output is compensated by only one CP (i.e., δ may only be one or zero). This assumption follows our interest of analyzing the relative effects of each CP on market outcomes separately.

In the first stage, before firms decide on their forward positions and spot market generation, the regulator organizes a one-time winner-takes-all renewable auction to procure a specified amount of renewable capacity $R_i > 0$. This new renewable capacity is technology neutral[10] and remains fixed for the rest of the periods. The auction winner obtains the rights to build the R_i units of renewable capacity and must incur a fixed investment cost, $F > 0$, which is equal for all firms and common knowledge.[11] To participate in the procurement auction, each firm decides on a combination of a bid and a technology choice (solar or wind energy).

The renewable capacity awarded in the auction can be compensated by a fixed-price FiT or a premium-price FiT. In the fixed-price FiT setting, each firm bids the price per MWh $\overline{P}_i$ that is willing to accept to build and operate the renewable facility for either wind or solar energy. In the premium-price FiT setting, firms bid the amount above market price

[10]In the procurement auction stage, firms may bid for solar or wind capacity; however, the regulator does not favor any technology.

[11]We first assume that the fixed investment cost F is equal for wind and solar, but this assumption is relaxed in Appendix 8.

per MWh, m_i, that it requires to build and operate the renewable facility for either wind or solar energy. Therefore, under this setting the compensation per MWh is $P_t(Q_t) + m_i$, where $P_t(Q_t)$ is the equilibrium spot price at time t. For either setting, the winner is the firm with the lowest bid. In the case of a tie, each firm wins with equal probability. For analytical tractability, we restrict firms' bids to the cent. We search for the pure-strategy Nash Equilibria (PSNE), where each firm's bid/technology combination must be a best response to its rival's bid/technology combination.

In our model, we abstract from dynamic cost constraints, such as ramping and start-up costs. We build upon previous studies that assume firms' forward positions are publicly known, firms are risk-neutral, and forward and spot prices are efficiently arbitrated, resulting in forward prices equaling expected spot prices (Allaz and Vila, 1993; Bushnell, 2007; Brown and Eckert, 2019).[12] Our analysis focuses on a one-shot game, where firms make output decisions for each spot market period. We employ backward induction and solve for the Subgame Perfect Nash Equilibrium (SPNE).

1.3.1 Third Stage: Spot Market

In this stage, firms simultaneously and independently choose their spot output for conventional energy (i.e., coal and natural gas) for each period $t = 1, 2, ..., T$. Forward positions q_{it}^f, price P_{it}^f, and new renewable capacity R_i are taken as given, and the strategic firms choose their outputs considering their impact on the market clearing price. Recall that $\delta \in [0, 1]$ determines the CP paid to the new renewable generation.[13] When $\delta = 1$ the new renewable capacity is compensated by a fixed-price FiT at a price $\overline{P_i}$, and when $\delta = 0$, the new renewable capacity is compensated by a premium-price FiT, which is paid $P_t(Q_t) + m_i$, where m_i is the value above spot price agreed in the auction. Each strategic firm $i = 1, 2, ..., N$ maximizes its spot market profits:

$$\begin{aligned} \underset{q_{it}^{conv}}{MAX} \ \Pi_{it} = & P_t(Q_t)\left[q_{it}^{conv} + q_{it}^{MR} - q_{it}^f\right] - C_{it}(q_{it}^{conv}) \\ & + \overline{P_i}\delta\theta_{it}R_i + \left[P_t(Q_t) + m_i\right](1-\delta)\theta_{it}R_i + P_{it}^f q_{it}^f \end{aligned} \tag{1.1}$$

[12] Even under the assumption of risk neutrality, firms still have strategic incentives to participate in the forward market (de Frutos and Fabra, 2012; Eijkel et al., 2016; Brown and Eckert, 2017; 2018).

[13] For the purpose of this paper, δ cannot take intermediate values. This is because we aim to compare both CPs rather than find the optimal policy structure. Setting δ equal to one or zero assumes that only one CP is active in the market for all periods. Future work that aims to find the optimal CP structure may relax this assumption and endogenize δ.

The first term of equation (1.1) represents the output that firms sell at the spot market. The second term is the cost of conventional energy generation. The third and fourth terms are the profits firms perceive for their new renewable output under a fixed-price FiT and a premium-price FiT, respectively. The last term represents the income from forward quantities. Regarding the fringe, we assume that it cannot sign forward contracts. In addition, the fringe (defined by the subscript fr) takes prices as given so, for interior solutions, it produces up to the point at which its marginal cost equals the market clearing price (i.e., $P_t(Q_t) = C'_{fr,t}(q_{fr,t}^{conv})$).

Assuming an interior solution, the first-order conditions that maximize the firm's payoffs, given the quantities chosen by its rivals, for $i = 1, 2, ..., N$, are as follows:

$$\frac{\partial \Pi_{it}}{\partial q_{it}^{conv}} = P'_t(Q_t)\left[q_{it}^{conv} + q_{it}^{MR} - q_{it}^{f}\right] + P_t(Q_t) - C'_{it}(q_{it}^{conv}) + P'_t(Q_t)(1-\delta)\theta_{it}R_i = 0 \quad (1.2)$$

Equation (1.2) shows that if the firm does not own the new renewable capacity (i.e., $R_i = 0$), then as its forward quantity converges to the spot quantity, such as the firm is fully contracted in the forward market ($q_{it}^{f} \rightharpoonup q_{it}^{conv} + q_{it}^{MR}$), the firm's behavior coincides with a perfectly competitive producer. This demonstrates the pro-competitive effects that forward contracts have on firms (Allaz and Vila, 1993). Using equation (1.2) we can derive the equilibrium conventional spot output, which depends on the forward quantities. In addition, the fringe (defined by the subscript fr) takes prices as given so, for interior solutions, it produces up to the point at which its marginal cost equals the market clearing price (i.e., $P_t(Q_t) = C'_{fr,t}(q_{fr,t}^{conv})$).

1.3.2 Second Stage: Forward Contracts

Once the auction results are known, in the second stage, strategic firms simultaneously decide their forward positions, q_{it}^{f}, for each period $t = 1, 2, ..., T$. In our model, firms participate in the forward market for strategic considerations.

Define $q_{it}^{conv}(q_i^f, q_{-i}^f)$ as firm i's optimal quantities derived in the third stage that depends on forward contracts. Further, note that $q_{-it}^{conv}(q_{-i}^f, q_i^f)$ are the optimal quantities from the third stage for all other firms that also depend on forward contracts. Hence, the second-stage problem, where each firm chooses its forward positions taking rival's forward positions as given, is as follows:[14]

[14] Recall that we employ the perfect arbitrage assumption where the forward price is equal to the expected value of the current spot price. This assumption removes the forward contract term directly from the profit

$$
\begin{aligned}
\underset{q_{it}^f}{MAX}\ \pi_{it}(q_{it}^{conv}, q_{-it}^{conv}) =& P_t(Q_t(q_{it}^f, q_{-it}^f)) \left[q_{it}^{conv}(q_{it}^f, q_{-it}^f) + q_{it}^{MR}\right] - C_{it}(q_{it}^{conv}(q_{it}^f, q_{-it}^f)) \\
&+ \overline{P_i}\delta\theta_{it}R_i + \left[P_t(Q_t(q_{it}^f, q_{-it}^f)) + m_i\right](1-\delta)\theta_{it}R_i
\end{aligned} \tag{1.3}
$$

Assuming an interior solution, the first-order conditions for each firm $i, j = 1, 2, 3, ..., N$ and $j \neq i$, are as follow:

$$
\begin{aligned}
\frac{\partial \pi_{it}(q_{it}^{conv}, q_{-it}^{conv})}{\partial q_{it}^f} =& P_t'(Q_t)\left[\frac{\partial q_{it}^{conv}}{\partial q_{it}^f} + \sum_{j=1}^{N} \frac{\partial q_{jt}^{conv}}{\partial q_{it}^f}\right]\left[q_{it}^{conv} + q_{it}^{MR}\right] + P_t(Q_t)\frac{\partial q_{it}^{conv}}{\partial q_{it}^f} \\
&- C_{it}'(q_{it}^{conv})\frac{\partial q_{it}^{conv}}{\partial q_{it}^f} + P_t'(Q_t)\left[\frac{\partial q_{it}^{conv}}{\partial q_{it}^f} + \sum_{j=1}^{N} \frac{\partial q_{jt}^{conv}}{\partial q_{it}^f}\right](1-\delta)\theta_{it}R_i = 0
\end{aligned} \tag{1.4}
$$

Adding and subtracting $P_t'(Q_t)q_{it}^f\frac{\partial q_{it}^{conv}}{\partial q_{it}^f}$, and using equation (1.2), we can rewrite equation (1.4) as:

$$
\frac{\partial \pi_{it}(q_{it}^{conv}, q_{-it}^{conv})}{\partial q_{it}^f} = P_t'(Q_t)q_{it}^f\frac{\partial q_{it}^{conv}}{\partial q_{it}^f} + P_t'(Q_t)\sum_{j=1}^{N}\frac{\partial q_{jt}^{conv}}{\partial q_{it}^f}\left[q_{it}^{conv} + q_{it}^{MR} + (1-\delta)\theta_{it}R_i\right] = 0 \tag{1.5}
$$

Brown and Eckert (2019) show that forward contracts are ambiguously affected by adding renewable energy to the market through direct and strategic effects. Equation (1.5) represents the firm's forward contracting decision. The first term in equation (1.5) represents the direct effect. This negative effect occurs when holding the rival's spot market quantities constant. An increase in firm i's forward contract puts upward pressure on its spot generation. This reduces the spot price, which lowers profits from the spot market and the forward contracts; hence firms have lower incentives to sign forward contracts. The second term represents the strategic effect, a positive effect that happens when firm i's spot quantity is held constant, and its forward contracts increase. This reduces its rival's spot quantities, which increases the spot price driving up profits from the spot market for firm i, and increasing the incentives to sign forward contracts.

function. As Holmberg and Willems (2015) state, the firms' payoffs do not depend directly on the forward contracts but on their strategic effect on the spot prices.

1.3.3 First Stage: Renewable Procurement Auction

In the first stage, before firms decide on their forward positions and spot market generation, the regulator organizes a one-time winner-takes-all renewable auction to procure a specified amount of renewable capacity $R > 0$. The auction winner obtains the rights to build the renewable capacity and must incur a fixed investment cost, $F > 0$, which is equal to all firms and common knowledge.[15] To participate in the procurement auction, each firm decides on a combination of a bid and a technology choice (solar or wind energy).

The objective of modeling the auction stage is to analyze the effects between the spot market's strategic behavior and the bidding behavior in the auction under different CPs. In addition, we include heterogeneous renewable technologies to investigate the interaction between renewable generation profiles (i.e., solar peaks production during high-demand hours, while wind produces more during off-peak hours) and the CPs. While in our model renewable output is deterministic, we characterize solar and wind energy to mimic their average generation profiles per hour. These generation profiles capture the essence of these renewable energy sources regarding their generation correlation with market demand, which we are most interested in.

To find the auction winner, we estimate the minimum bids that make firms indifferent between winning the auction or letting their rivals win.[16] This minimum bid will depend on what rival is expected to be awarded the new renewable capacity and the technology chosen by this rival.

Under a fixed-price FiT, the minimum $\overline{P_{ij}}$ for each firm i, relative to its rival j, is defined as:

$$\overline{P}_{ij}^{min} = \frac{F}{\sum\limits_{t}\theta_{it}R} - \left(\frac{1}{\sum\limits_{t}\theta_{it}R}\right)\sum_{t}\left(\Pi_{it,Ri}^{conv} - \Pi_{it,Rj}^{conv}\right) \quad for\ each\ i,j = 1,2,...,N\ and\ i \neq j \tag{1.6}$$

The first term represents the average fixed cost. The second term is the profit difference from the conventional output when firm i owns the new renewable capacity, $\Pi_{it,Ri}^{conv}$, versus its rival j, $\Pi_{it,Rj}^{conv}$. Note that under a fixed-price FiT, the effects of new renewable capacity are independent of who owns this new capacity; hence the second term of equation (1.6) is zero when comparing the same renewable energy technology (i.e., firm i and j own the same

[15] This assumption is relaxed in Appendix 8.

[16] For a detailed discussion and derivation of the minimum bids for both CPs, refer to Brown and Eckert (2019).

renewable technology). However, this term is different from zero when comparing across renewable technologies (e.g., firm i owns solar and firm j owns wind, or vice versa).

Under a premium-price FiT the minimum bid, m_{ij}^{min}, is defined as:

$$m_{ij}^{min} = \frac{F}{\sum_t \theta_{it} R} - \left(\frac{1}{\sum_t \theta_{it} R} \right) \sum_t \left(\Pi_{it,Ri}^{spot} - \Pi_{it,Rj}^{spot} \right) \;\; for\ each\ i,j = 1,2,...,N\ and\ i \neq j \tag{1.7}$$

The first term is the average fixed cost, and the second is the profit difference from spot output when the firm owns the new renewable capacity, $\Pi_{it,Ri}^{spot}$, versus when other firms own it, $\Pi_{it,Rj}^{spot}$. Note that, contrarily to $\overline{P}_{ij}^{min}$, under a premium-price FiT, firms take into account all spot profits, including the new renewable capacity and their conventional output. This is because firms are paid the spot price for their new renewable capacity and conventional output.

1.4 Numerical Analysis

In this section, we present the details of our numerical analysis in the following steps. First, as we adapt our simulation model to the Alberta wholesale electricity market, we start with a summarized description of the market, followed by a description of the main data required for the simulation model. Second, we estimate the residual demand function, net of price-responsive imports, faced by the firms. Third, we use our asset-level data to approximate smooth marginal cost curves for the four strategic firms and the fringe. Fourth, we apply the theoretical model of the previous section to our empirical analysis, and we describe the main predictions of our model. Finally, this is followed by a detailed description of the characteristics and specific features of the simulation model.

1.4.1 Alberta's Wholesale Electricity Market

The Alberta wholesale electricity spot market operates as a multi-unit auction with a uniform price. All firms submit hourly bids regarding the quantity of electricity (in MWh) they are willing to supply, and the price they will charge for every MWh supplied. For every hour of the day, the Alberta Electric System Operator (AESO) ranks the offers from lowest to highest. The last unit (i.e., the most expensive generation unit) accepted to satisfy demand (marginal unit) determines the uniform price paid to all firms providing electricity in that hour.[17]

[17] For a detailed description of the current Alberta forward market, refer to MSA (2022).

We use Alberta for four main reasons: First, it is an energy-only market,[18] allowing us to restrict the strategic behavior of the firms to energy generation and abstract from other factors like capacity markets.[19] Second, Alberta is an ideal setting to analyze market power because the exercise of market power is not forbidden,[20] so we can study how openly strategic firms react to the different incentives offered by the regulator. Third, each hour has a uniform spot price for all generators, which allows us to isolate the policy effect by a single price measure. Fourth, Alberta has recently used tenders and CPs to promote renewable energy sources.[21] Although we use Alberta, the results derived from our model can be extrapolated to a more general energy-only setting (e.g., markets in Australia, New Zealand, and Texas).

Table 1.1 summarizes Alberta's market structure for 2018.[22] The hourly average market-clearing price in 2018 was $50.35 per MWh, which had its peak reaching the upper bound of the market price ($999.99 per MWh), and its lowest value was the lower bound of zero. The internal demand load refers to the total electricity consumption of the province, including industrial load served by onsite generation and losses from transmission and distribution. On average, Alberta consumes 9,741 MWh, which is lower in summer and sees its maximum during winter.

The four largest companies account for approximately 48% of the generation capacity (TransAlta (TA), ATCO, ENMAX, and Capital Power), whereas the fringe (42 small firms plus the Balancing Pool) comprises the remaining 52%. The Balancing Pool was created as an independent entity during the deregulation of the Alberta wholesale electricity market, passing from a highly regulated market to a competitive market. The main duties of the Balancing Pool were to ensure the balance of the transitioning market (e.g., absorbing any excess of power purchase agreements and participating in the spot market). The main tasks of the Balancing Pool ended by the end of 2020, and as the Balancing Pool does not behave

[18] Energy-only market means that firms are only paid for the energy that they produce; hence there are no capacity payments or other reliability compensations.

[19] In general, in a capacity market setting, firms receive revenues from their electricity generation but also for providing capacity to the market if needed by the regulator, which depending on market design, might increase their incentives to invest in new generation capacity (Brown, 2018).

[20] In May 2017, the Alberta Market Surveillance Administrator (MSA) revoked the Offer Behaviour Enforcement Guidelines that allowed firms to engage in strategic generation withholding (MSA, 2011); however, the MSA did not impose an explicit prohibition on this behavior.

[21] Between 2017 and 2019, under the Renewable Electricity Program (REP), Alberta auctioned about 1,350 MW of new wind capacity in three rounds (Hastings-Simon et al., 2022).

[22] Between 2017 and 2018, Alberta launched three competitive renewable procurement auctions. As we aim to analyze the firms' incentives to own renewable and their bidding behavior, we base our model on the 2018 market structure. Additionally, the average spot price in 2018 was higher than in previous years ($50.3/MWh), which may allow us to observe high-demand hours more frequently. Nevertheless, in recent years, the Alberta wholesale electricity market has shown a higher average spot price, reaching $162.5/MWh in 2022, which may warrant an update of the model.

as a strategic firm, we include it in the fringe.

The Herfindahl-Hirschman Index (HHI) is approximately 778, which according to the United States Department of Justice (2010), means that the market is not concentrated and sufficient competition exists. However, evidence suggests that standard concentration metrics are a poor representation of market power in electricity markets (Borenstein et at., 1999), so we still expect to observe strategic behavior regarding market power.[23]

In terms of energy sources, in 2018, coal was the dominant generation source, accounting for 37% of the total market capacity. The second and third most important sources are co-generation and natural gas, with 30% and 17%, respectively. Additionally, in the last panel of Table 1.1, we can see that ENMAX's portfolio is based entirely on natural gas and hydro generation, while TA's portfolio is heavily based on coal. ATCO and Capital Power have relatively more diversified portfolios; although ATCO relies more on co-generation, Capital Power does not own co-generation units. The fringe's primary generation sources are co-generation and coal, but it also owns natural gas and wind plants. As mentioned earlier, the types of assets owned by the firms play a crucial role in their ability to exercise market power and, therefore, to own new renewable capacity.

Table 1.1: Alberta Electricity Market, 2018

Panel A: Market Share of generation Capacity

TransAlta (TA)	ATCO	ENMAX	Capital Power	Fringe
22%	10%	9%	7%	52%

Panel B: Annual Generation Capacity By Technology

Coal	Natural Gas	Cogeneration	Renewables	Other
37%	17%	30%	14%	2%

Panel C: Summary Statistics

	Unit	Mean	Std. Dev.	Min	Max
Internal Demand Load	MWh	9,741	732	7,819	11,697
Marginal Price	$/MWh	50.35	87.4	0	999
Imports	MWh	389	335	0	1,092

Panel D: Firms' Asset Portfolio (MW)

	ATCO	Capital Power	ENMAX	TA	Fringe
Coal	345	503	0	2,350	2,795
Natural Gas	198	465	1,229	0	750
Cogen	1,018	0	0	0	3,191
Hydro	32	0	217	804	58
Wind	0	150	0	396	682
Biomass	0	0	0	0	288

Notes: Cogen offered at $0/MWh, hydro, wind, and biomass are all considered as must-run.

[23] Our model predicts an average of 10% higher spot prices than a perfect competition setting, ignoring dynamic costs.

1.4.2 Data

For calibration purposes, hourly data is collected from the Alberta Electricity System Operator (AESO) from January 1, 2018, to December 31, 2018. This data set includes: quantities offered by each firm for each generating unit and the price they require, import quantities that arise mainly from British Columbia and Saskatchewan, observed offer price and quantities per firm, transmission capacities, observed electricity demand, and the ownership of the different assets. This data allows us to capture the Alberta wholesale electricity market's main features and characterize each strategic firm, including their generation portfolios market behavior. Maximum plant capacities per asset were obtained from Alberta's Market Surveillance Administrator (MSA, 2018)

We do not observe firms' marginal costs of conventional generation, so we need to estimate them. Natural gas and coal prices are among the main factors determining the marginal costs of conventional generation. We obtain the natural gas prices from Alberta's Natural Gas Exchange (NGX) and, for coal, we use data from the U.S. Energy Information Administration for Wyoming's Powder River Basin. Wyoming's Powder River Basin closely reflects the marginal cost estimates of coal units in Alberta (Brown and Olmstead, 2017). Another important factor determining marginal costs is the variable operational and maintenance (O&M) costs. Technology-specific variable O&M costs were collected from Energy Information Administration (EIA, 2013). To adjust the coal prices and variable O&M costs to Canadian dollar, we use the historical USD to CAD exchange rates from the Bank of Canada.

The heat rate determines the conversion from natural gas and coal to one unit of electricity (in MWh). Coal heat rates were obtained from CASA (2004). Likewise, we use natural gas heat rates from Alberta's Market Surveillance Administrator (MSA), the Alberta Utility Commission, and the AESO. Additionally, different assets require specific maintenance periods or face unexpected outages. To obtain more realistic generation estimates, we adjust the capacity by the derated forced outages. The derated forced outage statistics were collected from North American Electric Reliability Corporation (NERC, 2016).

To estimate the market demand in Alberta, we need to control for the hourly temperature. For instance, during extremely cold or hot days, electricity demand may increase substantially due to heating and air conditioned, respectively. We use standard heating and cooling degree days to account for temperature variation in the electricity demand.[24] For this, weather data of British Columbia (Vancouver City), Saskatchewan (Saskatoon), and Alberta (Edmonton and Calgary) are obtained from Environment Canada: Weather Information. We include weather data from British Columbia and Saskatoon because they are the main exporters of electricity to Alberta, so their exports may depend on weather conditions.

1.4.3 Residual Demand

We characterize the inverse demand function faced by generators in Alberta as follows. First, we define the market demand faced by the generators in Alberta as perfectly price-inelastic demand net of price-responsive imports supplied from neighboring provinces, British Columbia (BC) and Saskatchewan (SK). In order to estimate the import supply function, we use a slightly modified version of equation (6) from Brown et al. (2018):

$$\begin{aligned} Q_{jt}^{IM} &= \beta_{0j} + \beta_{1j} p_t + \beta_{2j} Weekday_t + \beta_{3j} Holiday_t + \beta_{4j} ImportCap_{jt} + \\ &\alpha_j h(temp_{jt}) + \sum_{h=1}^{24} w_{hj} Hour_{ht} + \sum_{m=1}^{12} \gamma_{mj} Month_{mt} + \epsilon_{jt} \quad \forall\ j \epsilon \{BC, SK\} \end{aligned} \tag{1.8}$$

where Q_{jt}^{IM} is the quantity imported from province j at time t. The system marginal price is represented by p_t. Weekday represents the day of the week. The variable Holiday is equal to 1 if the day is a holiday in Alberta and zero otherwise. ImportCap is the maximum line capacity from province j. The variable $h(temp_{jt})$ is a non-linear function of the temperatures in BC and SK that follows the heating and cooling degree methodology.[25] The variables Hour and Month represent the hour of day and month, respectively.

Given that the spot prices are endogenous with the import quantities, equation (1.8) is estimated separately for each neighboring region using two-stage least squares (2SLS) estimation. Following Mansur (2007) and Brown et al. (2018), we employ the day-ahead hourly demand forecast as an instrument for the 2SLS estimation. This is a valid instrument because wholesale electricity demand in Alberta is perfectly inelastic. Additionally, the day-

[24] Heating and cooling degree days are relative to a base temperature of 65°F (18°C). When the temperature is below the base temperature (i.e., a heating day), we subtract the base temperature minus the actual temperature. When the temperature is above the base temperature (i.e., cooling day), we subtract the actual temperature minus the base temperature. With this methodology, we can account for temperature variation in the electricity demand.

[25] Heating and cooling degrees variables are approximated using a quadratic function of the average degrees below a threshold (i.e., a commonly used comfortable temperature of 18.33 °C or 65 °F), which are the "heating degrees" (because we need heat to reach the threshold), and average degrees above the threshold that are the "cooling degrees" (because we need air conditioned to get to the threshold). We add these variables because as the hourly temperature deviates from the threshold (in both directions), the demand for energy to maintain a comfortable temperature.

ahead hourly demand forecast only affects imports through its impact on the market price.

With the coefficients of the import supply function, the price-responsive residual demand faced by the four large firms and the fringe can be derived. Equation (1.8) can be rewritten in reduced form as:

$$Q_{jt}^{IM} = \beta_{0j} + \beta_{1j} p_t + \omega X_{jt} + \epsilon_{jt} \;\; \forall \;\; j \epsilon \{BC, SK\} \tag{1.9}$$

where X_{jt} is the vector of controls described above. We construct the market demand by subtracting the estimated price-responsive import supply from the price-inelastic total demand $\bar{Q}_t$.[26]

1.4.4 Marginal Costs

The marginal costs are calculated for facilities that use coal or natural gas as their fuel source (i.e., conventional energy) at the spot market. In the case of renewables and most cogeneration facilities,[27] the marginal cost is assumed to be zero. The three main factors affecting each unit's marginal cost functions, which are fuel input costs, variable operating and maintenance costs (O&M), and costs related to environmental compliance:

$$MC_t^j = Input_t^j * HR^j + O\&M_t^j + e_t^j \tag{1.10}$$

where MC_{it}^j is the marginal cost of unit j of firm i at time t. Regarding input costs, prices for natural gas and coal are used. The heat rate provides the required input to produce one unit of electricity (in MWh). Therefore, input costs can be represented by the product of input price and HR, which varies by operating plant and technology.

The second factor, O&M, is obtained from the Energy Information Administration (EIA, 2013). The report provides detailed information about each asset's O&M cost. The third factor, environmental compliance, is the cost that firms face regarding the level of pollution that they emit. For 2018, this is based on the Technology Innovation and Emissions Reduction Regulation (Alberta King's Printer, 2019). Large CO_2 emitters (over 100,000 tons of CO_2) obtained emission credits based on the emission intensity of a representative efficient natural gas asset, which was set at 0.375. If large emitters pollute above the representative natural gas asset, they pay \$30 per tonne of CO_2e. Therefore, the marginal environmental cost of firm i of polluting above the threshold is $e_{it} = 30 * (EI_i - 0.375)$, where EI_i are the

[26] Refer to Appendix 4 for a detailed derivation of the residual demand.

[27] A small proportion of cogeneration facilities submit bids greater than zero to the spot market for the electricity generated beyond their on-site needs. In these cases, we calculate each asset's marginal cost and include them in the firm's aggregated marginal cost function for generation based on natural gas.

emissions intensities of firm i.[28]

Outages are another important factor to consider when calculating marginal costs. Similarly to Bushnell et al. (2008), we adjust the maximum capacity of the plants by the probability of outages in a given year to yield an expected available capacity. This factor is obtained from NERC (2016). Likewise, a minimum stable generation (MSG) is required for fossil-burning-based facilities. This MSG implies that facilities must reach a certain level of generation in order to maintain reliable combustion conditions. Following Brown et al. (2018), we set MSG = 35% for coal-based facilities. This means these plants must produce at least 35% of their (adjusted) maximum capacity to maintain reliable combustion and satisfy engineering constraints. In our case, facilities using natural gas do not have this constraint.

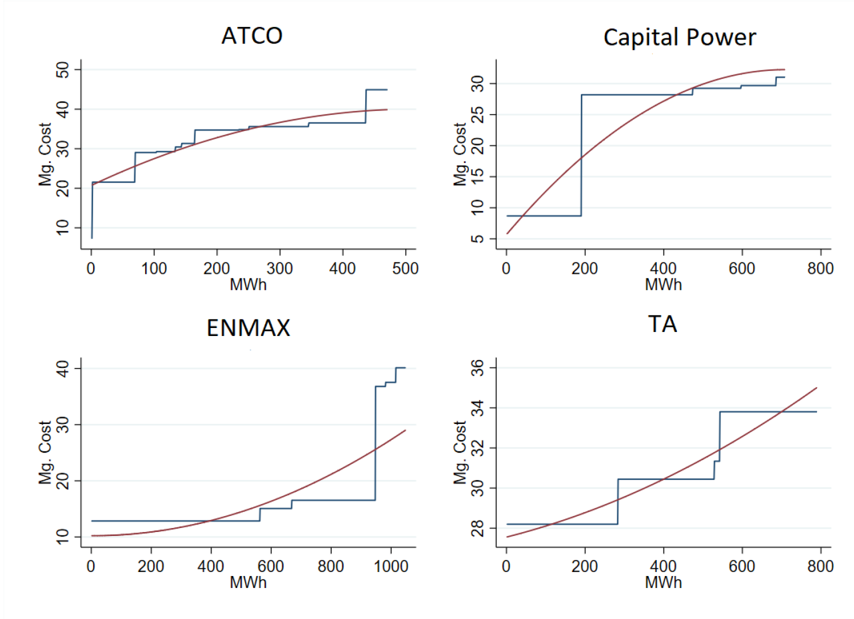
We use the asset-specific marginal cost to estimate each cluster's firm-level continuous marginal cost function. To do this, we aggregate each firm asset-specific marginal cost in ascending order and fit the curve to a quadratic non-decreasing smooth function. Figure 1.1 shows an example of the marginal cost functions for the four strategic firms and their respective fitted quadratic functions.[29] The blue lines represent the original marginal costs, while the red lines represent the quadratic approximations. Our approximations present R^2 of 85%, 78%, 60%, and 89% for ATCO, CP, ENMAX, and TA, respectively. In the case of ENMAX, the low R^2 is driven by the upper right-hand side portion of the marginal cost function because it has a few very expensive assets that would only generate electricity during extremely high hours of the year. While this is not optimal, it is unlikely to affect our main results.

Note that dynamic costs, such as ramping and start-up costs, are not considered because we assume a constant MSG. Therefore, coal assets are always producing at least 35% of capacity, while we abstract from such costs for natural gas assets. We assume there are not extra costs for producing at or close to maximum capacity.

[28] For more detailed information on the marginal environmental cost, refer to Brown et al. (2018).

[29] Refer to Appendix 3 for a graphical representation of the average marginal cost functions per firm across all clusters.

Figure 1.1: Cluster #17 Marginal Cost Functions



Notes: The red lines represent the fitted quadratic functions. The blue lines represent the step-wise marginal cost functions.

1.4.5 Numerical Model

This subsection presents the theoretical model adapted to the Alberta wholesale electricity market with four strategic firms plus a fringe. As we solve the model by backward induction, we start with the third stage, and continue with the second and first stages. In the first and second stages, we set the maximization problems for each firm and we lay out the main predictions derived from our model in these stages. Appendix 1 provides a detailed mathematical derivation of the spot-forward market model. Subsequently, we describe our approach to solve the procurement auction and present our main predictions. We finish with a description of the general characteristics of the simulation model.

In our model, $N = 5$ firms (four strategic firms and a price-taking fringe) compete to supply electricity over $t = 1, 2, ..., 8760$ (the number of hours in 2018). We consider a three-stage game. In the first stage, firms participate in a one-time winner-takes-all renewable procurement auction to obtain the rights to build and operate a renewable plant of capacity $R \geq 0$. In the second stage, firms make their forward contracting decisions q_{it}^{f} at a price p_{it}^{f}. In the third stage, taking the results of the previous stages as given, firms simultaneously choose their conventional spot market quantities q_{it}^{conv}. We formulate this three-stage game as an equilibrium problem with equilibrium constraints (EPEC), which is further described in subsection 1.4.5.4.

1.4.5.1 Third Stage: Spot Market

At this stage, each firm has a certain level of must-run generation $q_{it}^{MR} \geq 0$ with zero marginal cost, and conventional generation q_{it}^{conv} with production cost $C_{it}(q_{it}^{con})$.[30] Firms cannot produce conventional generation above their maximum capacities $q_{it}^{max\,conv}$ and below their minimum stable generation $q_{it}^{MSG} \geq 0$, which represent the necessary lower bound for the safe function of coal plants. The inverse residual demand in the spot market is denoted by $P_t(Q_t)$.

In the third stage, taking the forward contract levels and prices as given, each firm $i = 1, 2, 3, 4, 5$ choose q_{it}^{conv} to maximize equation (1.1) subject to the upper and lower bounds of conventional generation:

$$q_{it}^{max\,conv} \geq q_{it}^{conv} \quad : \quad \lambda_{it} \tag{1.11}$$

$$q_{it}^{conv} \geq q_{it}^{MSG} \quad : \quad \psi_{it}, \tag{1.12}$$

where λ_{it} and ψ_{it} are the Lagrangian multipliers of the upper and lower bounds, respectively. Each strategic firm $i = 1, 2, 3, 4$ solves for its optimal output, which satisfies the following complementarity conditions:[31]

$$P_t(Q_t) + P_t^{'}(Q_t)\left[q_{it}^{conv} + q_{it}^{MR} - q_{it}^{f}\right] - C_{it}^{'}(q_{it}^{conv}) - \lambda_{it} + \psi_{it} = 0 \tag{1.13}$$

$$q_{it}^{max\,conv} \geq q_{it}^{conv} \;\perp\; \lambda_{it} \geq 0, \; and \; q_{it}^{conv} \geq q_{it}^{MSG} \;\perp\; \psi_{it} \geq 0 \tag{1.14}$$

We assume that the price-taker fringe cannot sign forward contracts, so the first order condition (1.13) becomes $P_t(Q_t) - C_{ft}'(q_{ft}^{conv}) - \lambda_{ft} + \psi_{ft} = 0$, while the complementarity conditions in (1.14) are analogous for the fringe. In the second stage (forward contracts), each firm aims to maximize its profit by choosing its forward market quantity, q_{it}^{f}, taking into account its impact on the subsequent spot market equilibrium.

Based on this formulation of the third stage and following Brown and Eckert (2019), there are four main hypotheses that we aim to analyze in equilibrium: The first is that the addition of new renewable capacity under a fixed-price FIT leads to a lower price and

[30] For simplicity, conventional generation also includes other types of generation, such as hydro and biomass, that present marginal costs greater than zero. The share of these extra units is less than 4% in 2018 for Alberta, which is unlikely to affect the results significantly.

[31] Complementarity conditions are a mathematical programming approach to estimate the model (instead of an econometric approach). This mathematical method is more appropriate in our setting due to the complexity of our model. Nonetheless, Su and Judd (2012) show that the mathematical programming approach yields the same parameters as the econometric approach.

higher overall output than under a premium-price FiT. In their theoretical model, Brown and Eckert (2019) explain that under a premium-price FiT, firms with market power are incentivized to withhold production from their conventional generation units to mitigate the price-reducing impact of renewables. This leads to higher prices (which affects their conventional and renewable output) and lower overall output versus a setting with a fixed-price FiT.

Second, the results depend on who owns the new renewable capacity under a premium-price FiT. Further, the firm awarded the new renewable capacity decreases its conventional generation relatively more than in the scenarios where other firms own the new capacity. Under this CP, the new capacity is compensated by market prices, so owning the new capacity increases the incentives for firms to decrease their conventional generation. This is because by reducing their conventional generation, they increase the price paid to their spot market output, which includes their new renewable capacity and conventional generation.

Third, previous studies have found that market power may reduce emissions compared to competitive markets or lower levels of market power (Mansur, 2007; Genc and Reynolds, 2019). Therefore, under a premium-price FiT, we expect a relatively greater decrease in overall CO_2 emissions compared to a setting with a premium-price FiT. This greater decrease in overall CO_2 emissions is because conventional generation is expected to be lower in a setting with a premium-price FiT (due to the strategic incentives to withhold conventional capacity to increase prices).

Fourth, we expect a fixed-price FiT to be cheaper for the regulator than a premium-price FiT. This is due to the design of the fixed-price FiT that we are empirically analyzing. In our empirical model, the regulator pays the firm the difference between the equilibrium spot price and the fixed prices agreed in the auction, which may lead to positive or negative transfers. A negative transfer arises when the equilibrium spot price is above the fixed price agreed on the auction. In this case, the firm transfers the difference to the regulator, which decreases the policy's overall cost. The probability of observing negative transfers increases as the fixed price agreed on the auction decreases. We expect that the competitive bidding behavior of firms at the auction stage leads to a sufficiently low fixed price for the fixed-price FiT to be cheaper than the premium-price FiT.

1.4.5.2 Second Stage: Forward Contracts

In the second stage, each firm chooses its forward market quantity, q_{it}^{f}, to maximize its profit, taking into account its impact on the subsequent spot market equilibrium. Let $q_{it}^{max\,f}$ be the maximum forward position for firm $i = 1, 2, 3, 4$ in period $t = 1, 2, ..., 8760$.[32] Each firm's second-stage forward contracting problem can be represented as a mathematical program with equilibrium constraints (MPEC). This means that we treat the above spot-market optimality conditions (1.13) and (1.14) as equilibrium constraints in their second-stage problem:

$$\underset{q_{it}^{f}}{MAX} \quad P_t(Q_t)\left[q_{it}^{conv} + q_{it}^{MR}\right] - C_{it}(q_{it}^{conv}) + \overline{P_{it}}\delta\theta_{it}R_i + \left[P_t(Q_t) + m_i^{min}\right](1-\delta)\theta_{it}R_i \tag{1.15}$$

subject to the maximum capacity of forward contracts (i.e., $q_{it}^{max\,f} \geq q_{it}^{f}$), and constraints (1.13) and (1.14). Recall that we employ the perfect arbitrage assumption where the forward price is equal to the expected value of the current spot price. This assumption removes the forward contract term directly from the profit function. Equation (1.15) (including the forward contract constraints and constraints (1.13) and (1.14)) constitute each firm's MPEC. Following Xian et al. (2004), we can unify all MPECs into a EPEC, which solves every endogenous variable simultaneously for each firm $i = 1, 2, 3, 4, 5$, and period $t = 1, 2, ..., 8760$.

Based on this formulation and the theoretical foundation described in section 1.3.2, we expect that under a fixed-price FiT, the equilibrium level of forward contracts signed by the firms decreases. This is because adding renewable energy to the market, compensated at a fixed rate, affects all firms equally through its impact on the residual demand (this can be thought of as analogous to an inward shift of the spot market demand). As the conventional generation sold at the spot market decreases, the strategic effect of forward contracts weakens (less room for the rival's spot quantity to decrease), decreasing the incentives to sign forward contracts.

Additionally, under a premium-price FiT, we expect an increase in the equilibrium level of forward contracts for the firm that owns the new capacity. This arises because the firm that owns the new renewable capacity has more output exposed to wholesale prices (because now its renewable and conventional generation are paid the spot price). As a result, the strategic benefit of reducing its rival's output (which increases spot prices) by expanding its

[32] Forward contract maximum capacities are defined as the sum of the firm's conventional and must-run capacities, so we restrict forward contracts to be at or below the firm's maximum available capacity.

forward quantity results in a relatively higher benefit for the firm.

1.4.5.3 First Stage: Renewable Procurement Auction

In the first stage, the regulator organizes a one-time winner-takes-all renewable auction to procure renewable capacity $R > 0$. The auction winner obtains the rights to build the renewable capacity and must incur a fixed investment cost, $F > 0$, which is equal to all firms and common knowledge. To participate in the procurement auction, each firm decides on a combination of a bid and a technology choice (solar or wind energy). We use the minimum bids defined in section 1.3.3 to search for the pure-strategy Nash Equilibria (PSNE), where each firm's bid/technology combination must be a best response to its rival's bid/technology combination.

To estimate the minimum bids described in section 1.3.3, we allocate the new renewable capacity to one firm under one CP at a time and store the equilibrium outcomes of the forward-spot market stages of the model. With this information, we obtain the firms' profits in each scenario, which allows us to calculate each firm's minimum bids. For instance, under a premium-price FiT, we allocate the new capacity to firm i and characterize the equilibrium price and quantities in the model's forward-spot market stages (which provides us with the profit values needed for equations (1.6) and (1.7)). With this information, we calculate firm's i m_{ij}^{min}, that makes it indifferent between winning and letting firm j win, with $i, j = 1, 2, 3, 4$ and $i \neq j$. Subsequently, we allocate the new capacity to the next firm and perform the same analysis until we have all bids for every possible scenario.

Once we obtain all possible minimum bids for each CP, we search for the non-weakly dominated pure-strategy Nash equilibria (PSNE), where each firm's bid/technology combination must be a best response to its rival's bid/technology combination. We focus on non-weakly dominated PSNE primarily because it allows us to restrict the possible firm's bid/technology combination at or above the minimum bids. The intuition behind this restriction is that the firm is worse off by bidding below its minimum bid because if it wins the auction, it obtains negative profits. In contrast, if it fails to win the auction, it is indifferent between bidding below or at the minimum bid. This equilibrium refinement does not affect the auction winner, our primary focus.

With this approach, we expect that in equilibrium different technologies will be awarded under each CP. Under a fixed-price FiT, we expect wind energy to be awarded because of its lower impact on the spot price during peak hours. These results' intuition follows the fact that wind and solar outputs are assumed to have zero marginal cost and are always called upon to supply electricity. These features put downward pressure on the equilibrium spot price (because cheaper generation is added to the market), and the magnitude of this downward pressure depends on the generation profile of each renewable technology. Nevertheless, independent of the renewable technology, the equilibrium spot price decreases, which leads to lower conventional spot profits for the firms.

Wind energy peaks its production at night when demand and prices are relatively low (off-peak hours), while solar energy produces more during daytime-peak hours when demand and prices are high. Therefore, the equilibrium spot price decrease is expected to be greater with solar energy, leading to a greater decrease in conventional spot profits for the firms. So firms will choose the renewable technology that minimizes the decrease of their conventional spot profits, in this case, wind energy.

During high-demand hours all firms produce more conventional output at a higher marginal cost. As solar generation peaks during high-demand hours, the reduction in conventional generation, and therefore in marginal cost, is greater when solar capacity is awarded. As mentioned above, the equilibrium spot price is expected to decrease more with solar energy; however, under a premium-price FiT, withholding conventional generation to increase the equilibrium spot price (i.e., exercise of market power) affects the remuneration received for the conventional output but also for the new renewable output. This differs from under a fixed-price FiT where the remuneration for the new renewable output is fixed. This means that having more renewable output during these peak hours gives firms more flexibility to exercise market power and increase their profits from conventional and renewable output. Therefore, we expect solar capacity to be awarded under a premium-price FiT.

1.4.5.4 Simulation Model

As described above, we model a single procurement auction for renewable capacity at the beginning of the year, and forward and spot market stages for each hour of a representative year, 2018 (8760 hours). To solve the model, we set each firm's optimization problem as a mathematical program with equilibrium constraints (MPEC). In our setting, an MPEC means we include the equilibrium conditions from the third stage (spot market) as additional constraints for the firm's second-stage (forward market) problem.[33] Once we define each firm's MPEC, following Xian et al. (2004), we can unify them into a single equilibrium problem with equilibrium constraints (EPEC), which solves every endogenous variable si-

[33] Refer to Appendix 1 for a detailed mathematical derivation of the model.

multaneously for each firm and period $t = 1, 2, ..., 8760$. To estimate the EPEC, we use the software GAMS.

Following Reguant (2019), we use the k-means algorithm for computational tractability to reduce the data to a smaller representative sample. This allows us to group the 8,760 hours of a year to a handful of representative clusters, significantly decreasing the computational time needed to run the model. We choose 30 clusters of observations, but our results are robust to a different number of clusters. Appendix 2 shows the correlation matrices for the entire and clustered data. The k-means algorithm groups hours based on observable characteristics. We use hourly market supply, the total capacity available, imports, must-run generation, and marginal price to group the hours. The selection of these variables allows us to replicate a representative sub-sample of broader market conditions while decreasing the dimensionality of the data. We use the cluster average to run our model, which allows every hour to contribute to the analysis. Note that averages might incur temporal smoothing, decreasing the possibility of observing very high peak and low off-peak demand hours (Green et al., 2014).

Given that an EPEC contains a set of MPECs with non-convex constraints, we may encounter multiple equilibria depending on the starting value of our endogenous variables (Xian et al., 2004; Hu and Ralph, 2007; Yao et al., 2008). To maximize the probability of obtaining all possible equilibria, we run our model with 1,000 different starting values for all endogenous variables in each cluster, finding multiple optimal results. To choose among the different optimal results, we use the "most common criteria," where we select the most repeated feasible equilibrium for each scenario. The existence of multiple equilibria makes the comparison among scenarios more challenging. However, the most common result (among the feasible optimal solutions) arises between 53% and 64% of the time, depending on the scenario. In comparison, the second most common result arises between 12% and 17% of the time. This means that our results capture the most likely outcomes for each scenario. Additionally, in most cases, the second most common result only differs by a small percentage (less than 1%) compared to the first most common results.

Finally, we assume a fixed investment cost $F > 0$ to build the new renewable capacity. According to the U.S. Energy Information Administration (EIA), in 2018, the construction cost per KW for solar and wind was US\$1,848 and US\$1,382, respectively. We based our estimation on an average US-CAD exchange rate of 1.269 and a project's expected life of 25 and 20 years (estimated by the National Renewable Energy Laboratory, NREL) for wind and solar, respectively. This yield an annualized fixed cost, F, of about CA\$79 million and CAD\$84 million for wind and solar.[34] To isolate the effect of the CPs, we set $F = 80$ million for both firms, which we relax in Appendix 8.

To estimate the capacity factors for Alberta wind farms, we use the average capacity factor of the 20 wind farms operating in the province in 2018, which yields about 33%. Regarding the solar capacity factor, we use the PVWatts Calculator tool of the National Renewable Energy Laboratory (NREL), which gives an average capacity factor of 14.2%. Setting the renewable capacity auctioned in the model, R_i, to 900 MW,[35] yields approximately 2.59 and 1.12 million MWh of annual production for wind and solar, respectively. The main analysis considers equal aggregated output of 2.5 million MWh, which is relaxed in Appendix 9. Based on an aggregated output of 2.5 million MWh and a fixed cost of CAD80 million, the average fixed cost is \$30.9/MWh.

1.5 Results

In this section, we start with the model calibration results, representing how our model performs compared to the observed outcomes in 2018. Then, we present the results from each CP separately, assuming equal aggregated renewable output and fixed cost F. Following the main analysis, we consider an extension with exogenously increased electricity demand. This allows us to analyze the effects during high-demand hours when firms have more incentives and the ability to exercise market power. Throughout this section, we focus our analysis on the spot market outcomes, but the results of the forward market stage are presented in Appendix 6. Once we know the outcomes of the forward-spot model, we present the results of the auction stage. Finally, using the equilibrium outcome of the three-stage model, we estimate the pollution effects and the policy costs.

1.5.1 Model Calibration

The calibration results are presented in Table 1.2. Our model estimates an average spot price of \$31/MWh, while the observed average price was \$50/MWh. This difference can be explained by the infrequently extremely high price hours that our model does not predict.[36]

[34] The estimation of the annualized fixed costs for wind and solar are $\frac{(1{,}848 \cdot 1{,}000 \cdot 900) \cdot 1.269}{25}$ and $\frac{(1{,}382 \cdot 1{,}000 \cdot 900) \cdot 1.269}{20}$, respectively.

[35] We chose 900 MW because it was approximately the capacity auctioned in Alberta's first two rounds of the Renewable Electricity Program (Hastings-Simon et al., 2022). Nevertheless, our results are robust to changing the new capacity to 600 MW and 1,200 MW. Alberta's renewable capacity in 2018 was about 2,700 MW, and the total generating capacity was 16,106 MW (MSA, 2018).

[36] In 2018, Alberta had approximately 1.2% of hours with wholesale prices above \$499/MWh. For comparison, the Ontario electricity market studied by Genc and Reynolds (2019) exhibited a maximum price of

This occurs for two main factors: first, due to the complexity of the EPEC approach, we use linear residual demand, which tends to overestimate the level of imports putting downward pressure on prices, especially during high-demand hours. Second, we use the average of the observations within each cluster, which decreases the probability of extreme prices by temporarily smoothing our sample. While this is not ideal, our predicted median price of \$32/MWh closely matches the observed median price of \$33/MWh.

Regarding the supply by firms within Alberta, our model predicts an hourly average of 8,523 MWh, about 300 MWh lower than the observed value. Our model may overestimate imports, impacting our forecast outcomes for the five firms: ATCO, Capital Power, ENMAX, TA, and the fringe. On average, our model underestimates these firms' observed outcomes, except for ENMAX.[37] Note that the firm's outcomes include conventional generation, must-run, and MSG.

Despite the empirical challenges, our model can still inform us about our outcomes of interest and the theoretical predictions of section 1.4.5. This is because our model captures the overall structure of the Alberta wholesale electricity market, including the relative importance of each firm and their asset and cost structure. Additionally, as our model does not observe extremely high-demand hours (i.e., the hours when the exercise of market power is most profitable and likely to occur), it underestimates firms' equilibrium output and spot price, so that we can consider the effects found as a lower bound.

Table 1.2: Model Calibration

Variable	Observed		Forecast	
	Mean	Median	Mean	Median
Price	50	33	31	32
Total Supply	8,869	8,901	8,523	8,645
ATCO	836	822	744	738
Capital Power	769	789	643	652
ENMAX	808	846	970	1,001
TA	841	854	735	699
FRINGE	5,615	5,575	5,431	5,469

Notes: Price is presented in dollars per MWh, and all other variables in MWh.

1.5.2 Fixed-Price FiT

Table 1.3 shows the average price and conventional generation results when 900 MW of new renewable capacity is added to the market. This means that, on average, the new capacity adds about 300 MWh of wind and solar output, which reflects an increase of slightly

\$297/MWh.

[37] The marginal cost estimation for ENMAX underestimates the actual value for units close to the maximum capacity (recall Figure 1.1), which explains our model's forecast.

more than 10% of renewable energy capacity in the market. The first column of Table 1.3 shows the different scenarios, starting with the baseline, where no new renewable capacity is added, followed by the cases when wind and solar capacities are added. Given that the effects of adding new capacity under a fixed-price FiT are independent of who owns this new capacity, we show the results for one case in each scenario. The average price in the baseline is \$31.2/MWh, and Alberta's total supply is 8,523 MWh. ATCO produces, on average, 161 MWh of conventional energy, while Capital Power, ENMAX, TA, and the fringe produce 424 MWh, 921 MWh, 114 MWh, and 1,408 MWh, respectively.

The effects of adding new renewable capacity under a fixed-price FiT are very similar for wind and solar. When the new renewable capacity is allocated to any firm, the price decreases to \$30.0/MWh and \$30.1/MWh, and total production within Alberta increases to 8,526 MWh for wind and 8,525 MWh for solar (including renewable generation). All firms decrease their conventional generation, given the lower residual demand. The similarity of the wind and solar effects may be explained by the temporal smoothing issue described in section 1.4.5.4. This issue decreases the possibility of observing high peak and low off-peak demand hours, which scales down the effects of the different generation profiles (e.g., wind produces more at night and solar during the day).

Forward contracts allow firms to reduce their exposure to spot price volatility by buying or selling future spot market commitments at a fixed price. Table 1.10 in Appendix 5 shows that the forward contracts follow the expected patterns described in section 1.4.5. According to Table 1.10, the equilibrium level of forward contracts signed by the firms decreases in all cases. This shows that adding renewable energy to the market compensated by a fixed rate affects all firms equally through its impact on the residual demand (this can be thought of as analogous to an inward shift of the spot market demand). As the conventional generation sold at the spot market decreases, the strategic effect of forward contracts weakens (less room for the rival's spot quantity to decrease), decreasing the incentives to sign forward contracts.

Table 1.3: Predicted Average Price and Conventional Spot Generation, Fixed-Price FiT

Scenario	Price	Market Output	ATCO	Capital Power	ENMAX	TA	Fringe
Baseline	31.2	8,523	161	424	921	114	1,408
Wind Capacity is Awarded	30.0	8,526	132	383	881	76	1,262
Solar Capacity is Awarded	30.1	8,525	137	380	886	60	1,270

Notes: Prices are dollars per MWh. Output is presented in MWh. The additional renewable capacity is set at 900MW. Results based on equal aggregated output and fixed cost.

1.5.3 Premium-Price FiT

Table 1.4 shows the results of adding 900 MW of renewable capacity compensated under a premium-price FiT. The table is divided into three panels that represent the baseline scenario (Panel A), the scenario when wind capacity is awarded to the firms (Panel B), and the scenario when solar capacity is awarded to the firms (Panel C). For example, in Table 4, when the new wind capacity (Panel B) is allocated to ATCO, the prices decrease to \$30.2/MWh, and total production within Alberta increases to 8,525 MWh. ATCO decreases its conventional generation to 107 MWh, and Capital Power, ENMAX, TA, and the fringe produce 387 MWh, 885 MWh, 76 MWh, and 1,276 MWh, respectively. Contrarily to the fixed price setting, under a premium-price FiT, the equilibrium outcomes depend on which firm owns the new renewable capacity. This is because firms' incentives and ability to exercise market power varies with their generation portfolio and cost structure.

As expected, price decreases, and overall output supplied within Alberta increases no matter who owns this new capacity. However, the price (output) is always higher (lower) than under a fixed-price FiT, except when the renewable capacity is allocated to the price-taker fringe, which has no incentives to behave strategically. This suggests that firms exercise market power by withholding conventional output to increase prices. Further, the main difference with a fixed-price FiT is that ownership matters here. Firms behave differently depending on who owns this new capacity.

The price is lowest when TA owns the new wind and solar capacity (aside from when the fringe owns the new capacity). This shows that TA has relatively lower incentives or is less capable of withholding production. In fact, in the baseline, TA presents the lowest conventional output with 114 MWh, which shows that it has relatively limited room to exercise market power. In addition, as Figure 1.2 in Appendix 3 shows, TA has the highest starting marginal cost, which explains its relatively low conventional output in the spot market, hence its minor participation in the spot market. Additionally, as Table 1.1 shows, coal assets represent a significant share of TA's asset portfolio, limiting its ability to exercise market power.

When ENMAX owns the new capacity, it keeps prices relatively higher than in other scenarios. This suggests that the flexibility of ENMAX's portfolio and its relatively lower marginal cost allows it to influence the price relatively more by withholding production. Furthermore, the average production of ENMAX is 57% of all conventional spot output from the strategic firms, which facilitates its ability to influence the spot price due to its dominant position. Table 1.11 in Appendix 5 shows that the forward contracts follow the expected patterns.

The results of Table 1.4 support the second hypothesis from section 1.4.5 (i.e., the firm awarded the new renewable capacity decreases its conventional generation relatively more than in the scenarios where other firms own the new capacity). This is because the new renewable capacity is subject to market prices. When firms own it, they have relatively more incentives to withhold conventional production to increase prices because this price increase affects both their conventional and new renewable output.

Table 1.4: Predicted Average Price and Conventional Spot Generation, Premium-Price FiT

Panel A: Baseline							
	Price	Mkt. Output	ATCO	Capital Power	ENMAX	TA	Fringe
	31.2	8,523	161	424	921	114	1,408
Panel B: Wind Capacity Awarded							
Awarded Firm	Price	Total Output	ATCO	Capital Power	ENMAX	TA	Fringe
ATCO	30.2	8,525	107	387	885	79	1,276
Capital Power	30.4	8,525	141	311	895	87	1,300
ENMAX	30.7	8,524	150	409	730	101	1,342
TA	30.1	8,525	135	387	886	53	1,273
Fringe	30.1	8,526	132	383	881	76	1,262
Panel C: Solar Capacity Awarded							
Awarded Firm	Price	Mkt. Output	ATCO	Capital Power	ENMAX	TA	Fringe
ATCO	30.3	8,525	92	389	888	71	1,293
Capital Power	30.5	8,525	146	293	894	83	1,317
ENMAX	30.8	8,524	152	411	714	101	1,353
TA	30.2	8,525	141	389	888	26	1,290
Fringe	30.1	8,525	137	380	886	60	1,270

Notes: Prices are dollars per MWh. Output is presented in MWh. The additional renewable capacity is set at 900MW. Results based on equal aggregated output and fixed cost.

In general, solar energy yields slightly higher prices than wind energy. During high-demand hours all firms produce more conventional output at a higher marginal cost. As solar generation peaks during high-demand hours, the reduction in conventional generation, and therefore in marginal cost, is greater when solar capacity is awarded. In our setting, the firm that receives the renewable capacity becomes a lower marginal cost firm during high-demand hours. Under a premium-price FiT, withholding conventional generation to increase the equilibrium spot price (i.e., exercise of market power) affects the remuneration received for the conventional output but also for the new renewable output. As a result, the firm awarded the renewable capacity finds it optimal to reduce its conventional output by more. This differs from under a fixed-price FiT, where the remuneration for the new renewable output is fixed. This means that having more renewable output during these peak hours provides the firms more flexibility to exercise market power and increase their profits from conventional and renewable output. Alternatively, it may be the case that we are underestimating the effects of solar capacity because high-demand hours are underrepresented in our model (recall section 1.4.5.4).

1.5.4 Auction Stage

Now, we analyze the equilibrium outcome of the auction stage. To simplify the notation, every bid is defined as dollars per megawatt hour, \$/MWh. First, we start with the case when the new renewable output is compensated by a fixed-price FiT, and continue with the case under a premium-price FiT. Note that we use an equilibrium refinement to focus on non-weakly dominated pure strategy NE. Under this equilibrium refinement, we restrict our equilibrium to bids at or above their minimum amounts described in section 1.3.3. Ultimately, we are interested in identifying the auction winner, and this equilibrium refinement does not affect this outcome.

Fixed-Price FiT

As shown in section 1.5.2, under a fixed-price FiT the equilibrium outcomes do not depend on who owns the new capacity. This means that, for a given renewable energy technology, the profits of a firm are the same independent of who owns the new capacity. However, the equilibrium outcomes slightly differ when comparing across renewable technologies (recall Table 1.3). This means that the second term in the right-hand side of equation (1.6) is zero (i.e., $\Pi^{conv}_{it,Ri} - \Pi^{conv}_{it,Rj} = 0$) when comparing the same renewable technology and non-zero when comparing across technologies. For instance, the conventional profits of firm i when it owns wind capacity are different to its profits when one of its rivals own solar capacity (i.e., $\Pi^{conv}_{it,Ri\,wind} - \Pi^{conv}_{it,Rj\,solar} \neq 0$), while firm i's conventional profits are the same when it owns wind capacity or one of its rivals own wind capacity ($\Pi^{conv}_{it,Ri\,wind} - \Pi^{conv}_{it,Rj\,wind} = 0$). This will have important implications for the minimum bids of the firms and the equilibrium of the auction stage.

Note that if we consider only one renewable technology, $\overline{P}^{min}_{ij}$ is equal to the average fixed cost of \$30.9/MWh (because $\Pi^{conv}_{it,Ri} - \Pi^{conv}_{it,Rj} = 0$ in equation (1.6)) and the winner would be selected randomly. However, comparing across technologies leads to different minimum bids depending on what renewable technology firm i or its rivals own. Following section 1.4.5.4, assuming equal fixed cost and aggregated output, the average fixed cost, \$30.9/MWh, is the same for all firms when comparing the same renewable technology. When we compare across technologies, the minimum bids described by equation (1.6) are always lower for wind capacity than for solar capacity. This means that bidding for wind is preferred over bidding for solar because firms can profitably undercut a rival bidding for solar with a lower bid for wind.

The above analysis leads to a non-weakly dominated pure strategy NE where all firms bid for wind capacity at their average fixed cost and the winner is randomly selected. The winner earns zero profit on the renewable facility. The intuition behind this NE is that the firm is strictly worse off by unilaterally deviating downwards because it wins the auction, obtaining negative profits. Similarly, by unilaterally deviating to a higher bid, the firm still earns zero payoffs and has no option to win the auction. Consequently, there are no profitable unilateral deviations. No other higher bid leads to a non-weakly dominated pure strategy NE because at least one firm is incentivized to undercut its rival if the lowest bid is above the average fixed cost of renewable capacity. This reflects the Bertrand-like competition at this stage.[38]

Premium-Price FiT

We use the minimum dollar amount, m_{ij}^{min}, defined in equation (1.7) that makes firm i indifferent between winning the new capacity and letting rival j win, to characterize the relevant non-weakly dominated pure strategy NE in our setting.[39] One of the main differences under a premium-price FiT is that the equilibrium outcomes in the forward-spot market depend on who owns the new renewable capacity.

Table 1.18 in Appendix 6 shows that the only possible set of non-weakly dominated pure strategy NE is for TA to win the auction bidding for solar capacity. In this set of NE, TA bids \$2.11, ATCO bids \$2.12 for wind capacity, Capital Power bids at or above its minimum bids for either solar or wind capacity (i.e., $\geq$2.78 for wind and $\geq$3.03 for solar capacity). ENMAX bids at or above its minimum bids for either solar or wind capacity (i.e., $\geq$5.45 for wind and $\geq$6.69 for solar capacity). In this case, no firm can unilaterally improve its profits by deviating from its bid/technology combination.

[38]Note that when we relax the assumption of equal fixed cost and aggregated renewable output, the average fixed cost of solar increases. This means that, in this setting, we arrive to the same non-weakly dominated pure strategy NE where each firm bids the average fixed cost for wind, and the winner is randomly selected.

[39]Refer to Appendix 6 for a detailed discussion and characterization of the non-weakly dominated pure strategy NE.

Solar capacity is awarded under a premium-price FiT because acquiring the new renewable capacity results in a downward shift of the firm's marginal cost function. Therefore, as solar energy produces more during high-demand hours, the potential for cost saving is greater than wind energy. Additionally, firms can exercise more market power during high-demand hours, increasing their spot profits and incentives to own a renewable source that produces more during these high hours, in this case, solar energy.

Intuitively, we would have expected firms with lower marginal costs and more flexible generation (e.g., ENMAX) to be more likely to win the auction due to their relatively higher capability to exercise market power and increase the profits from the spot market, including the new renewable capacity. However, due to its high marginal cost (recall Figure 1.2) and relatively less flexible generation, TA's participation share in the conventional spot market is low (from Table 1.3, we see that it produces on average 114 MWh or about 3.8% of the total conventional generation at the spot market). This means that an additional 900 MW of renewable generation increases TA's spot output by more than 100%, a relatively greater increase in spot profits than other firms owning the new renewable capacity.

1.5.5 Analysis with Increased Demand

In the previous subsection, we find relatively limited market power, evidenced by the small price effects of renewable capacity expansion. This is consistent with Alberta's observed exercise of market power during 2018, which was relatively lower than in more recent years, like 2021 and 2022. For instance, the average spot prices were \$101.9/MWh and \$162.5/MWh in 2021 and 2022, respectively (AESO, 2022), widely larger than the \$50.3/MWh average observed in 2018. This is why, in this subsection, we exogenously increase the market demand by 15% to investigate the impacts of our model in a setting where market power is more prevalent.

Alberta's maximum internal demand load is 11,697 MWh (recall Table 1.1), which is about 20% above the province's average. Therefore, increasing demand by 15% allows us to analyze the market dynamics during the highest decile of hours. Understanding the market dynamics during these hours is important because a firm's strategic behavior becomes more relevant and profitable when prices are high. We expect an increase in the magnitude of the effects but no changes in their directions. We assume equal aggregated output for both renewable energy sources.

Fixed-Price FiT

Table 1.5 shows the results for the model with a 15% increase in demand under a fixed-price FiT. Naturally, average equilibrium prices and quantities are greater than the ones in the previous sections because the demand is higher. The market is relatively tighter in terms of supply, creating conditions where firms have elevated incentives and the ability to exercise market power. The baseline scenario shows an average price of \$72.1/MWh and an average overall supply within Alberta of $9,761$ MWh. This relatively high price is because firms are producing higher up in their marginal cost curve to cover the elevated demand.

Further, under a fixed-price FiT, price decreases to \$36.7/MWh (approximately 49% reduction) for wind energy and \$60.4/MWh (approximately 16% reduction) for solar energy, compared to the baseline, which evidences the relatively greater impact of wind energy. The big price decrease is because firms lower their conventional generation from assets with relatively high marginal costs along the steeper section of their marginal cost functions. This means that a decrease in conventional generation (which is replaced by zero marginal cost renewable output) leads to a higher decrease in marginal cost, hence equilibrium spot price. The intuition behind the greater effect of wind is similar to section 1.5.2. Note that a 15% demand increase is a linear transformation of our baseline model, so we expected similar patterns with different magnitudes. Table 1.12 in Appendix 5 shows that the forward market results follow the expected patterns.

Table 1.5: Predicted Average Price and Conventional Spot Generation, Fixed-Price FiT with Increased Demand

Scenario	Price	Market Output	ATCO	Capital Power	ENMAX	TA	Fringe
Baseline	72.1	9,761	287	614	1,017	352	1,998
Wind Capacity is Awarded	36.7	9,841	252	564	1,003	351	1,882
Solar Capacity is Awarded	60.4	9,787	273	594	1,015	334	1,950

Notes: Prices are dollars per MWh. Output is presented in MWh. The additional renewable capacity is set at 900MW. Results based on equal aggregated output and fixed cost.

Premium-Price FiT

Table 1.6 shows the results under a premium-price FiT. Under this CP, adding new renewable capacity affects firms' incentives to behave strategically. This strategic behavior yields average prices above those under a fixed-price FiT, except for the fringe that has no incentives to behave strategically. All previous results hold for the case of high-demand hours. Firms reduce their conventional production relatively more when they own the new renewable capacity.

An interesting change in this setting is that under a premium-price FiT during exceptionally high demand hours, TA can exercise relatively more market power than the other firms (recall that in the standard model, ENMAX was the firm that exercised more market power). Table 1.6 shows that the spot price when the new renewable is allocated to TA is \$64.8/MWh and \$69.9/MWh for wind and solar. Two factors can explain this result: first, during hours of high demand, Capital Power and ENMAX produce relatively close to their maximum conventional capacity, where their marginal cost becomes steep. Compared to the baseline scenario, Capital Power and ENMAX are the firms with the lowest increase in conventional generation during these high-demand hours. This suggests that these firms are in the steepest region of their marginal cost curves, closer to their maximum capacities. Second, TA's marginal cost curve is relatively flatter than other firms and still far from its maximum capacity, which increases its relative ability to exercise market power during these high-demand hours. Table 1.13 in Appendix 5 shows that, in general, forward contracts follow the expected patterns.

Table 1.6: Predicted Average Price and Conventional Spot Generation, Premium-Price FiT with Increased Demand

Panel A: Baseline							
	Price	Mkt. Output	ATCO	Capital Power	ENMAX	TA	Fringe
	72.1	9,761	287	614	1,017	352	1,998
Panel B: Wind Capacity Awarded							
Awarded Firm	Price	Total Output	ATCO	Capital Power	ENMAX	TA	Fringe
ATCO	62.3	9,783	194	588	1,005	315	1,892
Capital Power	56.0	9,797	267	426	1,009	370	1,935
ENMAX	59.4	9,790	264	607	772	388	1,969
TA	64.8	9,777	259	590	1,006	226	1,906
Fringe	36.7	9,841	252	564	1,003	351	1,882
Panel C: Solar Capacity Awarded							
Awarded Firm	Price	Total Output	ATCO	Capital Power	ENMAX	TA	Fringe
ATCO	62.8	9,782	240	606	1,015	353	1,947
Capital Power	68.4	9,769	284	523	1,015	346	1,980
ENMAX	69.1	9,768	287	604	922	345	1,989
TA	69.9	9,766	280	612	1,015	272	1,965
Fringe	60.4	9,787	273	594	1,015	334	1,950

Notes: Prices are dollars per MWh. Output is presented in MWh. The additional renewable capacity is set at 900MW. Results based on equal aggregated output and fixed cost.

These results provide insights into how important the firms' structure is to their ability to exercise market power and their incentives to own new renewable capacities. In 2018, Alberta observed wholesale electricity prices above \$70/MWh in 8.5% of the hours. These are the most profitable hours for firms to exercise market power, and, as the literature suggests, these hours play a crucial role in a firm's capacity investment decisions. As our results show, the strategic behavior of the firms is severely affected by the compensation policy used.

Auction Stage

Tables 1.19 to 1.22 in Appendix 7 present the minimum m_{ij}^{min} for each firm when we exogenously increase demand by 15%, and we assume equal aggregated output and fixed cost. An interesting result when analyzing the bidding behavior in a setting with a 15% demand increase is that owning the new renewable capacity becomes so profitable that some firms are willing to submit negative bids (which means they pay the regulator). Therefore, as electricity demand increases, government intervention becomes less necessary.

By analyzing Tables 1.19 to 1.22, we conclude that only one possible set of NE exists: TA wins the auction bidding for wind capacity. In this case, TA bids -\$7.4 for wind capacity, and Capital Power bids -\$7.39 for solar capacity. ATCO bids at or above \$16.41 and \$2.09 for solar and wind capacity, respectively. ENMAX bids at or above -\$7.29 and \$32.4 for solar and wind capacity, respectively.[40]

The winning bid is negative, indicating that government intervention is unnecessary with increased electricity demand. The market incentivizes firms to invest in new renewable energy capacity because it is profitable. An interesting change from the result found in subsection 1.5.4 is that now wind capacity is awarded instead of solar capacity. This result may arise because an increased electricity demand makes more profitable off-peak hours, while the wholesale market cap in the spot price limits peak hours profitability. On the one hand, the profitability of the solar capacity that produces more during peak hours is limited. On the other hand, the profitability of wind capacity that produces during off-peak hours has increased while also producing during peak hours.

1.5.6 Pollution

In this subsection, we quantify the reductions in CO_2 emissions from the equilibria found in the previous subsections for each CP (i.e., wind capacity awarded under a fixed-price FiT and solar capacity awarded to TA under a premium-price FiT).

We estimate the tonnes of CO_2 per MWh produced for each conventional asset (i.e.,

[40] Refer to Appendix 7 for an analysis of the SPNE identification.

coal and natural gas).[41] In the case of coal assets, we multiply the asset-specific heat rate, which indicates the amount of coal (in short tonnes) needed to generate one MWh of electricity, by the amount of CO_2 (in tonnes) per short ton of coal. In the case of natural gas assets, we transform the asset-specific heat rate (i.e., the amount of natural gas in Gigajoule needed to generate one MWh of electricity) from Gigajoule to million British Thermal Units (MMBTU). Then we multiply this by the amount of CO_2 (in tonnes) per million BTU of natural gas. This gives us the tonnes of CO_2 that each asset emits when generating an MWh of electricity.

Table 1.7 shows the annual tonnes of CO_2 reduction in both equilibria.[42] In the baseline, the combined annual emissions of CO_2 is about 56,4 million tonnes, which includes must-run and minimum stable generation. As expected, introducing new renewable capacity decreases CO_2 emissions, given that conventional generation is displaced by renewable generation. Under a fixed-price FiT with wind generation, we observe a total CO_2 reduction of 3.4% throughout the year. Capital Power and TA show the most significant reduction relative to their emissions, with 8.3% and 6.7% of emission reductions, respectively. This is not surprising given these firms' high share of coal assets. The fringe only reduces its emissions by 2.6%, but in absolute terms, it decreases almost 2 million tonnes of CO_2 during the year.

Under a premium-price FiT, when the renewable solar capacity is awarded to TA, we see an overall 3.6% reduction in CO_2 emissions. Again Capital Power and TA are the firms that present the highest reductions, with 7% and 15.2% of their total emissions, respectively. The high reduction in TA's emissions comes from owning the new renewable capacity, so TA reduces its conventional generation relatively more than in other scenarios. In absolute terms, the fringe leads the reduction with slightly more than 2 million tonnes of CO_2 during the year.

[41] Refer to Appendix 9 for a description of these estimations.

[42] Recall that the firm's marginal cost function is approximated by ranking the lowest cost assets to the highest cost assets. This means that we know the order that the assets will be dispatched at any given spot price. This allows us to estimate the total pollution by aggregating the emissions of each dispatched asset.

Table 1.7: Effects of New Renewable Capacity on Carbon Dioxide Emissions

Firm	Baseline (No New Renewables)	Fixed-Price (Wind Capacity)	Premium-Price (Solar Capacity Awarded to TA)
ATCO	3,757,481	-3.6%	-2.7%
Capital Power	2,962,664	-8.3%	-7.0%
ENMAX	2,773,163	-5.2%	-4.4%
TA	4,453,111	-6.7%	-15.2%
FRINGE	42,455,806	-2.6%	-2.2%
TOTAL	56,402,225	-3.4%	-3.6%

Notes: Emissions are presented in annual tonnes of CO_2.

As observed in Table 1.7, the total emission reduction under both CPs is similar. This is because, with equal aggregated output for wind and solar, the aggregated conventional generation displaced is also similar.[43] Still, as the premium-price FiT affects firms' incentives to exercise market power (exacerbated during peak hours), conventional generation is slightly lower than under a fixed-price FiT, leading to a slightly greater total decrease on CO_2 tonnes during the year. These results highlight the importance of identifying the characteristics of the firm awarded the new renewable capacity.

1.5.7 Policy Costs

From a regulator's perspective, an essential aspect of all policies is their cost. In the case of Alberta, the Renewable Energy Program implemented a fixed-price FiT policy called a contract for differences (CFD).[44] Under a CFD, the regulator pays the firm the difference between the fixed price agreed upon in the auction and the actual spot price for every period $t = 1, 2, 3, ..., 8760$, when the spot price is lower than $\overline{P}_i$ (i.e., the regulator pays in the case that $\overline{P}_i - P_t(Q_t) > 0$). However, if $P_t(Q_t) > \overline{P}_i$, the firm gives back the difference to the regulator (i.e., the regulator is paid $(P_t(Q_t) - \overline{P}_i)$). In the case of premium-price FiT, the regulator pays an amount m_i per MWh above market prices independent of the spot price level. In this section, we estimate the cost of each policy evaluated at the equilibria found in the previous analysis. Namely, we evaluate the annual cost of implementing a fixed-price FiT when wind energy is awarded at \$30.9/MWh and the annual cost of implementing a premium-price FiT when solar capacity is awarded to TA at \$2.11/MWh.

To estimate the net cost of a fixed-price FiT (or for the case of Alberta CFD), we calculate the difference between the \$30.9/MWh and the price estimated by the model for

[43] Part of the conventional generation displaced is replaced by imports that come largely from British Columbia and reflect hydroelectric generation.

[44] One of the first jurisdictions to adopt this type of contract in electricity markets was the UK in 2013. Refer to the Energy Act 2013, Chapter 32, for a detailed description.

each cluster ($30.9 - P_t(Q_t)$) for all $t = 1, 2, ..., 30$. Then we multiply this difference by the hourly wind capacity output for each observation within a cluster (note that a negative payment means a transfer from the firm to the regulator). Finally, we add up all payments for each observation across all clusters to obtain an annual cost of $4.1 million. This means that in a year, a fixed-price FiT policy results in a net payment from the regulator to the firms.

Estimating the net cost of a premium-price FiT policy is similar. We use the hourly solar capacity factor (adjusted to be equal to the wind aggregated output) to calculate the hourly solar output and multiplied it by $2.11/MWh for the equilibrium with TA receiving the new capacity. Finally, we add up all hourly transfers to obtain an annual cost of $5.4 million.

These results show that, in our case, a fixed-price FiT is about 24% cheaper for the regulator than a premium-price FiT. Moreover, if prices are consistently high, regulators will generate revenues. Hastings-Simon and Shaffer (2021) estimate that for the case of Alberta, between September 2019 and February 2021, the government made a net gain of about $2 million from the contracts awarded during the Renewable Energy Program.[45] Additionally, in the particular case of Alberta, those firms do not receive the emission credits of the Alberta TIER emissions regulation, which according to the authors, has saved the government about $26 million more. These features add interesting dynamics worth considering for policymakers.

1.6 Conclusion

The share of renewable energy in electricity generation is rapidly increasing, and support policies are still needed in most countries for this growth to succeed. This paper analyzes the effects of adding new renewable energy capacity compensated under a fixed-price FiT or a premium-price FiT. In addition, we study how these effects are sensitive to heterogeneous renewable sources, such as solar and wind energy. We use a three-stage simulation model with data from the Alberta electricity market for 2018. Based on Brown and Eckert (2019), in our model, firms make decisions at the spot market, forward contracts, and the auction stage.

Our findings show that the characteristics of each firm are crucial in the level of market power they can exercise, ultimately affecting the market outcomes. For instance, firms with

[45] Note that Hastings-Simon and Shaffer (2021) analyze a period after 2018, where prices were relatively higher ($54.9/MWh in 2019, $46.7/MWh in 2020, and $101.9/MWh in 2021).

relatively less flexible asset portfolios (e.g., a high share of coal assets) and steeper marginal cost functions exercise less market power at the spot market. Furthermore, our results show that the ability to exercise market power alone does not fully determine the incentives to acquire the new renewable capacity. Other factors, such as the relative change in the spot profits, play an essential role for firms with low shares of total spot generation (e.g., the case of TA).

The strategic behavior under a premium-price FiT is evidenced by a higher reduction in conventional production when the firm owns the new capacity and a smaller reduction when other firms own it. In addition, our model shows that, generally, under a premium-price FiT forward contracts increase when firms own the new capacity and decrease when other firms own it. Nevertheless, when the new capacity is compensated by a fixed-price FiT, forward quantities decrease no matter who owns the new capacity. These findings show the importance of the compensation mechanism of renewable capacity in the forward market.

Our model predicts that wind capacity is awarded under a fixed-price FiT with equal aggregated output, whereas solar capacity is awarded under a premium-price FiT. This is because, under a fixed-price FiT, all firms' conventional spot profits decrease. This reduction is greater during peak hours and is magnified by solar energy (given that it produces more during these hours). Therefore, firms have more incentives to adopt wind energy under a fixed-price FiT. On the other hand, acquiring the new renewable capacity under a premium-price price results in a downward shift of the firm's marginal cost function. Therefore, as solar energy produces more during high-demand hours, the potential for cost saving is greater than for wind energy. Additionally, firms can exercise more market power during high-demand hours, increasing their spot profits and incentives to own a renewable source that produces more during these high hours, in this case, solar energy.

In terms of CO_2 emissions, our model shows that, in equilibrium, they are minimized under a premium-price FiT. This is because TA's portfolio is based on coal units, so when it owns the new solar capacity, the reduction of its conventional output has a greater effect on CO_2 emissions. Further, policy costs are relatively lower under a fixed-price FiT, costing about 24% less than the premium-price FiT.

Our results emphasize the many trade-offs of compensation policies in wholesale electricity markets. We learned that different compensation policies affect how strategic firms behave and how this behavior translates into policy-relevant factors, such as CO_2 emissions, preferred renewable energy sources, and policy costs. These findings have important policy-design implications as competitive auctions and compensation policies continue to play an important role in adopting renewable energy generation. For instance, as shown by Hastings-Simon and Shaffer (2021), with consistently high spot prices and low fixed prices ($\overline{P}_i$ in our model), regulators can end up making money instead of paying the firms.

Our model assumes a deterministic productivity factor for renewable capacity, known for all firms before the auction stage. In reality, this factor is not known when firms make their investment decisions. Future research should consider a stochastic productivity factor to add uncertainty at the auction stage. Additionally, our study assumes dichotomic scenarios in which the new renewable capacity is compensated entirely by either a fixed-price FiT or a premium-price FiT. However, hybrid designs that mix policies might be more efficient. Future research could analyze the existence of an optimal combination of CPs (which in our model is represented by δ) or incorporate other ways to encourage renewable energy adoption. Finally, we assume that only one firm can be awarded the new renewable capacity. However, in most markets, several firms can own this capacity and be subject to different CPs. A setting where multiple firms can be awarded the new renewable capacity needs to be studied further.

Chapter 2

The Effects of Hydroelectric Projects on Local Communities: The Case of Chile

Abstract

Policymakers often see hydroelectric projects as a way to boost local economies, principally through local job creation and investment inflow. This paper estimates the local effects of hydroelectric projects using Chilean data spanning 27 years. It employs a weighted two-way fixed effect difference-in-differences estimator that accounts for selection into treatment and heterogeneous treatment effects over time. In particular, this study analyses the effects on salary, employment, the housing market (i.e., probability of owning a house versus renting), and health (i.e., probability of visiting a doctor). The results show that the effects are short-lived, limited only to the second and third years after the project's construction starts. During these years, the project increases salaries in the construction industry by 29%, with positive spillover effects on the manufacturing and hospitality industries. Further, across all industries, the projects increase salaries by 8% (concentrated in relatively poor counties), and the probability of owning a property increases by 7% (concentrated in relatively wealthy counties). The short-term nature of the effects highlights the necessity of understanding the local effects of energy projects, especially as we are increasingly transitioning to renewable energy.

2.1 Introduction

The ongoing renewable energy transition experienced another year of record growth in 2021, with hydropower (hydro) being the most used renewable energy generation worldwide (REN21, 2022). Policymakers often see hydro projects as a way to increase energy security and boost local economies, principally through local job creation and investment inflow (Faria et al., 2017; Ministry of Energy, 2017). Proponents of these projects argue that these local benefits outweigh the potentially adverse socioeconomic effects by, for example, improving infrastructure in rural areas (Koch, 2002). As a result, the number of hydro projects in Chile has tripled since 2000, increasing the installed hydro capacity by 59%, from $4,409$ megawatts (MW) to $6,990$ MW in 2021. At the same time, the social perception towards hydro plants has worsened, leading to social discontent, conflicts, and protests against the government and project developers (Ministry of Energy, 2011; 2015).

The most iconic example of decaying social perception towards hydro in Chile was related to the 2,750 MW HidroAysén project canceled by the government after national protests in 2011. Aside from environmental concerns, opponents to the projects argued that the promise of a better standard of life, principally through employment and salaries, does not materialize (Ministry of Energy, 2011). In general, hydro opponents emphasize that costs, such as involuntary displacement, impacts on vulnerable minority groups, and public health risks are often underestimated (Trussart et al., 2002). Furthermore, these adverse effects may be magnified if the development of hydro plants does not mitigate the possible loss of agricultural land and fisheries (Duflo and Pande, 2007; da Silva Soito and Freitas, 2011).

Despite the potential environmental benefits these projects can have on a global scale and the broader positive economic implications in the country, there is limited empirical evidence that rigorously analyzes these projects' short-term and long-term effects on nearby local communities. In this paper, I conduct one of the most comprehensive analyses of the effects of hydro plants on local communities in Chile. In light of the countervailing claims by each side, my goal is to establish an empirical methodology to identify, primarily, the local labor economic effects of hydro projects. Further, I assess the heterogeneous effects over time by project size and the county's demographic composition, particularly by the share of the Indigenous population in the county, who may be especially negatively affected by these types of projects (Kelly, 2018).

In order to evaluate the causal impact of a hydro plant, the ideal empirical setting would be for them to be randomly allocated across the country. In reality, hydro facilities are often located in communities with specific characteristics that attract projects but are also related to outcome variables, such as salaries or housing prices. To address this selection problem, I follow Abadie (2005) and use pre-treatment measures that predict treatment to estimate, for each county, the probability of being treated. This process allows me to obtain, based on observable characteristics, comparable control and treated counties. My primary specification relies on a newly developed two-way fixed effects (TWFE) difference-in-differences estimator that allows heterogeneous treatment effects over time and a continuous treatment variable (de Chaisemartin and D'Haultfoeuille, 2022a).

In the analysis, I consider 11 counties with projects ranging from 12 MW of capacity to 359 MW, located in counties with a relatively low population density. I include 175 counties that have never hosted hydro projects to serve as counterfactuals. I focus on the effects of hydro projects mainly on salaries and employment, but I also analyze the impacts on the housing market (i.e., house ownership, like renting or owning a property) and access to health (i.e., the probability to visit a healthcare provider). My study period is from 1990 to 2017, with data available roughly every second year.[46]

I find that salaries in the construction industry increase by 29% in counties with hydro plants (considering an average size plant of 79 MW) between the second and third year after construction starts; however, this effect disappears after three years. The hospitality and manufacturing industries show a similar salary pattern with an increase of 22% and 11% between the second and third year after construction starts and no effect after that.[47] These large short-term effects respond to a sudden increase in labor demand in relatively low densely populated counties.[48] Nevertheless, the magnitude of the results is lower when I analyze the average effects across industries. The average salary increases by 8%, but only between the second and third year of construction, and the effects dissipate after that. These results suggest that local labor market benefits, if any, are transitory, which is particularly important in the context of potentially longer-lasting environmental costs.

My work provides new empirical evidence contributing to the ongoing debate surrounding financial incentives for infrastructure and energy projects. Governments worldwide provide financial incentives arguing that these projects boost local economies, improving overall welfare. However, there is limited empirical evidence to support such claims. Based on my four outcome variables, my study suggests that policymakers should rely on something other than hydropower development to boost local economies in the long run.

The remainder of the paper proceeds as follows. Section 2.2 reviews the relevant literature. Section 2.3 provides background information about Chile and the geographic distribution of the hydroelectric projects. Section 2.4 and Section 2.5 detail the data and the theoretical framework. Section 2.6 presents the preliminary analysis and the identification strategy. Sections 2.7 and 2.8 introduce the results and the robustness checks. Finally,

[46] My main data is collected roughly every second year so, throughout the paper, a period represents about two years.

[47] The hospitality industry (e.g., accommodation, food and beverages services, and other amusement and recreation services) is likely to be affected by the projects if people outside the county are attracted or if people in the county have more disposable income to spend in this industry. In the case of the manufacturing industry, the impact of the hydro projects may be through their effects on the forestry and logging businesses, especially for larger projects that affect extensive land areas.

[48] For instance, according to Pacific Hydro (2012), 2,652 full-time workers were employed during the construction peak of their 111 MW plant in Machalí. At the time, Machalí had 32,583 inhabitants, covering an area of 2,865 km^2.

Section 2.9 concludes.

2.2 Literature Review

Extensive literature studies the local labor market effects of new establishments, businesses, or social events on their communities (Michaels, 2010; Aragon and Rud, 2013; Adams, 2016; Huang et al., 2016). In theory, a labor demand (or supply) shock in local labor market models with no frictions should not affect outcomes, such as salary or employment, in the long run. However, if we introduce real-life labor market frictions (e.g., imperfect mobility and flexible land supply), labor demand-side interventions, such as hydroelectric projects, can improve welfare (Kline and Moretti, 2014). These demand-side interventions can be short-term or long-term shocks affecting local communities.

Casino openings and their impact on local labor markets are good examples of demand-side shocks. Humphreys and Marchand (2013) find that casino openings in Canada positively affect employment and earnings in the local areas. However, the authors caution that these are short-term effects, concentrated within the gambling and hospitality industries only. Similarly, Adams (2016) studied the effects of opening a motor vehicle assembly plant in the United States. The author uses propensity score matching and finds a positive effect on local employment. However, he finds that this effect is lower than predicted by ex-ante input-output models used by state development agencies to support these projects.

Regarding natural resources, the literature generally finds that resource extraction increases employment and income. Using a quasi-experimental approach Marchand (2012) shows that local labor markets with energy resources in Western Canada have greater employment and earnings growth compared to labor markets with no energy resources. Along the same line, but using a differences-in-differences approach, Aragon and Rud (2013) show that a large gold mine project in Peru positively affected real income in the local economy. Nevertheless, the evidence is rather mixed regarding inequality and other socioeconomic variables (Michaels, 2010; Marchand, 2015; Fortin and Lemieux, 2015).

In the particular case of hydro projects, policymakers often view them as a way to boost local economies in the long run (Ministry of Energy, 2017). However, there is limited empirical evidence to support such claims. In particular, the debate of whether the local economic benefits of hydroelectric plants outweigh their social and environmental costs is wide open (Fearnside, 2001; Tilt et al., 2009; Ansar et al., 2014). This is where my study contributes by analyzing the local economic effects of hydro plants empirically.

Hydroelectric plants stand out from other types of businesses because they generate additional externalities and effects, such as involuntary displacement, environmental impacts, and housing market distortions (Rosenberg et al., 1995; Trussart et al., 2002; Manyari and de Carvalho, 2007; Bohlen and Lewis, 2009; von Sperling, 2012). As environmental effects can impact human health (Lerer and Scudder, 1999; Smith et al., 2013), in addition to the commonly analyzed labor market outcomes, I assess the probability of visiting a healthcare provider due to illness or accident. An increase in this probability may be seen as positive (e.g., people have more income to visit their healthcare provider or there is entry of new medical facilities as a result of the hydro project) or negative (e.g., people are getting sick or having accidents more often due to the construction of the hydro plant), depending on the underlying cause.

Further, the housing demand is directly affected by labor demand shocks (Moretti, 2011; Kline and Moretti, 2014). As I do not observe house prices, I rely on an indicator of owning versus renting a property to capture housing market changes. The housing market may be positively impacted by hydro projects through immigration, higher salaries, and higher employment. However, the decision to own versus rent property depends on whether the effects of hydro projects are expected to be transitory (increasing the probability to rent) or permanent (increasing the probability of owning property).

In two related papers, Faria et al. (2017) and de Alburquerque et al. (2019) study the effects of hydro plants in the Brazilian context. Faria et al. (2017) employ a TWFE difference-in-differences model to identify the causal effects of a binary treatment, using not-yet-treated counties as a control group. The authors find no evidence of increased average income or any long-term effects on other social indicators, such as life expectancy, educational level, access to electricity and piped water, HIV cases, and teenage pregnancy levels. Regarding the validity of their results, the authors warn that there may be unobserved differences between control and treated counties, such as electricity infrastructure (e.g., electricity transmission lines), that could play an essential role in the location decision of the plants. Considering this warning, I include electricity transmission lines, electricity generation installed capacity, and electricity substations in my analysis.

De Alburquerque et al. (2019) also studied the Brazilian context. The authors rely on a difference-in-differences approach and use Propensity Score Matching (PSM) based on observable characteristics such as municipality-installed power, population, and region dummies. The authors find a positive effect on salaries and employment, while no effect on health (except birth rate) and environmental indicators (i.e., deforestation). Their study focuses on plants with more than 100 MW of capacity, excluding the potential impact of small-scale projects. In Chile, around 90% of the currently operating hydro projects are less than 100 MW capacity. That is why including relatively small-scale projects in the analysis is crucial.

I extend the analysis of the above studies in several ways: first, I study the effects of hydroelectric plants in the Chilean context. While Chile and Brazil approve projects mainly based on their feasibility, Chile has a different regulatory framework that allows private firms to decide the location of the plants exclusively based on project profitability.[49][50] This different regulatory framework means that in contrast to Brazil, the Chilean regulatory process to approve a project is relatively short, which reduces the possibility of anticipatory effects that may bias the estimators. For instance, if a big project is expected to be approved and starts building in the coming months or years, the behavior of other businesses may be affected (e.g., expand or contract their operations as an anticipated response to the project). These features allow me to better identify the factors that determine the locations of the projects.

Second, I implement a continuous treatment indicator normalized by the county's population. Intuitively, bigger plants (i.e., higher generation capacity in MW relative to the county's population) have different requirements, such as more specialized labor and special land conditions, which may influence the magnitude and sign of the effects on the local population. So, relying on a continuous treatment allows me to identify heterogeneous effects depending on the plant size. To my knowledge, this is the first study that departs from the binary treatment indicator and analyzes the effects of hydroelectric plants based on their population-adjusted capacity. This modification allows me to include smaller plants in smaller counties, while previous studies only focused on large projects defined in absolute terms.

Third, I use newly developed techniques to obtain robust estimators that allow for heterogeneous treatment effects across time and treated counties (de Chaisemartin and

[49] In Chile, private firms submit independent applications for project approvals, and, as private businesses, they are primarily profit-motivated projects. In Brazil, the government decides the location of projects and auctions out the projects to the private sector through competitive auctions. In this case, the main motivation is not based on profits but on other features such as increasing electrification or boosting local economies (Lipscomb et al., 2013). The profit-driven nature of hydro projects in the Chilean case facilitates the identification of the factors that determine the location of these projects.

[50] Water rights and most of the land in Chile are privately owned.

D'Haultfoeuille, 2022a). New evidence has raised questions about the robustness of TWFE difference-in-differences estimators when facing heterogeneous treatment effects over time (de Chaisemartin and D'Haultfoeuille, 2020; Goodman-Bacon, 2021; de Chaisemartin and D'Haultfoeuille, 2022b). As mentioned earlier, the construction stage of a hydroelectric plant requires not only different types of workers but also a more significant number of workers compared to the operation stage of the plants (Faria et. al, 2017; de Alburquerque et al., 2019). Further, the construction stage involves most of the investment inflow of the project. Therefore, the effects of a hydroelectric plant may fluctuate over time, leading to biased estimates in the TWFE difference-in-differences models if not properly addressed.

Finally, relatively new evidence highlights the importance of public perception in successfully developing renewable energy technologies, including hydroelectricity (Mayeda and Boyd, 2020). Particular attention has been given to the effects of energy projects on local Indigenous communities (Susskind et al., 2014; Kelly, 2018) and the different ways of engaging with Indigenous communities in the development of renewable energy projects (Karanasios and Parker, 2018; Hoicka et al., 2021). Indigenous communities may be especially affected by these types of projects when they are asked to relocate or when their sacred lands are damaged, which influence negatively in their culture (Kelly, 2018). The existing literature focuses on particular case studies or relies on qualitative analysis. This paper is a first step to bridging the gap between qualitative case-specific analysis of hydroelectric projects' effects on Indigenous communities and a quantitative approach to estimating these effects. To accomplish this, I include an analysis of a sub-sample of counties populated predominantly by Indigenous communities.

2.3 Chilean Background

In this section, I provide relevant information about Chile and the geographic distribution of hydroelectric projects. The objective is to provide a broad view of the Chilean context and information on how the government revised and approved the projects. The legal process that project developers must undergo is crucial in determining the location of successful projects.

According to the Library of the National Congress,[51] Chile is divided into 346 counties, the smallest administrative subdivision. Based on the 2017 Census, the county's geographic

[51] The information of the Library of the National Congress (Biblioteca del Congreso Nacional de Chile) is publicly available on their website: www.bcn.cl.

area and population vary greatly, ranging from 6.5 km^2 to 48,974 km^2 and from 311 inhabitants to 617,914 (excluding the Antarctic county). The average county size is 300 km^2 (median 614 km^2), and the average population is 50,939 per county. INE (2018) reported that in 1992, 16.5% of the population lived in rural areas and that by 2017 that percentage decreased to 12.2%. In my context, and based on my data sources, rural areas are localities with less than 1,000 inhabitants or between 1,001 and 2,000 with less than 50% of its active population working in secondary and tertiary industries.[52]

In Chile, provincial and local jurisdictions exist, but the national government has the supreme legislative authority. For example, the same minimum wage and labor legislation apply to all counties, and local jurisdictions cannot modify this. This centralized authority configuration is convenient because all projects face the same regulations and legal conditions for approval. Additionally, Chile is one of the few countries worldwide with privatized water resources. In 1981, the federal government started distributing water rights to the private sector for free (in cubic liters per second). However, between January and March of 1990 (days before the first democratically elected president started his mandate after Pinochet's dictatorship), the vast majority of these property rights were allocated (about 74% of all property rights). These property rights were mainly allocated to the private electricity company ENDESA (now named ENEL). Today, the water market in Chile is characterized by an oligopoly where a few companies own the water rights. Therefore, the only missing pieces to start a hydro project are the land and the government's approval. These features suggest that the most critical factors that determine the project location are related to the project profitability (e.g., water flow and existing electricity infrastructure) and the local support or rejection of the project.[53]

Faria et al. (2017) discuss the importance of electricity infrastructure in the location decisions of the projects. In Chile, during my sample period, the electricity market was divided into four main independent sub-markets: Central Interconnected System (SIC), Grand North Interconnected System (SING), Aysen System (SEA), and Magallanes System (SEM).[54] Electricity generators face three different, independent markets: regulated consumers, unregulated consumers, and spot market. The regulator sets nodal prices for

[52] In Chile, the secondary industry includes manufacturing, electricity, natural gas and water supply, and construction. Tertiary industries include commerce, hospitality, transport, and other smaller industries.

[53] Susskind et al. (2014) highlight hydro projects' intense social scrutiny in the last decade, leading to social protests and legal disputes.

[54] In 2017 SIC and SING merged to form the National Electricity System (SEN), but this does not affect my analysis because 2017 is the last year of my study period.

regulated consumers (consumers below 5 MWh) twice a year aiming to reflect the marginal cost of generation, transmission, and distribution of electricity. If this regulated price truly captures the marginal cost of generation, then it does not affect the profitability of the project. For consumers above 5 MWh the price is unregulated and the firms can negotiate long-term contracts directly with the consumers. The Chilean regulator assumes that consumers above 5 MWh have bargaining power to negotiate with generators. In the spot market, firms interact with each other to sell and buy electricity to cover their long-term contracts and other necessities. In this market, the independent system operator (ISO) uses a cost-based dispatch to clear demand and supply.[55] The profitability (therefore the location of the projects) may be affected if generators sell most of their output to unregulated consumers or the spot market and can exercise market power; however, the final sample of projects that I am analyzing sell most of their output to regulated consumers.

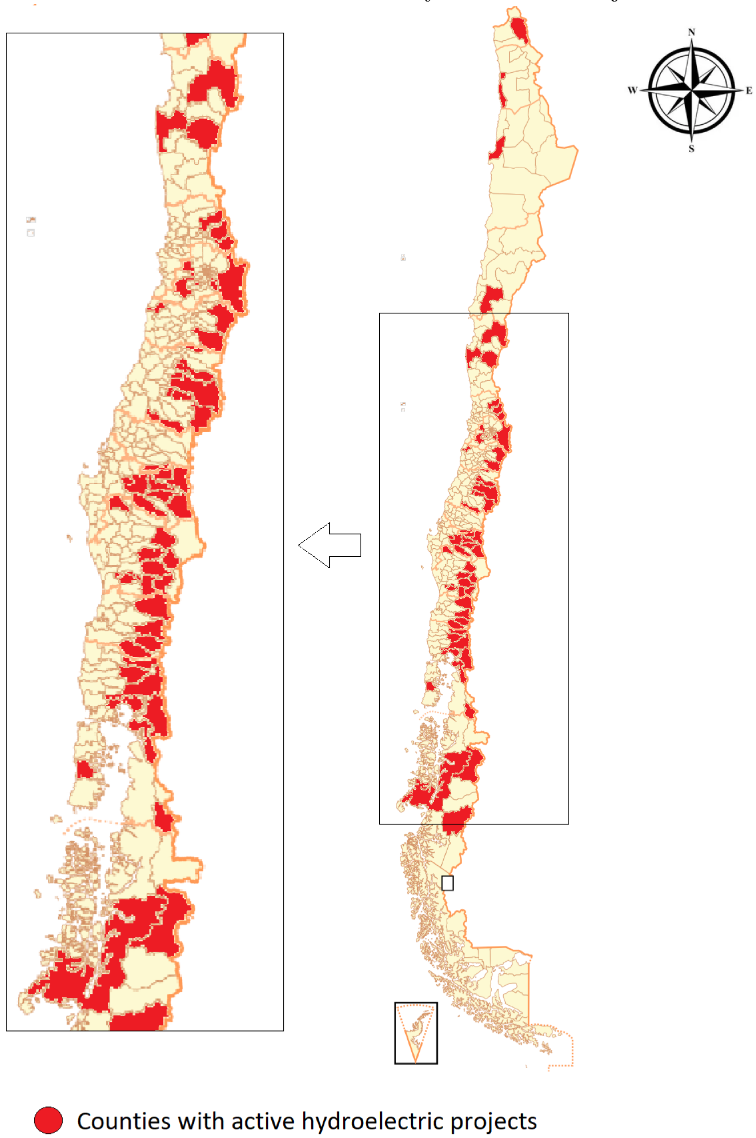
Private companies own the generation, transmission, and distribution of electricity and the government acts as a regulator and, in some cases, as a subsidiary for companies that need financial help. The electricity infrastructure (e.g., transmission lines and electricity substations) directly affect the profitability of the hydroelectric projects because the firm must cover the cost to transport its electricity generated to the nearest transmission line. This transmission line receives electricity from all surrounding generators, so it is important to know the total capacity already installed in the area.

According to the Chilean National Energy Commission, 185 private hydroelectric projects are currently operating, adding about 7,254 MW of capacity. This represents slightly less than 30% of the country's total generation capacity. As of 2022, there are 67 medium-to-large projects with sizes ranging from 10 MW to slightly less than 700 MW. Likewise, there are 118 small hydro projects of less than 10 MW. Approximately 51% of these plants are located in traditional Indigenous territory, creating disagreements between Indigenous communities and hydro proponents (Susskind et al., 2014; Kelly, 2018). Figure 2.1 shows the distribution of the counties with hydroelectric projects. The 61 counties with projects currently operating are highlighted in red. Aside from the three counties in the north, all hydroelectric projects are concentrated in the middle portion of the county, which helps me identify comparable counties without projects. Additionally, most of the counties with

[55] In Chile, power plants submit the marginal costs of their generation units to the ISO. Based on this information, the ISO ranks power plants from those with lower marginal costs to those with higher marginal costs and determines the generators required to balance demand and supply. The resulting spot market price is equal to the marginal cost of the most expensive unit of generation in use, which is published hourly at the node level (the most spatially disaggregated price points).

projects are located towards the east side of the country. While I do not have land elevation data, I control for river water distribution in the counties.

Figure 2.1: Distribution of Counties with Hydroelectric Projects in Chile



In Chile, private companies independently propose hydroelectric projects (Kelly, 2018). The main compulsory prerequisite requires projects larger than 3 MW to submit an environmental evaluation with a detailed description of the three main stages of the project: construction, operation, and closure (see, for example, SEA, 2021).[56] The project's proponent chooses the location and all technical specifications, which the government evaluates. In

[56]In some specific cases for proposed plants located in sensitive environmental areas, the government may require an environmental impact assessment for less than 3 MW projects.

addition, the government requires an Indigenous consultation per project; however, a project cannot be rejected solely based on a negative response to the consultation, which creates a disconnect between project developers and the local communities. This disconnect has led to considerable public opposition and local conflicts; for example, the Río Picoiquén project became operational despite the opposition of the local Mapuche communities (Susskind et al., 2014). After this project was built, there was a subsequent increase in conflicts in the area.[57]

To provide a sense of the magnitudes of the projects included in this study, I use Machalí as an example. Machalí, one of the counties with hydroelectric projects included in my analysis, started constructing a 111 MW hydro project in 2006. Machalí's population in that year was 32,583 inhabitants, and the county covers an area of 2,865 km^2. According to Pacific Hydro (2012), the hydroelectric plant "Chacayes" at its construction peak employed 2,652 full-time workers, and the construction investment was approximately US$450 million. While the company claims to provide training for local workers, it does not provide information regarding the origin of the workers hired during the construction stage (local or from outside the county).[58] This project meant a sudden labor demand of about 8.1% of the county population. Pacific Hydro argues that the construction of the hydroelectric plant helped more than 2,000 people directly and approximately 3,000 people indirectly, "contributing to the regional, local, and national development" (Pacific Hydro, 2012).[59] My study aims to examine these claims empirically.

2.4 Data

I combined data from five different sources to carry out the analysis while controlling for the variables that affect the location of projects. The primary dataset used is CASEN (Encuesta de Caracterización Socioeconomica Nacional), which is publicly available from the Ministry of Social Development of Chile. These are repeated cross-sectional surveys imple-

[57] Indigenous communities represent a large portion of the conflicts related to hydro projects. Mapuches are the largest indigenous community in Chile, with about 10% of the total population, followed by Aymara and Diaguita, with 1% and 0.5%, respectively (INE, 2018).

[58] According to IHA (2021), building medium and small-size hydroelectric projects do not require on-site housing unless they are located in highly isolated rural areas. In Chile, there is limited information regarding camp sites to host employees during the construction of the projects, especially for projects that are more geographically isolated. However, all the projects analyzed in this paper are close to towns, which decreases the probability of needing on-site housing.

[59] The quote "contributing to the regional, local, and national development" was translated from the Spanish "... contribuyendo así al desarrollo regional, local y nacional".

mented approximately every two years from 1990 to 2017.[60] CASEN is an individual-level survey representative of the national population that aims to characterize the socioeconomic conditions of Chilean households. The survey is administered through in-person interviews with household heads (or another adult) in randomly selected households in the country. CASEN contains measures of household size, education, gender, age, marital status, income other than salary, detailed health description, and household appliances, among others. All the outcome variables in this study (i.e., salary, probability of being employed, probability of renting versus owning a house, and probability of visiting a doctor) are based on CASEN data.

I obtained data from three independent sources that target the main factors that determine the location of the projects in the Chilean context: Indigenous political representation and conflicts, river water resources, and electricity infrastructure.

In Chile, Indigenous communities often openly reject the development of hydroelectric projects. Because of this opposition, I use information regarding Indigenous communities from the Mapuche Data Project (MDP). The MDP is a dataset that provides detailed county-level information about Indigenous land ownership, political representation (elected and running representatives), and conflict information. A conflict is generally defined as an alteration of the public order that needs the intervention of law enforcement.[61]

Intuitively, the amount of water flowing in the rivers is another factor that determines the viability of a hydroelectric project. I obtain the county-level water data from the Center for Climate and Resilience Research (CR2). The CR2 collects water flow from rivers (in cubic meters per second) at 788 stations along the country between 1930 and 2016. The daily observations are per river, but I aggregate them into a yearly county-level measure of river water flows.

Finally, I include electrical infrastructure (i.e., transmission lines and substations) with spatial data from the Chilean Ministry of Energy. I have mapped the transmission lines in GIS and created a variable that measures the length (in kilometers, km) of the transmission line per county per year and the number of electricity distribution substations. In the analysis, I adjust the km of lines and the number of substations by the county's population and geographic area. Additionally, I obtained the county's electricity generation capacity

[60] The relevant surveys for this study were carried out in 1990, 1992, 1994, 1996, 1998, 2000, 2003, 2006, 2009, 2011, 2013, 2015, and 2017.

[61] In my analysis, I include all types of conflicts but the results are robust to restricting the conflicts to energy-related projects.

installed from the National Energy Commission (CNE). The CNE provides detailed information about the type of generation facility (e.g., solar, wind, and natural gas), location, capacity, ownership, and year of operation. It is important to control for nearby generation facilities primarily because of possible electricity transmission congestion.

2.5 Theoretical Framework

In this section, I explore the theoretical framework that helps me to choose and define my outcome measures. The labor market demand and investment inflow are expected to be the main channels that hydroelectric plants affect the local communities during the construction stage. Therefore, I start by analyzing the mechanisms that can explain the effects on salary and employment using a modified version of the Rosen-Roback framework (Rosen, 1979; Roback, 1982) for the local labor market. In this study, I follow the insights of Moretti (2011) and Kline and Moretti (2014) to allow for local labor market frictions. Subsequently, considering the expected labor market effects, I analyze the possible channels that determine the effects on the housing market and health.

2.5.1 Labor Outcomes

In the standard Rosen-Roback theoretical framework, workers' utility depends on nominal salary and the cost of housing and local amenities. Among other assumptions, this theoretical framework assumes that labor is perfectly mobile and that land is the only immobile factor with a fixed supply. In this setting with a perfectly efficient local labor market, any local shock to the labor demand or supply has no long-term effects on workers' welfare, and only landowners benefit. For instance, a local labor demand shock will increase nominal wages, but subsequently, the cost of housing and local amenities will increase. Therefore, workers' welfare will see no real change, and only landowners will benefit.

Two particularly restrictive assumptions of the Rosen-Roback theoretical framework are perfect mobility and the fixed land supply. Perfect (and infinite) mobility of workers leads to a perfectly elastic labor supply, while fixed land leads to a perfectly inelastic land supply. However, in reality, the local labor market presents frictions that allow labor demand-side interventions to benefit local workers (Moretti, 2011; Kline and Moretti, 2014). Therefore, I base my theoretical framework on the models described by Moretti (2011) and Kline and Moretti (2014). In my context, there is likely limited mobility, land (and housing) is not fixed, and there are multiple industries and types of workers within a county.

The construction stage of hydroelectric projects attracts a large number of workers. For instance, Faria et al. (2017) report that building a 430 MW hydroelectric plant would create around 3,000 direct full-time jobs. In particular to my setting, as discussed in section 2.3, Pacific Hydro claims to have created 2,652 full-time jobs during the peak of the construction stage of the 111 MW plant (Pacific Hydro, 2012). In this study, I consider projects of between 10 MW and 359 MW capacity located in counties with a relatively low population (between 5,100 and 64,000 inhabitants). To fulfill the jobs created by the hydroelectric plants, I consider three possible channels: migration, switch between jobs, and employment of the unemployed and inactive population. I am interested in two labor outcomes, salary and employment. Salary is defined as the (logarithm of the) remuneration from the main job, while employment refers to the individual probability of being employed.

First, close to the standard Rosen-Roback framework with perfect mobility, let us assume that migrants from other counties fill all jobs and that the number of migrants equals the number of jobs. Then, I should observe an increase in salary and the probability of being employed.[62] I expect that the average salary of the treated county will increase because construction jobs pay above the average salaries.[63] If not all migrants find a job or if they migrate with working-age family members, employment still increases as long as half of the migrants find a job. Similarly, the average salary increases if a sufficient proportion of the migrants find a construction job. Due to the cross-sectional nature of my data, I do not observe migration; however, empirical evidence suggests that low-skill workers are less likely to migrate due to labor demand shocks (Topel, 1986; Bound and Holzer, 2000), which supports the limited mobility assumption of Moretti (2011) and Kline and Moretti (2014). High-skilled workers will be needed to manage special equipment and higher positions, but most construction jobs require relatively lower-skilled workers. Recall that given the size of the projects I analyze, it is likely that no on-site camps are needed and an important portion of the jobs are filled by local workers.

Second, I follow the intuition of the direct and indirect effects of labor demand-shocks on employment and salaries with different industries described by Moretti (2011).[64] Suppose

[62] Due to the nature of my data, I use the individual probability of being employed as a measure of employment effects. Therefore, when I speak about employment effects throughout the paper, I refer to the individual probability of being employed.

[63] The best-paid industries in Chile are Finance and Insurance, Mining, Communication, and Construction, while Agriculture and Fishing are the second worst-paid industries (Fundación Sol, 2020).

[64] Moretti (2011) categorizes industries as tradable and non-tradable, but the intuition holds for my analysis.

that the jobs are filled by employees currently working in other industries (i.e., there is a switch between jobs). The employment effects will depend on how many jobs are created in the construction industry, the number of vacant jobs in other industries, and the job destruction derived from the projects. Job destruction may occur if agricultural land is destroyed or diminishing fish resources (Duflo and Pande, 2007; da Silva Soito and Freitas, 2011); however, this is most likely to happen with large projects that require a dam construction. In my analysis, all but one project are run-the-river which do not require flooding. Assuming a low job destruction rate and at least some of the vacant jobs in other industries are fulfilled, I expect an increase in overall employment. Regarding average salary, I expect it to increase because workers will leave their current jobs if construction jobs are better paid. Even in the case of moderate industry-specific job destruction, I expect the average salary to increase during the construction stage because these jobs pay more than agriculture and fishing jobs.

Finally, assuming that there is some involuntary unemployment, the jobs may fulfilled only by local unemployed or inactive people who become active. In this case, we will observe an increase in employment and the average salary, leading to a possible welfare improvement by this demand-side intervention as stated by Kline and Moretti (2014). People that were not working before (earning no salary) become employed in a job that pays above the average. This channel is particularly relevant for low-skilled construction jobs in these medium-to-small-size hydroelectric projects. Building medium and small-size hydroelectric projects do not require on-site housing unless they are located in highly isolated rural areas (IHA, 2021), which is not the case for the selected projects in this study.

In reality, the effects will be driven by a mix of these three channels. I expect to see an increase in both variables, the probability of being employed and the average salary. The duration and magnitude of these effects will depend on whether workers and the private sector perceive this shock as a long-run development propeller or just as a short-lived opportunity. On the one hand, if the labor demand shock is seen as transitory, the effects will disappear (or at least decrease) after the construction is finished. On the other hand, if the labor demand shock is perceived as permanent, the effects will continue after the construction stage. Additionally, these results will be exacerbated if the infrastructure investment has positive spillover effects in other industries. These spillover effects would increase the labor demand and salaries in other industries, which, as long as the cost of living (including housing) increases in a smaller proportion, would lead to an overall improvement for workers in the county.

2.5.2 Housing and Health Outcomes

To study the effects of the hydro projects on the housing market I use the probability to rent versus own property.[65] This variable is defined as a binary indicator equal one for households that rent and 0 for households that own the property. I only consider household heads, and I rule out other types of ownership, like conceded with no ownership (the owner lets the occupant live in the house with no charge and property rights), usufruct (limited right to occupy a property), irregular occupancy (properties that illegally occupied), among others. Regarding the health effects of hydro projects, I focus on the individual probability to visit a healthcare provider.

The positive effects on salaries and employment, together with possible migration, will increase demand for housing in treated counties. On the one hand, higher disposable income allows one to afford a better house and possibly switch from renting to owning a house. At the same time, increasing income and migration will shift the housing demand upward, putting upward pressure on house and renting prices. The effects will depend on whether the shock is permanent or transitory (Dynarsky and Sheffrin, 1985; Robst et al., 1999; Zheng et al., 2018). If the community expects the increasing economic development to be permanent, the incentives to own a house increase compared to renting one. Otherwise, if the migration and the increase in income and employment are transitory, we should see an increase in the probability of renting during the construction stage and no effects after that.

As pointed out in previous studies, hydroelectric plants may cause significant environmental damage, such as the emission of harmful gasses (Manyari and de Carvalho, 2007). These environmental effects can impact the health of people living nearby (see Fearnside, 2001; Smith et al., 2013; de Alburquerque et al., 2019). In my study, health is measured by the probability of visiting a doctor due to illness or accidents. An increase in this probability does not necessarily have a negative connotation because there could be three main explanations: first, with a salary increase, people may be able to afford better care and, in the short run, increase their doctor visits.[66] If this is the case, we should observe an increase during the first few years after the construction starts, followed by a reduction

[65] In my data, I do not observe housing prices or other relevant variables, so home ownership is the closest I can do to get an idea of housing effects.

[66] Chile has private and public health services, with the private services located mainly in bigger cities. In general, the cost of the private health services is too high for most of the population, resulting in 87.4% using the public healthcare system (FONASA, 2020).

below pre-construction levels (refer to Adda et al. (2009) and Schwandt (2018) for evidence of income effects on health).

Second, an increase in the probability of visiting a doctor can also mean that the person is getting sick or is having accidents more often. If this happens during the construction stage only I would see a temporary increase in the probability of visiting a doctor. However, if the person is getting sick more often as a result of the hydro project, I would see a sustained constant increase in the probability of visiting the doctor, which would have a negative connotation. Third, if the treated counties build additional hospitals, people will have more options to visit the doctor more often. In this case, I would also expect a constant increase in the probability of visiting the doctor, which will be associated with a positive effect.

Using data on hospital additions and information on the reason why individuals visit the doctor, I can identify the most dominant mechanism driving the results. During my study period, from 1990 to 2017, I did not observe significant hospital additions in the treated counties, which weakens the third channel. Additionally, the health indicator used in this paper includes only acute illnesses and accidents, which means that channel two is more likely to explain the sign of the effects. There is no reason to believe that an increase in income (channel one) leads to an increase in short-term illnesses and accidents for people relying on the public health system. Therefore, I consider an increase in the probability of visiting a doctor to be associated with adverse health effects.

2.6 Empirical Methodology and Preliminary Analysis

In this section, I present a detailed description of the treated counties (i.e., counties with hydroelectric projects starting during my study period) and summary statistics comparing the treated and control groups before the treatment occurs. The purpose of this section is to explain the main methodological challenges, starting from understanding how well-suited are the control counties to be a good comparison group for treated counties. I show that control and treated counties are different in various dimensions, which needs to be addressed before they can be comparable. Further, I discuss the process of creating comparable control groups detailing the primary identification strategy.

2.6.1 County Groups Description

During my period of study, 32 counties initiated the construction of hydroelectric projects. I use the 11 counties for which I have at least three periods of pre-treatment data. Table 2.1 briefly describes the treated counties considered in my analysis. Of the 11 treated counties, Melipeuco has the lowest total population, while Los Andes is the most populated. There is a significant variation in the rural population, ranging from counties that are almost entirely urban, like Mejillones, to other counties with around 70% rural population, like Puerto Octay and Colbún. Likewise, the Indigenous population share is low in most treated counties, and only three counties are above the national average of 13%. Regarding geographic area, San Esteban is the smallest, and Coyhaique is the largest. The largest plant in my sample is in San Fernando, with 359 MW capacity, while the smallest is in San José de Maipo, with 12 MW. Two plants started construction in 2000, four in 2006, four in 2009, and one in 2011.

Table 2.1: Description of Treated Counties

County	Population	Rural Population	Indigenous Population	Area	Plant Capacity	Construction Year
Melipeuco	5,781	61%	48%	1,107	11.7	2006
Puerto Octay	9,517	68%	9.6%	1,795	22.9	2011
Mejillones	7,834	1.3%	1.2%	3,803	177.5	2009
Chonchi	12,941	66%	21%	1,362	13	2009
San José de Maipo	12,606	30%	4.6%	4,994	12	2009
San Esteban	13,560	54%	1.0%	681	25.7	2000
Colbún	17,686	71%	0.7%	2,899	48.5	2006
Machalí	28,427	6.9%	0.5%	2,597	124	2006
Coyhaique	44,017	12%	10%	7,290	14	2000
San Fernando	64,524	21%	1.6%	2,441	359	2009
Los Andes	56,627	6.6%	1.6%	1,248	61	2006

Note: Plant capacity and area are expressed in MW and KM^2. Averages using pre-treatment periods.

The primary specification includes 11 treated counties and 175 control counties. The selection of counties was based primarily on data availability. Additionally, some counties were excluded from the primary analysis if they had previous operating hydroelectric projects. This exclusion means that I am comparing treated counties with never-treated counties in my main specification. I relax this constraint in the robustness checks of Section 2.8.

Table 2.2 shows the summary statistics of the four output variables that I focus on my analysis. The full comparison, including other relevant variables, can be found in Table 2.3 of Appendix 10, I compare treated and control counties during the pre-treatment periods.[67]

[67] As shown in Table 2.1, the starting date of the construction stage (i.e., the treatment) differs depending on the treated county. This means that pre-treatment periods will depend on what county I am considering.

The only variables that are similar between control and treated counties are the probabilities of visiting a doctor and of being employed. In average salary and probability to rent versus own there is a sizable difference between groups.

According to Table 2.2 (and Table 2.3 in Appendix 10), in my sample, hydroelectric projects tend to be located in areas with higher salaries, greater electricity infrastructure, and fewer water resources.[68] Additionally, projects are self-selected into relatively peaceful counties with higher Indigenous representation. A possible explanation is that the national government reviews the project proposals (instead of local governments), and that, depending on the location of the project, some Indigenous communities may accept the hydro facilities (or Indigenous communities that oppose the projects are not powerful enough to impose their will). All these differences demonstrate that there are some observable discrepancies across the treatment and control counties. Consequently, an empirical methodology that controls these differences will be necessary.

Table 2.2: Summary Statistics, Treated vs. Control Group

Variable	Group	Mean	Standard Deviation	Minimum	Maximum
Average Salary	Treated	283	424	0	7,177
	Control	205	340	0	7,465
Probability to Visit a Doctor	Treated	0.09	0.28	0	1
	Control	0.09	0.29	0	1
Probability to Rent versus Own	Treated	0.21	0.41	0	0
	Control	0.13	0.34	0	0
Probability of Being Employed	Treated	0.36	0.48	0	1
	Control	0.33	0.47	0	1

Notes: The averages presented are considered before 2000, when the first project started to be constructed. Probability of being employed include the whole population (not only people of working age). Salaries are expressed in CAD per month. I test for differences between control and treated means in the balance test in Appendix 2.

As noted above, the main challenge of this study is the endogeneity of project allocation. In the specific case of Chile, there are reasons to suspect the existence of endogeneity because hydroelectric plants may depend on factors that affect not only the feasibility of the project but also its profitability, such as river conditions, Indigenous representation, and electricity infrastructure. This is why I employ a two-stage estimation: first, following Abadie (2005), I use inverse probability weighting so, based on observable characteristics, control and treated

For example, 2003 is considered pre-treatment for a county treated in 2006, but post-treatment for a county treated in 2000. The earliest year a county becomes treated is 2000, so the summary statistics in Tables 2.2 and 2.3 are averages from 1990 to 1998.

[68] Treated counties are located in counties with fewer water resources; however, an average of 39.2 m^3/second is consider abundant water resources.

counties have a similar probability of being treated. Second, based on de Chaisemartin and D'Haultfoeuille (2022a), I incorporate the weights of the first stage and employ a TWFE difference-in-differences estimator that is robust to heterogeneous treatment effects over time.

2.6.2 Identification Strategy

This study aims to analyze the effects of hydroelectric plants on salaries, employment, the housing market, and health at the county level. While the treatment is at the county level (i.e., once a county is treated, all individuals in that county become treated), I observe individual-level measures; therefore, I perform individual-level estimations.

The salary variable is defined as the logarithm of inflation-adjusted salaries to reduce the influence of outliers. This definition means that I restrict the analysis to employed individuals with observed positive salaries. The employment variable is defined by a binary indicator that equals one if the person is working and zero otherwise. In this specification, I include only people aged between 15 and 65 years old. The housing variable is represented by a binary indicator that equals one for households that rent and 0 for households that own the property.[69] I only consider household heads, and I rule out other types of ownership, like conceded with no ownership (the owner lets the occupant live in the house with no charge and property rights), usufruct (limited right to occupy a property), irregular occupancy (properties that illegally occupied), among others.[70] Finally, the health variable is a binary indicator that equals one if the person has visited the doctor due to illness or accident in the last three months and zero otherwise. I include all county's population in this specification.

As mentioned earlier, the construction stage involves most of the investment inflow and is expected to create the most jobs. Therefore, I set the start of the construction stage as the initial treatment period. In the sample, the construction stage lasts between 2 and 6 years, depending on the project size.[71] The data is collected roughly every second year, which means that one period in the data is translated into approximately two years. Hence, in this analysis, the construction stage lasts between one and three periods (in the sample, only one plant took three periods to be built).

[69] CASEN has a variable that indicates each household member's relationship to the household head. The family chooses the household head, typically the working adult (e.g., father or mother).

[70] Renting and owning a property accounts for, on average, 93% of total types of ownership, which is relatively stable over time. While I cannot rule out that composition changes over time in treated and control counties, I assume that the proportion of other types of ownership is sufficiently small not to impact my results significantly.

[71] The duration of the construction stage is approximated and based on a informal documents.

To mitigate the problem of selection into treatment, Abadie (2005) proposed the weighted difference-in-differences estimator to find control groups with similar pre-treatment characteristics to treated groups, such that both groups have a similar probability of being treated based on these observable factors. To determine what factors are relevant to estimate the weights, I employ a balance test that analyzes what variable means are statistically different between control and treated counties.[72] I incorporate variables related to the electricity infrastructure (e.g., transmission lines and number of substations), Indigenous political representation, and river water distribution, among others.[73] In this estimation, each observation represents the pre-treatment county-level average and the variables were chosen based on previous literature (Faria et al., 2017; de Alburquerque et al., 2019), and variables that may especially apply to the Chilean case (e.g., Indigenous variables). The detailed results of the balance test are in Appendix 11.

The main takeaway of the balance test results is that electricity infrastructure and Indigenous presence are critical factors determining the location of the projects. For instance, the balance test indicates that counties with more electricity infrastructure and less conflicts are more likely to be treated. Additionally, they show that the county's water distribution is not significantly different between treated and control counties. This may be explained by the relatively homogeneous distribution of water resources along the country (except in the extreme north and south, where water resources are more scarce and abundant, respectively). Using the results of the balance test I estimate the weights. Subsequently, I include these weights in the primary model, which ensures that treated and control counties have a similar probability of being treated based on the observable characteristics used to estimate the weights.

To obtain the average treatment effect on the treated, I rely on a TWFE difference-in-differences estimator. However, as de Chaisemartin and D'Haultfoeuille (2020) and Goodman-Bacon (2021) point out, the standard TWFE difference-in-differences estimator is not robust when treatment is not constant over time. In my case, there are strong arguments for believing that the effects of hydroelectric projects are heterogeneous over time, particularly comparing the construction and post-construction periods. Therefore, I rely on a new version of this estimator proposed by de Chaisemartin and D'Haultfoeuille (2022a). This estimator is a generalization of the event-study approach that allows for con-

[72]In essence, the balance test analyzes if the means reported in Tables 2.2 and 2.3. are statistically different from each other.

[73]Refer to Appendix 11 for a complete list of the variables included in the balance test.

tinuous treatment and heterogeneous treatment effects over time and across treated units. The estimated effects post-treatment are relative to the first period before the treatment started.

Adapting de Chaisemartin and D'Haultfoeuille's model to my study, I start by considering individual observations $i = 1, ..., N$ for each county $c = 1, ..., C$ at time $t = 1, ..., T$.[74] Note that in repeated cross-sectional data, individuals in a given county vary over time. Let F_c be the period where treatment started (i.e., years 2000, 2006, 2009, or 2011, depending on the treated county) and $Y_{ict}(d_1, ..., d_t)$ be the potential outcome of individual i, from county c at time t, with $(d_1, ..., d_t)$ being the treatment status from period 1 to t. In my design, once a county becomes treated at period F_c, all county individuals remain treated for every period after that.

In their model, de Chaisemartin and D'Haultfoeuille (2022a) define $D_{ct} = I_c 1\{t \geq F_c\}$ as the treatment indicator for county c at time t, where I_c represents the county specific intensity of treatment. This represents the continuous nature of the treatment indicator and, in my setting, it is defined as MW for each 1,000 inhabitants: $D_{ct} = \left(\frac{I_c 1\{t \geq F_c\}}{population_{ct}}\right) 1,000$.[75] This treatment definition is one of the main departures of de Chaisemartin and D'Haultfoeuille (2022a) from a standard event-study model. Let $\delta_{ict} = E(Y_{ic,F_c+l} - Y_{ic,F_c+l}(D_{c,1}, ..., D_{c,1}))$ be the difference between the outcome of individual i at county c at $F_c + l$ periods and the unobserved outcome of the same individual if the treatment in county c would have remained the same as period 1 (i.e., untreated). As I cannot observe the counterfactual world where the county is not treated, we use the estimator proposed by Chaisemartin and D'Haultfoeuille (2022a) to estimate this value.

To estimate δ_{ict} de Chaisemartin and D'Haultfoeuille (2022a) propose to compare the $F_c - 1$-to-$F_c + l$ outcome evolution between county c and counties whose treatment has not changed in $F_c + l$ and started $t = 1$ with the same treatment as county c (i.e., untreated in my setting). Additionally, placebo tests are conducted to test for the pre-treatment parallel trend assumption on which the estimator relies. The following equation represents the model estimated in my setting:

$$Y_{ict} = \alpha + \sum_{t=-q}^{F_c-1} \kappa_t D_{ct} + \sum_{t=F_c}^{T} \gamma_t D_{ct} + \lambda_t + \mu_c + X_{ict} + \epsilon_{ict} \tag{2.1}$$

[74] In my case, time t represents the year of the survey.

[75] If population increases because of the hydro project my results would be biased downwards. This means that my results would be a lower bound. Nevertheless, I observe no statistically significant difference in population before and after the hydro project.

where Y_{ict} is one of the four outcome variables (i.e., salary, employment, the housing market, and health). α represents the intercept, κ is the coefficient of the placebo estimators for each pre-treatment period from $t = -q$ to $t = F_c - 1$. In this main specification, I include three leads and four lags. This is because the number of treated counties is too small for longer pre- and post-treatment periods, which leads to less precise estimators. The κ coefficient allows me to test the fundamental parallel trend assumption of a difference-in-differences design. γ is the coefficient of the treatment effects for each $t \geq F_c$. Treatment D is defined as above. λ and μ are time and county fixed effects, respectively. X is a vector of control variables.[76] As the treatment occurs for the whole county simultaneously, the error term, ϵ, is clustered at the county level.

The estimator described in equation (2.1) represents the average effect for each period, but it does not have a direct interpretation. This average effect depends on the number of MW built per $1,000$ inhabitants in each period. For instance, if the estimator for period one is 0.1, it means that the average effect of hydro projects in period one is 0.1 per the number of MW built per $1,000$ inhabitants in period one. If there were two MW per $1,000$ inhabitants built in period one, this means that the effect of each MW built per $1,000$ inhabitants was 0.05. Therefore, to estimate the effects of each MW built per $1,000$ inhabitants, I need to complement the reduced-form event-study estimator described in equation (2.1) with a first-stage event study where the treatment indicator replaces the outcome variables. The estimators of this first-stage event study represent the average value of the treatment across all groups (which, by definition, is zero for all pre-treatment periods), which is defined as the average MW of capacity per $1,000$ inhabitants built in each period. Therefore, the interpretation of the γ coefficients in equation (2.1) will depend on the average treatment estimator of each post-treatment period, and it is calculated following:

$$ATET_t = \gamma_t \left(\frac{MW\,cap \cdot 1,000}{population} \right) \left(\frac{1}{\overline{\overline{MW\ added}}} \right) \tag{2.2}$$

where $ATET$ is the average treatment effect on the treated at period t. γ is the estimator effect in period t. $MW\,cap$ and $population$ are the average capacity of the hydroelectric plants in the sample and the average population of the treated counties, respectively (in my sample, the average $cap = 79$ MW and the average $population = 27,000$). Recall that

[76]The controls for salary are age, gender, education, and the number of members in the household. For the probability of being employed, I control for age, gender, and education. For the probability of renting versus owning a house, I add the household salary, education, and age. Finally, for the probability of visiting a doctor, I include household salary, age, and gender as control variables.

the treatment indicator is MW per 1,000 inhabitants, so I need to correct this to get an average effect for the treated counties (hence, the $1,000$ in the second term). Additionally, $\overline{MW\ added}$ represents the average MW per 1,000 inhabitants added from period zero to t. Intuitively, equation (2.2) transforms the estimator effect, γ, into a "per MW effect", and then scales it up by the population-adjusted plant size. To obtain the effects per MW per 1,000 population, one sets $MW\ cap = 1$.

Aside from this main specification, I analyze heterogeneity tests per industry, county's income level, and share of the Indigenous population. In the industry analysis, I include mining, manufacturing, construction, agriculture (including the fishing industry), and hospitality and commerce because these are the most relevant industries in the treated counties.[77] I only observe industries reported by employed individuals, so the industry analysis is focused on salary. To group counties per income level, I use the pre-treatment poverty share of counties estimated by Agostini et al. (2008). Using their estimates, I obtain six treated and 38 control counties below the poverty average of 26.7% in 2000, and there are three treated and 114 control counties above the poverty average. Finally, the CASEN survey started asking questions about Indigenous identification in 2000. I use this data to divide counties with a higher and lower Indigenous population.[78] The average Indigenous population was 7% in 2000 and 2003 (pre-treatment periods). There were 136 control and six treated counties below the national average and 29 control and three treated counties above the average.

In general, I expect heterogeneous effects in different industries. This is because some industries may be negatively affected (e.g., agriculture), while some others positively (e.g., construction). Regarding Indigenous communities in Chile, they view salaried jobs, private property, and Western medicine as alien to their culture (Kelly, 2018), which may affect my dependent variables. For instance, if a relatively large share of the county's population presents voluntary unemployment, the probability of being employed in that county is relatively low. Therefore, a project that attracts workers (from outside the county or other industries) may have a greater effect.

The county samples vary when I analyze the effects of the hydro plants by income level and the Indigenous population. This leads me to perform new balance tests for these

[77]The most important industries in Chile are mining, entrepreneurial and financial services, manufacturing, construction, agriculture (including fishing and forestry), and hospitality and commerce (Banco Central de Chile, 2020).

[78]The Indigenous identification variable started in 2000, so I exclude the two counties treated that year.

specifications and to re-estimate the weights.[79] The balance test for counties below the poverty average indicates that the variables that are statistically different between treated and control groups are: average river water, number of electricity substations, number of electricity substations per km^2, and the km of electricity transmission lines per km^2. The relevant variables for counties above the poverty average are the share of the rural population, average river water, number of electricity substations per km^2, km of electricity transmission lines per km^2, km of electricity transmission lines per $1,000$ inhabitants, and the number of Indigenous conflicts.

Similarly, the relevant variables for counties with a share of Indigenous population below the average are the share of the rural population, number of electricity substations per km^2, number of electricity substations per $1,000$ inhabitants, and km of electricity transmission lines per km^2. Finally, the variables for counties with a share of Indigenous population above the average are the share of the rural population, the number of electricity substations per $1,000$ inhabitants, km of electricity transmission lines per km^2, km of electricity transmission lines per $1,000$ inhabitants, MW of capacity per km^2, the number of Indigenous conflicts, and the number of Indigenous politicians running for office.

2.7 Results

In this section, I present the results from the identification strategy detailed in the previous section. I start with the first-stage event-study results that show the intensity of the treatment for every period after the treatment starts. Recall that the estimator described in equation (2.1) represents the average effect for each period, but it does not have a direct interpretation. This average effect depends on the number of MW built per $1,000$ inhabitants in each period. For instance, if the estimator for period one is 0.1, it means that the average effect of hydro projects in period one is 0.1 per the number of MW built per $1,000$ inhabitants in period one. If there were two MW per $1,000$ inhabitants built in period one, this means that the effect of each MW built per $1,000$ inhabitants was 0.05.

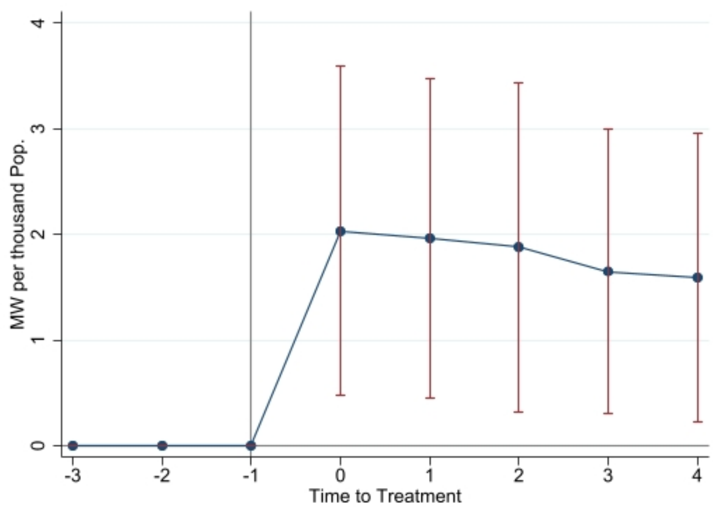
Following the first-stage event-study results, I present the results from the main specification including all outcomes of interest. Subsequently, I present the industry-level analysis to explore the effects on the five most important industries in Chile: construction, mining, agriculture, manufacturing, and hospitality. Finally, I complement the results with the income-level and Indigenous-level specifications.

[79] The weights are similar for all samples, which leads to robust results across the set of weights used.

2.7.1 First-Stage Results

Figure 2.2 shows the first-stage event-study results. In this and the following figures, the 95% confidence intervals are represented by the vertical red lines. Period zero represents the year construction started in each treated county. On the left-hand side of zero, the placebo estimators show the average treatment before construction started, which is, by default, zero (i.e., there cannot be MW build before the construction of the hydro project started in the treated countries). The graph indicates that at periods zero and one, the average treatment intensity is about 2 MW per $1,000$ inhabitants (i.e., on average, there were 2 MW per $1,000$ inhabitants built in periods zero and one). After the post-treatment period two, the treatment intensity decreases, reaching 1.6 MW per $1,000$ inhabitants in period four. The estimates of Figure 2.2 represent the term $MW\ cap \cdot 1,000$ in equation (2.2). Therefore, the results presented in the following sections will be relative to these estimates.

Figure 2.2: First-Stage Event-Study



Note: The 95% confidence intervals are represented by the vertical red lines. Blue line represent the period-by-period trend.

2.7.2 Full Sample Results

After analyzing the industry-level effects on salary, it is important to understand the effects on other variables and across all industries. This assesses the claims that hydro projects will have broad economic benefits to the local communities. Figure 2.3 shows the effects of hydroelectric projects on average salaries, employment, the housing market, and health. Panel a) shows that before treatment started, the logarithm of salary was not statistically different between control and treated counties, which validates the parallel trend assumption. The results show that the hydro project is responsible for increasing salary during the two periods right after the construction begins and disappears from period two onward. In period two, the average effect is a 0.1% salary increase per MW built. As the average plant capacity in my sample is 79 MW, the average effect is about 8%, below the 12.5% found by de Alburquerque et al. (2019).[80]

Panel b) shows that the parallel trend assumption is no violated; however, hydroelectric projects have no significant effects on employment during construction or operation stages. This result raises questions about who is employed in these projects. In the example of Machalí, Pacific Hydro claims to have employed $2,652$ full-time workers during the peak of the construction stage. This is an important labor demand shock for a small county, but I do not observe such a significant effect.[81] It may be the case that a similar number of jobs were destroyed, so the net effect is insignificant. Another explanation is that migrants take the jobs and commute from their neighboring counties. If this is the case, these workers will declare their residencies in their home neighbor county, and I will not see any effects on employment in the treated county.

The housing results are presented in panel c) of Figure 2.3. The placebo estimators suggest that the parallel trend assumption is not violated, although, for period -2, the outcome variable is statistically different from zero between control and treatment counties at the 90% level. There is no statistically significant effect the year construction starts, but one period after, there is a 7.1% statistically significant decrease in the probability of renting a house versus owning a house (considering a 79 MW plant).[82] This negative effect of renting a house goes in line with the salary increase from panel a) and the mechanism described in Section 2.5.2 if workers believe that the labor shock is permanent and when their salary increases, they switch from renting to owning a house. Additionally, it may be that individuals under other living arrangements (e.g., conceded with no ownership, usufruct, or irregular occupancy), which are initially excluded from the estimations in panel c), can own a house, hence, are included in the post-treatment sample. However, the proportion of individuals under other living arrangements is relatively low (about 7% on average), so this

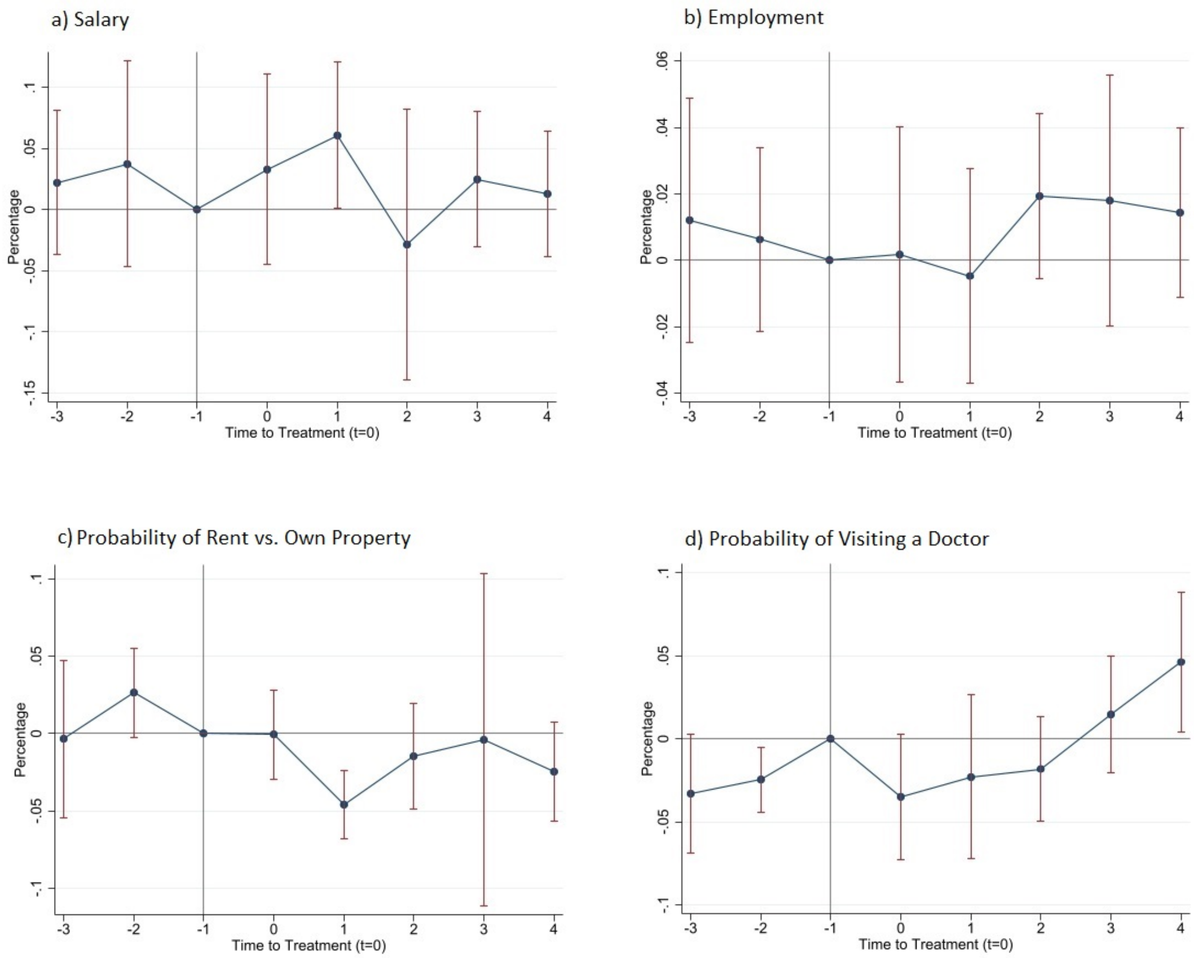
[80]Note that de Alburquerque et al. (2019) analyze plants starting at 100 MW of capacity. Therefore, for a 111 MW capacity, like in the Machalí example, my results would indicate a 9.4% salary increase, which is closer to what the authors find.

[81]The effects shown in Figure 2.3 are averages across all treated units. It may be the case that the in the specific case of Machalí, the employment results are significant during the construction stage; however, I cannot separate the individual effects with my current setting.

[82]The calculation of the housing effect in period two is: $ATET = -0.04\left(\frac{79 \cdot 1{,}000}{27{,}000}\right)\left(\frac{1}{2}\right) \approx -7.1\%$.

is unlikely to affect the results significantly. Finally, panel d) presents the health results; however, the placebo estimators are statistically different from zero, suggesting that my estimates may be biased, so I interpret them cautiously.

Figure 2.3: Main Specification Results



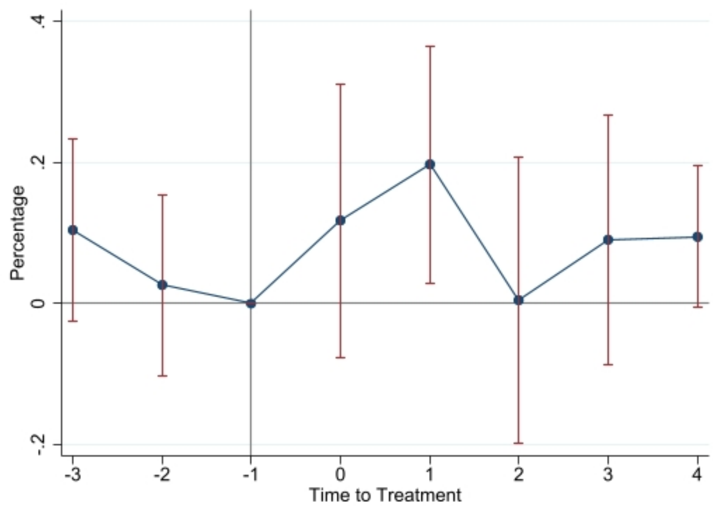
Note: The 95% confidence intervals are represented by the vertical red lines. Blue line represent the period-by-period trend.

The results across industries show a weak positive effect on salaries during the first period after the construction stage starts (i.e., two or three years after the construction starts). However, no long-term effects in any of the outcomes studied. This means that, at the county level in my setting, there is no evidence to support the positive long-term economic effects argued by proponents of hydroelectric projects in Chile.

2.7.3 Results by Industry

Figure 2.4 shows the effects of the hydroelectric projects on the salaries in the construction industry. The format of the figure is the same as the previous results. The placebo estimators test the parallel trend assumption for the pre-treatment periods to the left of zero. In this case, the estimators are not statistically different from zero, which indicates that the parallel trend assumption is satisfied. The graph shows that salaries increase during the construction stage in periods zero and one; however, this effect disappears from period two onward. The only significant estimator at the 95% level is in period one, with a value of about 0.2.

Figure 2.4: Salary Results, Construction Industry



Note: The 95% confidence intervals are represented by the vertical red lines. Blue line represent the period-by-period trend.

Recall that a period means between two and three years in my setting. This means that the effects are only significant after two or three years once the construction starts. Following equation (2.2), the average treatment effect of a 79 MW plant (the average size of a plant in my sample) on the treated counties in period one is a 29% increase in salary, or 0.37% per MW of capacity built. This large effect is only present during the construction peak and quickly disappears after 4 to 6 years (i.e., from period two). In the example of Machalí county detailed in Section 2.3, my results indicate that the average salary increased by 34% in this industry during the peak of the construction stage.[83]

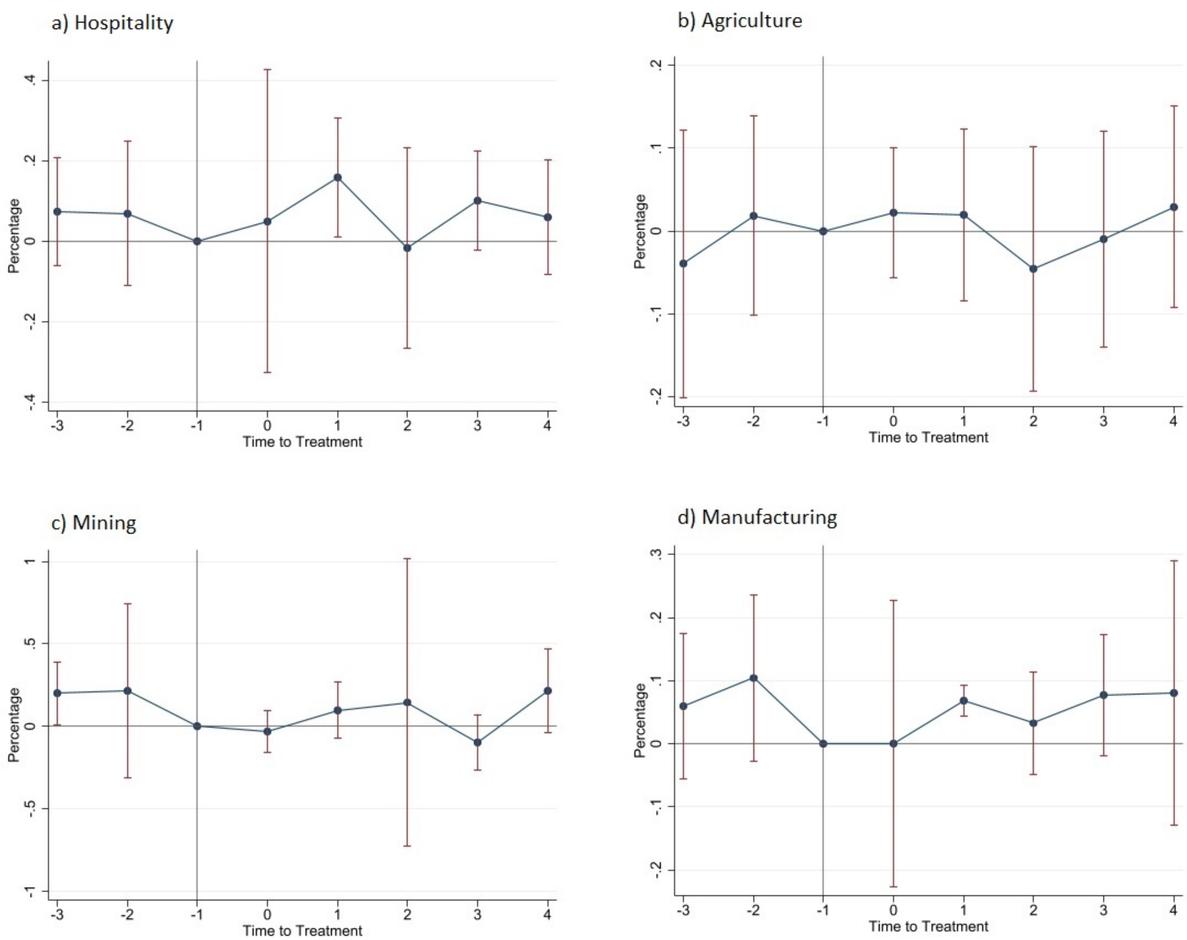
Figure 2.5 shows the results of possible spillover effects to the other four industries. Panel a) of Figure 2.5 shows that in the hospitality industry, there is a significant increase in salary

[83] The calculation of the Machalí example es: $ATET_{Machalí} = 0.2\left(\frac{111 \cdot 1{,}000}{32{,}583}\right)\left(\frac{1}{2}\right) \approx 34\%$.

in period one, but this effect disappears after that. The value of the estimate is 0.15, which corresponds to an average increase of 0.27% per MW of capacity built in the salaries of the hospitality industry (the ATET for a 79 MW plant is 21.9%). Panel b) shows the effects on agriculture, which is often cited as one of the most impacted industries by hydroelectric projects (Duflo and Pande, 2007; da Silva Soito and Freitas, 2011). This industry sees no significant effect on salaries at any period, which may be because the projects in my sample are not big enough to disrupt the agricultural labor market significantly. Additionally, ten of the eleven projects analyzed divert water from the rivers instead of relying on a dam structure, which may decrease the loss of agricultural land.

Panel c) of Figure 2.5 shows the effects on the mining industry. While there are no significant effects, the placebo estimator of period -3 is statistically different from zero, indicating a parallel trend assumption violation. This violation means that the results may be unreliable and must be treated accordingly. Finally, panel d) shows a positive effect on the manufacturing industry in period one. The estimator indicates a salary increase of 0.14% per MW built or 11.7% for a 79 MW plant. This result may be driven by the wood (and wood appliances) industry included in the manufacturing category (Banco Central de Chile, 2020). As large forest areas need to be removed, the wood industry may observe a positive shock in its labor market. Nevertheless, this effect is short-lived and disappears from period two onward.

Figure 2.5: Salary Results, Multiple Industries



Note: The 95% confidence intervals are represented by the vertical red lines. Blue line represent the period-by-period trend.

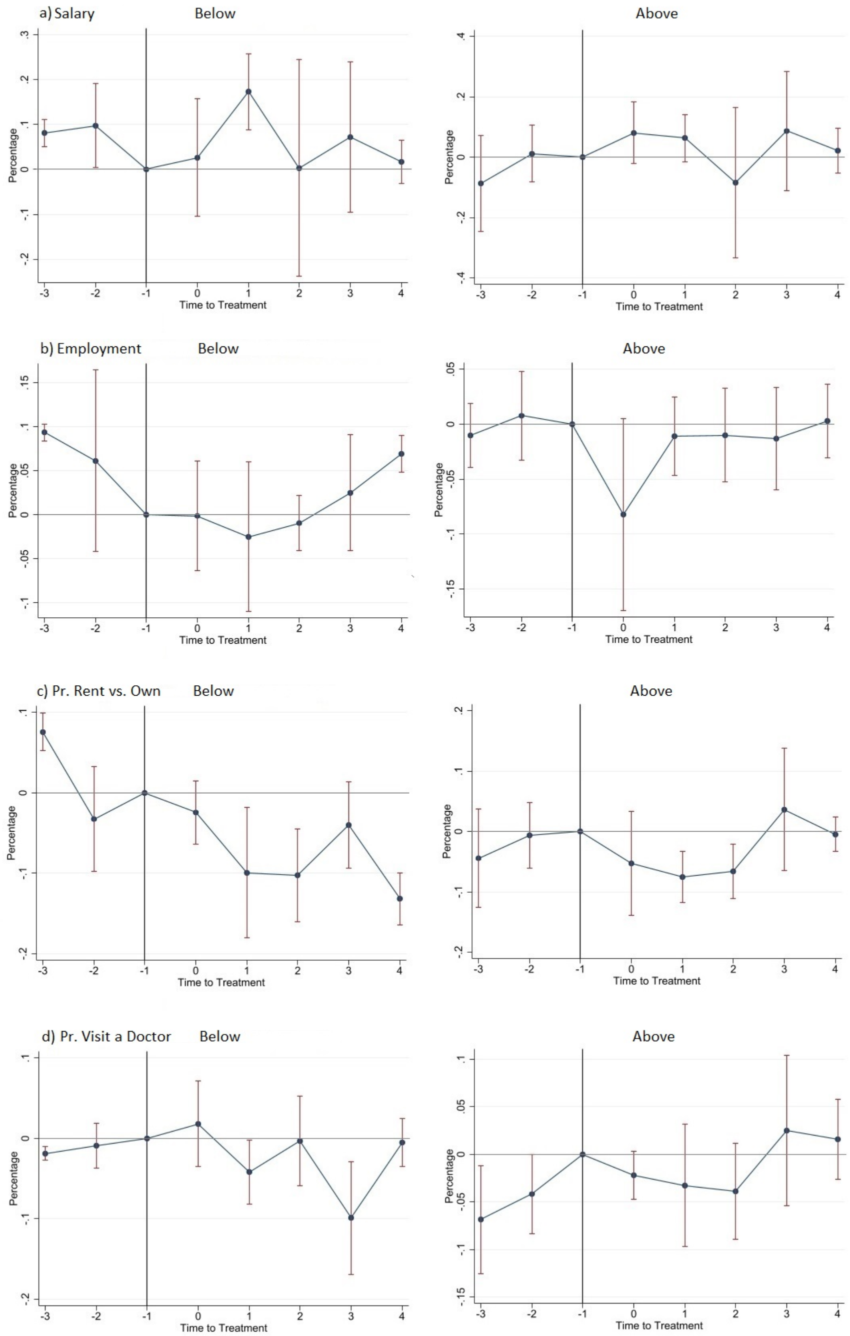
The industry-level results indicate a local effect on salary within these specific industries. As the construction stage of hydroelectric projects is labor intensive, I expected to observe an effect on the salaries of this industry during the peak of the construction stage. As anticipated, this effect disappears after the construction finishes. Additionally, I observe spillover effects in other closely related industries, like hospitality and manufacturing.

2.7.4 Results by Poverty Level

If the government uses hydroelectric projects to boost local economies, it may be that the effects are concentrated in relatively poorer counties. Figure 2.6 shows the results for the four outcome variables, separated by counties below the poverty average (on the left) and above it (on the right). The salary effects in panel a) seem to be concentrated in relatively poor counties; however, the placebo estimators indicate that the parallel assumption is not satisfied for counties below the poverty average (in all four outcomes). This violation of the parallel assumption may be driven by the low number of treated counties in this specification (i.e., three treated counties).

Nevertheless, in the case of relatively rich counties, I can rule out any significant effect on salaries and employment, which indicates that the effects observed in panel a) of Figure 2.3 may be driven by relatively poor counties. Additionally, panel c) indicates that the probability of renting versus owning a house decreases in relatively rich counties for periods one and two. Finally, the placebo estimators in panel d) for counties above the poverty average indicate that the parallel trend assumption is not satisfied.

Figure 2.6: Results per Poverty Level



Note: The 95% confidence intervals are represented by the vertical red lines. Blue line represent the period-by-period trend.

2.7.5 Results by Indigenous Population

As highlighted by Susskind et al. (2014) and Kelly (2018), Indigenous people may be especially negatively affected by the development of hydroelectric projects. Figure 2.7 shows the results for the four outcome variables for counties with an Indigenous population share above the national average (on the left) and counties with an Indigenous population share below the national average (on the right).

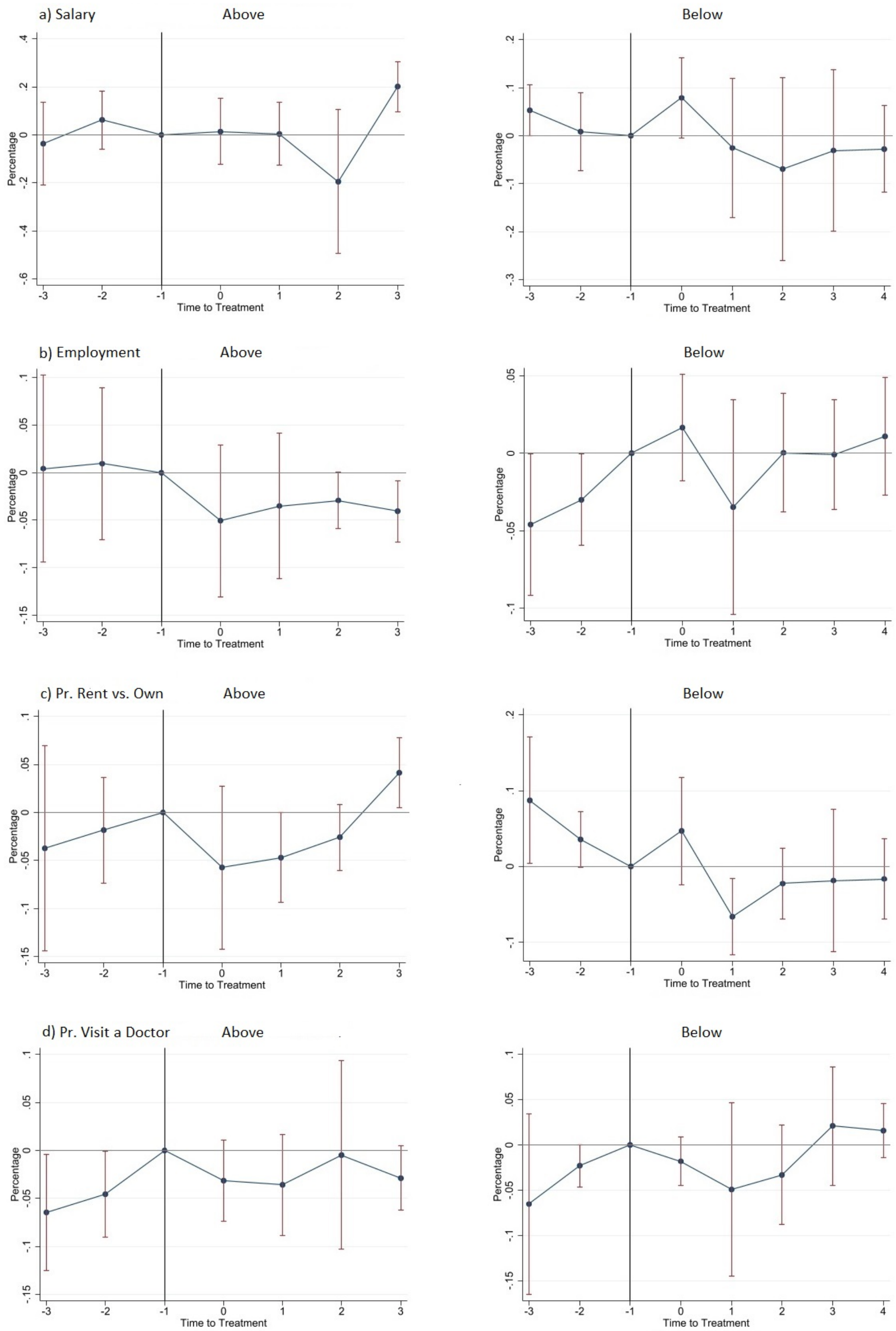
The placebo estimators for the counties with an Indigenous population below the national average violate the parallel trend assumption. Therefore, the analysis is concentrated on the effects of hydro projects on counties with a higher share of Indigenous population.[84] Panel a) shows that salary increases in period three after the construction stage began. Additionally, panels b) and c) show a decrease in employment and an increase in the probability of renting versus owning a house. It may be that workers hired during the construction stage lose their jobs after construction is finished. This would be consistent with channel two discussed in section 2.5.1 (switch between jobs). If workers switch between jobs, we should not observe changes in employment during the construction stage. However, once the construction of the plant is finished, those workers become unemployed, so the probability of being employed decreases.

The three treated counties used in the relatively high percentage of Indigenous specification are the smallest in the sample, with less than $10,000$ inhabitants. Chonchi, one of the three treated counties, has in motion a "Plan for County Development" that aims to attract new businesses and residents to the county (see Soval, 2018, for a detailed description of this plan). The plan started the design stage in 2005, but the construction of local infrastructure (e.g., roads and new neighborhoods) started in 2015. Using the CASEN data, I have estimated that the inflation-adjusted county average salary increased by 47.2% from 2013 to 2017 (there is no data in 2015). This means that the results in the third period after construction starts may be affected by this external shock. Moreover, this county development plan may attract an excess workforce, which would help explain the decrease in employment and the increase in the probability of renting versus owning a property (panels b) and c), respectively).

Finally, the placebo estimators in panel d) show that the parallel trend assumption is not satisfied in the health specification.

[84] The event-study graphs for relatively more Indigenous counties present only three lags because the three projects analyzed only have three post-period data.

Figure 2.7: Results by Indigenous Population



Note: The 95% confidence intervals are represented by the vertical red lines. Blue line represent the period-by-period trend.

2.8 Robustness Checks

2.8.1 Including Previous Hydroelectric Projects

According to Figure 2.1, in Chile, there were 61 counties with active hydroelectric projects, from which 50 were excluded from the main analysis.[85] In this subsection, I analyze the effects of hydroelectric projects, including counties with existing hydro plants (for the purpose of this analysis I will identify them as early treated and the eleven counties analyzed in this paper as late treated). Due to data availability,[86] from the 50 initially excluded counties, only five are considered for this analysis.

If the hydro projects have a significant effect on early treated counties, including them into the control group should biased downward my estimate of the effects on late treated counties. This is because the outcome variables of the control group (including the early treated counties) would be shifted in the same direction as the effects expected in the late treated counties.

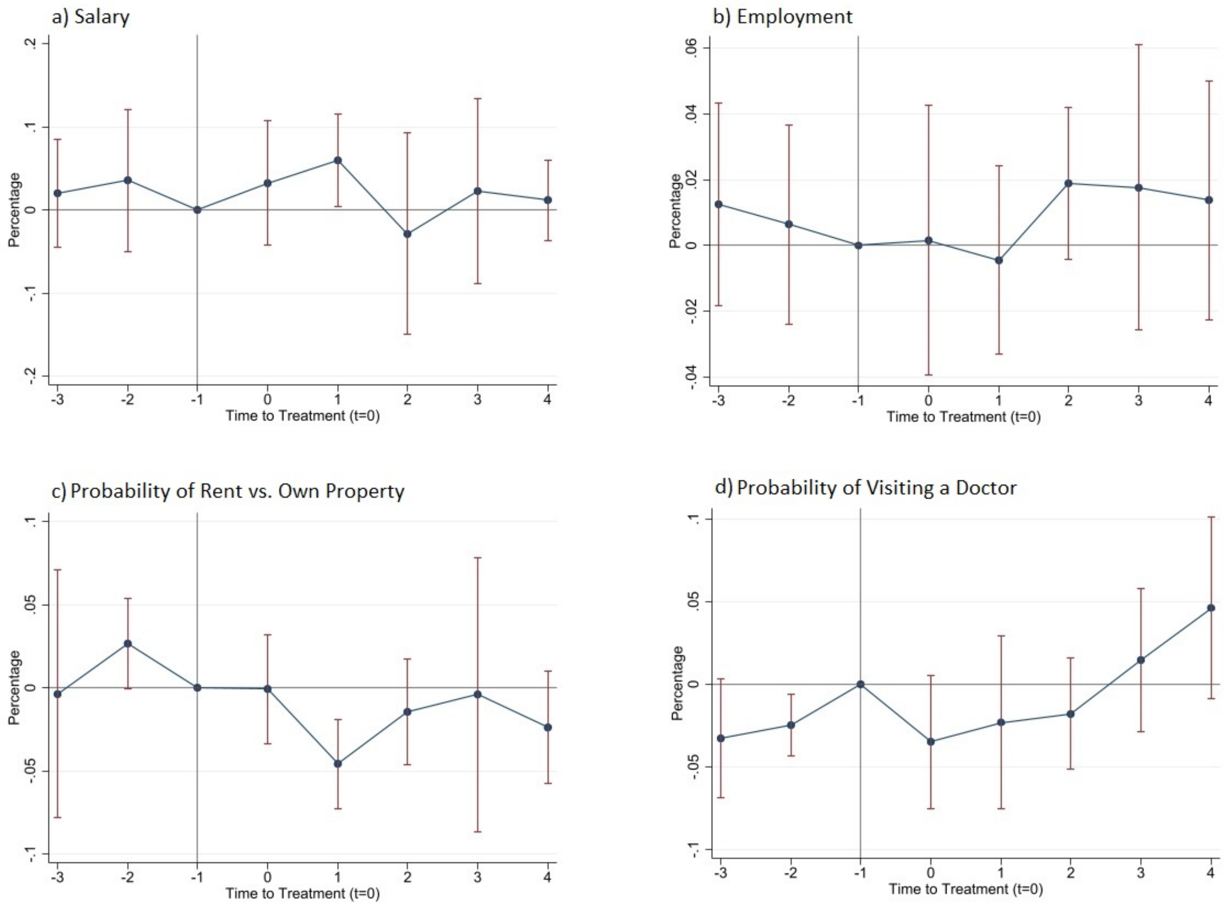
Figure 2.8 presents the results for the four outcome variables. The effects' intensity and direction are similar to those in the main model. Salary increases one period after construction starts, and the probability of renting decreases during the same period. There are no significant effects on employment and health outcomes.

These results suggest that the weights estimated to control for the selection into treatment work well. This is because including counties previously treated does not significantly affect the results; therefore, counties without hydroelectric projects serve well as a control group in the Chilean case.

[85] Eleven counties qualified as treated, so the reminder 50 counties with hydroelectric projects were excluded from the main analysis.

[86] The main data limitation comes from CASEN. In early versions of the survey several counties were not properly represented, so cannot be used. This means that all projects in those counties must be dropped from the analysis.

Figure 2.8: Results Including Previous Hydro



Note: The 95% confidence intervals are represented by the vertical red lines. Blue line represent the period-by-period trend.

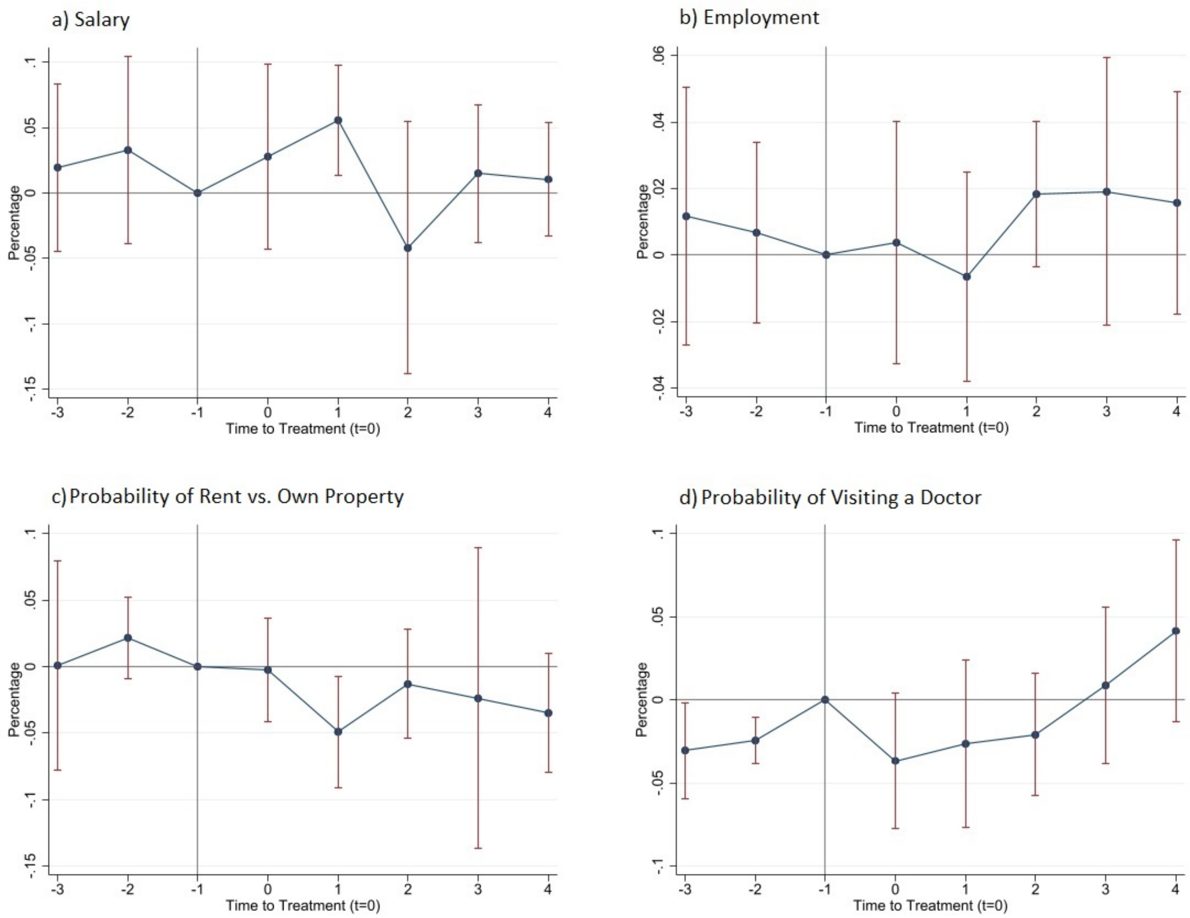
2.8.2 Excluding Neighbor Counties

If workers commute from neighboring counties to the treated counties, spillover effects may bias our results downward. This is because, for example, neighbor counties could see salary benefits. As a result, this would bias down the difference between treated and control groups. In this subsection, I limit the control group to non-neighbor counties, excluding 50 counties from the control group. Excluding neighboring counties will provide us with some intuition on whether between-counties commuting is an issue in our sample.

Figure 2.9 shows that when I exclude the neighbor counties, the results remain similar to the main specification. Panels a) and c) show that the salary and housing effects are similar to the main model, with a slight difference in precision. Further, I do not observe any significant effect on employment and health.

The similarity of these results and the main model suggest that my results are robust to excluding neighboring counties that could bias my results downwards.

Figure 2.9: Results Excluding Neighbor Counties



Note: The 95% confidence intervals are represented by the vertical red lines. Blue line represent the period-by-period trend.

2.9 Conclusions

In this paper, I study the effects of hydroelectric projects on local communities in Chile. In particular, I analyze the effects on salaries, employment, the housing market, and health. I combine data from four independent sources: the Ministry of Social Development of Chile, the Mapuche Data Project, the Center for Climate and Resilience Research, the Chilean Ministry of Energy, and the National Energy Commission. To identify the effects, I rely on a weighted two-way fixed effects difference-in-differences estimator that allows for heterogeneous treatment effects over time and controls for selection into treatment. I define treatment as the beginning of the construction stage, given that most of the investment and labor demand is expected to happen during this stage. To my knowledge, this is the first study that applies a continuous treatment indicator based on the project's capacity and the county population instead of the standard binary indicator. It is particularly important to control for the population-adjusted size of the projects because plant sizes vary greatly across the country.

The results show that two or three years after the beginning of the construction stage, the overall average effect for an average-size plant is an 8% increase in salary and a 7% decrease in the probability of renting versus owning a property. I do not observe any significant effects on employment and health. These results suggest that people that perceive a higher salary are more prone to switch from renting to owning property. Aside from these short-term effects, I do not observe any significant longer-term effects on any of the four variables studied.

Further, the positive salary effects seem to be more prominent in relatively poor counties, while the housing effects are concentrated in wealthier counties. Relatively Indigenous counties see an effect at the end of the construction stage and the beginning of the operation stage of the plant; however, these results may be affected by a large county-wide development policy in one of the treated Indigenous counties analyzed.

According to the standard local labor market theory with frictions (Kline and Moretti, 2014), the significant need for labor during the construction stage puts upward pressure on salaries, which is supported by my results. I observe a 29% increase in salaries within the construction industry during the second and third years after construction started; however, this effect disappears afterwards. I observe spillover effects in the hospitality and manufacturing industries, which show the same evolution as the construction industry. These results show that the construction of a hydro project, in fact, increases salaries, but these effects are short-lived, ending when construction ends. This suggests that the hydroelectric project alone does not encourage the proliferation of other businesses or developments.

As governments worldwide continue supporting hydropower development, this paper's results highlight the importance of backing up this support with empirical evidence. Similarly to Faria et al. (2017), I do not find evidence of long-term benefits for local communities in the Chilean context. The only positive effects are short-lived and during the construction stage of the projects. Policymakers seeking local support for these projects may rely on more comprehensive development strategies. This development strategy could use the hydro project initiatives as a stepping point and incorporate a longer-term vision for the county, including the sustainable development of other industries while respecting the local opinion.

Another possibility to gain local support relies on hydroelectricity's global environmental and economic benefits (e.g., lower electricity prices and pollution). Transferring part of the global benefits to local communities for the long-term use of their surrounding resources may also improve the local perception of these projects. Increasing local benefits may facilitate the development of currently disputed and controversial projects.

My work provides new empirical evidence that contributes to the ongoing debate surrounding financial incentives for infrastructure and energy projects. Governments worldwide provide financial incentives arguing these types of projects boost local economies improving overall welfare. However, there is limited empirical evidence to support such claims. My study, based on my four outcome variables, suggests that policymakers should not rely on hydropower development to boost local economies in the longer run.

It is important to be aware of some limitations of my work. First, the cross-sectional nature of my data does not allow me to study migration patterns. If projects attract temporary workforce from neighbor counties, there may be spillover effects to these neighbor counties. These spillovers would decrease the effects observed in the treated counties of my analysis. Depending on data availability, future research should consider the migration effects of these projects. While empirical evidence suggests that relatively lower-skilled workers are less likely to migrate (Topel, 1986; Bound and Holzer, 2000), it is unrealistic to believe that migration does not happen and that the local labor market fills all jobs created.

Second, in this paper, I analyze the effects of hydro at the county level. While the average county area and population are relatively small, future research with more granular geographic area warrants investigation. Intuitively, the effects could be more substantial in towns and villages close to the projects; however, I anticipate that hydro projects alone will not have the long-term effects expected by policymakers and private developers. This is because of the last decade's tendency to build small and medium-sized projects that, by themselves, do not have the potential to significantly improve the economy in the long term. This, of course, would change if a more comprehensive development strategy accompanied the projects.

Chapter 3

The Effects of Renewable Compensation Policies on Conventional Energy Investment

Abstract

This paper investigates the interaction between renewable energy compensation policies (CPs) and conventional energy capacity investment decisions in a setting with imperfect competition and uncertain demand. Using a two-stage duopoly model, we assume that firms have a fixed amount of renewable capacity and can invest in conventional energy capacity. Conventional output is compensated at market prices, but renewable output can be compensated by two commonly used CPs: a fixed-price feed-in tariff (FiT) and a premium-price FiT. Intuitively, a fixed-price FiT decreases the incentives to exercise market power relatively more, which promotes more competition in the spot market. This pro-competitive effect encourages capacity investment because it allows the firm to expand its spot market output during peak hours when capacity is binding. Nevertheless, the main result of the model shows that modifying the renewable CP has an ambiguous effect on the level of capacity investment, which depends on the relative size of the renewable capacity owned by the firm and its rival. For instance, as the share of renewable output compensated under a fixed-price policy increases, for sufficiently high (low) renewable capacity owned relative to its rival, a firm is encouraged to increase (decrease) its conventional energy capacity investment. With this stylized model, we provide the basic theoretical framework to characterize the relationship between renewable CPs and conventional energy capacity investment. This is especially important to understand, given the continuing focus on transitioning towards renewable energy sources while maintaining a reliable supply through conventional generation.

3.1 Introduction

According to the 2022 Global Status Report (REN21, 2022), renewable energy sources reached an ever-high installed capacity worldwide in 2021. The report indicates that this increased adoption of renewable energy capacity has been largely motivated by different renewable compensation policies (CPs). CPs are usually long-term contracts between regulators and renewable energy producers that specify the electricity price and other conditions for firms to develop renewable energy projects and provide electricity. In particular, we focus on two commonly used CPs: a fixed-price FiT, where the firm receives a fixed dollar amount per megawatt-hour (MWh) generated, and a premium-price FiT, where the firm receives a fixed dollar amount above market prices per MWh generated. Despite the broad deployment of these CPs, there is limited empirical research on their effects on incentives to invest in conventional energy capacity, especially natural gas.[87]

Conventional generation, in the form of natural gas, is expected to remain a key piece of the generation portfolio in the medium term as part of the transition to a lower carbon emissions-intensive portfolio (Milstein and Tishler, 2011).[88] Many jurisdictions worldwide, such as Alberta,[89] Texas,[90] and Greece,[91] are actively incorporating additional natural gas capacity into their energy generation matrix. This coexistence of expanding natural gas capacity and the integration of renewable energy sources underscores the significance of comprehending their interrelation and dynamics.

The primary objective of this paper is to examine the mechanisms by which different CPs interact with investment in conventional energy capacity in a setting with imperfect competition and uncertain demand. We consider a scenario in which firms own a fixed amount of renewable capacity and can invest in conventional capacity to generate and sell electricity. While conventional output is compensated at market prices, renewable output can be compensated through two commonly used CPs: a fixed-price FiT and a premium-price FiT. To conduct our analysis, we build a stylized two-stage duopoly model and complement our main findings with a numerical example.

In the first stage of our model, firms simultaneously and independently decide their conventional capacity investment, which is irreversible and fixed for the rest of the game. In the second stage, firms simultaneously and independently engage in Cournot competition to supply a homogeneous good (i.e., electricity) in response to the realization of spot market demand, taking into account the outcomes of the first stage. Given that the renewable

[87] The International Energy Agency reports that gas-fired generation capacity has steadily increased from 2015 to 2021 (except in 2020, which remained constant, IEA, 2022*a*). The advantages of gas-fired generation complementing renewable energy sources are its low cost and operative flexibility (compared to coal-fired plants).

[88] Energy storage is increasingly used at the wholesale level; however, its wholesale market penetration is still too low to be the only short-term backup option for renewable energy sources (IEA, 2022*b*).

[89] The Cascade Power Project consist in a 900MW combined cycle facility (Cascade Power, 2018).

[90] For example, Net Power LLC announced its plans to build a 300MW natural gas power plant, which would include carbon capture (Net Power, 2022).

[91] Greece has started the construction of a 840MW natural gas plant in Alexandroupolis, with the objective to export power to the Balkan region (GE, 2023).

output is compensated by a fixed-price FiT or a premium-price FiT, we analyze the impacts of these renewable CPs by changing the proportion of renewable output compensated by each CP. This approach allows us to examine how equilibrium capacity investment is influenced.

Our results show that the impact of modifications to renewable CPs on firms' conventional capacity investment is ambiguous and depends on the ownership structure of renewable capacity between firms. For instance, consider the case of symmetric renewable capacity owned by the firms. Increasing a firm's output lowers the market price, which not only reduces the revenue it earns from its conventional generation, but also from any renewable generation subject to the market price plus a premium. Hence, as the proportion of renewable generation subject to a fixed price increases, the firm has an incentive to increase output and capacity, since less of its renewable revenue will be subject to the price reduction. When the firms have symmetric renewable capacity, in equilibrium they both increase output and conventional capacity as the proportion of renewable generation subject to a fixed price increases. Increasing conventional capacity investment decreases the probability of being capacity constrained and allows the firm to increase its conventional output during scarcity periods when it is producing at capacity.

The incentives regarding the choice of conventional capacity and generation change when the renewable capacities of the two firms are very different. In that case, an increase in the proportion of renewable output subject to a fixed price will shift the second-stage best-response function of the firm with the most renewable capacity by a disproportionately large amount, so that the firm with the least renewable capacity decreases its conventional output and capacity. Nevertheless, the total conventional capacity invested in the market unambiguously increases when a fixed-price FiT becomes more dominant. This is because the positive shift in the second-stage best-response function of the firm with the most renewable capacity is always relatively larger than the negative shift of the firm with the least renewable capacity.

Further, our results show that the equilibrium price is negatively affected when a fixed-price FiT becomes more dominant while the total equilibrium market output increases. We illustrate our findings with a numerical example, that shows that consumer surplus increases and firm's profits decrease as more renewable output is compensated by a fixed price. These opposing effects lead to a decrease in total surplus. While informative, our numerical example ignores some real-world features that may affect the direction of the total surplus effects. Therefore, more empirical research is needed to test the robustness of our findings.

This study contributes to the current literature on capacity investment by establishing a direct connection between the renewable CPs adopted by policymakers and firms' conventional capacity investment decisions. Although there is extensive research on conventional capacity investment, the link between renewable CPs and conventional capacity investment has yet to be explored. For instance, several studies examine capacity investment incentives and how those incentives decrease with higher market competition (e.g., Murphy and Smeers, 2005; Milstein and Tishler, 2012; Grimm and Zoettl, 2013). The characteristics of the market and firms have been found to play a vital role in determining the conventional capacity investment chosen by firms (Boom, 2009; Fabra et al., 2011; Brown and Sappington, 2021). Other studies focus on factors that directly affect the profitability of the conventional capacity, such as the ability to exercise market power during peak hours (Brown and Olmstead, 2017) or the volatility of input costs (Gal et al., 2016). However, further investigation is warranted as the ongoing shift towards renewable energy poses new challenges, such as the proper adoption of renewable CPs.

In this context, the transition towards renewable energy sources has been shown to impact not only electricity prices and outputs (Genc and Reynolds, 2019; Ortega et al., 2023) but also the decisions of firms regarding their investments in conventional capacity. For instance, using a two-stage optimization model, Milstein and Tishler (2011) examine the optimal investment mix in renewable and conventional energy capacity under uncertain input prices. Their findings suggest that as solar energy capacity increases, the need for conventional capacity during peak hours decreases, but this also increases the average market price and price volatility. Similarly, Pinho et al. (2018) develop a theoretical model to investigate the impact of renewable energy on firms' incentives to invest in conventional energy sources. They incorporate uncertainty in demand and supply (i.e., supply scenarios with and without wind) and find that introducing renewables leads to lower equilibrium prices and a decrease in conventional capacity investment.

The studies mentioned above assume that renewable output is compensated by market prices. However, many jurisdictions encourage the adoption of renewable energy sources through compensation mechanisms, such as fixed-price FiT and premium-price FiT (REN21, 2022). Previous studies have analyzed these mechanisms and their impact on market outcomes, such as price, output, and carbon dioxide emissions (Oliveira, 2015; Brown and Eckert, 2019; Fabra and Imelda, 2021; Ortega et al., 2023). However, our study advances the literature by examining how these renewable CPs affect firms' conventional capacity investment decisions. To the best of our knowledge, this study is the first to directly analyze the relationship between renewable CPs and conventional capacity investment.

The findings of our study demonstrate that the impact of CPs extends beyond the adoption of renewable energy sources and affects the investment incentives of conventional energy capacity. By providing insights into the directions of these effects and the key parameters to consider, our stylized model offers valuable guidance for policymakers. This is especially important given the increasing focus on transitioning towards renewable energy sources while maintaining a reliable supply. While our model is stylized and simplifies some of the complexities of the real world, our analysis is a helpful tool to draw attention to the spillover effects of renewable CPs on conventional capacity investment.

The rest of the paper is structured as follows. Section 2 describes the model. Section 3 derives the equilibrium outcomes and discusses the main results. Section 4 presents a numerical example to illustrate the main results of the model. Section 5 concludes.

3.2 Model

In our model, two firms compete to supply a homogeneous good (i.e., electricity). In this game, firms make decisions in two stages: in the first stage, each firm $i = 1, 2$ simultaneously and independently decides its level of investment in conventional capacity, K_i, that is fixed and irreversible for the rest of the game. At this stage, the realization of demand is unknown, but the distribution of the demand function is common knowledge to both firms. In the second stage, taking K_i, the realization of the spot market demand, and the renewable capacity R_i own by each firm as given, firms simultaneously and independently engage in Cournot competition to supply electricity in the spot market. Consistent with previous studies, we rely on Cournot competition to model the dynamics of a wholesale electricity market with strategic firms (Milstein and Tishler, 2011; 2012; Mendes and Soares, 2014; Pinho et al., 2018).

The spot market demand is denoted by the inverse linear demand curve $P(Q) = a - \beta Q$, where a and β are positive parameters. Firms face demand uncertainty characterized by the parameter a, which follows a uniform distribution $a \sim U\left[\underline{a}, \overline{a}\right]$, and this distribution is common knowledge for both firms. We assume $\beta = 1$ for analytical tractability, but our main conclusions are robust to this simplification. The total quantity supplied in the spot market is defined as $Q = q_1 + q_2 + \alpha(R_1 + R_2)$, where q_1 and q_2 represent the conventional outputs of firm 1 and 2, respectively, R_1 and R_2 represent the exogenous renewable capacity owned by each firm, and α represents the capacity utilization of the renewable generation.[92] To simplify notation, we assume throughout the paper that $\alpha = 1$, but our results are robust to smaller values of α. For expositional purposes, we assume a single spot market with different possible demand realizations, but the main conclusions hold if we extend the model to have multiple spot market periods.

The cost function for the conventional generation of firm i, given capacity K_i, is given by $C_i(q_i) = c_i q_i$ for $q_i \leq K_i$, where $c_i > 0$. We restrict firms' conventional output to be at or below their maximum capacity. Additionally, the cost per MW of investing in new conventional capacity is given by $C_i^K(K_i) = \omega_i K_i$, where ω_i is a positive constant. For simplicity and following previous studies (Fabra et al., 2011; Milstein and Tishler, 2011), we assume symmetric constant marginal cost for conventional generation and capacity investment (i.e., $c_i = c_j = c$ and $\omega_i = \omega_j = \omega$, with $\omega < \frac{\overline{a}-\underline{a}}{2}$).[93] We assume that renewable energy generation has zero marginal cost and renewable output is always dispatched; however, in equilibrium, we assume that renewable output does not fully satisfy total demand. Therefore, in equilibrium, the market always requires a positive amount of conventional output to meet total spot market demand.

Conventional generation is compensated at the spot market price. Renewable output is compensated either by a fixed-price FiT, represented by $\overline{P}_i$ per MW of output, or by a premium-price FiT that pays the firm the market price, $P(Q)$, plus a premium, m_i, per MW of output. This means that the total price per MW of output perceived by the firms under a premium-price FiT is $P(Q)+m_i$. Additionally, define $\delta \in [0, 1]$ as the proportion of renewable output compensated by a fixed-price FiT, and $(1-\delta) \in [0, 1]$ as the proportion of renewable output compensated by a premium-price FiT. Both firms face the same δ, meaning they have the same fraction of their renewable output compensated by each CP. This assumption is based on our interest in analyzing how changes in renewable compensation at the market level affect conventional capacity investment decisions. Analyzing changes in renewable compensation at the market level excludes the possibility of having a different δ for each

[92]Contrary to Milstein and Tishler (2011), in which renewable energy capacity is endogenous, we are interested in the CPs and their effect on conventional capacity investment. To better isolate these effects, we define renewable capacity exogenously.

[93]Note that $\omega < \frac{\overline{a}-\underline{a}}{2}$ assumes that the capacity investment cost is positively related to demand uncertainty. As uncertainty increases (i.e., $(\overline{a}-\underline{a}) \rightharpoonup \infty$), the capacity investment cost increases. This assumption is line with the evidence showing that firms facing higher demand uncertainty have a more rigid short-run cost structure with higher fixed and lower variable costs (Banker et al., 2014; Hagspiel et al., 2016).

firm, which is outside of the scope of this paper. Further, renewable CPs are often defined at the market rather than the firm level.[94][95]

We assume that firms are risk neutral and have complete market information (i.e., firms know their rival's profit functions, capacity choices, cost structure, and the distribution of demand realization). We use backward induction to solve for the Subgame Perfect Nash Equilibrium (SPNE).

3.3 Equilibrium Analysis

In this section, we characterize the SPNE of the game using backward induction, starting with the second stage (spot market). After deriving the equilibrium outcomes in the spot market, we characterize the optimal capacity investment decision in the first stage. In this first stage, each firm maximizes its expected profit function. We finish this section with a discussion regarding the effects of the compensation policies on the equilibrium capacity investment.

3.3.1 Spot Market Equilibrium

In this stage, we derive the equilibrium outcomes assuming that, as the market demand function shifts outward, firm i is constrained before than firm j, where $i, j = 1, 2$, with $i \neq j$ (i.e., firm i optimal output reaches its maximum capacity before firm j). Note that with this notation, we include in the analysis the cases when firm 1 is capacity-constrained first and when firm 2 is capacity-constrained first. This allows us to include all possible scenarios in our analysis. At this stage, the firms take the capacity investments, K_i, and the realization of demand as observable and given. We consider three possible cases based on the realization of the demand parameter a: low demand (i.e., low values of a), when neither firm is capacity constrained; medium demand (i.e., intermediate values of a), when firm i is capacity constrained and firm j is not; and high demand (i.e., high values of a), when both firms are capacity constrained.

3.3.1.1 Low Demand: Unconstrained Firms

The demand parameter a is sufficiently low in this case, so neither firm is capacity con-

[94] Refer to AESO (2016) for an example in Alberta, and Couture and Gagnon (2010) for a comparison among several jurisdictions across Europe and North America that employ different renewable CPs.

[95] To ensure that firms produce positive amounts of conventional output, we assume that the lowest demand realization, net from renewable capacity for a given δ, is sufficiently high to offset the marginal cost of conventional generation (i.e., $\underline{a} - R_i(3 - 2\delta) - \delta R_j > c$ for $i, j = 1, 2$, with $i \neq j$).

strained. Firm $i = 1, 2$ aims to maximize its spot market profits according to the following spot profit function:

$$\pi_i^u(q_1^u, q_2^u) = [P(Q) - c]\, q_i^u + \overline{P}_i \delta R_i + (P(Q) + m_i)(1 - \delta) R_i, \tag{3.1}$$

where q_i^u represents the unconstrained conventional output for firm i, which is compensated at the spot price $P(Q)$. Additionally, a fraction $\delta \in [0, 1]$ of the renewable energy output R_i is compensated at a fixed price $\overline{P}_i$, while the remaining fraction $(1-\delta) \in [0, 1]$ is compensated at the spot price plus the premium m_i.

Solving the corresponding first order conditions and focusing on interior solutions, we derive the equilibrium outputs, prices, and profit functions for the unconstrained case for firms $i, j = 1, 2$, with $i \neq j$:

$$q_i^{u*} = \frac{a + \delta(2R_i - R_j) - 3R_i - c}{3} \; ; \; q_j^{u*} = \frac{a + \delta(2R_j - R_i) - 3R_j - c}{3} \tag{3.2}$$

$$P^{u*} = \frac{a + 2c - \delta(R_i + R_j)}{3} \tag{3.3}$$

$$\pi_i^{u*} = (P^{u*} - c) q_i^{u*} + \overline{P_i} \delta R_i + (P^{u*} + m_i)(1 - \delta) R_i \tag{3.4}$$

$$\pi_j^{u*} = (P^{u*} - c) q_j^{u*} + \overline{P_j} \delta R_j + (P^{u*} + m_j)(1 - \delta) R_j \tag{3.5}$$

To ensure that firms produce positive amounts of conventional output, we assume that the lowest demand realization, net from renewable capacity for a given δ, is sufficiently high to offset the marginal cost of conventional generation (i.e., $\underline{a} + \delta(2R_i - R_j) - 3R_i > c$ for $i, j = 1, 2$, with $i \neq j$).

In this unconstrained case, we use firm i's equilibrium output of equation (3.2) to determine the highest value of a at which firm i is not capacity constrained (recall, firm i denotes the firm that is constrained first). This value is denoted by a_i, where $\underline{a} \leq a_i < \overline{a}$:

$$q_i^{u*} \leq K_i \quad \Longleftrightarrow \quad a_i = 3K_i + 3R_i + c - \delta(2R_i - R_j) \tag{3.6}$$

If the realization of a is greater than a_i, such that firm j still produces below its maximum capacity, we are in the medium demand case where firm i is capacity constrained and firm j is not.

3.3.1.2 Medium Demand: Only Firm i is Capacity Constrained

Following equation (3.6), we define a medium demand realization to reflect a setting where firm i is capacity constrained in equilibrium (i.e., $a > a_i$), but its rival is not. In this case, the equilibrium output of firm i is $q_i^{K_i*} = K_i$. The subscript represents the firm that is constrained first, in this case firm i reaches its maximum capacity K_i. As we assume that firm j is not capacity constrained, equation (3.1) for $i, j = 1, 2$, with $i \neq j$ becomes:[96]

$$\pi_i^{K_i}(K_i, q_j^{K_i}) = [P(Q) - c]\, K_i + \overline{P}_i \delta R_i + (P(Q) + m_i)(1 - \delta) R_i \tag{3.7}$$

$$\pi_j^{K_i}(K_i, q_j^{K_i}) = [P(Q) - c]\, q_j^{K_i} + \overline{P}_j \delta R_j + (P(Q) + m_j)(1 - \delta) R_j, \tag{3.8}$$

where equations (3.7) and (3.8) represent the spot profit function for firms i (i.e., the firm that is capacity constrained) and j, respectively, assuming that $q_j^{K_i}$ is such that firm i's best response is K_i.

Solving the corresponding first-order conditions yields the following equilibrium outputs, price, and profit functions:

$$q_i^{K_i*} = K_i \;;\; q_j^{K_i*} = \frac{a - K_i - R_i - 2R_j - c + \delta R_j}{2} \tag{3.9}$$

$$P^{K_i*} = \frac{a - K_i + c - R_i - \delta R_j}{2} \tag{3.10}$$

$$\pi_i^{K_i*} = (P^{K_i*} - c) K_i + \overline{P_i} \delta R_i + (P^{K_i*} + m_i)(1 - \delta) R_i \tag{3.11}$$

$$\pi_j^{K_i*} = (P^{K_i*} - c) q_j^{K_i*} + \overline{P_j} \delta R_j + (P^{K_i*} + m_j)(1 - \delta) R_j \tag{3.12}$$

Note that, in this case, the spot output and profits depend on whether firm 1 or 2 is capacity constrained first.

Now suppose that there exists an a_j, where $a_i \leq a_j \leq \overline{a}$ that represents the minimum value of a where firm j is capacity constrained in equilibrium. This means that for any $a_i \leq a < a_j$ firm i is capacity constrained and firm j is not, and for any $a_j \leq a \leq \overline{a}$, both firms are capacity constrained. Using the equilibrium spot output of firm j in equation (3.9), we obtain an expression for a_j as follows:

$$q_j^{K_i*} \leq K_j \quad \Longleftrightarrow \quad a_j = 2K_j + K_i + R_i + 2R_j + c - \delta R_j, \tag{3.13}$$

which provides the highest value of a where firm j is not capacity constrained. If the realization of a is greater than a_j, then we are in the case where both firms are capacity

[96] Note that the spot profit function to be maximized depends on whether the firm is constrained first. Hence, the two different spot profit functions.

constrained.

3.3.1.3 High Demand: Both Firms are Capacity Constrained

If the realization of a falls between a_j and $\overline{a}$, we are in the high demand scenario where both firms are capacity constrained in equilibrium and their optimal output choices are equal to their capacities (i.e., $q_i^{c*} = K_i$ and $q_j^{c*} = K_j$ for $i, j = 1, 2$, with $i \neq j$). In this case, the spot price is $P^{c*} = a - K_i - K_j - R_i - R_j$ and their profit functions are $\pi_i^{c*} = (P^{c*} - c)K_i + \overline{P}_i \delta R_i + (P^{c*} + m_i)(1-\delta)R_i$ and $\pi_j^{c*} = (P^{c*} - c)K_j + \overline{P}_j \delta R_j + (P^{c*} + m_j)(1-\delta)R_j$ $\forall\ i, j = 1, 2$, with $i \neq j$. These results are independent on whether firm 1 or 2 is capacity constrained first. Note that firms are capacity constrained, so δ has no effect on output decisions. Lemma 1 summarizes the spot market equilibrium structure.

Lemma 1 *In the spot market, for given capacities and demand realization, the equilibrium structure is characterized as follows:*

1. *Low Demand: If $\underline{a} \leq a < a_i$, firms are not constrained by their capacities and sell their conventional output q_i^{u*} and q_j^{u*} at price P^{u*}.*

2. *Medium demand: If $a_i \leq a < a_j$, firm i is capacity constrained and firm j is not. In this firm i sells all its conventional capacity, K_i, and firm j sells $q_j^{K_i *}$ at price $P^{K_i *}$*

3. *High Demand: If $a_j \leq a \leq \overline{a}$, both firms are capacity constrained so they sell all their conventional capacity, K_i and K_j, at price P^{c*}.*

Where $a_i = 3K_i + 3R_i + c - \delta(2R_i - R_j)$ and $a_j = 2K_j + K_i + R_i + 2R_j + c - \delta R_j$.

3.3.2 Capacity Investment Equilibrium

Once the equilibrium outcomes in the spot market have been derived for each possible demand realization, we proceed to the first stage of our model. In this stage, firms simultaneously and independently choose their conventional capacity investments, considering how these capacities will affect the equilibrium in the spot market. Given that the firms' expected profits depend on what firm is capacity constrained first, we switch notation to express the capacity investment problem in terms of firm 1 and 2. Firm 1's expected profits, as a function of K_1 and K_2 for the cases when firm 1 is capacity constrained first (i.e., $a_1 = 3K_1 + 3R_1 + c - \delta(2R_1 - R_2) < a_2 = 3K_2 + 3R_2 + c - \delta(2R_2 - R_1)$) and when firm 2 is capacity constrained first (i.e., $a_2 = 3K_2+3R_2+c-\delta(2R_2-R_1) < a_1 = 3K_1+3R_1+c-\delta(2R_1-R_2)$), are given by:[97]

$$E\left[\pi_1(K_1,K_2)\right] = \begin{cases} \int\limits_{\underline{a}}^{a_1} \pi_1^{u*}h(a)da + \int\limits_{a_1}^{a_2} \pi_1^{K_1*}h(a)da + \int\limits_{a_2}^{\overline{a}} \pi_1^{c*}h(a)da - \omega K_1 & \text{if } a_1 < a_2 \\ \int\limits_{\underline{a}}^{a_2} \pi_1^{u*}h(a)da + \int\limits_{a_2}^{a_1} \pi_1^{K_2*}h(a)da + \int\limits_{a_1}^{\overline{a}} \pi_1^{c*}h(a)da - \omega K_1 & \text{if } a_2 < a_1, \end{cases} \tag{3.14}$$

where the equilibrium profits come from the spot market equilibrium structure illustrated in Lemma 1 and $h(a)$ represents the probability density function of the uniform distribution of a (i.e., $h(a) = \frac{1}{\overline{a}-\underline{a}}$). Employing the Leibniz Rule to differentiate equation (3.14) and rearranging terms, we obtain the following first order conditions for firm 1, assuming $a_1 < a_2$ (note that the final result is analogous if we assume the second case where $a_2 < a_1$):[98]

$$\frac{\partial E\left[\pi_1(\cdot)\right]}{\partial K_1} = \int_{a_1}^{a_2} \frac{\partial \pi_1^{K_1*}}{\partial K_1} h(a)da + \int_{a_2}^{\overline{a}} \frac{\partial \pi_1^{c*}}{\partial K_1} h(a)da - \omega = 0 \tag{3.15}$$

$$\frac{\partial E\left[\pi_2(\cdot)\right]}{\partial K_2} = \int_{a_2}^{\overline{a}} \frac{\partial \pi_2^{c*}}{\partial K_2} h(a)da - \omega = 0, \tag{3.16}$$

where equation (3.15) represents the equilibrium condition for the firm that gets capacity constrained when realized demand is medium (in this case firm 1), and equation (3.16) represents the equilibrium condition for the firm that gets capacity constrained only with the high demand realization (in this case firm 2).

From equations (3.15) and (3.16), we observe that firms will invest in capacity until their marginal benefit equals its marginal cost ω. The marginal benefit of the capacity is driven by the cases when capacity is binding. For firm 1, this means cases with medium and high demand, while for firm 2, only the case of high demand. The marginal unit of capacity invested has two opposing effects on profits when capacities are binding. To illustrate the medium demand case for firm 1, it can be shown that the derivative of firms 1's realized profit in the medium demand case is defined by:

$$\frac{\partial \pi_1^{K_1*}}{\partial K_1} = \frac{\partial P^{K_1*}}{\partial K_1}\left[K_1 + (1-\delta)R_1\right] + P^{K_1*} - c = 0 \tag{3.17}$$

[97]Note that firm j's expected profits are analogous to equation (3.14), but replacing firm i's profit expressions for firm j's.

[98]Refer to Appendix 12 for a detailed derivation of the capacity investment stage.

The term $\frac{\partial P^{K_1*}}{\partial K_1}[K_1 + (1-\delta)R_1]$ represents the disincentive of capacity investment: as capacity expands, the marginal profit of firm 1 decreases because it puts downward pressure on the spot price (note that $\frac{\partial P^{K_1*}}{\partial K_1} < 0$). Notably, as δ approaches one (i.e., fixed-price FiT dominates) in equation (3.17), there is less renewable output exposed to the spot market price, which decreases the disincentive effect of the capacity expansion, thereby strengthening capacity expansion incentives. However, the second term of equation (3.17), P^{K_1}, depends negatively on δ,[99] which decreases the capacity expansion incentives, creating a trade-off that will be further investigated in subsection 3.3.3. Note that in the case when firm 1 is capacity constrained and firm 2 is not, $\frac{\partial \pi_2^{K_1*}}{\partial K_2} = 0$ because firm 2 is not capacity constrained in the medium demand scenario. Further, the trade-off expressed in equation (3.17) also arises in the region of $a > a_j$. This is because $\frac{\partial \pi_1^{c*}}{\partial K_1} = \frac{\partial P^{c*}}{\partial K_1}[K_1 + (1-\delta)R_1] + P^{c*} - c = 0$, which contains the same negative and positive effects of δ.

Solving equations (3.15) and (3.16) with respect to K_1 and K_2 and checking the second-order conditions, we obtain the optimal capacity investment for each firm.[100] Lemma 2 presents the solution for the optimal capacity investment decision for firms 1 and 2.

Lemma 2 *In the conventional capacity investment stage, there is a unique solution for the equilibrium conventional capacity investment independent of what firm is capacity constrained first. Each firm chooses its equilibrium conventional capacity investment, denoted by K_1^* and K_2^*, following:*[101]

$$K_1^* = \frac{\overline{a} - c - 3R_1 + \delta(2R_1 - R_2) - \sqrt{2\omega(\overline{a} - \underline{a})}}{3} \tag{3.18}$$

$$K_2^* = \frac{\overline{a} - c - 3R_2 + \delta(2R_2 - R_1) - \sqrt{2\omega(\overline{a} - \underline{a})}}{3} \tag{3.19}$$

Note that the equilibrium conventional capacity investment described in Lemma 2 is independent of what firm is capacity constrained first. This is because we assume symmetry in their cost structure (for conventional output and capacity investment), and the results only depend on the relative size of their renewable capacity.

[99] The equilibrium price when only firm 1 is capacity constrained is $P^{K_1*} = \frac{a - K_1 - R_1 + c - \delta R_2}{2}$, hence $\frac{\partial P^{K_1*}}{\partial \delta} = -\frac{R_2}{2}$.

[100] Refer to Appendix 13 for the proof regarding solution feasibility.

[101] Similar to Section 3.1.1, we assume that $\underline{a} - R_i(3 - 2\delta) - \delta R_j > c + \sqrt{2\omega(\overline{a} - \underline{a})}$ for $i, j = 1, 2$, with $i \neq j$, which ensures that conventional capacity investments are never negative. Additionally, recall that q_i^{u*} is always smaller than K_i^* for any $a < a_1$, and it is equal to K_i^* otherwise.

3.3.3 Impacts of δ

This section examines how renewable CPs impact investment incentives. We begin analyzing the spot market under the three possible demand realizations and the overall effect of δ on the expected equilibrium spot output and price. Subsequently, we move on to the capacity investment decision and how it is affected by δ.

3.3.3.1 Spot Market

We begin with Proposition 1 and investigate how the equilibrium outcomes in the spot market are affected when we vary the proportion of renewable output compensated by each renewable CP, holding capacities constant. Recall that the parameter of interest is represented by $\delta \in [0,1]$. As δ approaches one (zero), renewable output is compensated by a fixed-price (premium-price) FiT. Proposition 1 summarizes how the value of δ affects the spot market outcomes.

> ***Proposition* 1** *In the spot market stage, for each demand realization and firms* $i, j = 1, 2,$ *with* $i \neq j$*, the equilibrium output change as we vary the renewable compensation policy used (i.e.,* δ*) as follows:*

$$(i).\frac{\partial q_i^{u*}}{\partial \delta} = \begin{cases} > 0 & if\ 2R_i > R_j \\ = 0 & if\ 2R_i = R_j \\ < 0 & if\ 2R_i < R_j \end{cases} \qquad (ii).\frac{\partial q_i^{K_i*}}{\partial \delta} = 0 \qquad (iii).\frac{\partial q_j^{K_i*}}{\partial \delta} > 0 \qquad (iv).\frac{\partial q_i^{c*}}{\partial \delta} = \frac{\partial q_j^{c*}}{\partial \delta} = 0$$

Proposition 1 summarizes the effects of varying the share of renewable output compensated by each compensation policy on the spot market equilibrium output for each demand realization. From (i), an increase in δ has an ambiguous effect on the unconstrained output, and it depends on the relative renewable capacity owned by each firm. If firm i owns a sufficiently large renewable capacity compared to its rival, then an increase in δ increases its spot market output; however, the opposite happens when firm i owns a sufficiently small renewable capacity relative to its rival (note that the analysis is analogous from the point of view of firm j). This effect can be understood using the opportunity cost intuition.

An opportunity cost to the firm of selling an additional unit of conventional output is that it earns a lower price on the renewables it owns that are covered under a premium-price FiT. Now, when δ increases, that decreases the marginal cost of each firm (including the opportunity cost), but by different amounts depending on how much renewable capacity each firm has. This ambiguous effect is illustrated by the best response functions derived from equation (3.2).[102] In equilibrium, changes in δ shift the best response functions of firms i and j in different magnitudes. For instance, suppose that R_1 is sufficiently large but R_2 is small, then as δ increases, the total amount of renewables subject to a premium-price FiT falls a lot for firm 1 but not much for firm 2. As a result, with an increase in δ, the lost renewable revenues to firm 1 from an additional unit of conventional output becomes much less, while for firm 2 it only falls by a small amount. Hence, as δ is increased, firm 1's best response function shifts out a lot, while firm 2's shifts out a little, potentially resulting in firm 1's output increasing while firm 2's output decreases.

Further, at the point when $2R_i = R_j$, the two channels offset each other for firm i, resulting in no change in its spot output with changes in δ. Note that when $2R_i = R_j$, it must be true that $2R_j > R_i$ (i.e., firm j owns a sufficiently large share of the total renewable capacity), so while firm i does not change its spot output because the two channels explained above offset each other, firm j increases its spot output. In our model, the point where $2R_i = R_j$ indicates the threshold for firm i's renewable capacity to be considered sufficiently large or small. As δ determines the payment mechanism received by the renewable output, owning a relatively large or small amount compared to its rival will determine the final effect of δ on the spot output and, subsequently, on the conventional capacity investment.

Continuing with Proposition 1, when capacity is binding for firm i, changes in δ do not affect its spot market output, as indicated in (*ii*). This is because the firm has no incentives to decrease its production, and the firm wants to increase its production, but it is capacity constrained. On the other hand, for firm j, the effect is unambiguously positive according to (*iii*), meaning that an increase in the proportion of renewable output compensated by a fixed-price FiT leads to an increase in firm j's spot market output. This is because firm i does not react to the change in δ, limiting the strategic substitution of firm j's output as q_j^{u*} varies. Further, the pro-competitive impact of the fixed-priced CP still exists. This results in an increase of firm j's conventional generation output. Lastly, when firms are already producing at their maximum capacities, as stated in (*iv*), changes in δ do not affect the spot market outputs.

Next, we turn our attention to Proposition 2, which presents the effects of δ on the

[102] The best response function for firm i is $q_i^u(q_j^u) = \frac{a_t - q_j^u - 2R_i - R_j - c + \delta R_i}{2}$, which is analogous for firm j. The best response function shows that δ affects firms i equilibrium output through the effect on its rival's output, q_j^u, and directly through $\frac{R_i}{2}$.

overall expected spot output and price levels.

Proposition 2 *In the spot market stage, for any demand realization and firms $i, j = 1, 2$, with $i \neq j$, the expected output and expected price change as we vary the renewable compensation policy used (i.e., δ) as follows:*

$$(i). \frac{\partial E(q_i^*)}{\partial \delta} = \frac{2R_i - R_j}{3(\overline{a} - \underline{a})}\left[\overline{a} - \underline{a} - \sqrt{2\omega(\overline{a} - \underline{a})}\right] \quad (ii). \frac{\partial E(P^*)}{\partial \delta} = -\frac{R_i + R_j}{3(\overline{a} - \underline{a})}\left[\overline{a} - \underline{a} - \sqrt{2\omega(\overline{a} - \underline{a})}\right]$$

Proposition 2 summarizes the effects of changing δ on the expected spot output and price. Note that the results of (i) are analogous for firm j.[103] From (i), the effect of δ on the expected spot market output is ambiguous and depends on the relative size of the renewable capacity owned by each firm. Similar to (i) in Proposition 1, when $2R_i > R_j$ ($2R_i < R_j$) the expected spot output of firm i increases (decreases) as δ increases, and it is unchanged when $2R_i = R_j$.[104] Note that, while the effects of the individual firm's expected output is ambiguous, δ has an unambiguous positive effect on total market output (i.e., as delta approaches one total market output increases). As shown in (ii), the effect of increasing δ on the expected spot price is unambiguously negative (recall that $\overline{a} - \underline{a} - \sqrt{2\omega(\overline{a} - \underline{a})} > 0$). This means that, the spot price decreases as a fixed-price FiT becomes more dominant in the market, which supports the pro-competitive effect of a fixed-price FiT documented in previous studies (Brown and Eckert, 2019; Ortega et al., 2023).

3.3.3.2 Capacity Investment

We analyze how changes in δ affect firms' incentives to invest in new conventional capacity, as discussed in Lemma 2. Proposition 3 summarizes the relationship between the optimal capacity investment and δ.

***Proposition* 3** *In the conventional capacity investment stage, for each demand realization and firms $i, j = 1, 2$, with $i \neq j$, the equilibrium conventional capacity investment changes as we vary the renewable compensation policy used (i.e., δ) as follows:*

[103] The marginal effect of δ on firm j's expected spot output is $\frac{\partial E(q_j^*)}{\partial \delta} = \frac{2R_j - R_i}{3(\overline{a} - \underline{a})}\left[\overline{a} - \underline{a} - \sqrt{2\omega(\overline{a} - \underline{a})}\right]$.

[104] As mentioned in Appendix 2, throughout the model we assume that $\omega < \frac{\overline{a} - \underline{a}}{2}$, which ensures that $\overline{a} - \underline{a} - \sqrt{2\omega(\overline{a} - \underline{a})} > 0$.

$$\frac{\partial K_i^*}{\partial \delta} = \begin{cases} > 0 & if\ 2R_i > R_j \\ = 0 & if\ 2R_i = R_j \\ < 0 & if\ 2R_i < R_j \end{cases}$$

Proposition 3 shows that δ has an ambiguous effect on the equilibrium conventional capacity invested by the firms.[105] Similar to the unconstrained case of Proposition 1, the effects of changing the proportion of renewable output paid a fixed-price FiT and a premium-price FiT depend on the relative size of firms' renewable capacity.

First, suposse firm i's renewable capacity is sufficiently large relative to its rival. In that case, an increase in the share of renewable output compensated by a fixed-price FiT increases firm i's incentives to invest in conventional capacity. As shown in Proposition 1, firm i has incentives to increase its conventional spot output. Therefore, increasing conventional capacity investment decreases the probability of being capacity constrained and allows firm i to increase its conventional output during scarcity periods when it is producing at capacity. Additionally, as δ approaches one (i.e., fixed-price FiT dominates), there is less renewable output exposed to the spot market price, which decreases the disincentive effect of the capacity expansion, thereby strengthening capacity expansion incentives (first term of equation (3.17)). For sufficiently large renewable capacity owned by firm i, this effect dominates the negative impact on spot market price that decreases the capacity expansion incentives (second term of equation (3.17)).

Second, when firm i's renewable capacity is sufficiently small, increasing the proportion of renewable output compensated by a fixed-price FiT decreases firm i's conventional capacity investment incentives. Given that R_i is sufficiently small, the positive effect described in the first term of equation (3.17) is relatively smaller than the negative effect on the market price that decreases conventional capacity investment incentives. Therefore, the net effect is a disincentive to invest in conventional capacity.

Similar to Proposition 1, at the point that $2R_i = R_j$, there is no change in firm i's conventional capacity investment incentives with changes in δ. Note that when $2Ri = Rj$, it must be true that $2Rj > Ri$, so while firm i does not change its spot output, firm j increases it (recall the first case of Proposition 2). In our model, the point where $2Ri = Rj$ represents the threshold for firm i's renewable capacity to be considered sufficiently large or

[105] Note that the results of Proposition 3 are analogous for K_j when $i, j = 1, 2$, with $i \neq j$.

small for the first positive effect to dominate or be dominated by the second negative effect of equation (3.17).

Note that, while the effect of δ on firm's equilibrium conventional capacity investments is ambiguous, the effect on overall equilibrium conventional capacity (i.e., the sum of both firms' conventional capacity, K^{Market}) is unambiguously positive. Proposition 4 summarizes the effect of δ on the overall equilibrium conventional capacity.

> ***Proposition*** 4 *In the conventional capacity stage, for each demand realization and firms $i, j = 1, 2$, with $i \neq j$, the equilibrium market conventional capacity investment changes as we vary the renewable compensation policy used (i.e., δ) as follows:*

$$\frac{\partial K^{Market}}{\partial \delta} = \frac{R_i + R_j}{3}$$

Proposition 4 shows that δ has an unambiguous positive effect on conventional capacity investment at the market level. The magnitude of this effect depends on the renewable energy capacity owned by the firms. The result of Proposition 4 indicates that increasing the share of renewable output compensated by a fixed-price FiT increases the overall conventional capacity investment in the market. As mentioned earlier, a fixed-price FiT has a pro-competitive effect in the spot market that leads to more conventional output. As the market increases its conventional output, more conventional capacity is needed to allow more generation during high-demand hours when firms produce at maximum capacities.

3.4 Numerical Example

This section provides a numerical example to illustrate our main results. This numerical analysis is purely to serve as an illustrative example. While we calibrate the model parameters to fit features of real-world electricity markets, it still represents a stylized model that simplify reality. We assume that $a \sim U\,[635, 905]$, with the average realized $a = 770$, the conventional capacity investment per MW is $\omega = 8.9$,[106] and the marginal cost c is 70 based on a natural gas plant that generates during peak hours (CEC, 2016).[107] The upper and lower bound for the demand parameter a were chosen to simplify the calculations and

[106] According to EIA (2022), the weighted levelized capital cost of a combined-cycle natural-gas plant is US$7.72 per MWh. Assuming a capacity factor of 87%, the weighted levelized capital cost per MW of capacity installed is US$8.9.

[107] Note that we include only the levelized capital cost of conventional capacity investment. If we consider a total levelized cost of electricity it increases to US$35.53 (EIA, 2022). Nevertheless, our main conclusions are robust to changes in the cost of capacity investment.

simulate the observed daily variation in demand in jurisdictions like Texas and Ontario.[108] Consistent with previous literature, these parameters yield a price elasticity of demand of 0.1 in the average perfectly competitive equilibrium without renewables (Faruqui and Sergici, 2010).[109]

We present the results for the three cases when $2R_1 \lesseqqgtr R_2$, assuming a scenario where most of the renewable output is compensated by a fixed-price FiT (i.e., $\delta = 0.8$) and a scenario where most of the renewable output is compensated by a premium-price FiT (i.e., $\delta = 0.2$). In all cases, we set the total renewable energy capacity to 252 MW, which represents approximately 30% of the conventional output at the perfectly competitive equilibrium at the highest demand realization (i.e., $R_1 + R_2 = 252$). For the case when $2R_1 > R_2$, we set $R_1 = R_2 = 126$, while when $2R_1 = R_2$ we set $R_1 = 84$ and $R_2 = 168$. Finally, when $2R_1 < R_2$, we set $R_1 = 52$ and $R_2 = 200$.

Table 3.1 presents the expected equilibrium market outcomes for each firm and scenario. Following CEER (2017) for the case of Germany in 2015, we assume that renewable output compensated by a fixed-price FiT is paid US$65 per MWh, while the premium above market price is US$5.[110] However, the fixed price and premium values do not affect our total welfare analysis. This is because they affect the consumer and producer surplus in opposing directions and the same magnitudes. However, they will affect the distribution of consumer surplus and firms' profits.

Table 3.1: Numerical Example Results

	$R_1 = R_2 = 126$		$R_1 = 84; R_2 = 168$		$R_1 = 52; R_2 = 200$	
Variable	$\delta = 0.2$	$\delta = 0.8$	$\delta = 0.2$	$\delta = 0.8$	$\delta = 0.2$	$\delta = 0.8$
$E(P)$	292.5	242.1	292.5	242.1	292.5	242.1
$E(q_1)$	112.8	137.9	146.4	146.4	171.9	152.8
$E(q_2)$	112.8	137.9	79.2	129.6	53.6	123.2
K_1	137.6	162.8	171.2	171.2	196.8	177.6
K_2	137.6	162.8	104.0	154.4	78.4	148.0
K^{Market}	275.2	325.6	275.2	325.6	275.2	325.6
$E(CS)$	$53,850$	$72,837$	$53,850$	$72,837$	$53,850$	$72,837$
$E(\pi_1)$	$55,759$	$35,780$	$52,394$	$32,891$	$48,830$	$30,691$
$E(\pi_2)$	$55,759$	$35,780$	$59,124$	$38,669$	$61,688$	$40,870$
$E(TS)$	$165,368$	$144,398$	$165,368$	$144,398$	$165,368$	$144,398$

Note: $E(CS)$ and $E(TS)$ denote expected consumer and expected total surplus, respectively.

[108] In Texas, the ratio of average load in the lowest to highest-demand hours for 2018 was 0.74 (estimated with data from the hourly load data archives of the Electric Reliability Council of Texas), while for Alberta was 0.67 (estimated with data from the Alberta Electric System Operator).

[109] In a perfectly competitive equilibrium without renewable, the equilibrium price and market quantity are \$70 and 700, respectively. Given our average demand function Q = 770-P, the price elasticity of demand in equilibrium is $\eta = \frac{\partial Q}{\partial P}\frac{P}{Q} = 0.1$.

[110] CEER (2017) provides the fixed price and the premium in Euros. The average EUR-USD exchange rate in 2015 was 1.11.

Table 3.1 illustrates the findings of Section 3.3. First, note that the expected equilibrium price, expected consumer and total surpluses, $E(CS)$ and $E(TS)$, are the same as the renewable output allocation varies across the two firms for a given δ value. This is because we fixed the total renewable capacity to 252 MW for all cases, so the aggregated conventional capacity is always the same for a given δ. We impose this restriction so the results are comparable across the three cases. Further, note that TS does not depend on the levels of the fixed price, $\overline{P_i}$, and the premium m_i because they enter with opposite signs into the CS and the firms' profits, canceling each other out. However, the fixed price and the premium values will affect the distribution of CS and firms' profits.

Following (i) of Proposition 1, firms have incentives to increase their expected equilibrium spot market output as δ increases when $2R_i > R_j$. In this first case, firm j also increases its output because $2R_j > R_i$.[111] When $2R_i = R_j$, firm i's spot output remains unchanged, while firm j's increases. This is because if $2R_i = R_j$, it must be true that $R_j > R_i$, which is represented in the first case of Table 3.1. Since firm j owns more renewable capacity than its rival, it produces relatively less conventional output. This means that firm j has a smaller proportion of output exposed to the spot price reduction as it expands its output when δ increases, strengthening the incentives to expand its spot market output. Further, when $2R_i < R_j$, we observe the opposite effect for both firms as δ increases. Firm i reduces its spot market output in response to firm j's aggressive spot-market output increase. Nevertheless, as Proposition 4 summarizes, Table 3.1 shows that total conventional capacity unambiguously increase as δ increases.

Expected spot market price unambiguously decreases when δ increases, consistent with (ii) in Proposition 2. Independent of the relative renewable capacity ownership, a fixed-price FiT decreases the equilibrium price suggesting lower incentives to exercise market power. The results of conventional capacity investments are consistent with Proposition 3. Firm i increases (decreases) its conventional capacity investment when $2R_i > R_j$ ($2R_i < R_j$), while it keeps it unchanged when $2R_i = R_j$. Firm j always increases its conventional capacity investment because in all three cases of Table 3.1 it is true that $2R_j > R_i$. Recall that increasing the conventional capacity investment gives the firm more flexibility to react to an increase in δ by expanding its conventional output during high-demand periods.

Finally, due to the spot price decrease, expected CS always increases when a fixed-

[111]Note that the symmetric equilibrium shown in Table 3.1 arises because we set $R_i = R_j$.

price FiT becomes more dominant. However, this increment in expected CS is offset by a reduction in firms' profits, leading to an overall reduction in expected TS as δ increases.

This numerical example illustrates how firms' behavior and incentives change as a response to changes in renewable output compensation. The findings are consistent with the results from Section 3.3, illustrating the ambiguous effect of renewable compensation policies on conventional capacity investment. Further, our results highlight the importance of the relative size of renewable capacity owned by the firms in shaping their behavior.

3.5 Conclusions

Despite the broad penetration of renewable CPs, little is known about their effects on the incentives to invest in conventional energy capacity. In this paper, we derive the channels through which two different renewable CPs (fixed-price FiT and premium-price FiT) and conventional capacity investment interact. We build a stylized two-stage duopoly model in a setting with imperfect competition and uncertain demand. In the first stage of our model, firms simultaneously and independently decide their conventional capacity investment. In the second stage, taking conventional capacity investments, the realization of the spot market demand, and the renewable capacity own by each firm as given, firms engage in Cournot competition at the spot market to supply electricity.

In line with previous studies, our model finds that the expected spot price decreases as a fixed-price FiT becomes more dominant. Further, increasing the proportion of renewable output compensated by a fixed-price FiT increases the total capacity investment in the market, but has an ambiguous effect on the level of conventional capacity investment of each firm. The direction of the effect depends on the size of the renewable capacity owned by the firm relative to its rival. For instance, when a firm owns a sufficiently large (small) share of the renewable capacity, its expected conventional output is relatively smaller (larger) compared to its rival's. So, increasing the share of renewable output compensated by a fixed-price FiT pushes the firm to behave more (less) competitively, expanding (contracting) its conventional spot output. This pro-competitive (anti-competitive) effect of the fixed-price FiT is because less (more) of the firm's spot output is exposed to the reduction in the spot market price as its output expands. Additionally, the ability to expand the conventional spot output is determined by the conventional capacity owned by the firm. Therefore, we find that when a firm owns a sufficiently large (small) share of the renewable capacity, it is incentivized to increase (decrease) its conventional capacity investments.

From our numerical example, we find that the expected consumer surplus unambiguously increases as more renewable output is compensated by a fixed-price FiT, which can be explained by the decrease in the expected spot price. However, the increment in expected consumer surplus is offset by a decrease in firms' profit, leading to a decrease in expected total surplus when a fixed-price FiT becomes more dominant. Our numerical example is calibrated to fit real-world electricity markets, but a more comprehensive empirical analysis is needed to study the robustness of our results.

Admittedly, our theoretical results are based on a stylized model. Nevertheless, the model sheds light on the importance of understanding the spillover effects of renewable CPs on conventional renewable capacity. As jurisdictions increasingly employ these CPs while advocating for conventional capacity investment as a mechanism to complement the renewable energy transition, it is important to be aware of the relationship between them. This paper is a first step to provide the theoretical foundations to describe this relationship.

In reality, the same jurisdiction may have CPs applied differently to each firm, especially when analyzing an extended period. In this paper, we assume that the same proportion of renewables is compensated by a specific CP (denoted by the parameter δ). Future research may relax this assumption and allow each firm its renewable output compensation structure (i.e., different δ for each firm). We anticipate the results will still depend on the renewable capacity size, but formal proof is needed. Further, we assume that renewable output is known by the firms when deciding their conventional capacity investment; however, the realization of renewable output and its distribution (e.g., solar energy only produces during the day) may significantly impact the firms' investment decisions. Different renewable generation sources may affect conventional energy sources differently,[112] so this area warrants further research.

Finally, we assume exogenous renewable capacity for each firm. In reality, the conventional and renewable energy capacity investment decisions are endogenous, which increases the importance of the fixed price and the premium of each CP. In our analysis, we aim to isolate a single channel through which the compensation mechanism can affect conventional investment decisions. Future research may endogenize renewable capacity (similar to Milstein and Tishler, 2011), to understand the dynamics in this setting.

[112] For example, Linn and Shih (2019) show that renewables like wind energy tend to displace coal generation, while solar displaces natural gas.

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Appendix 1: Mathematical Derivation

We model a single procurement auction for renewable capacity at the beginning of the year as well as forward and spot market stages for each hour of a representative year, 2018 (8760 hours). We adapt the model to represent the Alberta wholesale electricity market with four strategic firms plus a fringe.

First, we start with the third stage of the model, in which firms choose their wholesale output. The total output of each firm is the sum of its conventional generation (q_{it}^{conv}), must-run assets (q_{it}^{MR}), and output generated by new renewable capacity if awarded in the first stage ($\theta_{it}R_i$). In the third stage, taking P_i^f, R_i, and q_{it}^f as given, each firm maximizes its profits by choosing its conventional output, q_{it}^{conv}. So, for the strategic firm $i = 1, 2, 3, 4$:

$$\begin{aligned} \underset{q_{it}^{conv}}{MAX} \quad & P_t(Q_t)\left[q_{it}^{conv} + q_{it}^{MR} - q_{it}^{f}\right] - C_{it}(q_{it}^{conv}) + \\ & + \overline{P_i}\delta\theta_{it}R_i + \left[P_t(Q_t) + m_i\right](1-\delta)\theta_{it}R_i + P_{it}^f q_{it}^f \end{aligned} \tag{1.16}$$

subject to the maximum and minimum generation for conventional generation:

$$q_{it}^{max\,conv} \geq q_{it}^{conv} \quad : \quad \lambda_{it} \tag{1.17}$$

$$q_{it}^{conv} \geq q_{it}^{MSG} \quad : \quad \psi_{it} \tag{1.18}$$

where λ_{it} and ψ_{it} are the Lagrangian multipliers of the upper and lower bound, respectively. Equation (1.17) indicates that a firm cannot produce more than the maximum capacity of its assets. Equation (1.18) ensures that all firms maintain reliable production at or above their minimum stable generation. Each strategic firm $i = 1, 2, 3, 4$ solves for its optimal output, which satisfies the following complementarity conditions:

$$P_t(Q_t) + P_t^{'}(Q_t)\left[q_{it}^{conv} + q_{it}^{MR} - q_{it}^{f}\right] - C_{it}^{'}(q_{it}^{conv}) - \lambda_{it} + \psi_{it} = 0 \tag{1.19}$$

$$q_{it}^{max\,conv} \geq q_{it}^{conv} \;\perp\; \lambda_{it} \geq 0, \; and \; q_{it}^{conv} \geq q_{it}^{MSG} \;\perp\; \psi_{it} \geq 0 \tag{1.20}$$

In the second stage, strategic firms choose their level of forward contracts, q_{it}^f, that maximizes their profit. We set each firm's second-stage optimization problem as a mathematical program with equilibrium constraints (MPEC). Let $q_{it}^{max\,f}$ be the maximum forward position for firm i in period t,[113] so the MPEC for each strategic firm $i = 1, 2, 3, 4$ is:

[113] Forward contract maximum capacities are defined as the sum of the firm's conventional and must-run

$$\underset{q_{it}^{f}, q_{it}^{conv}}{MAX} \quad P_t(Q_t)\left[q_{it}^{conv} + q_{it}^{MR}\right] - C_{it}(q_{it}^{conv}) + \overline{P_i}\delta\theta_{it}R_i + \left[P_t(Q_t) + m_i^{min}\right](1-\delta)\theta_{it}R_i \tag{1.21}$$

subject to the maximum capacity of forward contracts, $q_{it}^{max\,f} \geq q_{it}^{f}$, and constraints (1.19) and (1.20). For simplicity and without altering the results, we use MR_{it} to denote the must-run generation plus the MSG. Additionally, we introduce slack variables $s1_{it}$ and $s2_{it}$, so the MPEC for firm $i = 1, 2, 3, 4$ becomes:

$$P_t(Q_t) + P_t^{'}(Q_t)\left[q_{it}^{conv} + MR_{it} - q_{it}^{f}\right] - C_{it}^{'}(q_{it}^{conv}) - \lambda_{it} + s1_{it} = 0 \tag{1.22}$$

$$q_{it}^{conv} - q_{it}^{conv\,max} + s2_{it} = 0 \tag{1.23}$$

and for the fringe:

$$P_t(Q_t) - C'_{ft}(q_{ft}^{conv}) - \lambda_{it} + s1_{ft} = 0 \tag{1.24}$$

$$q_{ft}^{conv} - q_{ft}^{conv\,max} + s2_{ft} = 0 \tag{1.25}$$

Additionally, for firm $i = 1, 2, 3, 4, 5$:

$$s1_{it} \geq 0 \;\perp\; q_{it}^{conv} \geq 0 \tag{1.26}$$

$$s2_{it} \geq 0 \;\perp\; \lambda_{it}^{conv} \geq 0 \tag{1.27}$$

Following Facchinei and Kanzow (1997) and Xian et al. (2004), we use the following nonlinear complementarity function to transform equations (1.26) and (1.27):

$$\psi(a,b) = \sqrt{a^2 + b^2} - a - b \;\Leftrightarrow\; a \geq 0 \;\perp\; b \geq 0 \tag{1.28}$$

Therefore, we can unify each firm's MPEC into an EPEC to obtain the model. The EPEC is represented by the following Karush-Kuhn-Tucker (KKT) conditions:

capacities, so we restrict forward contracts to be at or below the firm's maximum available capacity.

$$q_{it}^{conv}: \quad P_t'(Q_t)\left[q_{it}^{conv} + MR_{it}\right] + P_t(Q_t) - C_{it}'(q_{it}^{conv}) + P_t'(Q_t)(1-\delta)\theta_{it}R_i + \lambda_i^i\left[2P_t'(Q_t) - C_{it}''(q_{it}^{conv})\right]$$
$$+ \sum_{k \neq i}^{4} \lambda_k^i P_t'(Q_t) + \eta_i^i + \beta_i^i\left[\left[(s1_{it})^2 + (q_{it}^{conv})^2\right]^{-\frac{1}{2}} q_{it}^{conv} - 1\right] = 0 \quad \forall \quad i,k = 1,2,3,4 \tag{1.29}$$

$$q_{kt}^{conv}: \quad P_t'(Q_t)\left[q_{it}^{conv} + MR_{it}\right] + P_t'(Q_t)(1-\delta)\theta_{it}R_i + \lambda_k^i\left[2P_t'(Q_t) - C_{kt}''(q_{kt}^{conv})\right] +$$
$$\sum_{j \neq k}^{4} \lambda_j^i P_t'(Q_t) + \eta_k^i + \beta_k^i\left[\left[(s1_{kt})^2 + (q_{kt}^{conv})^2\right]^{-\frac{1}{2}} q_{kt}^{conv} - 1\right] = 0 \quad \forall \quad i,j,k = 1,2,3,4 \; i,j \neq k \tag{1.30}$$

$$q_{5t}^{conv}: \quad P_t'(Q_t)\left[q_{it}^{conv} + MR_{it}\right] + P_t'(Q_t)(1-\delta)\theta_{it}R_i + \lambda_5^i\left[2P_t'(Q_t) - C_{kt}''(q_{kt}^{conv})\right] + \sum_{j=1}^{4} \lambda_j^i P_t'(Q_t)$$
$$+ \eta_5^i + \beta_5^i\left[\left[(s1_{5t})^2 + (q_{5t}^{conv})^2\right]^{\frac{1}{2}} q_{5t}^{conv} - 1\right] = 0 \qquad \forall \quad i,j = 1,2,3,4 \tag{1.31}$$

$$q_{it}^{f}: \; \lambda_i^i P_t'(Q_t) + \psi_{it} = 0 \qquad \forall \quad i = 1,2,3,4 \tag{1.32}$$

$$\lambda_j^1: \quad P_t'(Q_t)\left[q_{jt}^{conv} + MR_{jt} - q_{jt}^{f}\right] + P_t(Q_t) - C_{jt}'(q_{jt}^{conv}) + P_t'(Q_t)(1-\delta)\theta_{jt}R_j - \alpha_{jt}^{c}$$
$$+ s1_{jt} = 0 \qquad \forall \quad j = 1,2,3,4 \tag{1.33}$$

$$\lambda_5^1: \quad P_t(Q_t) - C_{5t}'(q_{5t}^{conv}) - \alpha_{5t}^{c} + s1_{5t} = 0 \tag{1.34}$$

$$\eta_j^1: \quad q_{jt}^{conv} - q_{jt}^{conv,max} + s2_{jt} = 0 \qquad \forall \quad j = 1,2,3,4,5 \tag{1.35}$$

$$\beta_j^1: \quad \left[(s1_{jt})^2 + (q_{jt}^{conv})^2\right]^{\frac{1}{2}} - s1_{jt} - q_{jt}^{conv} = 0 \qquad \forall \quad j = 1,2,3,4,5 \tag{1.36}$$

$$\psi_{it}: \quad q_{it}^{f,max} \geq q_{it}^{f} \Rightarrow \left[(q_{it}^{f,max} - q_{it}^{f})^2 + (\psi_{it})^2\right] - (q_{it}^{f,max} - q_{it}^{f}) - \psi_{it} = 0 \qquad \forall \quad i = 1,2,3,4 \tag{1.37}$$

$$\alpha_{it}^{conv}: \quad -\lambda_i^i + W_i^i \left[\left[(s2_{it})^2 + (\alpha_{it}^{conv})^2\right]^{-\frac{1}{2}} \alpha_{it}^{conv} - 1\right] = 0 \qquad \forall \quad i = 1,2,3,4 \tag{1.38}$$

$$\alpha_{jt}^{conv}: \quad -\lambda_j^i + W_j^i \left[\left[(s2_{jt})^2 + (\alpha_{jt}^{conv})^2\right]^{-\frac{1}{2}} \alpha_{jt}^{conv} - 1\right] = 0 \qquad \forall \quad i = 1,2,3,4 \; j = 1,2,3,4,5 \; j \neq i \tag{1.39}$$

$$s1_{it}: \quad \lambda_i^i + \beta_i^i \left[\left[(s1_{it})^2 + (q_{it}^{conv})^2\right]^{-\frac{1}{2}} s1_{it} - 1\right] = 0 \qquad \forall \quad i = 1,2,3,4 \tag{1.40}$$

$$s1_{jt}: \quad \lambda_j^i + \beta_j^i \left[\left[(s1_{jt})^2 + (q_{jt}^{conv})^2\right]^{-\frac{1}{2}} s1_{jt}^{conv} - 1\right] = 0 \qquad \forall \quad i = 1,2,3,4 \; j = 1,2,3,4,5 \; j \neq i \tag{1.41}$$

$$s2_{it}: \quad \eta_i^i + W_i^i \left[\left[(s2_{it})^2 + (\alpha_{it}^{conv})^2\right]^{-\frac{1}{2}} s2_{it} - 1\right] = 0 \qquad \forall \quad i = 1,2,3,4 \tag{1.42}$$

$$s2_{jt}: \quad \eta_j^i + W_j^i \left[\left[(s2_{jt})^2 + (\alpha_{jt}^{conv})^2\right]^{-\frac{1}{2}} s2_{jt} - 1\right] = 0 \qquad \forall \quad i = 1,2,3,4 \; j = 1,2,3,4,5 \; j \neq i \tag{1.43}$$

$$W_j^1: \quad \left[\left[(s2_{jt})^2 + (\alpha_{jt}^{conv})^2\right]^{-\frac{1}{2}} s2_{jt} - \alpha_{jt}^{conv}\right] = 0 \qquad \forall \quad j = 1,2,3,4 \tag{1.44}$$

For each firm, we have an MPEC. Based on Xian et al. (2004), these MPECs can be unified as an equilibrium problem with equilibrium constraints (EPEC), which solves every endogenous variable simultaneously for each t. To estimate the EPEC, we use the software

GAMS.

Appendix 2: Correlation Matrix

Table 1.8: K-means Clustering Correlation Matrix, Full Data

	Market Supply	Market Available	SK Import	BC Import	Total Must Run	Spot Price
Market Supply	1					
Market Available	0.464	1				
SK Import	-0.082	-0.309	1			
BC Import	-0.119	-0.371	0.154	1		
Total Must Run	0.232	0.259	-0.086	0.458	1	
Spot Price	0.170	-0.084	0.128	0.079	-0.120	1

Table 1.9: K-means Clustering Correlation Matrix, Clustered Data

	Market Supply	Market Available	SK Import	BC Import	Total Must Run	Spot Price
Market Supply	1					
Market Available	0.573	1				
SK Import	-0.107	-0.353	1			
BC Import	-0.177	-0.419	0.174	1		
Total Must Run	0.280	0.322	-0.106	0.519	1	
Spot Price	0.177	-0.094	0.133	0.087	-0.117	1

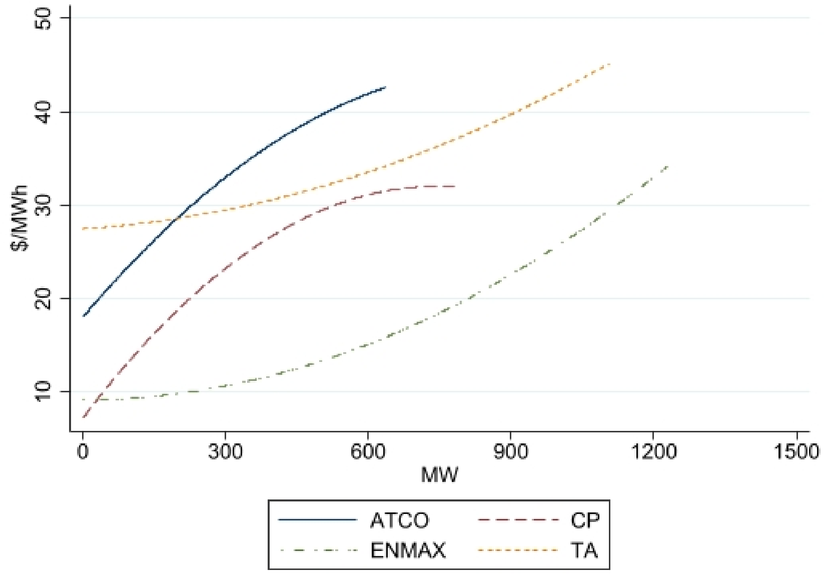
Appendix 3: Average Marginal Cost across All Clusters

Figure 1.2 shows the weighted average marginal cost functions across all 30 clusters.[114] As the figure shows, ENMAX and Capital Power have lower marginal costs than ATCO and TA, especially for low outputs. The differences in marginal cost functions will be essential factors in determining the level of market power that each firm will be able to exercise. Holding everything else constant, a firm with higher marginal costs has a smaller share of generation in the spot market, which limits its ability to exercise market power and profit from new renewable capacity. Additionally, upward-sloping marginal costs diminish the pro-competitive effects of forward contracts (Breitmoser, 2013),[115] which could exacerbate or decrease the effects of new renewable capacity, depending on what CP is used.

[114] Recall that each cluster has a different number of observations, so to scale to an annual average marginal cost, we need to weight the functions by the number of observations in each cluster.

[115] ENMAX is the only major vertically integrated provider in the Alberta wholesale electricity market. This will decrease its incentives to sign forward contracts (Anderson et al., 2007); however, analyzing the effect of this market structure feature is out of this study's scope.

Figure 1.2: Conventional Marginal Cost Curves per Firm, Weighted Average across all Clusters



Appendix 4: Residual Demand Derivation

The residual demand of Alberta can be decomposed into the price-inelastic total demand, $\bar{Q}_t$, minus the price-responsive imports from BC and SK:

$$Q_t(p_t) = \bar{Q}_t - \sum_{j \epsilon \{BC,SK\}} \hat{Q}_{jt}^{IM}(P_t) \tag{1.45}$$

Replacing the imports with equation (1.8):

$$Q_t(p_t) = \bar{Q}_t - \hat{\beta}_{0SK} - \hat{\beta}_{1SK} p_t - \hat{\omega} X_{SKt} - \hat{\beta}_{0BC} - \hat{\beta}_{1BC} p_t - \hat{\omega} X_{BCt} \tag{1.46}$$

Define:

$$\hat{\alpha}_t = \bar{Q}_t - \hat{\beta}_{0SK} - \hat{\omega} X_{SKt} - \hat{\beta}_{0BC} - \hat{\omega} X_{BCt} \tag{1.47}$$

$$\hat{\gamma} = \hat{\beta}_{1SK} + \hat{\beta}_{1BC} \tag{1.48}$$

We can rewrite equation (1.46) as:

$$Q_t(p_t) = \hat{\alpha}_t - \hat{\gamma} p_t \tag{1.49}$$

Solving for p_t, the inverse residual demand is obtained:

$$p_t = \frac{\hat{\alpha}_t - Q_t}{\hat{\gamma}} \tag{1.50}$$

Define:

$$a_t = \frac{\hat{\alpha}_t}{\hat{\gamma}} \tag{1.51}$$

$$b_t = \frac{1}{\hat{\gamma}} \tag{1.52}$$

We obtain the price-inelastic residual demand faced by the incumbent firms and the fringe, net from import supply:

$$P_t(Q_t) = a_t - b_t Q_t \tag{1.53}$$

Appendix 5: Forward Market Results, Equal Aggregated Renewable Output

Main Model

Table 1.10 shows the effects on forward positions. In all scenarios, forward quantities decrease in levels and as a percentage of total capacity when renewable energy is added to the market. Firms have fewer incentives to sign forward contracts because new renewable capacity compensated by a fixed price decreases the conventional quantity sold at the spot market. Less conventional output at the spot market weakens the strategic effect of forward contracts, decreasing the incentives to sign them. This supports the hypothesis stated in subsection 1.4.5.

Table 1.10: Predicted Average Forward Contracts under a Fixed-Price FiT

Scenario	ATCO		Capital Power		ENMAX		TA	
	Level	% of Total Capacity	Level	% of Total Capacity	Level	% of Total Capacity	Level	% of Total Capacity
Baseline	728	45.7	633	56.6	958	66.3	702	19.8
Wind Capacity is Awarded	683	42.9	591	52.9	917	63.4	633	18.7
Solar Capacity is Awarded	708	44.4	589	52.7	920	63.6	527	14.8

Notes: The additional renewable capacity is set at 900MW. Results based on equal aggregated output and fixed cost.

From table 1.11, under a premium-price FiT, we observe that when the new wind capacity in Panel B is allocated to ATCO, the level of forward contracts increases for ATCO from 728 MWh (in the baseline of Panel A) to 959 MWh, but the forward contract coverage as a percentage of total capacity decreases. Further, the forward contracts for Capital Power, ENMAX, and TA decrease to 596 MWh, 921 MWh, and 594 MWh, respectively.

Table 1.11 shows that forward contracts follow an expected pattern. Owning the new renewable capacity increases the level of forward contracts signed by the firm, while the level decreases when other firms own the new renewable capacity. This reaction is because the new renewable capacity increases firm i's spot quantities, intensifying the forward contracts' strategic effect. Therefore, the firm that owns this new capacity has more incentives to sign forward contracts to induce its rivals to reduce their spot market output, increasing the spot price perceived by its conventional and renewable generation. These dynamics highlight the ambiguous effect Brown and Eckert (2019) found on forward contracts, depending on the CP used. Nonetheless, the forward contract coverage as a percentage of the total output decreases relatively more when the firm owns the new renewable capacity.

Table 1.11: Predicted Average Forward Contracts under a Premium-Price FiT

Panel A: Baseline								
	ATCO		Capital Power		ENMAX		TA	
	Level	% of Total Capacity	Level	% of Total Capacity	Level	% of Total Capacity	Level	% of Total Capacity
	728	45.7	633	56.6	958	66.3	702	19.8
Panel B: Wind Capacity Awarded								
Awarded Firm	ATCO		Capital Power		ENMAX		TA	
	Level	% of Total Capacity	Level	% of Total Capacity	Level	% of Total Capacity	Level	% of Total Capacity
ATCO	959	38.5	596	53.3	921	63.7	594	16.7
Capital Power	681	42.7	809	40.1	932	64.5	498	14.0
ENMAX	716	44.9	618	55.3	1,047	44.6	662	18.6
TA	684	42.9	595	53.2	923	63.8	912	20.5
Panel C: Solar Capacity Awarded								
Awarded Firm	ATCO		Capital Power		ENMAX		TA	
	Level	% of Total Capacity	Level	% of Total Capacity	Level	% of Total Capacity	Level	% of Total Capacity
ATCO	933	37.4	597	53.4	924	63.9	586	16.5
Capital Power	685	43.0	789	39.1	930	64.3	670	18.9
ENMAX	704	44.2	620	55.5	1,030	43.9	577	16.3
TA	692	43.4	597	53.4	924	63.9	735	16.5

Notes: The additional capacity is set at 900MW. Results based on equal aggregated output and fixed cost.

Model with Increased Demand

According to Table 1.12, forward contracts decrease for Capital Power and ENMAX but increase for TA and ATCO. This shows that during high-demand hours, the strategic effect of forward contracts dominates the direct effect for TA and ATCO. This may be explained by these firms' relatively high marginal cost and their inflexible asset structure. These characteristics limit the firm's ability to exercise market power, so they use the forward market as an alternative to increasing spot prices.[116]

Table 1.12: Predicted Average Forward Contracts under a Fixed-Price FiT, with Increased Demand

Scenario	ATCO		Capital Power		ENMAX		TA	
	Level	% of Total Capacity	Level	% of Total Capacity	Level	% of Total Capacity	Level	% of Total Capacity
Baseline	862	54.1	828	74.1	1,062	73.5	901	25.4
Wind Capacity is Awarded	827	51.9	775	69.4	1,047	72.5	893	25.2
Solar Capacity is Awarded	846	53.1	806	72.2	1,060	73.4	881	24.9

Notes: The additional renewable capacity is set at 900MW. Results based on different aggregated output and fixed cost.

Under a premium-price FiT, Table 1.13 shows that forward quantities increase relatively more when firms own the new capacity than when other firms own it. Similarly to the case under a fixed-price FiT, ATCO and TA may be using forward contracts to increase their ability to increase the spot price.

[116] The existence of corner solutions may also explain the exceptions of ATCO and TA during these high-demand hours. For instance, when a firm is producing at or very close to the maximum capacity, the direct effect of forward contracts weakens, leading to a decrease in the level of forward contracts. Nevertheless, these results only affect our key conclusions to the extent of these extremely high hour demands, which is less than 2% of the year's hours.

Table 1.13: Predicted Average Forward Contracts under a Premium-Price FiT, with Increased Demand

Panel A: Baseline	ATCO		Capital Power		ENMAX		TA	
	Level	% of Total Capacity	Level	% of Total Capacity	Level	% of Total Capacity	Level	% of Total Capacity
	862	54.1	828	74.1	1,062	73.5	901	25.4

Panel B: Wind Capacity Awarded

Awarded Firm	ATCO		Capital Power		ENMAX		TA	
	Level	% of Total Capacity	Level	% of Total Capacity	Level	% of Total Capacity	Level	% of Total Capacity
ATCO	994		765		1,050		839	
Capital Power	815		877		1,053		937	
ENMAX	803		806		1,027		982	
TA	794		802		1,026		1055	

Panel C: Solar Capacity Awarded

Awarded Firm	ATCO		Capital Power		ENMAX		TA	
	Level	% of Total Capacity	Level	% of Total Capacity	Level	% of Total Capacity	Level	% of Total Capacity
ATCO	875		820		1021		900	
Capital Power	859		834		1059		858	
ENMAX	862		817		1049		883	
TA	836		825		1060		928	

Notes: The additional capacity is set at 900MW. Results based on different aggregated output and fixed cost.

Appendix 6: Premium-Price FiT Nash Equilibria

The renewable procurement auction takes place before firms decide on their forward positions and spot market generation. The four strategic firms bid simultaneously, having complete information regarding other firms' strategies and payoffs. A strategy for a firm is a combination of a technology choice (solar or wind energy) and a bid. This means that under a fixed-price FiT, a strategy involves firms biding the dollar value per MWh that they are willing to accept to build the new facility associated with either wind or solar energy. Likewise, under a premium-price FiT, a strategy involves firms biding the dollar value per MWh amount above the spot price required to build the new solar or wind facility. From hereon, all bids represent dollar values per MWh.

We start our analysis by presenting every m_{ij}^{min} for each strategic firm in Tables 1.14 – 1.17, considering both types of renewables and assuming equal aggregated output and fixed cost, F. These minimum bids include the profits of owning the new capacity and profits when their rivals own the new capacity (recall equations (1.6) and (1.7)). Each row shows the minimum amount above the market price, m_{ij}^{min}, that makes firm i indifferent between winning the new capacity and letting its rival j win. We restrict each firm's bid to be equal or greater to their minimum m_{ij}^{min}. For instance, the minimum amount for wind capacity that ATCO is willing to bid to prevent Capital Power from being awarded wind capacity is \$2.26 (Table 1.14). Further, ATCO's minimum bid increases to \$2.56 to prevent ENMAX from winning the auction. Finally, ATCO may bid as low as \$2.04 for wind capacity to prevent TA from being awarded wind capacity. Additionally, ATCO may bid for solar capacity instead of wind. Table 1.17 shows that, in this case (i.e., rivals bidding for wind), ATCO may bid for solar capacity as low as \$2.43, \$2.74, and \$2.22 to prevent Capital Power, ENMAX, and TA, respectively, from winning.

Restricting each firm's bid to be equal or greater to their minimum m_{ij}^{min} is based on the assumption that firms decide their bids solely on the profits and no other strategies are relevant (e.g., predatory pricing). This means that bidding below the minimum m_{ij}^{min} is weakly dominated by bidding at this value. If firm i bids below its minimum bid with respect to firm j and wins the auction, it will receive negative profits, so it is better off bidding at the minimum bid even if that allows firm j to win. Likewise, if by bidding below m_{ij}^{min}, the firm does not win the auction, it would be indifferent between that bid and the m_{ij}^{min}. This restriction means we use an equilibrium refinement where we focus on non-weakly dominated pure strategy NE.[117]

To illustrate the different possibilities that firms face, consider a starting point where all firms bid \$10 for wind capacity. According to Table 1.15, all firms have incentives and the ability to lower their bids to win the auction. However, if, for example, ATCO bids \$9.99 (winning the auction), all other firms have incentives to decrease their bid further to \$9.98. This dynamic continues until no firm has incentives to lower its bid or to switch to the alternative technology (solar in this case). According to Table 1.15, once firms reach a wind bid of \$6.4 and Capital Power lowers its bid to \$6.39, ENMAX can no longer lower its bid. Note that ENMAX does not have incentives to switch technology either, as its minimum bid for solar to prevent Capital Power from winning the wind capacity is \$7.65 (Table 1.17).

If instead of Capital Power lowering its bid to \$6.39, ATCO or TA do it, ENMAX has incentives and the ability to lower its bid. In fact, ENMAX will lower its bid up to \$5.6 and \$5.52 to prevent ATCO and TA from winning, respectively. In both cases, ENMAX has no incentive to switch to solar because its minimum solar bids are higher than its minimum wind bids (Table 1.17). Bellow \$5.52, only ATCO, Capital Power, and TA have

[117] In our setting, restricting the bids below does not change the auction's winner, which is our main focus.

the incentives and ability to undercut their rivals. Capital Power's minimum wind bids to prevent ATCO and TA from winning the wind capacity are \$2.87 and \$2.83, respectively (Table 1.18). Bellow these bids, only ATCO and TA can undercut each other bids. In this case, Capital Power does not have incentives to switch to solar because solar bids are above its wind bids (Table 1.17).

Finally, ATCO's minimum wind bid to prevent TA from winning the wind capacity is \$2.04, while TA's minimum wind bid is \$1.95. This means that TA may lower its wind bid to \$2.03, so ATCO cannot lower its wind bid and it has no incentives to switch to solar. In this case, TA wins the wind capacity; however, Table 1.21 shows TA's minimum solar bid if ATCO bids for wind capacity is \$1.73. This lower solar bid means a higher markup, so TA has incentives to switch to solar capacity. Note that if TA bids \$2.03 for solar capacity, the \$2.04 wind bid of ATCO is infeasible. According to Table 16, ATCO's minimum wind bid if TA bids for solar capacity is \$2.12, which gives TA the incentive to increase its bid up to \$2.11. With this new bid, ATCO cannot lower its wind bid, and does not have incentives to switch to solar (from Table 1.15, ATCO's minimum solar bid when TA bids solar is \$2.3).

In this example, a set of Nash equilibria arises when TA bids \$2.11 for solar capacity, ATCO bids \$2.12 for wind capacity, and Capital Power and ENMAX bid at or above their minimum wind bids of \$2.78 and \$5.45, respectively (these are the minimum wind bids when TA bids solar, from Table 1.16).

Table 1.14: Minimum Bids of Wind versus Wind

$i \setminus j$	ATCO	Capital Power	ENMAX	TA
ATCO	-	2.26	2.56	2.04
Capital Power	2.87	-	3.85	2.83
ENMAX	5.60	6.40	-	5.52
TA	1.95	2.10	2.40	-

Notes: The minimum bids, m_{ij}, are presented as dollar per MWh.
These bids are based on equal aggregated output and fixed cost.

Table 1.15: Minimum Bids of Solar versus Solar

$i \setminus j$	ATCO	Capital Power	ENMAX	TA
ATCO	-	2.53	2.79	2.30
Capital Power	3.15	-	4.20	3.03
ENMAX	6.95	7.71	-	6.69
TA	1.55	1.81	2.17	-

Notes: The minimum bids, m_{ij}, are presented as dollar per MWh.
These bids are based on equal aggregated output and fixed cost.

Table 1.16: Minimum Bids of Wind versus Solar

$i \setminus j$	ATCO	Capital Power	ENMAX	TA
ATCO	-	2.35	2.61	2.12
Capital Power	2.90	-	3.94	2.78
ENMAX	5.70	6.46	-	5.45
TA	1.77	2.03	2.39	-

Notes: The minimum bids, m_{ij}, are presented as dollar per MWh.
These bids are based on equal aggregated output and fixed cost.

Table 1.17: Minimum Bids of Solar versus Wind

$i \setminus j$	ATCO	Capital Power	ENMAX	TA
ATCO	-	2.43	2.74	2.22
Capital Power	3.12	-	4.10	3.08
ENMAX	6.85	7.65	-	6.77
TA	1.73	1.88	2.18	-

Notes: The minimum bids, m_{ij}, are presented as dollar per MWh.
These bids are based on equal aggregated output and fixed cost.

Using the minimum bids from Tables 1.14 to 1.17 and following a similar analysis as the above example, it is straightforward to conclude that there are no scenarios where ENMAX could wind the auction either with wind or solar capacity. ENMAX minimum bids are always higher than the minimum bids of all three other strategic firms, which means that ENMAX rivals always have the incentives and ability to undercut ENMAX, preventing it from winning. Therefore, to identify the winner of the auction, we can ignore ENMAX.

Using the same arguments to exclude ENMAX, we can observe that Capital Power's bids are always higher than the bids of ATCO and TA. This means that ATCO and TA have the incentives and ability to undercut Capital Power in every possible scenario, preventing Capital Power from winning the auction with either technology. This leads us to a simplified game with only two players, summarized in Table 1.18.

Section 1 on Table 1.18 shows the wind bids of ATCO and TA when faced with a wind bid. Section 2 represents ATCO's and TA's solar bids when faced with a solar bid. In Section 3, ATCO and TA bid for wind when facing a solar bid, and in Section 4, they bid for solar when facing a wind bid. For ATCO, bidding for solar capacity is weakly dominated by bidding for wind capacity. If TA bids for wind capacity, ATCO may bid as low as \$2.04 (Section 1) or \$2.22 (Section 4) for wind and solar capacity, respectively. If TA bids for solar capacity, ATCO may bid as low as \$2.12 (Section 3) or \$2.3 (Section 2) for wind and solar capacity, respectively. In both cases, the minimum wind bid is lower than the minimum solar wind, so bidding for wind capacity weakly dominates for ATCO.

In the case of TA, bidding for solar strongly dominates bidding for wind. On the one hand, if ATCO bids for wind capacity, TA may bid as low as \$1.95 (Section 1) or \$1.73 (Section 4) for wind and solar capacity, respectively. On the other hand, if ATCO bids for solar capacity, TA may bid as low as \$1.77 (Section 3) or \$1.55 (Section 2) for wind and solar capacity, respectively. In both cases, TA is strictly better by bidding for solar because the markup is higher, which increases its profits from owning the new renewable capacity.

This iterative elimination of weakly dominated strategies leads us to one possible outcome: ATCO bids for wind and TA bids for solar capacity. The relevant minimum bids are \$2.12 for ATCO (Section 3) and \$1.73 for TA (Section 4). This means that TA has the incentive to bid \$2.11 for solar capacity, while ATCO bids \$2.12 for wind capacity. In this Nash equilibrium[118] Capital Power may bid for wind (at or above \$2.78) or solar (at or above \$3.03), while ENMAX may also bid for either wind (at or above \$5.45) or solar (at or above \$6.69). This analysis shows that, in our setting, there are no other possible sets of Nash equilibria, and TA is the only possible winner of the auction by bidding for solar capacity.[119]

Table 1.18: Simplified Game, ATCO vs. TA

Section 1	ATCO(w)	TA(w)	Section 2	ATCO(s)	TA(s)
ATCO(w)	-	2.04	ATCO(s)	-	2.3
TA(w)	1.95	-	TA(s)	1.55	-
Section 3	**ATCO(s)**	**TA(s)**	**Section 4**	**ATCO(w)**	**TA(w)**
ATCO(w)	-	2.12	ATCO(s)	-	2.22
TA(w)	1.77	-	TA(s)	1.73	-

Appendix 7: Premium-Price FiT Nash Equilibria, Increased Demand

Tables 1.19 to 1.22 present the minimum bids, m_{ij}^{min}, for each firm and technology when we exogenously increase demand by 15%. Note that when demand increases, some bids become negative (i.e., the firms pay the regulator). This means that investing in renewable capacity becomes profitable enough that government support is not needed.

[118] Technically, there are infinite Nash equilibria because Capital Power and ENMAX may bid at or above their minimum bids.

[119] A complete analysis of each scenario can be provided upon author's request.

Table 1.19: Minimum Bids of Wind versus Wind, with Increased Demand

$i \setminus j$	ATCO	Capital Power	ENMAX	TA
ATCO	-	-11.17	-13.56	2.09
Capital Power	9.12	-	2.35	15.23
ENMAX	23.44	1.45	-	32.40
TA	1.29	-6.00	15.62	-

Notes: The minimum bids, m_{ij}, are presented as dollar per MWh.
These bids are based on equal aggregated output and fixed cost.

Table 1.20: Minimum Bids of Solar versus Solar, with Increased Demand

$i \setminus j$	ATCO	Capital Power	ENMAX	TA
ATCO	-	24.76	30.46	20.78
Capital Power	-34.59	-	1.04	4.33
ENMAX	-47.15	5.19	-	10.29
TA	-8.62	-17.37	-13.24	-

Notes: The minimum bids, m_{ij}, are presented as dollar per MWh.
These bids are based on equal aggregated output and fixed cost.

Table 1.21: Minimum Bids of Wind versus Solar, with Increased Demand

$i \setminus j$	ATCO	Capital Power	ENMAX	TA
ATCO	-	10.44	16.15	6.46
Capital Power	-11.98	-	23.65	26.94
ENMAX	-7.47	34.50	-	49.98
TA	-9.55	-18.29	-14.17	-

Notes: The minimum bids, m_{ij}, are presented as dollar per MWh.
These bids are based on equal aggregated output and fixed cost.

Table 1.22: Minimum Bids of Solar versus Wind, with Increased Demand

$i \setminus j$	ATCO	Capital Power	ENMAX	TA
ATCO	-	3.14	0.75	16.41
Capital Power	-13.49	-	-20.26	-7.39
ENMAX	-16.24	-38.24	-	-7.29
TA	2.21	-5.08	16.55	-

Notes: The minimum bids, m_{ij}, are presented as dollar per MWh.
These bids are based on equal aggregated output and fixed cost.

This appendix shows a simplified way to identify all Nash equilibria.[120] First, note that all ATCO's wind bids when its rivals bid for wind (Table 1.19) are below its solar bids (Table 1.22). Further, when its rivals bid for solar capacity, ATCO's wind bids (Table 1.21) are below its solar bids (Table 1.20). This means that, for ATCO, bidding for wind capacity weakly dominates bidding for solar capacity, so ATCO will bid for wind capacity. Using the same analysis, Capital Power and ENMAX bid for solar capacity, and TA bids for wind capacity. This simplification leads to a reduced game, summarized in Table 1.23.

[120]The full Nash equilibria analysis yields the same result. The full analysis is available upon request.

According to Table 1.23, ATCO's bids are strictly greater than any of its rivals' bids. This means that there is no scenario where ATCO wins the auction. Furthermore, when considering Capital Power, ENMAX, and TA, we observe that ENMAX's bids are strictly above its rivals'. Therefore, the game is reduced to Capital Power and TA. Given that TA's minimum bid is below Capital Power's minimum bid, the auction winner is TA.

Based on the above analysis, we find that the only set of Nash equilibrium is achieved when TA bids -\$7.4 for wind capacity and Capital Power bids -\$7.39 for solar capacity. ATCO bids at or above \$16.41 and \$2.09 for solar and wind capacity, respectively. ENMAX bids at or above -\$7.29 and \$32.4 for solar and wind capacity, respectively.

Table 1.23: Reduced Game, with Increased Demand

$i \setminus j$	ATCO (w)	Capital Power (s)	ENMAX (s)	TA (w)
ATCO (w)	-	10.44	16.15	2.09
Capital Power (s)	-13.49	-	1.04	-7.39
ENMAX (s)	-16.24	5.19	-	-7.29
TA (w)	1.29	-18.29	-14.27	-

Notes: The minimum bids, m_{ij}, are presented as dollar per MWh.
These bids are based on equal aggregated output and fixed cost.

Appendix 8: Forward-Spot Results, Different Aggregated Output

Fixed-Price FiT

Assuming equal aggregated output for wind and solar energy helps us to analyze whether their output's correlation with demand impacts market outcomes under this CP. However, in reality, these types of renewable energy sources have different generation distributions and aggregated capacity factors.

Tables 1.24 and 1.25 show the magnitude of the effects when solar energy changes.[121] The average spot price is \$30.8/MWh, higher than under wind energy. This occurs because of two factors: first, on average, solar produces less than wind. Second, the reduction in solar production occurs during peak hours when firms can exercise market power to increase prices. Additionally, each firm produces more conventional output compared to the wind scenario.

The negative effect on forward contracts is smaller than under wind energy. This is because, in the solar energy scenario, there is relatively more output at the spot market by

[121] Recall that for the analysis of equal aggregated output, we modified the solar capacity to match the wind capacity. Therefore, relaxing this constraint only changes the effects of the solar capacity.

conventional generation, which strengthens the strategic effect of signing forward contracts relative to the wind scenario.

Table 1.24: Predicted Average Price and Conventional Spot Generation under a Fixed-Price FiT

Scenario	Price	Market Output	ATCO	Capital Power	ENMAX	TA	Fringe
Baseline	31.2	8,523	161	424	921	114	1,408
Wind Capacity is Awarded	30.1	8,526	132	383	881	76	1,262
Solar Capacity is Awarded	30.8	8,524	150	405	906	90	1,350

Notes: Prices are dollars per MWh. Output is presented in MWh. The additional renewable capacity is set at 900MW. Results based on different aggregated output and fixed cost.

Table 1.25: Predicted Average Forward Contracts under a Fixed-Price FiT, Percentage of

Scenario	ATCO		Capital Power		ENMAX		TA	
	Level	% of Total Capacity	Level	% of Total Capacity	Level	% of Total Capacity	Level	% of Total Capacity
Baseline	728	45.7	633	56.6	958	66.3	702	19.8
Wind Capacity is Awarded	683	42.9	591	52.9	917	63.4	633	18.7
Solar Capacity is Awarded	690	43.3	614	54.9	942	65.1	643	18.1

Notes: The additional renewable capacity is set at 900MW. Results based on different aggregated output and fixed cost.

As solar energy produces more during peak hours, we expected to observe more significant effects compared to wind energy; However, as Tables 1.24 and 1.25 show, wind energy has greater impacts on price and output. This might be explained by the three factors mentioned earlier: First, due to the linearity of our residual demand function, our model may overestimate the level of imports in high-demand hours, putting downward pressure on price, which is where solar energy has its peak. Second, we use the average values of each cluster, which might cause temporal smoothness decreasing the probability of observing high prices and limiting the relative advantage of solar energy. Third, solar produces less aggregated total output than wind and zero output during off-peak hours.

Premium-Price FiT

Tables 1.26 and 1.27 present the results of adding 900 MW of new renewable capacity of wind and solar with different aggregated outputs. As expected, the price-reduction effect of new solar capacity is smaller than in the previous section, given that solar output is fundamentally lower, resulting in a smaller merit-order effect. Panel C shows that the spot price is lowest when ATCO is awarded the new solar capacity, which suggests that ATCO is relatively less able to exercise market power. The asset portfolio of conventional generation of ATCO is mainly based on coal and cogen, which limits its relative flexibility to exercise market power. Additionally, ATCO has a steeper marginal costs curve than TA (recall that TA presented the lowest ability to exercise market power) for low output levels. Therefore, as solar output is lower than with the scenario of equal aggregated renewable output, firms produce more in the spot market, which becomes relatively more expensive for ATCO than for its competitors restricting ATCO's capability of exercising market power.

In contrast to ATCO, ENMAX's conventional portfolio is heavily based on natural gas, and it presents a relatively low marginal cost, allowing for more flexibility to exercise market power and keep the spot price up to \$31/MWh.

Table 1.27 presents the effect on forward contracts. As expected, firms increase the level of forward quantities when they own the new capacity. However, the level decreases when their rivals own the new capacity for both renewable energy sources. Again, this is because the new capacity increases firm i's spot quantities, intensifying the forward contracts' strategic effect. Additionally, the forward contract coverage decreases relatively more when the firm owns the new renewable capacity.

Table 1.26: Predicted Average Price and Conventional Spot Generation under a Premium-Price FiT

Panel A: Baseline							
	Price	Mkt. Output	ATCO	Capital Power	ENMAX	TA	Fringe
	31.2	8,523	161	424	921	114	1,408
Panel B: Wind Capacity Awarded							
Awarded Firm	Price	Total Output	ATCO	Capital Power	ENMAX	TA	Fringe
ATCO	30.2	8,525	107	387	885	79	1,276
Capital Power	30.4	8,525	141	311	895	87	1,300
ENMAX	30.7	8,524	150	409	730	101	1,342
TA	30.1	8,525	135	387	886	53	1,273
Fringe	30.1	8,526	132	383	881	76	1,262
Panel C: Solar Capacity Awarded							
Awarded Firm	Price	Mkt. Output	ATCO	Capital Power	ENMAX	TA	Fringe
ATCO	30.8	8,524	138	406	909	93	1,354
Capital Power	30.9	8,524	153	376	909	99	1,364
ENMAX	31.0	8,523	155	416	849	105	1,375
TA	30.9	8,524	152	410	909	66	1,363
Fringe	30.8	8,524	150	405	906	90	1,350

Notes: Prices are dollars per MWh. Output is presented in MWh. The additional renewable capacity is set at 900MW. Results based on different aggregated output and fixed cost.

Table 1.27: Predicted Average Forward Contracts under a Premium-Price FiT

Panel A: Baseline

	ATCO		Capital Power		ENMAX		TA	
	Level	% of Total Capacity	Level	% of Total Capacity	Level	% of Total Capacity	Level	% of Total Capacity
	728	45.7	633	56.6	958	66.3	702	19.8

Panel B: Wind Capacity Awarded

Awarded Firm	ATCO		Capital Power		ENMAX		TA	
	Level	% of Total Capacity	Level	% of Total Capacity	Level	% of Total Capacity	Level	% of Total Capacity
ATCO	959	38.5	596	53.3	921	63.7	594	16.7
Capital Power	681	42.7	809	40.1	932	64.5	498	14.0
ENMAX	716	44.9	618	55.3	1,047	44.6	662	18.6
TA	684	42.9	595	53.2	923	63.8	912	20.5

Panel C: Solar Capacity Awarded

Awarded Firm	ATCO		Capital Power		ENMAX		TA	
	Level	% of Total Capacity	Level	% of Total Capacity	Level	% of Total Capacity	Level	% of Total Capacity
ATCO	816	32.7	615	55.0	946	65.4	679	19.1
Capital Power	680	42.7	710	35.2	945	65.4	576	16.2
ENMAX	727	45.6	625	55.9	1,003	42.8	626	17.6
TA	692	43.4	619	55.4	945	65.4	725	16.3

Notes: The additional capacity is set at 900MW. Results based on different aggregated output and fixed cost.

The results in this section show us that marginal costs and asset portfolios play an essential role in the ability of firms to exercise market power when awarded new renewable capacity. Allocating the new renewable capacity to firms with lower marginal costs and more flexible conventional generation yields the smallest price reduction, which evidences their ability to exercise market power. On the other hand, when renewable capacity is allocated to firms with high marginal costs and relatively inflexible portfolios, we observe the most significant price reduction.

Premium-Price FiT Nash Equilibria, Different Aggregated Output

Tables 1.28 to 1.31 present the minimum bids, m_{ij}^{min}, for each firm and technology when we relax the assumption of equal annual aggregated output and fixed cost. The interpretation of the tables is analogous as to Appendix 6. Solar energy has a lower capacity factor in Alberta, and its fixed cost is higher than wind energy, which makes wind more attractive to firms. The impact of the lower solar capacity factor and higher fixed cost is reflected on the higher value of the solar bids.

Following the same methodology of Appendix 6, it is straightforward to see that firms do not have incentives to bid for solar capacity because their minimum bids are well above the minimum bids for wind capacity. Any firm can profitably switch technology, lower its bid, and be awarded the new renewable capacity.

For instance, suppose every firm bids for solar capacity (Table 1.29). Independent of who is the winner, all firms have incentives to switch to wind capacity, including the winning firm. According to Table 1.30, all non-winning firms can switch to wind to lower their bids and potentially win the auction. Likewise, the winning firm can increase its markup and profits by switching to wind. Note that the bids for solar capacity when the rivals bid for wind capacity (Table 1.31) are strictly greater than bidding for wind capacity (Table 1.28).

This leads to a set of Nash equilibria where the auction winner is TA bidding $2.03 for each MWh of wind generation, and ATCO bidding $2.04. Capital Power bids anything at or above $2.83 and $52.67 for wind and solar capacity, respectively. ENMAX bids anything at or above $5.52 and $61.79 for wind and solar capacity, respectively.[122]

Table 1.28: Minimum Bids of Wind versus Wind

$i \setminus j$	ATCO	Capital Power	ENMAX	TA
ATCO	-	2.26	2.56	2.04
Capital Power	2.87	-	3.85	2.83
ENMAX	5.60	6.40	-	5.52
TA	1.95	2.10	2.40	-

Notes: The minimum bids, m_{ij}, are presented as dollar per MWh.
These bids are based on different aggregated output and fixed cost.

Table 1.29: Minimum Bids of Solar versus Solar

$i \setminus j$	ATCO	Capital Power	ENMAX	TA
ATCO	-	51.00	51.61	50.47
Capital Power	52.96	-	55.36	52.67
ENMAX	62.38	64.15	-	61.79
TA	48.48	49.09	49.92	-

Notes: The minimum bids, m_{ij}, are presented as dollar per MWh.
These bids are based on different aggregated output and fixed cost.

Table 1.30: Minimum Bids of Wind versus Solar

$i \setminus j$	ATCO	Capital Power	ENMAX	TA
ATCO	-	10.79	11.40	10.26
Capital Power	12.07	-	14.48	11.79
ENMAX	18.54	20.31	-	17.95
TA	9.44	10.05	10.88	-

Notes: The minimum bids, m_{ij}, are presented as dollar per MWh.
These bids are based on different aggregated output and fixed cost.

[122] The full Nash equilibria analysis yields the same result. The full analysis is available upon request.

Table 1.31: Minimum Bids of Solar versus Wind

$i \setminus j$	ATCO	Capital Power	ENMAX	TA
ATCO	-	50.78	51.49	50.30
Capital Power	52.87	-	55.14	52.78
ENMAX	62.16	64.00	-	61.97
TA	48.91	49.24	49.94	-

Notes: The minimum bids, m_{ij}, are presented as dollar per MWh.
These bids are based on different aggregated output and fixed cost.

Appendix 9: Pollution Estimation per Asset

To estimate the effects of the renewable CP on CO_2 emissions, we calculate each firm's tonne of CO_2 emission per MWh of coal and natural gas assets. In the case of coal assets, the estimation is based on the following equation:

$$\frac{Ton\,of\,CO_2}{MWh} = 3,747.36 \cdot (Heat\,Rate) \cdot \left(\frac{1}{2,204.62}\right) \tag{1.54}$$

where the first number represents the amount of CO_2 (in pounds) per short ton of coal.[123] The heat rate is the number of short tons of coal needed to produce an MWh of electricity, and the last term is used to transform the pounds of CO_2 per short ton of coal into tons of CO_2 per short ton of coal.

In the case of assets based on natural gas, the emissions are calculated as follows:

$$\frac{Ton\,of\,CO_2}{MWh} = 0.947 \cdot (Heat\,Rate) \cdot 121.31 \cdot \left(\frac{1}{2,204.62}\right) \tag{1.55}$$

where 0.947 is the transformation factor from million British Thermal Units (MMBTU) to Gigajoules (GJ). The heat rate is the number of GJ needed to generate an MWh of electricity. The number 121.31 represents the amount of CO_2 (in pounds) per MMBTU, and the last term is used to transform the pounds of CO_2 per MMBTU into tonnes of CO_2 per MMBTU.

[123] A short ton of coal is equal to 2,000 pounds.

Appendix 10: Control versus Treated Counties

Table 2.3: Full Summary Statistics, Treated vs. Control Group

Variable	Group	Mean	Standard Deviation	Minimum	Maximum
Average Population	Treated	42,773	17,956	5,714	63,974
	Control	32,386	16,610	769	76,476
Rural Population	Treated	18.4%	17.3%	0%	72.0%
	Control	32.8%	23.9%	0%	100%
Indigenous Population	Treated	4.5%	5.5%	0.4%	48.3%
	Control	4.6%	10.8%	0%	96.4%
Average Area	Treated	3,491	2,471	681	7,290
	Control	1,785	5,082	51	49,924
Average Salary	Treated	283	424	0	7,177
	Control	205	340	0	7,465
Average Education	Treated	9.1	4.2	0	21
	Control	8.0	4.2	0	21
Average Conflicts	Treated	0	0	0	0
	Control	0.52	3.1	0	36
Mean Water	Treated	39.1	18.0	0.05	94.6
	Control	51.0	100.8	0.01	588.0
Ind. Running Politicians	Treated	0.37	0.79	0	3
	Control	0.23	0.82	0	8
Ind. Elected Politicians	Treated	0.18	0.53	0	2
	Control	0.03	0.30	0	3
Average Age	Treated	29.47	20.4	0	99
	Control	29.6	20.8	0	102
Transmission Line	Treated	32.5	34.8	0	99.5
	Control	13.8	35.2	0	556.3
Trans. Line per 1,000 Pop.	Treated	0.9	1.6	0	10.3
	Control	0.8	3.8	0	185
Elec. Substations per 1,000 Pop.	Treated	0.1	0.13	0	0.78
	Control	0.03	0.07	0	1.7
Capacity per 1,000 Pop.	Treated	4.4	12.6	0	70.6
	Control	0.7	6.5	0	141.8
Probability to Visit a Doctor	Treated	0.09	0.28	0	1
	Control	0.09	0.29	0	1
Probability to Rent versus Own	Treated	0.21	0.41	0	0
	Control	0.13	0.34	0	0
Probability of Being Employed	Treated	0.36	0.48	0	1
	Control	0.33	0.47	0	1

Notes: Area in KM^2. Salary in CAD per month. Education in years. Conflicts per year.
Mean water is the annual average of m^3/second. Transmission line represented in KM.

Appendix 11: Balance Test Results

The variables are defined as:

- Rural/Urban: it shows the proportion of people living in rural areas in each county.
- Mean water: it represents the annual mean amount of water from all the main rivers of each county. It is measured by cubic meter per second per day.
- Total water: it represents the annual sum of the water in the main rivers of each county. It is measured by cubic meter per second.
- Substation: it represents the total number of substations per county.
- Substation per geographic area: it represents the number of substations per kilometer squared of each county.
- Substation per capita: it represents the number of substations per 1,000 inhabitants of each county.
- Line per geographic area: it represents the lines (in KM) per kilometer squared of each county.
- Lines per capita: it represents the lines (in KM) per inhabitant of each county.
- Capacity per geographic area: it represents the total capacity (in MW) per kilometer squared of each county.
- Capacity per capita: it represents the total capacity (in MW, including all types of generation) per inhabitant of each county.
- Conflicts: it represents the total number of conflicts involving indigenous people per year in each county.
- Total politicians running for office: it represents the total number of indigenous politicians running for office in each county. For elections held in a year between my sample, I add them to the following year with data (e.g., if I have data of 2000 and 2003, and an election happens in 2002, I count the number of running politicians towards 2003).
- Total politicians elected for office: it represents the total number of indigenous politicians elected for office in each county. Both, the running and elected politicians are for four political positions: senators, deputy, mayor, and councilor. All of these positions last four years, so I account for this according to the timing of the elections.

Table 2.4: Balance Test All Treated Counties

Variable	P-Value	Observations	Direction of Difference
Rural/Urban	0.13	1,616	41% rural population in control vs. 29% in treated
Mean Water	0.80	576	49 m^3/s per day in control vs. 45 m^3/s per day in treated
Total Water	0.85	576	16,719 m^3/s in control vs. 15,670 m^3/s in treated
Substations	0.00	1,616	1.19 substations in control vs. 3.45 in treated
Substations Area	0.14	1,616	0.002 substations per km^2 in control vs. 0.001 in treated
Substations Per Capita	0.26	1,616	0.11 substations per 1,000 pop. in control vs. 0.20 in treated
Line Area	0.00	1,311	0.07 km of line in control vs. 0.02 in treated
Line per Capita	0.11	1,311	0.008 km of line per inhabitant in control vs. 0.003 in treated
Capacity Area	0.21	1,616	0.03 MW per km^2 in control vs. 0.06 MW in treated
Cap. per Capita	0.12	1,616	0.002 MW per inhabitant in control vs. 0.01 in treated
Conflicts	0.00	1,616	0.5 conflicts per year in control vs. 0 in treated
Politician Running	0.23	1,616	0.58 running politician in control vs. 0.39 in treated
Politician Elected	0.59	1,616	0.10 elected politician in control vs. 0.14 in treated

Note: The main specification includes 11 treated counties and 175 control counties.

Appendix 12: Derivation of Capacity Investment Stage

In this stage, firms simultaneously and independently choose their capacity investment understanding how these capacities will affect the equilibrium in the spot market. For mathematical tractability, we assume that firm 1 is capacity constrained before firm 2, but the results are independent of what firm is assumed to be capacity constrained first. Firm $i = 1, 2$ choose its capacity investment, K_i, to maximize its expected profits, represented by equation (3.14).

Define $f_i^x(K_i, a_t)$ for $x = u, K_1, c$ (i.e., the three cases described in section 3.3) as the argument of each integral of equation (3.14) evaluated at a. Using the Leibniz rule to differentiate equation (3.14) for $i = 1, 2$, we obtain:

$$\frac{\partial E\left[\pi_i(\cdot)\right]}{\partial K_i} = \frac{\partial a_1}{\partial K_i} f_i^u(K_i,a_1) - \frac{\partial \underline{a}}{\partial K_i} f_i^u(K_i,\underline{a}) + \int\limits_{\underline{a}}^{a_1} \left(\frac{\partial f_i^u(K_i,a)}{\partial K_i}\right) da + \frac{\partial a_2}{\partial K_i} f_i^{K_1}(K_i,a_2)$$
$$- \frac{\partial a_1}{\partial K_i} f_i^{K_1}(K_i,a_1) + \int\limits_{a_1}^{a_2} \left(\frac{\partial f_i^{K_1}(K_i,a)}{\partial K_i}\right) da + \frac{\partial \overline{a}}{\partial K_i} f_i^c(K_i,\overline{a}) - \frac{\partial a_2}{\partial K_i} f_i^c(K_i,a_2)$$
$$+ \int\limits_{a_2}^{\overline{a}} \left(\frac{\partial f_i^c(K_i,a)}{\partial K_i}\right) da - \omega = 0 \tag{3.20}$$

We know that $\frac{\partial \underline{a}}{\partial K_i} = \frac{\partial \overline{a}}{\partial K_i} = \frac{\partial f_i^u(K_i,a)}{\partial K_i} = 0$, which simplifies equation (3.20) to:

$$\frac{\partial E\left[\pi_i(\cdot)\right]}{\partial K_i} = \frac{\partial a_1}{\partial K_i} f_i^u(K_i,a_1) + \frac{\partial a_2}{\partial K_i} f_i^{K_1}(K_i,a_2) - \frac{\partial a_1}{\partial K_i} f_i^{K_1}(K_i,a_1) + \int\limits_{a_1}^{a_2} \left(\frac{\partial f_i^{K_1}(K_i,a)}{\partial K_i}\right) da$$
$$- \frac{\partial a_2}{\partial K_i} f_i^c(K_i,a_2) + \int\limits_{a_2}^{\overline{a}} \left(\frac{\partial f_i^c(K_i,a)}{\partial K_i}\right) da - \omega = 0 \tag{3.21}$$

Further, for firm 2's FOC we know that $\frac{\partial a_1}{\partial K_2} = \frac{\partial f_2^{K_1}(K_2,a)}{\partial K_2} = 0$. Rearranging terms the FOC's for firm 1 and 2 continue as follow:

$$\frac{\partial E\left[\pi_1(\cdot)\right]}{\partial K_1} = \frac{\partial a_1}{\partial K_1}\left(f_1^u(K_1,a_1) - f_1^{K_1}(K_1,a_1)\right) + \frac{\partial a_2}{\partial K_1}\left(f_1^{K_1}(K_1,a_2) - f_1^c(K_1,a_2)\right)$$
$$+ \int\limits_{a_1}^{a_2} \left(\frac{\partial f_1^{K_1}(K_1,a)}{\partial K_1}\right) da + \int\limits_{a_2}^{\overline{a}} \left(\frac{\partial f_1^c(K_1,a)}{\partial K_1}\right) da - \omega = 0 \tag{3.22}$$

$$\frac{\partial E\left[\pi_2(\cdot)\right]}{\partial K_2} = \frac{\partial a_2}{\partial K_2}\left(f_2^{K_1}(K_2,a_2) - f_2^c(K_2,a_2)\right) + \int\limits_{a_2}^{\overline{a}} \left(\frac{\partial f_2^c(K_2,a)}{\partial K_2}\right) da - \omega = 0 \tag{3.23}$$

Evaluating the arguments of the integrals at a_1 and a_2, we can eliminate the first and second terms of equation (3.22) and the first term of equation (3.23). This is because

$f_1^u(K_1,a_1) = f_1^{K_1}(K_1,a_1) = \left[(K_1 + R_1(1-\delta))K_1 + \overline{P_1}\delta R_1 + (K_1 + c + R_1(1-\delta) + m_1)(1-\delta)R_1\right] h(a)$

and

$f_1^{K_1}(K_1,a_1) = f_1^c(K_1,a_1) = \left[(K_2 + R_2(1-\delta))\,K_1 + \overline{P_1}\delta R_1 + (K_2 + c + R_2(1-\delta) + m_1)(1-\delta)R_1\right] h(a).$

Solving the derivatives inside the integrals and rearranging terms, equations (3.22) and (3.23) become:

$$\frac{\partial E\left[\pi_1(\cdot)\right]}{\partial K_1} = \int_{a_1}^{a_2} \left(\frac{a-c-R_1(\delta-2)-\delta R_2-2K_1}{2}\right) da + \int_{a_2}^{\overline{a}} \left(a-c-2K_1-K_2-R_2+R_1(\delta-2)\right) da - \omega(\overline{a}-\underline{a}) = 0 \tag{3.24}$$

$$\frac{\partial E\left[\pi_2(\cdot)\right]}{\partial K_2} = \int_{a_2}^{\overline{a}} \left(a-c-K_1-2K_2-R_1+R_2(\delta-2)\right) da - \omega(\overline{a}-\underline{a}) = 0 \tag{3.25}$$

Equations (3.24) and (3.25) can be simplified to:

$$\frac{\partial E\left[\pi_i(\cdot)\right]}{\partial K_i} = \omega(\underline{a}-\overline{a}) + \epsilon - \frac{(c+3K_i+3R_i-\delta(2R_i-R_j))^2}{4} + \frac{\overline{a}^2}{2} - \frac{\beta_i^2}{4} + \beta_j(\beta_i-\overline{a}) = 0 \tag{3.26}$$

$$\frac{\partial E\left[\pi_j(\cdot)\right]}{\partial K_j} = \omega(\underline{a}-\overline{a}) + \frac{\overline{a}^2}{2} + \beta_i\left(\frac{\beta_i}{2}-\overline{a}\right) = 0 \tag{3.27}$$

where $\epsilon = (\beta_j - K_j + R_j(\delta-1))\,(K_i - K_j + (1-\delta)(R_i - R_j))$ and $\beta_i = c + K_i + 2K_j + R_i + R_j(2-\delta)$ and $\beta_j = c + K_j + 2K_i + R_j + R_i(2-\delta)$ $\forall\ i,j = 1,2$, with $i \neq j$.

Solving equations (3.26) and (3.27) with respect to K_i and K_j and checking the second-order conditions, we obtain the optimal capacity investment for each firm.

Appendix 13: Proof of Solution Uniqueness

Based on equations (3.26) and (3.27), our model predicts four possible pair solutions for $K_i^*$and K_j^*. We characterize each set using the superscript for $i, j = 1, 2$, $i \neq j$. We focus on the case when firm 1 is capacity constrained before firm 2, because the proof is analogous for the other case. The following expression describes solutions one and two:

$$K_i^{*1,2} = \frac{\overline{a}-c-3R_i+2\delta R_i-\delta R_j \pm \sqrt{2\omega(\overline{a}-\underline{a})}}{3} \tag{3.28}$$

Solutions three and four are as follows:

$$K_1^{*3} = \overline{a}-c-R_1-\delta R_2+\sqrt{2\omega(\overline{a}-\underline{a})}\ ;\ K_2^{*3} = R_2(\delta-1)-\sqrt{2\omega(\overline{a}-\underline{a})} \tag{3.29}$$

$$K_1^{*4} = \overline{a}-c-R_1-\delta R_2-\sqrt{2\omega(\overline{a}-\underline{a})}\ ;\ K_2^{*4} = R_2(\delta-1)+\sqrt{2\omega(\overline{a}-\underline{a})} \tag{3.30}$$

To prove the feasibility of the solutions, we use equations (3.6) and (3.13) that define a_i and a_j, respectively, and the fact that, by definition, the realized level of demand, a, falls between $\underline{a}$ and $\overline{a}$.

First, let us start with solution one and two. By definition $\underline{a} \leq a_i \leq \overline{a}$, and using equation (3.6) and substituting $K_1^{*1,2}$ from equation (3.28), we obtain:

$$\underline{a} \leq 3\left[\frac{\overline{a} - c - 3R_1 + 2\delta R_1 - \delta R_2 \pm \sqrt{2\omega(\overline{a} - \underline{a})}}{3}\right] + 3R_1 + c - \delta(2R_1 - R_2) \leq \overline{a} \quad (3.31)$$

$$\underline{a} \leq \overline{a} \pm \sqrt{2\omega(\overline{a} - \underline{a})} \leq \overline{a} \quad (3.32)$$

We know that $\omega(\overline{a} - \underline{a}) > 0$, so for equation (3.32) to be feasible, we need the sign of the squared root to be negative. This rules out K_1^{*2} from the feasible solutions of the model. Note that employing the same analysis for a_j with equation (3.13), we arrive at the same conclusion of equation (3.32): only solution one is feasible. Further, note that we can rearrange equation (3.32), using only solution one (i.e., negative squared root) as:

$$\sqrt{2\omega(\overline{a} - \underline{a})} \leq \overline{a} - \underline{a} \leq \overline{a}, \quad (3.33)$$

which is always true for $\omega < \frac{\overline{a} - \underline{a}}{2}$. This shows that solution one is always at or within the upper and lower bounds of the uniform distribution of a.

Regarding solution three, it is straightforward to notice that K_2^{*3} is strictly negative, which is a contradiction because the capacity level investment is bounded below by zero. As $\delta \in [0, 1]$, the maximum value that K_2^{*3} can take is $-\sqrt{2\omega(\overline{a} - \underline{a})}$, which is strictly negative because $\omega(\overline{a} - \underline{a}) > 0$. This rules out solution three as part of our model solution.

Finally, regarding solution four, we show that it yields a value of a_j greater than the upper bound $\overline{a}$. Using equation (3.13) and substituting the optimal capacity investment values of expression (3.30), we obtain:

$$2\left[R_2(\delta - 1) + \sqrt{2\omega(\overline{a} - \underline{a})}\right] + \overline{a} - c - R_1 - \delta R_2 - \sqrt{2\omega(\overline{a} - \underline{a})} + R_1 + R_2(2 - \delta) - c \leq \overline{a} \quad (3.34)$$

$$\overline{a} + \sqrt{2\omega(\overline{a} - \underline{a})} \leq \overline{a} \quad (3.35)$$

As argued before, equation (3.35) leads to a contradiction given that, by definition, $\omega(\overline{a} - \underline{a}) > 0$. This proves that solution four is unfeasible and that our model yields a unique feasible solution. ■