



**HAL**  
open science

# Three essays on the impact of renewable energy deployment

Félix Michelet

► **To cite this version:**

Félix Michelet. Three essays on the impact of renewable energy deployment. Economics and Finance. Université Paris sciences et lettres, 2024. English. NNT : 2024UPSLM018 . tel-04791201

**HAL Id: tel-04791201**

**<https://pastel.hal.science/tel-04791201v1>**

Submitted on 19 Nov 2024

**HAL** is a multi-disciplinary open access archive for the deposit and dissemination of scientific research documents, whether they are published or not. The documents may come from teaching and research institutions in France or abroad, or from public or private research centers.

L'archive ouverte pluridisciplinaire **HAL**, est destinée au dépôt et à la diffusion de documents scientifiques de niveau recherche, publiés ou non, émanant des établissements d'enseignement et de recherche français ou étrangers, des laboratoires publics ou privés.



**THÈSE DE DOCTORAT**

**DE L'UNIVERSITÉ PSL**

Préparée à MINES Paris - PSL

**TROIS ESSAIS SUR LES IMPACTS DU DÉPLOIEMENT DES  
ÉNERGIES RENOUVELABLES**

Soutenue par

Félix MICHELET

Le 27 septembre 2024

École doctorale n°543

**Sciences de la Décision,  
des Organisations de la  
Société et de l'Échange**

Spécialité

**Économie**

Composition du jury :

Anna CRETI

Professeure à l'Université Paris Dauphine

*Présidente*

Mar REGUANT

Full Professor à Northwestern University

*Rapporteur*

Klaus GUGLER

Professor à WU University

*Rapporteur*

Nicolas ASTIER

Professeur à l'École d'économie de Paris

*Examineur*

François LÉVÊQUE

Professeur à l'École des Mines (CERNA) - PSL

*Directeur de thèse*

Sven HEIM

Associate Professor à l'École des Mines (CERNA) - PSL

*Directeur de thèse*





**THÈSE DE DOCTORAT**  
**DE L'UNIVERSITÉ PSL**

Prepared at MINES ParisTech

**Three Essays on the Impacts of Renewable Energy  
Deployment**

Presented by

Félix MICHELET

On September 27, 2024

Doctoral School No. 543

**SDOSE**

Specialty

**Economics**

Composition of the jury:

Anna CRETI

Professor at Université Paris Dauphine

*President*

Mar REGUANT

Full Professor at Northwestern University

*Reviewer*

Klaus GUGLER

Professor at WU University

*Reviewer*

Nicolas ASTIER

Professor at Paris School of Economics

*Examiner*

François LÉVÊQUE

Professor at Mines Paris (CERNA) - PSL

*Advisor*

Sven HEIM

Associate Professor at Mines Paris (CERNA) - PSL

*Advisor*



# Remerciements - Acknowledgements

Ces quatre années ont été riches en apprentissage, mais aussi en rencontres. Je ne peux pas citer toutes les personnes qui ont été importantes, trop de papier serait nécessaire. Mais sachez que vous êtes tous dans mon cœur.

Je tiens en premier lieu à remercier mes directeurs. François, merci d'avoir cru en moi quand je suis venu à l'École des Mines proposer mon projet de thèse. Vos conseils, francs et de grande qualité, m'ont énormément servi. Je crois pouvoir dire que j'ai appris à écrire pendant ce doctorat, et vous en êtes en grande partie responsable. Sven, thank you for everything. I have learned a lot working with you, both in econometrics and in writing and publication strategy. Over the years, I have felt myself becoming a full-fledged researcher. You have been a role model on this journey. More than that, your calm and serenity have been important during the tough moments of the PhD. I will not forget the fun of discovering that you are also a fan of Will Ferrell, an extraordinary shared interest. In a word: dankeschön.

I am grateful to Mar Reguant and Klaus Gugler for agreeing to be the reviewers of this dissertation. I also thank Nicolas Astier and Anna Creti for their participation as examiners. I deeply value the time and effort you dedicate to reading this thesis. This jury is exceptional, especially since each participant has inspired me through their remarkable work.

I would like to thank Mario Liebensteiner. You were the first to talk to me about the environmental value of renewable energy, which is the central concept of my research. Your methodological ideas have been immensely helpful, especially for my job market paper. I also discovered root beer with you, and I love it!

Je remercie également Olivier Massol avec qui j'ai pu travailler les six premiers mois de ce doctorat sur un papier non inclus dans le manuscrit final, mais qui j'en suis sûr sera bientôt publié. J'ai beaucoup appris grâce à toi sur le fonctionnement des marchés du gaz naturel et sur les méthodologies d'analyse des séries temporelles. Je me dois également de remercier la Chaire The Economics of Gas pour son financement.

Travailler au sein du CERNA a été un plaisir et une chance que je mesure. Bien sûr, les bâtiments sont magnifiques, et la vue du jardin du Luxembourg me manquera. Mais le plus important a été les rencontres que j'y ai faites. Je suis sûr qu'elles auraient même été aussi heureuses dans un blockhaus, type ancien siège de l'OTAN !

---

En premier, je suis reconnaissant aux professeurs du laboratoire. Matthieu, merci pour les nombreuses conversations, qu'elles aient été professionnelles ou non. Ta bonne humeur à toute épreuve est toujours communicative. Ce sera toujours un plaisir de te recroiser dans le monde académique, ou à un concert d'Idles une pinte à la main. Pierre, tes conseils, notamment au début de la thèse, ont toujours été éclairés. J'ai engagé ma réflexion sur la meilleure manière de communiquer des résultats grâce à eux. Olivier, merci pour tes invitations et les délicieux dîners.

Viennent ensuite les "anciens". Les brillants doctorants qui étaient déjà là quand je suis arrivé et qui m'ont ouvert la voie. Vous avez d'abord été des modèles, avant de devenir des amis. Nos déjeuners ont été des moments de détente, de débat et d'ouverture. Simon, merci pour tes précieuses premières relectures. Victor, Rémi et Amélie, vos réflexions politiques et votre culture incommensurable m'ont permis de découvrir et de m'intéresser à un monde que je ne connaissais pas. It was also a pleasure to share my office with Eili. Thank you for making me discover Barry's. Les nouveaux doctorants ont pris le relais avec brio. Guillaume le crack de l'économétrie, tes relectures attentives ont été extrêmement précieuses. Je ne pense pas prendre beaucoup de risque en te prédisant un grand avenir académique. Tiphaine, merci de m'avoir accompagné environ 500 fois au sport. Ta vision du monde et de l'économie alternatives m'ont souvent fait réfléchir. France, ton humour de toulousaine est arrivé au meilleur moment pour la fin de ma thèse. Enfin, Robin a été d'une aide précieuse. Avoir un assistant de recherche inventif et, qui plus est, excellent grimpeur est une très bonne idée. Je n'oublie bien sûr pas tous les autres qui ont participé à la vie du CERNA : Renaud, Dennis, Margaret, Philippe, Antoine, Nassir, Émilie, Pol, Othmann, Manal et Ekaterina.

Un paragraphe est nécessaire pour remercier Barbara. Avoir si peu à penser à l'administratif est une chance rare, si ce n'est inédite dans le monde académique.

I was fortunate to be welcomed for a visiting period by Mar and her team at BSE. Those few months were among the most productive of my thesis. The winter was mild and happy, and I can only thank Jacint, Claudia, Charlotte, Mayra, and everyone else. You are excellent researchers but also wonderful human beings.

Je remercie mes amis : Henri, présent depuis chez Thérèse, pour ton humour caustique ; Pierre et Emma, pour votre gentillesse venue d'un autre monde ; Coline et Fabien, pour nos road trips au soleil ; Jeanne, pour les bières Butte aux Cailles ; Olivier, pour nos sessions radicales et notre quête de vitesse ; Félix, Thomas, JB et Charles, car les amitiés formées en prépa sont sûrement éternelles ; Benjamin, en espérant ton retour prochain du Canada ; Caroline, pour tes bons plans. Je n'oublie pas aussi Margot, Elliott, Joséphine, JB, Fred, Bart, et mes nombreux compagnons de navigation.

Merci à ma famille. Mes parents de m'avoir permis de partir en sport étude, puis en

---

prépa, et d'avoir cru en moi. Merci à mes grands-parents : Papi et Mamette pour votre gentillesse et votre attention, et en particulier merci à Papi d'avoir attendu que je sois en vacances pour faire une crise cardiaque sans me déranger dans mon travail ; Mamo et Papy d'Afrique, pour sans doute m'avoir transmis génétiquement la fibre éducative et scientifique.

Enfin, je remercie Lucie. Tu es la personne la plus douce et rassurante que je connaisse. Et tu fais des quiches. Merci d'avoir été là pendant la rédaction de ce manuscrit. Même si mes soucis, une régression qui ne donne rien, un bug dans mon code, ou l'écriture qui n'avance pas, semblent tout petits à côté de ton travail consistant simplement à guérir voire sauver des enfants, tu as été là dans le stress comme dans la joie. Merci pour tout.



---

---

## Résumé de la thèse

Cette thèse est composée de trois chapitres indépendants ayant pour thématique commune les implications du déploiement des énergies renouvelables. Ils visent à comprendre comment ces énergies contribuent de façon hétérogène à la baisse des émissions de gaz à effet de serre d'une part, et comment les populations locales peuvent être négativement impactées d'autre part.

Les deux premiers chapitres se concentrent sur la notion de valeur environnementale des énergies renouvelables. En deux mots, cela désigne le nombre de tonnes de CO<sub>2</sub> évitées par la génération d'un mega-watt-heure additionnel de renouvelables. Le premier chapitre étudie comment cette valeur est modifiée par l'intégration des marchés de l'électricité. Le deuxième chapitre comment cette valeur varie régionalement et en fonction des prix des combustibles et du CO<sub>2</sub> aux États-Unis.

Le troisième chapitre examine l'impact du déploiement des éoliennes en Allemagne sur le prix du foncier. La méthode des prix hédoniques y est utilisée afin de documenter les causes du NIMBYism, acronyme anglais pour "Not In My Backyard", phénomène d'opposition locale au déploiement des renouvelables. Voici un résumé succinct de chaque chapitre.

Le premier, intitulé *The impact of electricity market integration on the cost of CO<sub>2</sub> emissions abatement through renewable energy promotion*, étudie comment l'intégration des marchés de l'électricité peut impacter la valeur environnementale des énergies renouvelables, et in fine modifier le prix à payer par les consommateurs pour éviter l'émission d'une tonne de CO<sub>2</sub> additionnelle. Il se concentre également sur les enjeux distributifs de cette question. Qui paie quoi, qui gagne, et qui perd. Plus précisément, je tire parti de l'expansion soudaine et substantielle de l'interconnexion électrique entre l'Espagne et la France pour examiner empiriquement les effets conjoints de l'intégration croissante des marchés énergétiques européens et du déploiement des énergies renouvelables sous divers angles. Dans la spécification principale, j'étudie comment l'intégration a modifié le type de génération conventionnelle remplacé en Espagne et en France par l'éolien espagnol, et ainsi comment l'effet marginal de cet éolien sur les émissions de chaque pays a évolué. Les modifications de l'effet marginal sur les prix des deux pays sont aussi quantifiés. En employant une méthode quasi-expérimentale, je trouve que l'intégration des marchés a augmenté les émissions de CO<sub>2</sub> évitées en France de 45 kilogrammes par mega-watt-heure d'éolien espagnol additionnel. En revanche, les émissions évitées en Espagne ont diminué de 175 kilogrammes par mega-watt-heure. L'effet total est négatif, ce qui signifie que la valeur environnementale de l'éolien espagnol a diminué de façon agrégée avec l'intégration.

---

Ce résultat est attribué à une substitution moindre du charbon en Espagne et à une substitution plus importante du gaz en France. J'utilise ensuite les estimations obtenues pour calculer le coût de réduction d'une tonne de CO<sub>2</sub> pour le consommateur espagnol à travers le programme de subvention de l'énergie éolienne. Il a légèrement augmenté, bien que le consommateur bénéficie encore d'un effet de prix qui dépasse le coût de la subvention : - 26 euros par tonne évitée avant l'expansion contre - 3 euros après. Au total le consommateur bénéficie toujours de façon nette grâce à la baisse des prix de l'électricité induite. Enfin, je calcule l'impact marginal de la génération éolienne sur le surplus total en considérant le surplus des consommateurs et des producteurs d'électricité dans les deux pays ainsi que la baisse des émissions. Au total, l'impact est positif à partir d'un coût du carbone de 60 €/tCO<sub>2</sub> pré-expansion et de 70 €/tCO<sub>2</sub> post-expansion. En général, ce chapitre souligne des implications importantes de l'intégration des marchés de l'énergie souvent négligées, telles que les incitations à profiter des programmes de subvention d'autres pays et l'incidence de politiques énergétiques unilatérales. Il soulève la question suivante : est-il normal qu'un pays puisse reporter une diminution de ses émissions obtenue grâce à une politique publique menée dans un autre pays sans contrepartie ?

Le deuxième chapitre, intitulé *How fuel switching impacts the environmental value of renewable energy*, est un travail conjoint avec Sven Heim et Mario Liebensteiner. Nous quantifions les réductions d'émissions de CO<sub>2</sub> régionales attribuées à la génération d'énergie solaire et éolienne aux États-Unis pendant l'ère des prix bas du gaz naturel causée par la révolution du gaz de schiste. Nous explicitons également comment l'intensité de cette réduction varie en fonction d'un prix fictif du CO<sub>2</sub> obtenu par préférence révélée. L'analyse utilise plusieurs jeux de données sur la génération d'énergie renouvelable et thermique dans des régions produisant à la fois de l'électricité au charbon et au gaz et déployant de façon significative de la capacité renouvelable. Pour contrôler l'effet potentiel du *fuel switching*<sup>1</sup>, un terme d'interaction entre le rapport des prix du charbon et du gaz et la génération renouvelable est utilisé. Ce rapport de coût détermine si les énergies renouvelables remplacent de la génération au charbon ou au gaz. Cela influence directement la valeur environnementale des renouvelables, car les centrales au charbon émettent environ deux fois plus de CO<sub>2</sub> que les centrales au gaz. Les deux résultats principaux sont les suivants. Premièrement, la valeur environnementale des renouvelables varie de façon importante régionalement, et ce jusqu'à un facteur deux<sup>2</sup>. Le second résultat est qu'à un ratio de coût ou un prix du carbone faible, les renouvelables sont plus susceptibles

---

<sup>1</sup>Cet anglicisme désigne le fait qu'un combustible auparavant moins cher qu'un autre devienne plus cher.

<sup>2</sup>De 0,4tCO<sub>2</sub>/MWh, correspondant à l'intensité carbone de la génération au gaz, à 1tCO<sub>2</sub>/MWh, correspondant à celle de la génération au charbon.

---

de compenser la génération alimentée au gaz. Puis quand le ratio ou le prix du carbone augmente, c'est la génération au charbon qui est remplacée. Cela est du au *fuel switching*. Le charbon devient plus cher que le gaz. Il en résulte une valeur environnementale élevée. Enfin, à des ratios de coût ou des prix du carbone élevés, les renouvelables tendent à remplacer à nouveau la génération au gaz, indiquant un bénéfice environnemental plus faible. C'est le cas car le charbon n'est plus assez compétitif économiquement et n'est donc plus utilisé. Ce papier offre des perspectives importantes sur l'optimisation des politiques publiques pour la réduction des émissions de CO<sub>2</sub>. Nous recommandons ainsi de promouvoir d'avantage les énergies renouvelables quand elles permettent d'éviter plus de CO<sub>2</sub>, et plus quand il reste encore de la génération au charbon compétitive à éviter.

Le troisième chapitre, intitulé *Wind Turbines and Local Economies: Effects on Housing, Tourism, and Municipality Income* est également un travail conjoint avec Sven Heim et Mario Liebensteiner. Nous évaluons empiriquement l'opposition locale au déploiement des éoliennes en Allemagne. Cette opposition, souvent qualifiée de syndrome NIMBY (pour *Not In My Backyard*), découle des externalités locales telles que les nuisances visuelles et la pollution sonore. Ce papier quantifie de manière causale la valeur que les ménages accordent à ces désagréments non marchands en utilisant la méthode des prix hédoniques. Afin de surmonter les problèmes d'endogénéité dus à la simultanéité entre le prix de l'immobilier et les installations d'éoliennes, le papier applique une nouvelle stratégie de variable instrumentale qui tire parti des variations géographiques et temporelles des subventions à l'énergie éolienne en Allemagne. Le principal résultat est que l'implantation des éoliennes diminue les prix d'achat des maisons de 1,9 % dans les municipalités affectées et que cet effet adverse est plus prononcé pour les premières turbines installées. De plus, l'implantation des éoliennes réduit le tourisme local et entraîne une diminution des permis de construire délivrés pour les appartements et maisons, exacerbant la pénurie de logements. Du côté positif, chaque éolienne installée augmente de 1,8 % la capacité fiscale locale d'une municipalité grâce à sa contribution aux recettes fiscales commerciales locales. Bien que la transition vers les énergies renouvelables finira par augmenter le bien-être grâce à des prix de l'électricité plus bas et des émissions réduites, ce chapitre documente que les infrastructures d'énergie renouvelable entraînent des coûts locaux hétérogènes significatifs qui doivent être pris en compte pour un déploiement stratégique. Nous recommandons de placer en priorité les éoliennes dans les zones où l'opposition est faible et de favoriser autant que possible l'agrandissement de champs d'éoliennes existants à la construction d'une première éolienne dans une zone. De plus, nos résultats suggèrent que les externalités négatives peuvent être atténuées en investissant les revenus fiscaux accrus dans les services publics locaux, compensant ainsi

---

les effets adverses des éoliennes.

DISCIPLINE : Sciences Économiques

MOTS-CLEFS : énergies renouvelables, intégration des marchés, décarbonisation, révolution du schiste, NIMBY, externalités locales, économétrie

---

## Thesis summary

This thesis comprises three independent chapters centered around the theme of renewable energy deployment, its heterogeneous implications on greenhouse gas emission reduction and its potential negative impacts on local populations.

The first two chapters focus on the environmental value of renewable energies, defined as the quantity of CO<sub>2</sub> avoided per additional megawatt-hour of renewable generation. The first chapter explores how this value is affected by the integration of electricity markets. The second chapter how it varies regionally and according to the prices of fuels and CO<sub>2</sub> in the US.

The third chapter assesses the impact of wind turbine deployment in Germany on land prices, using the hedonic pricing method to document the causes of NIMBYism. This acronym standing for "Not In My Backyard" refers to local opposition to renewable deployment. A succinct summary of each chapter is provided below.

The first chapter, *The Impact of Electricity Market Integration on the Cost of CO<sub>2</sub> Emissions Abatement Through Renewable Energy Promotion*, examines how electricity market integration can impact the environmental value of renewable energies and ultimately alter the cost of avoiding an additional ton of CO<sub>2</sub>. It also focuses on the distributive issues at stake: who pays, who gains, and who loses. Specifically, I leverage the sudden and substantial expansion of the electricity interconnection between Spain and France to empirically examine the effects of increasing European energy market integration and renewable energy deployment from various angles. In the main specification, I study how integration has altered the type of conventional generation replaced in Spain and France by Spanish wind energy, and thus how the marginal effect of this wind energy on CO<sub>2</sub> emissions in each country has changed. Modifications in the marginal effect on the prices of both countries are also quantified. Using quasi-experimental methods, I find that market integration has increased CO<sub>2</sub> emissions avoided in France by 45 kilograms per additional megawatt-hour of Spanish wind energy. Conversely, the emissions abated in Spain have decreased by 175 kilograms per megawatt-hour. The overall effect is negative, which means that the environmental value of Spanish wind energy has decreased on aggregate with integration. This result is attributed to less substitution of coal generation in Spain and more substitution of gas generation in France. I then use the estimates obtained to calculate the cost of reducing one tonne of CO<sub>2</sub> for the Spanish consumer through the wind energy subsidy program. It has increased slightly, although the consumer still benefits from a price effect that exceeds the cost of the subsidy: -26 euros per ton avoided before the expansion versus -3 euros afterwards. Overall, the consumer still

---

realizes a net benefit resulting from the reduction in electricity prices. Finally, I calculate the marginal impact of wind generation on the total surplus, accounting for the consumer surplus and the producer surplus in both countries, as well as the decrease in emissions. Overall, the impact is positive pre-expansion from a carbon cost of 60 €/tCO<sub>2</sub> and 70 €/tCO<sub>2</sub> post-expansion. This chapter highlights important implications of market integration often overlooked in the context of energy market integration, such as incentives to freeride on other countries' unilateral energy policies and subsidy programs. It raises the following question: Is it normal for one country to offset a reduction in its emissions obtained through a public policy carried out in another country without any counterpart?

The second chapter, *How Fuel Switching Impacts the Environmental Value of Renewable Energy*, is co-authored with Sven Heim and Mario Liebensteiner. We quantify regional CO<sub>2</sub> emission reductions attributed to solar and wind energy generation in the United States during the era of low natural gas prices following the shale gas boom. We also detail how the intensity of this reduction varies according to an estimated CO<sub>2</sub> price obtained by revealed preference. The analysis uses several datasets on renewable and thermal energy generation in regions producing both coal and gas electricity and deploying significant renewable capacity. To control for potential fuel switching, an interaction term between the coal and gas price ratio and renewable generation is included. This ratio determines whether renewables replace coal or gas generation, directly influencing the environmental value of renewables since coal plants emit about twice as much CO<sub>2</sub> as gas plants. The two main results are as follows. First, the environmental value of renewables varies significantly regionally, up to a factor of two<sup>3</sup>. Second, at a low cost ratio or carbon price, renewables are more likely to offset gas-fired generation. Then, as the ratio or carbon price increases, coal generation is replaced. This is due to fuel switching: coal becomes more expensive than gas, resulting in a higher environmental value. Finally, at high cost ratios or carbon price, renewables tend to replace gas generation again, indicating a lower environmental benefit. This occurs because coal is no longer economically competitive and therefore less used. This paper offers important insights on optimizing public policies for CO<sub>2</sub> emission reduction. We recommend subsidizing renewables more when they avoid more CO<sub>2</sub>, and more when there is still competitive coal generation to avoid.

The third chapter, *Wind Turbines and Local Economies: Effects on Housing, Tourism, and Municipality Income*, is also co-authored with Sven Heim and Mario Liebensteiner.

---

<sup>3</sup>Ranging from 0.4 tCO<sub>2</sub>/MWh, which corresponds to the carbon intensity of gas-fired generation, to 1 tCO<sub>2</sub>/MWh, representative of coal-fired generation.

---

It empirically evaluates local opposition to wind turbine deployment in Germany. This opposition, often referred to as the NIMBY syndrome, stems from local externalities such as visual disamenities and noise pollution. This paper causally quantifies the value that households place on these non-market disamenities using the hedonic pricing method. To overcome potential endogeneity problems due to simultaneity between property prices and wind turbine installations, the paper applies a novel instrumental variable strategy that leverages the geographic and temporal variations of wind energy subsidies in Germany. The main result is that the installation of wind turbines reduces house purchase prices by 1.9% in affected municipalities, and that this adverse effect is more pronounced for the first turbines installed. Moreover, the installation of wind turbines reduces local tourism and leads to a decrease in building permits issued for apartments and houses, exacerbating the housing shortage. On the positive side, each wind turbine installed increases a municipality's local tax capacity by 1.8% due to its contribution to local business tax revenues. Although the transition to renewable energies will eventually increase well-being through lower electricity prices and reduced emissions, this chapter documents that renewable energy infrastructure entails significant heterogeneous local costs that must be considered for strategic deployment. We recommend prioritizing wind turbine placement in areas where opposition is low and favoring the expansion of existing wind farms over the construction of a first turbine in an area. Furthermore, our results suggest that negative externalities can be mitigated by investing increased tax revenues in local amenities and services, thus offsetting the adverse effects of wind turbines.

DISCIPLINE: Economics

KEYWORDS: Renewable energy, market integration, decarbonization, shale gas boom, NIMBY, local externalities, econometrics



---

# Table of contents

Résumé de la thèse . . . . .	7
Thesis summary . . . . .	11
<b>Table of contents</b>	<b>15</b>
<b>Figures</b>	<b>18</b>
<b>Tables</b>	<b>20</b>
Introduction générale . . . . .	23
General Introduction . . . . .	45
<b>1 The impact of electricity market integration on the cost of CO<sub>2</sub> emissions abatement through renewable energy promotion</b>	<b>64</b>
1.1 Introduction . . . . .	67
1.2 Background and Conceptual Framework . . . . .	71
1.2.1 Benefits of electricity markets integration . . . . .	71
1.2.2 The environmental value of renewable electricity . . . . .	75
1.2.3 Merit order effect . . . . .	76
1.2.4 Wind power promotion in Spain . . . . .	77
1.2.5 Conceptual Framework . . . . .	78
1.3 Data . . . . .	80
1.3.1 Electricity mix in Spain and in France . . . . .	80
1.3.2 Emissions . . . . .	83
1.3.3 Wind generation and load . . . . .	83
1.3.4 Cost ratio . . . . .	84
1.4 Empirical Analyses . . . . .	85
1.4.1 Marginal abatement effect and cross-border marginal abatement effect . . . . .	85
1.4.1.1 Econometric framework . . . . .	85
1.4.1.2 Results and discussion . . . . .	86
1.4.1.3 Heterogeneous effects . . . . .	89
1.4.2 Merit order effect . . . . .	91
1.4.2.1 Econometric framework . . . . .	91
1.4.2.2 Results and discussion . . . . .	93
1.4.3 Robustness checks . . . . .	94
1.5 The cost of reducing CO <sub>2</sub> emissions . . . . .	94

1.6	Marginal impact of wind generation on welfare . . . . .	95
1.6.1	Decomposition of Economic Surplus: . . . . .	96
1.6.2	Results . . . . .	97
1.7	Policy discussion . . . . .	98
1.8	Conclusion . . . . .	99
1.A	Appendices . . . . .	101
1.A.1	Literature . . . . .	101
1.A.2	Additional Tables . . . . .	104
1.A.3	Additional Figures . . . . .	108
<b>2</b>	<b>How fuel switching impacts the environmental value of renewable energy</b>	<b>111</b>
2.1	Introduction . . . . .	113
2.2	Background . . . . .	118
2.2.1	Electricity markets . . . . .	118
2.2.2	The environmental value of renewable electricity - <i>Static merit order</i>	120
2.2.3	U.S. electricity mix and fuel switching . . . . .	123
2.3	Conceptual framework . . . . .	126
2.3.1	Supply function . . . . .	126
2.3.2	How does the carbon intensity of the marginal plant vary? . . . . .	127
2.4	Data . . . . .	129
2.4.1	Dependent Variables . . . . .	130
2.4.2	Control variables . . . . .	131
2.5	Methodology . . . . .	133
2.5.1	Identification strategy . . . . .	133
2.5.2	Mapping of the cost ratio to carbon price . . . . .	135
2.6	Results . . . . .	136
2.6.1	Electricity generation . . . . .	136
2.6.2	Environmental value of renewable generation . . . . .	138
2.6.3	Heterogeneity in the environmental value of renewable generation as a function of the cost ratio . . . . .	140
2.7	Discussion . . . . .	143
2.7.1	Location, Location, Location - Geographic Differentiation in Renewable Energy Policy . . . . .	144
2.7.2	Think One Step Ahead . . . . .	144
2.7.3	Policy Implications for Other Countries . . . . .	145
2.7.4	Avenues for future research . . . . .	145
2.8	Conclusion . . . . .	146
2.A	Appendices . . . . .	147
2.A.1	Fuel switching enabling conditions . . . . .	147
2.A.2	Conceptual framework extension: Effect of the increase in renewable electricity capacity . . . . .	147
2.A.3	Mapping cost ratios with carbon prices . . . . .	150
2.A.4	Additional Tables . . . . .	152
2.A.5	Additional Figures . . . . .	153

---

<b>3</b>	<b>Wind Turbines and Local Economies: Effects on Housing, Tourism, and Municipality Income</b>	<b>155</b>
3.1	Introduction . . . . .	157
3.2	Institutional background . . . . .	159
3.2.1	Wind energy expansion in Germany . . . . .	159
3.2.2	Benefits versus local opposition . . . . .	162
3.2.3	Valuing the costs to local residents . . . . .	163
3.3	Conceptual framework . . . . .	165
3.4	Data . . . . .	167
3.4.1	House prices . . . . .	167
3.4.2	Wind turbines . . . . .	168
3.4.3	Expected revenue . . . . .	170
3.4.4	Control variables . . . . .	173
3.5	Identification strategy . . . . .	173
3.6	Results . . . . .	176
3.6.1	Main results . . . . .	176
3.6.2	Effect of first vs. additional wind turbines . . . . .	177
3.6.3	Robustness tests . . . . .	179
3.6.3.1	Effect of future wind turbine placements on contemporaneous house prices . . . . .	179
3.6.3.2	Randomized siting of wind turbines . . . . .	181
3.6.3.3	Alternative time periods . . . . .	181
3.6.4	Different outcome variables . . . . .	182
3.6.5	Commercial taxes . . . . .	183
3.7	Discussion and Policy Recommendations . . . . .	185
	<b>Bibliography</b>	<b>189</b>

# Figures

1	Risques mondiaux classés par sévérité à court et long terme . . . . .	24
2	Emissions net de GES 1990-2019 . . . . .	25
3	Trajectoires des émissions mondiales compatibles avec un réchauffement limité à 1,5 °C . . . . .	26
4	Répartition des émissions de GES par secteur 1990-2020 . . . . .	27
5	Production d'électricité par source 1990-2023 . . . . .	28
6	Illustration du croisement des courbes d'offre et de demande pour une heure donnée. . . . .	31
7	Global Risks Ranked by Severity in the Short and Long Term . . . . .	46
8	Net GHG Emissions 1990-2019 . . . . .	47
9	Trajectories of global emissions compatible with limiting warming to 1.5°C . . . . .	47
10	Distribution of GHG emissions by sector 1990-2020 . . . . .	49
11	Electricity generation by source 1990-2023 . . . . .	49
12	Illustration of the intersection of supply and demand curves for a given hour. . . . .	52
1.1	Average daily electricity demand in Spain and France and Wind generation in Spain (GWh) . . . . .	84
1.2	Hour-by-hour Spanish coal replacement per MWh of Spanish Wind Power . . . . .	89
1.3	Hour-by-hour French gas replacement per MWh of Spanish Wind Power . . . . .	90
1.4	Marginal Surplus Effects of Spanish Wind . . . . .	97
1.A1	Average monthly electricity demand in Spain and France and Wind generation in Spain (GWh) . . . . .	108
1.A2	Average daily photovoltaic generation in Spain and France (GWh) . . . . .	108
1.A3	Marginal Surplus Effects of Wind with varying Social Cost of Carbon . . . . .	109
2.1	Commodity price developments (\$/MWh) . . . . .	114
2.2	U.S. electricity production by source (TWh) . . . . .	115
2.3	U.S. CO <sub>2</sub> emissions by source (Mt) . . . . .	115
2.4	Merit order . . . . .	118
2.5	Monthly dry shale gas production in the US by play in billions cubic feet . . . . .	123
2.6	Marginal carbon intensity as a function of the price of gas . . . . .	129
2.7	Independent system operators map . . . . .	130
2.8	Ratio of coal over gas fuel costs in each region during 2009-2022 . . . . .	132
2.9	Renewable electricity monthly generation per region during 2009-2022 (GWh) . . . . .	133

---

2.10 Renewable generation environmental value with varying carbon price . . . . .	142
2.A1 Effect of additional RE capacity for a small decrease of the gas price . . . . .	149
2.A2 Effect of additional RE capacity for a small decrease of the gas price . . . . .	149
2.A3 Effect of additional RE capacity for a small decrease of the gas price . . . . .	150
2.A4 Illustration of the impact of a change in the price of gas on the marginal plant . . . . .	153
3.1 Development of wind energy in Germany, 2000–2022 . . . . .	160
3.2 Development of feed-in tariffs for wind, 2005-2017 . . . . .	161
3.3 Bid curves of buyers . . . . .	166
3.4 Means and within municipality variation of the house price index 2008–2017 . . . . .	169
3.5 Development of wind turbines in Germany between 2008 and 2017 . . . . .	170
3.6 Wind power potential in Germany . . . . .	171
3.7 Expected revenue and within variations . . . . .	172
3.8 Expected revenues and wind turbine installations correlation . . . . .	175
3.9 Placebo test . . . . .	181
3.10 Development of wind turbine characteristics over time . . . . .	185

# Tables

1.1	Installed capacity (MW)	81
1.2	Annual generation (TWh)	81
1.3	Emissions regression results	87
1.4	Generation per fuel type regression results	88
1.5	Merit order effect	93
1.A1	Emissions Offsets Due to Renewable Electricity	101
1.A2	Merit order effect	102
1.A3	Effects of RE on exports (MWh exports per MWh of RE)	104
1.A4	Emissions regression results - Augmented local linear	105
1.A5	Emissions regression results - Control variables are not interacted with the indicator	106
1.A6	Emissions regression results - Daily aggregation	107
2.1	Summary Statistics	131
2.2	Mapping cost ratio to carbon price	136
2.3	Effect of the coal over gas cost ratio and renewable energy generation on fossil fuel generation	137
2.4	Effect of the coal over gas cost ratio and renewable energy generation on emissions	139
2.5	Aggregate effect of renewable energy deployment	140
2.A1	RE environmental value with varying cost ratio (carbon price)	152
3.1	Summary statistics of main variables	168
3.2	First-stage regression estimates, IV-GMM	176
3.3	Effect of wind turbine deployment on house prices	178
3.4	Effect of first WT vs. effect of additional WTs	179
3.5	Placebo test with lagged dependent variable	180
3.6	Robustness: Alternative time periods	182
3.7	Alternative outcome variables	183
3.8	WTs and commercial taxes	184







## Introduction générale

Cette introduction est structurée comme suit. Je commence par présenter la problématique environnementale principale à laquelle le déploiement des énergies renouvelables cherche à répondre : le changement climatique. Puis j'expose la part de responsabilité du secteur électrique, l'intérêt des énergies renouvelables et ce qu'est leur *valeur environnementale*. Les trois concepts centraux de ce manuscrit que sont l'*intégration* des marchés de l'électricité, le *fuel switching* et le *NIMBYism*<sup>4</sup> sont ensuite définis. Enfin, je présente les objectifs, les méthodologies et les contributions de cette thèse.

## Émissions de gaz à effet de serre et changement climatique

### Le changement climatique, risque majeur

Le défi est aussi grand qu'il est pressant. Les émissions de gaz à effet de serre (GES) anthropiques doivent être réduites. Dans le cas contraire, les conséquences sont établies. Réchauffement climatique, phénomènes météorologiques extrêmes, sixième extinction, déplacements forcés de populations et j'en passe. Le tableau est sombre mais les solutions sont connues. Pour se fixer les idées, commençons par un état des lieux de la situation et des tendances.

Il est aujourd'hui reconnu que le changement climatique est dû aux activités humaines (IPCC, 2023b). Ses implications sont également clairement documentées, notamment dans la partie *Impacts, Adaptation et Vulnérabilité* du sixième rapport du Groupe d'experts intergouvernemental sur l'évolution du climat (GIEC<sup>5</sup>) (IPCC, 2023a) qui fait référence. Citons entre autres les impacts négatifs déjà observés sur la santé physique et mentale des individus, l'augmentation de la fréquence des vagues de chaleur et des feux de forêt, ou la prolifération accélérée des virus. S'il n'était pas assez clair que la situation est critique, le Forum Économique Mondial a mis les choses en perspective en analysant et classant les principaux risques mondiaux (WEF, 2024). Chacun est associé à une catégorie : économique, environnementale, géopolitique, sociétale et technologique. À dix ans, les quatre premiers relèvent tous de la catégorie environnementale. Ils comprennent, dans l'ordre, les événements météorologiques extrêmes, les perturbations de la biosphère, la perte de biodiversité et l'effondrement des écosystèmes et les pénuries de ressources naturelles (voir Figure 7). Pour ce qui est de l'impact direct sur les vies humaines,

---

<sup>4</sup>*Not In My Backyard* - Pas dans mon jardin.

<sup>5</sup>L'acronyme anglais IPCC est utilisé pour les citations.

Figure 1: Risques mondiaux classés par sévérité à court et long terme



Notes: Ce graphique provient du rapport d'évaluation des risques mondiaux du Forum Économique Mondial. Le classement est obtenu avec un sondage de 1500 experts mondiaux provenant des milieux académiques, des gouvernements, de l'industrie et de la société civile. Les réponses ont été collectées entre septembre et octobre 2023.

l'Organisation mondiale de la santé (OMS<sup>6</sup>) estime qu'entre 2030 et 2050, le changement climatique sera responsable de 250 000 morts additionnels chaque année (WHO, 2021). Le coût direct des dommages à la santé humaine est également évalué à 2-4 milliards de dollars par an d'ici 2030.

## Émissions : où nous en sommes, où nous allons, où nous devons aller

L'atténuation de ces risques doit donc être une préoccupation majeure de notre siècle. Mais où en sommes-nous, et vers où allons-nous ?

Commençons par la cause. Le réchauffement climatique est dû à la concentration de plusieurs molécules dans l'atmosphère<sup>7</sup> dont le potentiel de réchauffement est exprimé en équivalent carbone<sup>8</sup>. La Figure 2 montre l'évolution des émissions mondiales des

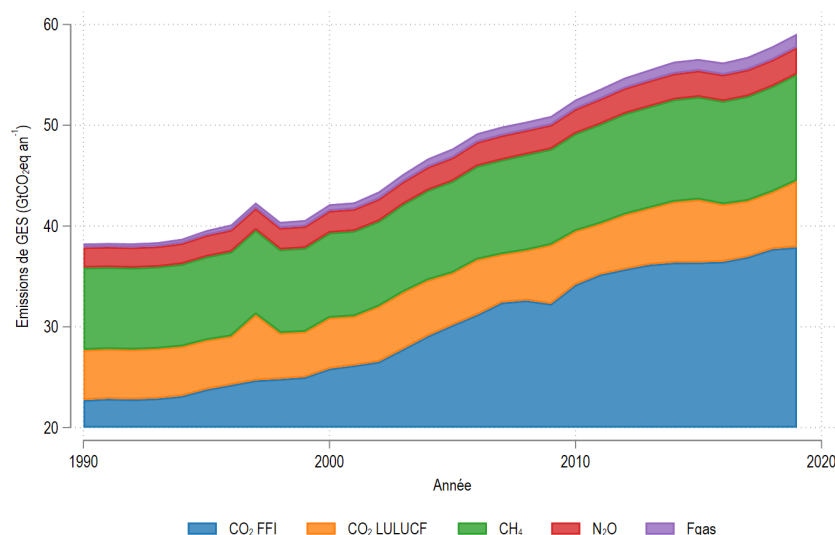
<sup>6</sup>L'acronyme anglais WHO est utilisé pour les citations.

<sup>7</sup>Les principales émissions par l'activité humaine dont les quantités sont reportées par la Convention sur le Changement Climatique des Nations Unies (UNFCCC) sont les suivantes : CO<sub>2</sub> issu de la combustion des combustibles fossiles et des processus industriels (CO<sub>2</sub>-FFI) ; émissions nettes de CO<sub>2</sub> issues de l'utilisation des terres, du changement d'affectation des terres et de la foresterie (CO<sub>2</sub>-LULUCF) ; méthane (CH<sub>4</sub>) ; protoxyde d'azote (N<sub>2</sub>O) ; et gaz fluorés (Fgas) comprenant les hydrofluorocarbones (HFC), les perfluorocarbones (PFC), l'hexafluorure de soufre (SF<sub>6</sub>), ainsi que le trifluorure d'azote (NF<sub>3</sub>).

<sup>8</sup>L'équivalent CO<sub>2</sub> compare les effets de différents gaz à effet de serre sur le réchauffement climatique, en utilisant le CO<sub>2</sub> comme référence, qui a un potentiel de réchauffement global (PRG) fixé à 1. Ainsi, le PRG quantifie l'impact de chaque gaz par rapport au CO<sub>2</sub>. Par exemple, le PRG du méthane (CH<sub>4</sub>) est estimé à 28 fois celui du CO<sub>2</sub> sur 100 ans, donc une tonne de méthane équivaut à 28 tonnes de CO<sub>2</sub>

principales molécules entre 1990 et 2019. Elles sont en constante augmentation avec en 2019 près de 60 milliards de tonnes de CO<sub>2</sub> équivalent (GtCO<sub>2</sub>eq) émises. En 2020, une réduction a eu lieu mais est attribuée à la pandémie de Covid-19 (Le Quéré et al., 2021), et un rebond a suivi en 2021 (IEA, 2021b). La tendance mondiale est claire : les émissions continuent inlassablement d’augmenter.

Figure 2: Emissions net de GES 1990-2019



Notes: Cette figure montre l'évolution au cours du temps des émissions de GES en équivalent CO<sub>2</sub>. Les données sont issues de la base EDGAR (Minx et al., 2021).

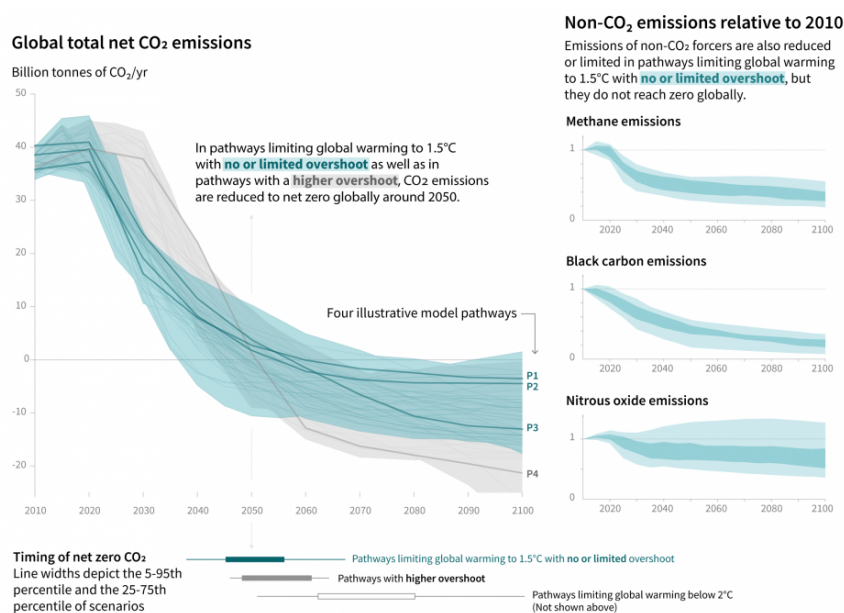
Face à cela, le GIEC fournit dans son rapport spécial sur les conséquences d’un réchauffement planétaire de 1,5 °C les trajectoires consistantes avec un réchauffement limité à 1,5 °C avec peu ou pas de dépassement (IPCC, 2018). Pour la plupart des projections, cela nécessite de diminuer les émissions de 45% d’ici 2030 par rapport à 2010, et d’atteindre zéro émission nette d’ici 2050. Pour un réchauffement limité à 2 °C, la réduction doit être de 25% d’ici 2030 et zéro émission nette doit être atteint avant 2070. La Figure 3 illustre ces trajectoires.

La tendance actuelle d’augmentation des émissions - *où nous allons* - est donc grandement incohérente avec les recommandation du GIEC - *où nous devons aller*.

## Responsabilité sectorielle des émissions de GES

D’où proviennent les émissions de CO<sub>2</sub> anthropiques ? Quels secteurs sont responsables de leur croissance ? Ce sont les premières questions à poser pour trouver des pistes d’atténuation. Le coupable principal ne se cache pas vraiment. La plupart des émissions dans les bilans d’émissions.

Figure 3: Trajectoires des émissions mondiales compatibles avec un réchauffement limité à 1,5 °C



Notes: Cette figure, directement extraite du Rapport Spécial 1,5 (IPCC, 2018), montre les caractéristiques générales de l'évolution des émissions nettes anthropiques qui limitent le réchauffement planétaire à 1,5 °C avec peu ou pas de dépassement.

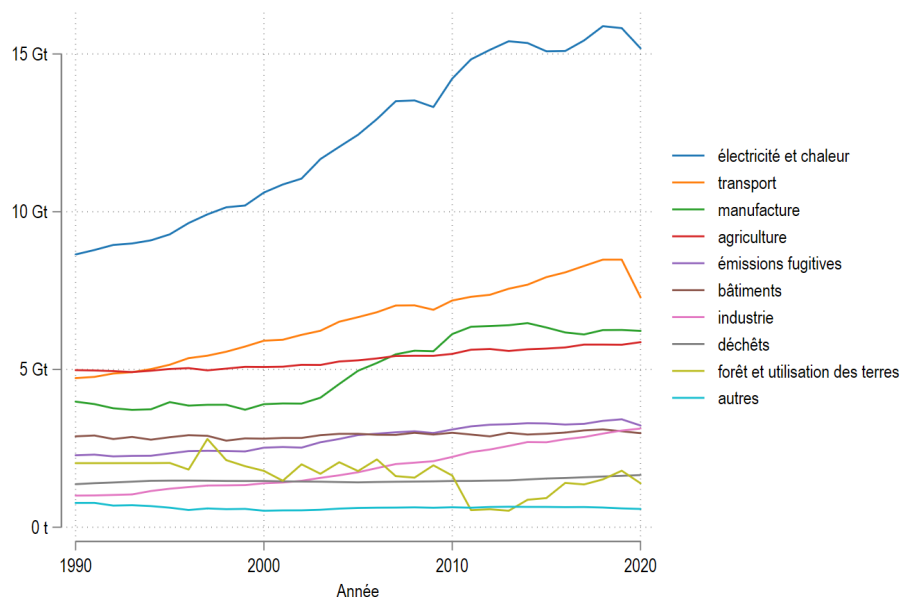
rejetées dans l'atmosphère sont dues au processus de combustion<sup>9</sup>. Et le combustible portant la plus grande part de responsabilité est de loin le charbon. En 2021, sa combustion est responsable de l'émission dans l'atmosphère de 15 GtCO<sub>2</sub> (44% des émissions), devant le pétrole de 11 GtCO<sub>2</sub> (32% des émissions), le gaz naturel de 7 GtCO<sub>2</sub> (22% des émissions) et les biocarburants de 0,5 GtCO<sub>2</sub> (1,6% des émissions). Ces combustibles sont respectivement responsables de la génération de 27%, 29%, 23% et 10% de la génération totale d'énergie (IEA, 2023). Le charbon est donc aussi le combustible avec la plus grande intensité carbone, c'est à dire celui qui émet le plus de gaz à effet de serre par unité d'énergie produite.

La Figure 4 illustre la contribution des différents secteurs économiques aux émissions mondiales. Le premier secteur contribuant aux émissions mondiales est celui de la production d'électricité et de chaleur. Plus, c'est aussi le premier secteur responsable de l'augmentation des émissions. En 1990, il représentait 26% des émissions devant

<sup>9</sup>L'équation 4 décrit la réaction de combustion classique avec l'exemple du méthane. Pour chaque molécule de méthane brûlée, une molécule de CO<sub>2</sub> est émise.



Figure 4: Répartition des émissions de GES par secteur 1990-2020



Notes: Cette figure montre l'évolution au cours du temps des émissions par secteur. Les données proviennent de ClimateWatch ([ClimateWatch, 2023](#)). La nomenclature des secteurs est basée sur celle du GIEC.

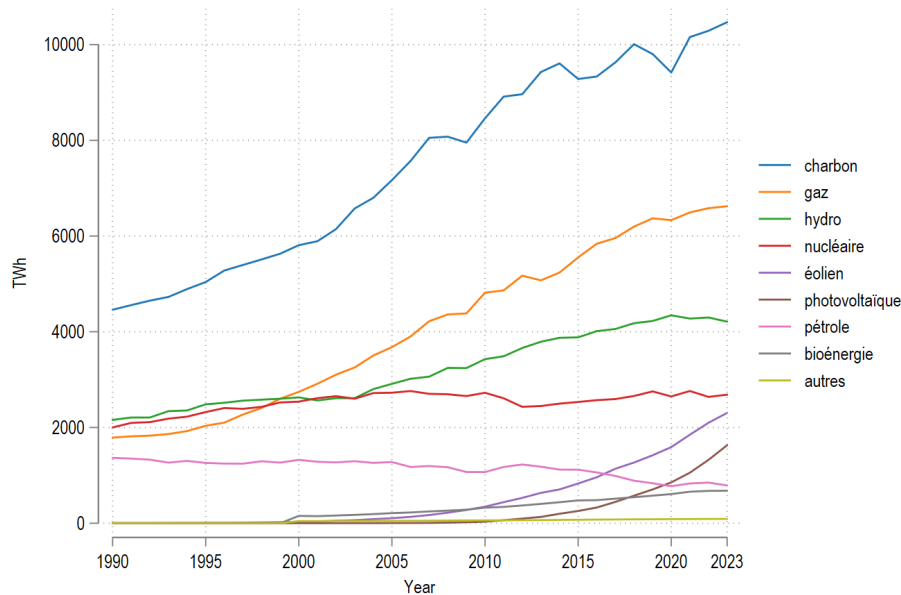
l'agriculture avec 15%, les transports avec 14% et le secteur manufacturier avec 12%. En 2020, c'est près de 31% des émissions qui sont dues à la production d'électricité. Et c'est ici aussi le charbon qui domine. La Figure 5 montre la production mondiale d'électricité par source au cours du temps entre 1990 et 2023. Bien que sa proportion dans la génération totale ait diminué ces dernières années avec l'augmentation de la génération au gaz naturel et des énergies renouvelables, le charbon est toujours loin devant et sa consommation continue d'augmenter.

Bien sûr, cette tendance est mondiale. Certains pays ont déjà une électricité décarbonée comme les pays nordiques ou la France. La consommation de charbon des pays de l'OCDE a même commencé à diminuer cette dernière décennie ([IEA, 2021a](#)). Mais d'autres en sont encore très dépendants, la Chine en tête de liste<sup>10</sup>.

Pourquoi la production d'électricité à base de combustibles fossiles, et donc les émissions, augmentent-elles ? Cela s'explique par la croissance économique et l'augmentation de la demande mondiale. La richesse des pays développés a augmenté en moyenne de 2 % par an durant le vingtième siècle. Entre 1950 et 1998, le PIB mondial a été multiplié par six, plus que jamais auparavant ([Maddison, 2006](#)). A la racine de cette croissance économique, on trouve la croissance démographique. D'ici 2050, la population mondiale

<sup>10</sup>La part de la consommation mondiale de charbon attribuée à la Chine seule est de plus de 50% en 2021 ([IEA, 2021a](#)).

Figure 5: Production d'électricité par source 1990-2023



Notes: Cette figure montre l'évolution au cours du temps de la génération d'électricité mondiale annuelle en TWh par source. Les données proviennent de [Ember \(2024\)](#). Elles sont collectées à partir de multiples sources (EIA, Eurostat, Energy Institute, ONU).

va augmenter de 7 à 9 milliards. Cette augmentation correspond presque à la population entière en 1950. La tendance est profondément ancrée : la population augmente, l'économie grossit, et donc la consommation d'électricité, toujours en majorité carbonée, suit. Le défi de l'atténuation réside donc dans la manière de se débarrasser des combustibles fossiles polluants, au premier rang desquels le charbon, tout en servant une consommation toujours croissante.

## Les énergies renouvelables

### Une progression qui doit se poursuivre

Une des principales stratégies adoptées par de nombreuses grandes puissances consiste à déployer massivement les énergies renouvelables - l'éolien en mer et sur terre, le photovoltaïque et les bio-énergies<sup>11</sup>. Cette thèse se concentre sur les deux premières.

La Figure 5 montre la fulgurante progression de la production d'électricité éolienne à partir des années 2000 et photovoltaïque après 2010. Même si leurs parts dans la pro-

<sup>11</sup>L'énergie hydraulique est aussi considérée comme renouvelable mais la possibilité d'augmenter sa capacité dans le futur est relativement faible. Je ne parle pas non plus du nucléaire, de la sobriété et de l'efficacité énergétique, mais ils font bien sûr partie des solutions pour arriver à zéro émission nette (voir par exemple [IEA \(2021c\)](#)).

duction totale restent faibles avec respectivement 7,8% et 5,5% en 2023, elles sont en constante augmentation. Les pentes de leur évolution sont également les plus fortes. Les institutions internationales faisant autorité sur ce sujet recommandent de poursuivre cette forte progression, voire de l'accélérer. Le GIEC indique que toutes les trajectoires permettant la diminution des émissions illustrée Figure 3 requièrent le remplacement rapide des combustibles fossiles par des énergies renouvelables, l'amélioration de l'efficacité énergétique, et le développement de méthodes de capture du CO<sub>2</sub> (IPCC, 2023). L'Agence Internationale de l'Énergie (AIE<sup>12</sup>) et l'Agence Internationale pour les Énergies Renouvelables (AIER<sup>13</sup>) préconisent toutes deux de tripler la génération renouvelable d'ici 2030 (IEA, 2021c; IRENA, 2023). L'AIE, dans son rapport net zéro étudiant la façon optimale d'arriver à zéro émission nette en 2050, propose même une multiplication par huit du renouvelable d'ici 2050, pour arriver à 90% de la génération totale et ainsi exclure quasi totalement les combustibles fossiles polluants. D'après eux, cette augmentation peut provenir en grande majorité de l'éolien et du photovoltaïque. Ces recommandations sont intégrées dans l'accord final de la COP 28<sup>14</sup>. Les 133 pays signataires *notent* en particulier celles de l'AIE et de l'AIER et s'*engagent*<sup>15</sup> à travailler ensemble pour tripler la génération renouvelable d'ici 2030, tout en prenant en considération l'avancement actuel hétérogène des différents pays et les circonstances locales.

## Des politiques ambitieuses

En accord avec les ambitions précédemment citées, les grandes puissances mondiales ont élaboré des plans audacieux pour encourager la poursuite du déploiement des énergies renouvelables. Notons que ces nations sont aussi les principales responsables des émissions, tant passées que présentes. Parmi elles, la Chine et les États-Unis se positionnent en tant que chefs de file de cette ruée vers les énergies propres. Ce sont les deux pays les plus dépensiers avec respectivement 83 et 56 milliards d'euros investis en 2019<sup>16</sup>. Le président Biden a proposé comme objectif que 80% de la production d'électricité américaine soit décarbonnée d'ici 2030, et 100% en 2035 (WP, 2020). L'*Inflation Reduction Act* (IRA) passé par le Congrès américain en 2022 prévoit aussi 370 milliards de dollars dédiés à l'accélération de la transition énergétique. De son côté, la Chine s'est fixée l'objectif d'atteindre 24% de consommation d'énergie renouvelable d'ici 2030, selon son dernier plan quinquennal (UNDP, 2021). L'Europe, cherchant également à accroître son

---

<sup>12</sup>L'acronyme anglais IEA est utilisé pour les citations

<sup>13</sup>L'acronyme anglais IRENA est utilisé dans les citations

<sup>14</sup>Voir <https://www.cop28.com/en/global-renewables-and-energy-efficiency-pledge> pour la communication officielle. Le lien a été consulté pour la dernière fois le 29/05/2024.

<sup>15</sup>*commit* dans la communication officielle en anglais.

<sup>16</sup>Source : Bloomberg



indépendance énergétique pour réduire sa dépendance au gaz russe, vise à atteindre une proportion de 45% d'énergies renouvelables dans sa production électrique d'ici 2030 dans le cadre du plan REPowerEU (EC, 2022). Elle est actuellement de 22%. Ce plan s'appuie sur le paquet "Ajustement à l'objectif 55" qui soutient l'objectif de réduire les émissions de 55% d'ici 2030 grâce à un doublement de la part des renouvelables. Cette initiative a également comme but l'atteinte de la neutralité carbone d'ici 2050, conformément au Pacte vert européen. Pour donner un ordre de grandeur, le financement total dédié à cette initiative s'élève à 225 milliards d'euros<sup>17</sup>.

Des fonds importants sont donc dédiés à la promotion et la diffusion des énergies renouvelables. Mais comment sont-ils utilisés concrètement ? Dans la pratique, différents instruments ont été mis en place dès le milieu des années 2000. Citons les principaux. Les *obligations d'achat à prix garantis* donnent au producteur d'énergie renouvelable un revenu fixe par unité d'électricité produite. Le montant est indépendant du prix de marché. Les *compléments de rémunération* accordent une prime fixe ou variable au producteur en supplément du prix de marché auquel il vend son électricité. Les *appels d'offres* sont un type d'enchère. L'État lance cette procédure et retient les propositions les moins coûteuses. Les développeurs ayant remporté l'enchère sont ensuite rémunérés au prix demandé. Pour les citer car ils gagnent en popularité, d'autres instruments prix sont les *contrats pour différence* et les *power purchase agreement*. Outre les subventions directes, des crédits d'impôts et des standards de portefeuille renouvelables<sup>18</sup> sont aussi mis en place.

Sans rentrer dans les détails, l'utilisation de ces instruments a pour but de corriger les défaillances du marché. Ils visent notamment à résoudre des problématiques telles que les effets bénéfiques indirects de la recherche et du développement, les effets d'apprentissage, ainsi que les économies d'échelle. Un prix initial plus élevé est justifié pour stimuler l'innovation de part sa nature de bien publique. Comme les bénéfices de l'innovation ne peuvent pas être complètement appropriés, le niveau d'investissement serait trop faible sans aide publique (Fischer and Newell, 2008). La disparité des prix avec les combustibles fossiles lorsque les coûts environnementaux ne sont pas internalisés est aussi en quelque sorte prise en compte. Remarquons cependant qu'en aucun cas ces instruments ne prennent en compte directement la quantité d'émissions effectivement évitée par les énergies renouvelables. Cette quantité, appelée la *valeur environnementale* des renouvelables, est au cœur des deux premiers chapitres.

---

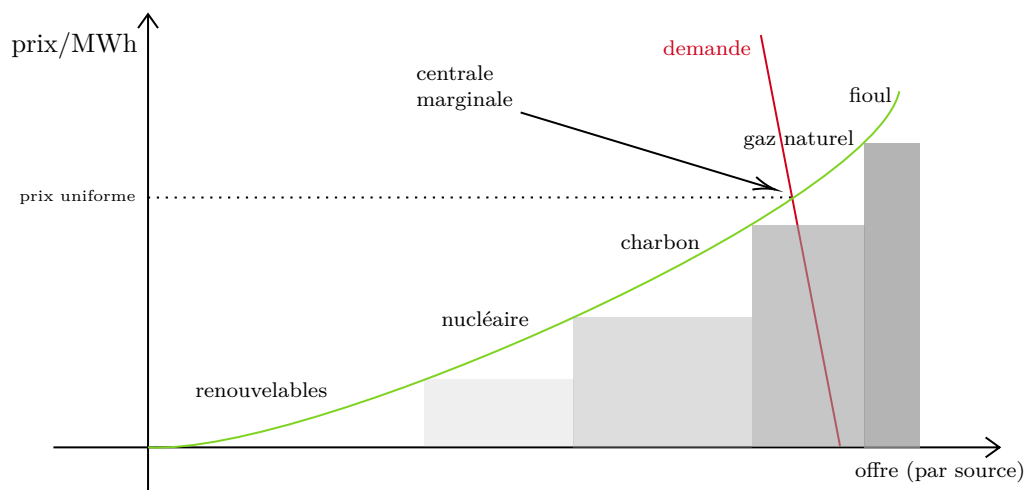
<sup>17</sup>72 milliards sous forme de subventions et 225 milliards sous forme de prêts.

<sup>18</sup>Ces normes, appliquées principalement aux États-Unis, obligent les fournisseurs d'électricité à produire une certaine proportion de leur électricité à partir de sources renouvelables.

## La valeur environnementale

L'idée est simple : combien de tonnes de CO<sub>2</sub> sont marginalement évitées par la génération d'énergie renouvelable ? Pour donner une intuition de la façon dont cette valeur est déterminée, rappelons de façon schématique et simplifiée le fonctionnement des marchés de gros de l'électricité (voir par exemple [Glachant et al. \(2021\)](#) pour une explication détaillée). Côté génération, les producteurs sont caractérisés par différentes technologies et types de combustibles utilisés, chacun avec une capacité et un coût marginal<sup>19</sup> donné. Typiquement, ils soumettent une série d'enchères sur le marché chaque jour. Si le marché est compétitif, le prix demandé correspond au coût marginal. La courbe d'offre ou *ordre de mérite* est alors composée des quantités proposées par les producteurs ordonnées par coûts marginaux croissants. La demande participe aussi au marché et est généralement faiblement élastique. Pour chaque période, par exemple une heure de la journée, les producteurs sont appelés dans l'ordre jusqu'au croisement des courbes d'offre et de demande. L'enchère est dite uniforme, c'est à dire que le prix de marché correspond au coût marginal du dernier producteur appelé. Ce dernier producteur est nommé le producteur *marginal*. La Figure 12 illustre schématiquement ce fonctionnement.

Figure 6: Illustration du croisement des courbes d'offre et de demande pour une heure donnée.



Notes: Cette figure illustre l'ordre de mérite classique. La centrale marginale est la dernière appelée pour servir la demande. Illustration de l'auteur.

Maintenant que nous avons en tête cette ordonnancement par coûts marginaux croissants, revenons à la notion de valeur environnementale des renouvelables. Ceux-ci ont un coût marginal négligeable et se trouvent tout à gauche de l'ordre de mérite. Ils sont donc

<sup>19</sup>Le coût marginal est le coût de production d'une unité d'électricité. Il est fonction des coûts variables d'opération et de maintenance, du rendement énergétique, du prix du combustible, du contenu carbone du combustible et du prix du carbone ([Cullen and Mansur, 2017](#)).

injectés en priorité. Schématiquement, une unité d'énergie renouvelable supplémentaire décale la courbe d'offre vers la droite. Il en résulte une diminution de la génération de la centrale marginale. Si la demande est parfaitement inélastique, cette diminution est de un pour un. Et si la centrale marginale est thermique à flamme<sup>20</sup>, la réduction de sa production peut être associée à la réduction d'une quantité  $x$  d'émissions. C'est ce  $x$  qui représente la valeur environnementale<sup>21</sup>.

$$+1 \text{ MWh de renouvelable} \Rightarrow -x \text{ tCO}_2 \quad (2)$$

Un exemple pour illustrer l'importance de ce concept. Imaginons un marché **A** dont toute la génération thermique est à base de charbon, et un marché **B** avec seulement des centrales à gaz. La demande est parfaitement inélastique dans les deux marchés. Un MWh de renouvelable dans le pays **A** réduirait la production à base de charbon d'un MWh, et donc les émissions de 0,9 tonne<sup>22</sup>. En revanche, cette réduction ne serait que de 0,44 tonne dans le pays **B**. La valeur environnementale est donc très différente dans les deux cas du fait de l'intensité carbone différente des centrales marginales. Et cette hétérogénéité est effectivement observée dans la littérature. Mais quelle est l'intérêt de mesurer *ex-post* ou de prévoir *ex-ante* cette valeur ? Comme précisé précédemment, les mécanismes de soutien aux renouvelables ne la prennent pas directement en compte. Une des recommandations principales de cette thèse<sup>23</sup> est au contraire de considérer cette hétérogénéité. Les subventions basées sur la génération vont continuer à jouer un rôle important dans l'accélération des nouveaux investissements et le déploiement des énergies renouvelables. Les différences régionales dans les mix électriques et la valeur environnementale des énergies renouvelables locales vont aussi perdurer, du moins jusqu'à la décarbonation complète des mix. Le design de politiques d'incitation reflétant ces différences peut permettre de diriger les nouveaux investissements vers les régions et les technologies les plus efficaces environnementalement parlant.

### Une note sur l'effet *matelas d'eau*

Cette idée de subventionner davantage les énergies renouvelables avec une plus forte valeur environnementale est valable pour les régions sans quotas d'émissions. Elle est discutable

---

<sup>20</sup>C'est à dire avec pour combustible du charbon, du gaz ou du fioul.

<sup>21</sup>Cette notion est parfois appelée l'effet marginal d'abatement. Elle est utilisée dans de nombreux papiers. Quelques exemples fondateurs sont Cullen (2013); Fell and Linn (2013) and Novan (2015)

<sup>22</sup>0,9 et 0,4 sont les valeurs d'intensités carbones moyennes pour les centrales au charbon et au gaz aux États-Unis en 2022. Source: U.S. Energy Information Administration, State Electricity Profiles, U.S. Profile, Table 5 (net generation) and 7 (emissions). <https://www.eia.gov/tools/faqs/faq.php?id=74&t=11>. Dernière consultation le 30/05/2024.

<sup>23</sup>Voir Chapitre 2.

dans le cas contraire. Si un marché du carbone est en place, par exemple le marché européen du carbone ou système d'échange de quotas d'émissions (SEQE), un instrument additionnel visant à réduire les émissions aura pour résultat de les augmenter ailleurs. C'est l'effet appelé de façon imagée *matelas d'eau*. En effet, comme les émissions totales à la fin de la période sont fixées<sup>24</sup>, une politique additionnelle ne peut alors pas avoir d'impact sur le volume global d'émissions. Dans le cas du Chapitre 2, ce n'est pas un problème car les marchés étudiés sont aux États-Unis dans des régions n'ayant pas instauré de marché du carbone. Une discussion plus approfondie sur ce sujet est en revanche proposée dans le Chapitre 1 qui se concentre sur des données européennes. J'y fais deux remarques. D'abord, les pays européens ont chacun leurs propres ambitions en termes de réduction des émissions qu'ils reportent à la Commission européenne, notamment à travers l'inventaire national des émissions de gaz à effet de serre et les Plans nationaux en matière d'énergie et de climat (PNEC). Ensuite, la Réserve de Stabilité du Marché (RSM) du SEQE a été introduite en 2019 pour répondre à cette problématique. La RSM régule l'offre de quotas en les retirant du marché lorsque ceux-ci sont trop nombreux et en les réinjectant lorsqu'ils sont trop peu nombreux. Ceci afin de stabiliser le marché. Ce mécanisme permet ainsi de percer le matelas d'eau, garantissant une diminution réelle des émissions totales. [Perino \(2018\)](#) et [Rosendahl \(2019\)](#) proposent une discussion détaillée de cette problématique.

## Des modifications de la valeur environnementale

Le fait que la valeur environnementale dépende du type de combustible utilisé par le producteur marginal implique que celle-ci peut varier en fonction d'une variété de paramètres. Régionalement selon les mix électriques locaux ([Cullen and Mansur, 2017](#); [Fell and Johnson, 2020](#)), au sein d'un marché avec le niveau de demande à un instant donné ([Novan, 2015](#)) et la quantité même d'énergie renouvelable produite ([Gugler et al., 2021](#)), avec le niveau d'intégration des marchés ([Fell et al. \(2021\)](#); [Gonzales et al. \(2022\)](#), Chapitre 1 de cette thèse) ou encore avec des modifications des coûts marginaux relatifs des différentes technologies du mix (Chapitre 2 de cette thèse). C'est sur ces deux derniers facteurs que mon travail se concentre particulièrement. Voici une rapide description de la façon dont ils peuvent impacter la valeur environnementale des renouvelables.

L'intégration des marchés désigne le processus de mise en commun de l'offre et de la demande d'électricité entre différentes zones de prix, permettant ainsi une maximisation globale du surplus économique de ces zones. Lorsque les capacités d'interconnexion entre

---

<sup>24</sup>L'exercice est typiquement d'un an. Par exemple en 2021, le nombre de permis était de 1 571 583 007. Un permis permet d'émettre une tonne de CO<sub>2</sub>.

deux zones de prix ne sont pas congestionnées, cela entraîne une convergence des prix entre ces zones. Un algorithme détermine simultanément les prix et attribue implicitement les capacités transfrontalières d'interconnexion. La zone ayant la production la moins chère exporte, celle ayant la production la plus coûteuse importe, et ce jusqu'à ce que la parité des prix soit atteinte. Schématiquement, cela revient à réduire la demande dans le pays importateur et à l'augmenter dans le pays exportateur. Les producteurs marginaux ne sont alors pas les mêmes que si les pays étaient en autarcie, ce qui peut modifier la valeur environnementale des renouvelables. Ce phénomène est central dans le Chapitre 1.

Jusqu'à maintenant, nous avons raisonné avec ce que l'on peut appeler un ordre de mérite *statique*. L'ordre d'appel de producteurs était toujours le même car les coûts marginaux étaient supposés stables. Mais ils peuvent bien sûr varier en fonction de leurs paramètres explicités plus haut et amener à du *fuel switching*. Cet anglicisme désigne le changement de position des combustibles dans l'ordre de mérite. Pour y voir plus clair, l'équation des coûts marginaux est la suivante :

$$CM = O\&M + HR \times P_{combustible} + HR \times \frac{CO_2}{btu} \times P_{CO_2} \quad (3)$$

avec  $CM$  le coût marginal,  $O\&M$  les coûts variables d'opération et de maintenance,  $HR$  le rendement énergétique de la centrale,  $P_{combustible}$  le prix du combustible,  $\frac{CO_2}{btu}$  le contenu carbone du combustible et  $P_{CO_2}$  le prix du carbone.

Les deux paramètres pouvant évoluer au cours du temps et causer du *fuel switching* sont le prix du combustible et le prix du  $CO_2$ . Prenons un exemple. Dans un marché fictif, la demande est de 2 MWh. Les  $O\&M$  sont égaux pour le gaz et le charbon, et il n'y a pas de prix du carbone. Un producteur utilisant du charbon propose 1 MWh à 10 euros et un autre utilisant du gaz naturel 1 MWh à 20 euros. La centrale marginale est donc une centrale à gaz, et une unité supplémentaire de renouvelable éviterait les émissions associées à ce combustible. Mais si le prix du gaz diminue assez pour que le producteur puisse offrir sa production à 5 euros par MWh sans modification du prix du charbon, il y a *fuel switching*. La centrale marginale change et le renouvelable évite cette fois les émissions du charbon. De façon équivalente, le même phénomène peut avoir lieu avec des prix des combustibles fixes mais une augmentation du prix du carbone. Cela réduirait la compétitivité relative du charbon et pourrait amener au même résultat. Cette interaction entre les prix relatifs des combustibles et la valeur environnementale des renouvelables est le sujet principal du Chapitre 2.

## Pas dans mon jardin !

La valeur environnementale ne représente qu'une dimension des bénéfices externes du déploiement des renouvelables. Les autres, comme les effets d'apprentissage ou les impacts positifs sur la santé humaine grâce à la réduction des émissions de polluants locaux, sont difficiles à quantifier. Mais il existe également des externalités négatives, et ne pas les prendre en compte peut conduire à une mauvaise allocation des ressources. En particulier, le déploiement des éoliennes est de plus en plus accusé de causer des désagréments visuels et sonores (Quentel, 2023), d'affecter la biodiversité en perturbant les oiseaux et les chauves-souris (Kumara et al., 2022), ou de nuire à la faune marine pour les turbines en mer (Bergström et al., 2014). La particularité de ces externalités est qu'elles sont locales, tandis que les énergies propres visent à résoudre un problème global, à savoir le réchauffement climatique. Il y a donc une tension : la plupart des gens sont favorables à la décarbonation et au déploiement des renouvelables, mais pas devant leurs yeux. En tout cas, pas dans leur jardin, comme l'exprime le désormais célèbre slogan anglais *Not In My Backyard*<sup>25</sup>.

Évaluer monétairement ce rejet des ménages concernés par la dégradation de leur environnement local due à la construction d'éoliennes à proximité est nécessaire. Douenne and Fabre (2020, 2022) et Dechezleprêtre et al. (2022) ont montré que les coûts perçus et l'équité des politiques climatiques sont des déterminants importants du soutien public à la transition climatique. Dans le cas des infrastructures d'énergie renouvelable, la diminution du soutien des communautés locales peut entraîner des frictions dans leur déploiement et retarder la transition énergétique (Jarvis, 2021). Pour éviter cela, concentrer les nouveaux projets dans les zones avec le moins d'opposition et compenser monétairement les populations lésées peut être une solution. Le Chapitre 3 porte sur cette question.

## Cette thèse

Cette thèse rassemble trois travaux de recherche empiriques indépendants portant sur l'influence de l'intégration des marchés de l'électricité sur la valeur environnementale des renouvelables (Chapitre 1), sur celle des prix relatifs des combustibles et du prix du CO<sub>2</sub> sur cette valeur (Chapitre 2), et sur l'évaluation du désagrément perçu par les ménages à proximité de parcs éoliens à travers les modifications induites des prix de l'immobilier (Chapitre 3). Les méthodes utilisées mobilisent des données issues de trois contextes différents : l'Espagne et la France (Chapitre 1), les États-Unis (Chapitre 2), et

---

<sup>25</sup>Ce terme a été popularisé par Mike Davis dans son livre *City of quartz*. Il y désigne avec cet acronyme les mobilisations locales des propriétaires aisés contre des projets d'aménagement dans le Los Angeles de la fin du vingtième siècle.

l'Allemagne (Chapitre 3).

L'objectif de ce manuscrit est de mesurer des effets externes du déploiement des énergies renouvelables qui ne sont pas internalisés par le marché. Cela en examinant d'une part comment la quantité de CO<sub>2</sub> qu'elles évitent marginalement varie, à la fois régionalement et en fonction d'autres facteurs (Chapitres 1 et 2). Et d'autre part en estimant monétairement la perception négative de la proximité d'éoliennes par préférence révélée (Chapitre 3).

Ci-dessous, un résumé de la contribution de chaque chapitre est proposé. Puis les différentes approches méthodologiques et les données utilisées sont décrites. Enfin, j'esquisse quelques recommandations de politiques publiques et des pistes pour de futurs travaux.

### Contribution par chapitre

Le premier chapitre, intitulé *The impact of electricity market integration on the cost of CO<sub>2</sub> emissions abatement through renewable energy promotion*, examine comment l'intégration des marchés de l'électricité peut influencer la valeur environnementale des énergies renouvelables, et *in fine* modifier le coût à payer pour éviter l'émission d'une tonne supplémentaire de CO<sub>2</sub>. Précisément, j'évalue l'impact causal de l'expansion de l'interconnexion électrique entre la France et l'Espagne sur la quantité de CO<sub>2</sub> évitée chaque heure par l'éolien espagnol dans les deux pays, sur la génération de combustibles fossiles, et sur les prix de gros de l'électricité. La méthode de *régression avec discontinuité dans le temps* est utilisée. Le résultat principal est que les émissions évitées en Espagne grâce à l'éolien espagnol ont diminué post expansion, et celles évitées en France ont augmenté<sup>26</sup>. Cela est expliqué par moins de réduction de la génération à base de charbon en Espagne au profit de plus de réduction de celle à base de gaz naturel, marginalement moins émettrice, en France. Les prix en France baissent également avec la génération éolienne d'autant plus que la capacité d'interconnexion est élevée<sup>27</sup>. L'évolution de l'impact de l'éolien espagnol sur les surplus économiques des deux pays induite suggère que le fonctionnement actuel des marchés peut inciter à avoir un comportement de passager clandestin et à profiter indûment des politiques de subventions aux énergies propres de nations frontalières.

La principale contribution de ce chapitre est d'ajouter à la rare littérature empirique évaluant l'impact de l'intégration des marchés de l'électricité sur le déploiement des énergies renouvelables. Une nouveauté de ce chapitre est de se concentrer sur la connexion de

---

<sup>26</sup>Précisément, 25,35 mega tonnes de CO<sub>2</sub> étaient évitées annuellement en Espagne pré expansion contre 20,15 post expansion. En France, la diminution était de 0,34 mega tonnes pre expansion contre 2,06 post expansion.

<sup>27</sup>En moyenne de 0,77€/MWh pre expansion et de 1,72€/MWh post expansion. L'effet en Espagne est respectivement une baisse de 13€/MWh et 10€/MWh.

deux pays. Les deux articles les plus proches de ce travail sont ceux de [Fell et al. \(2021\)](#) et [Gonzales et al. \(2022\)](#) et s'intéressent à la connexion entre deux régions au sein d'un même pays. Aux États-Unis et plus précisément au Texas pour [Fell et al. \(2021\)](#), et au Chili pour [Gonzales et al. \(2022\)](#). Considérer deux pays implique une réflexion sur les enjeux distributifs, en particulier en terme d'allocation des coûts d'atténuation des émissions. Qui paie quoi, et qui bénéficie est une question bien différente ici que dans le cas d'une intégration des marchés intra-nationale. Une seconde nouveauté importante est que l'intégration de deux zones "sales"<sup>28</sup> a lieu. Dans le cas des deux papiers précédemment cités, c'est la connexion d'une zone "propre" concentrant une grande majorité d'énergie renouvelable, et une zone "sale" qui a lieu. Il n'y a donc pas d'ambiguïté sur l'effet de l'intégration sur la valeur environnementale des renouvelables.

Le deuxième chapitre, intitulé *How fuel switching impacts the environmental value of renewable energy*, est un travail conjoint avec Sven Heim et Mario Liebensteiner. Nous quantifions les réductions régionales des émissions de CO<sub>2</sub> attribuables à la production d'énergie solaire et éolienne aux États-Unis durant la période de prix bas du gaz naturel induite par la révolution du gaz de schiste. Nous cartographions également comment l'intensité de ces réductions varie en fonction d'un prix fictif du CO<sub>2</sub>, déterminée par préférence révélée. Pour tenir compte du problème de sélection lié à l'interruption de la production de certaines centrales au fil du temps, nous utilisons la méthode en deux étapes d'Heckman. Ces interruptions de production se produisent lorsque les centrales sont en maintenance ou ferment pour des raisons économiques.

Cette étude contribue à plusieurs domaines en expansion dans la littérature économique. Tout d'abord, elle enrichit les travaux évaluant *ex-post* la valeur environnementale des renouvelables de manière générale. Ensuite, notre sujet est étroitement lié aux travaux portant sur les interactions entre différents instruments de politique publique. Nous mettons en évidence un contexte important où deux instruments de prix, ici les incitations au déploiement des énergies renouvelables et une taxe carbone, ne s'additionnent pas nécessairement pour offrir des réductions d'émissions plus importantes. L'effet des politiques combinées peut même être moins efficace que celui de la seule taxe carbone. Empiriquement, l'obtention de ce résultat a été permise par l'utilisation de données sur une longue période suivant la révolution du gaz de schiste. Ainsi, nous avons pu innover en profitant de variations inédites des prix relatifs du gaz et du charbon.

Le troisième chapitre, intitulé *Wind Turbines and Local Economies: Effects on Housing, Tourism, and Municipality Income* est également un travail conjoint avec Sven Heim

---

<sup>28</sup>Les deux sont dépendantes de génération polluante à la marge.



et Mario Liebensteiner. Nous examinons dans quelle mesure les ménages subissent des désagréments dus au déploiement d'éoliennes à proximité, cela en nous basant sur des données granulaires allemandes sur une longue période. Nous étudions l'internalisation de ces désagréments avec la méthode hédonique en exploitant les variations des prix de l'immobilier.

Ce chapitre contribue à la littérature de plusieurs façons. Tout d'abord, nous avons accès à une base de données inédite détaillée pour l'univers des communes allemandes comprenant les prix des transactions immobilières et des données socio-économiques clefs. Nous sommes à notre connaissance les premiers à utiliser cette base de données avec [Quentel \(2023\)](#) qui l'a exploité pour son récent papier de job market. Deuxièmement, nous abordons le problème d'endogénéité potentielle de l'implantation des éoliennes à l'aide d'une méthode de variables instrumentales ayant recours aux variations quasi-expérimentale de la rentabilité induite par les subventions. Précisément, nous tirons parti des variations exogène, à la fois longitudinales et temporelles, des revenus espérés par les promoteurs de fermes éoliennes.

## Données et méthodes utilisées

Conduire ces recherches empiriques a soulevé les défis importants de collecte de données et du choix de méthodes économétriques solides répondant de façon causale aux différentes questions de recherche de ce manuscrit.

### Données

Les deux premiers chapitres évaluant la valeur environnementale des énergies renouvelables, bien que dans des contextes et en fonction de paramètres différents, requièrent des données similaires. Comme le rappelle l'équation 5, les émissions de CO<sub>2</sub> et la production renouvelable sont nécessaires. Contrôler pour les facteurs confondants nécessite également des variables clefs des marchés de l'électricité : la demande, la génération thermique par type de combustible, les prix de ces combustibles et le prix du CO<sub>2</sub> s'il existe. Idéalement, ces données doivent être aussi granulaires que possible. Typiquement horaires pour correspondre à la fréquence classique des marchés de l'électricité, et pour chaque générateur ou centrale.

Malheureusement, j'ai dû travailler hors de ce cadre idéal dans les deux cas. Pour le Chapitre 1, j'ai pu collecter des données horaires des marchés de l'électricité français et espagnol couvrant une période d'un an avant et un an après octobre 2015, date marquant la disponibilité de la capacité supplémentaire d'interconnexion entre les deux pays. Cela signifie que l'ensemble de données se compose d'environ 17 500 observations. La

période analysée est relativement courte afin de minimiser le risque de capturer également les ajustements du marché causés par l’expansion de l’interconnexion, tels que les investissements dans de nouvelles centrales. Les données de production et de demande pour l’Espagne et la France proviennent de leurs gestionnaires de réseau de transport respectifs, *Red Eléctrica* (REE) et le *Réseau de transport d’électricité* (RTE). Les prix du charbon, du gaz naturel et du carbone (SEQE) sont obtenus auprès de *Bloomberg*. Les prix du gaz naturel et du CO<sub>2</sub> sont quotidiens, tandis que les prix du charbon sont mensuels. J’utilise aussi pour instrumenter la demande des données horaires de température provenant du site *European Climate Assessment and Dataset*, et un indice de production construit par l’OCDE. La valeur des émissions horaires par type de combustible n’étant pas disponible directement, elles sont calculées en utilisant des coefficients d’émissions. Ceux-ci sont disponibles pour chaque année tant pour l’Espagne que pour la France et sont calculés à partir des données énergétiques de l’AIE conformément aux Lignes directrices 2006 du GIEC pour les inventaires nationaux de gaz à effet de serre. La limitation principale du jeu de données final obtenu est l’absence de coûts des combustibles pour chaque centrale.

Pour le Chapitre 2, nous avons au contraire pu collecter des données longitudinales précises. Nous combinons des données mensuelles au niveau des centrales de janvier 2009 à décembre 2022 pour trois régions, englobant la production d’énergie à partir de gaz naturel, de charbon et de sources renouvelables. Ces trois régions sont associées à des gestionnaires de réseau indépendants distincts (ISOs) : l’Electric Reliability Council of Texas (ERCOT), le Midcontinent Independent System Operator (MISO), et le Southwest Power Pool (SPP). Les données de production nette sont issues du formulaire EIA<sup>29</sup> 923. Ce formulaire fournit également des informations sur le type et la quantité de combustible utilisé. Chaque centrale est ensuite associée à l’ISO auquel elle appartient en utilisant le formulaire EIA 860M. Au total, nous disposons de données pour 432 centrales au charbon et au gaz pour SPP, 399 pour ERCOT, et 1217 pour MISO. Les émissions ne sont là aussi pas directement mesurées. Mais il est possible d’obtenir une valeur pour chaque centrale. Pour ce faire, nous multiplions la quantité mensuelle de combustible consommée en MMBtu, fournie par le formulaire EIA 923, par le contenu carbone correspondant du combustible. Nous utilisons les valeurs fournies par l’Agence de Protection de l’Environnement des États-Unis. Le taux de conversion en chaleur en MMBtu/MWh pour chaque centrale est obtenu en divisant la quantité mensuelle de combustible utilisée en MMBtu par la production nette mensuelle en MWh. Cette valeur est ensuite multipliée par les dépenses mensuelles en combustible fournies par le formulaire EIA 923, ce qui donne les prix du charbon et du gaz pour chaque centrale en dollars par MWh d’électricité

---

<sup>29</sup>US Energy Information Administration.

produite. Les prix régionaux du gaz et du charbon sont également calculés en prenant la moyenne pondérée par la production mensuelle du produit du taux de conversion en chaleur et des dépenses en combustible au niveau des centrales. Pour la production d'énergie renouvelable, les données mensuelles de production éolienne et photovoltaïque sont également issues du formulaire EIA 930. Dans ce chapitre, la principale limitation des données est qu'elles sont mensuelles et non pas horaires, ce qui ne nous permet pas de discuter l'hétérogénéité horaire de nos résultats. Cette contrainte est discutée en détail dans le corps de texte.

Enfin, les données utilisées dans le Chapitre 3 sont inédites. Elles sont issues de la base RWI-GEO-RED du Centre de Données de Recherche Ruhr à l'Institut de Recherche Économique de la Rhénanie-Westphalie (FDZ Ruhr). Ces données incluent les prix des transactions immobilières, le nombre d'éoliennes et leur capacité, ainsi que les caractéristiques socio-économiques locales telles que la densité de population, le pouvoir d'achat moyen et l'âge moyen pour l'ensemble des communes allemandes sur la période de 2008 à 2017.

### Méthodes

La méthode utilisée dans le premier chapitre est adaptée à l'étude de choc avec des séries temporelles à haute fréquence. Elle est précisément expliquée par [Hausman and Rapson \(2017\)](#) qui donne d'importantes recommandations pour son utilisation crédible. Cette stratégie gagne en popularité en particulier pour l'étude de l'effet de politiques publiques environnementales impactant un ensemble d'individus ou d'entreprises sans distinction. De façon générale, l'obtention d'un groupe de contrôle et l'utilisation de la méthode de différence de différence est alors rendue impossible par l'absence de variation longitudinale. L'idée est inspirée de la technique classique de régression sur discontinuité. Son avantage réside dans l'utilisation de données à haute fréquence pour intégrer des contrôles flexibles et utiliser un polynôme de tendance temporelle d'ordre potentiellement supérieur à un. Cet ordre est choisi avec le critère bayésien de Schwartz. Le concept sous-jacent à cette approche est que la variable dépendante peut avoir évolué de manière continue autour de la date du traitement en l'absence de celui-ci, et le polynôme de tendance permet de prendre en compte cette possibilité.

Dans le deuxième chapitre, je profite de la structure de panel des données pour utiliser la méthode des effets fixes. Estimer naïvement le modèle directement par les moindres carrés ordinaires (MCO) donnerait des résultats biaisés. En effet, nous observons des périodes d'inactivité temporaire ainsi que des fermetures permanentes d'installations (c'est-à-dire des périodes de production nulles jusqu'à la fin de l'échantillon). L'application des moindres carrés ne tiendrait pas compte de ce problème de sélection. Les fermetures définitives

et les périodes de production nulle ne seraient capturées que par la marge extensive. Cette dernière se réfère aux installations qui cessent leur production temporairement ou définitivement en raison des variations des prix des combustibles ou de l'injection des énergies renouvelables (ainsi que d'autres variables de contrôle), tandis que la marge intensive se rapporte aux variations des émissions des installations (et donc aux variations de la production d'électricité) lorsqu'elles sont en activité. Pour cette raison, nous appliquons le modèle en deux étapes d'Heckman<sup>30</sup> pour estimer l'effet complet, incluant les réponses sur la marge intensive (production conditionnée au fonctionnement) et sur la marge extensive (décision de mise en marche/arrêt).

Enfin, le troisième chapitre utilise la méthode des prix hédoniques pour évaluer l'impact des éoliennes sur les prix de l'immobilier. Cette méthode est largement utilisée dans la littérature pour estimer les prix implicites des caractéristiques au sein d'une classe de produits. Freeman III et al. (2014) en offrent une description exhaustive. Le concept repose sur l'idée que si une classe de produits, dans notre cas des parcelles de terrain en Allemagne, contient suffisamment d'éléments avec des caractéristiques différentes, il est alors possible d'estimer une relation implicite qui détermine le prix du produit en fonction des valeurs de ses diverses caractéristiques. Cette relation est appelée fonction de prix hédonique. La dérivée partielle de cette fonction par rapport à l'une de ses caractéristiques donne alors son prix marginal implicite. Cette méthode est particulièrement utile car elle permet de décomposer le prix d'un bien composite en une série de prix implicites pour chacune de ses caractéristiques. Pour les parcelles de terrain, ces caractéristiques peuvent inclure la superficie, la proximité des infrastructures, la qualité de l'environnement, etc. En utilisant cette approche, nous pouvons isoler et quantifier l'impact de chaque caractéristique sur le prix total de l'immobilier.

## **Recommandations de politiques publiques et pistes pour de futurs travaux**

Atténuer les émissions issues de la génération thermique est une priorité pour atteindre les objectifs de l'accord de Paris. Le déploiement massif des énergies renouvelables fait partie des actions mises en place mondialement pour aller dans ce sens.

Le premier chapitre montre que l'efficacité environnementale des politiques unilatérales de subvention aux énergies propres peut être influencée par l'intégration des marchés, et que les marchés des pays connectés peuvent également être impactés. Cela souligne l'importance d'une politique énergétique européenne coordonnée. Je ne propose pas que toutes les décisions stratégiques soient centralisées au niveau de la Commission eu-

---

<sup>30</sup>Voir Heckman (1976) pour une description détaillée de la méthode.

ropéenne, mais il est nécessaire d'augmenter la surveillance proactive et le dialogue afin d'évaluer les coûts et les implications des décisions nationales. En particulier, une réforme politique abaissant les prix de l'électricité dans un pays voisin peut créer de l'incertitude quant à la construction de nouvelles centrales et affecter la future structure du mix énergétique européen. Cela peut entraîner une insécurité concernant le retour sur investissement des nouvelles installations, conduisant à un sous-investissement et à des défis en matière de sécurité d'approvisionnement. Par conséquent, je recommande la mise en place de cadres réglementaires afin de garantir que les décisions ayant des impacts transfrontaliers significatifs fassent l'objet de discussions communautaires approfondies avant leur mise en œuvre. Cela permettra de mieux coordonner les politiques énergétiques et de maximiser les bénéfices environnementaux tout en minimisant les risques économiques. Les recherches futures pourraient évaluer les impacts de l'intégration sur d'autres enjeux clés comme le pouvoir de marché. La littérature a montré que des acteurs des systèmes énergétiques pouvaient prendre des décisions stratégiques anti-concurrentielles nuisibles, comme du curtailment<sup>31</sup> et ainsi manipuler les prix à leur bénéfice (Bergler et al., 2017). Comment ce pouvoir de marché évolue avec l'intégration des marchés est une question importante qu'il reste à étudier empiriquement.

Les conclusions du deuxième chapitre appellent à une analyse *ex-ante* de la valeur environnementale régionale des renouvelables potentielle, et de son évolution au cours du temps. Comprendre les variations géographiques et l'influence des prix des combustibles ou du CO<sub>2</sub> est crucial pour concevoir des politiques de soutien optimales visant à réduire les émissions rapidement. Sur la base de nos observations empiriques, deux recommandations stratégiques sont proposées. La première, que nous appelons *Localisation, localisation, localisation*, est de promouvoir plus vigoureusement les énergies renouvelables dans les régions où leur valeur environnementale est plus élevée. La deuxième, *Penser à l'avenir*, est d'anticiper les changements futurs des valeurs environnementales régionales et favoriser les zones où ces valeurs sont susceptibles d'augmenter. La recherche future pourra utiliser une méthode similaire pour mesurer l'influence du *fuel switching* sur la valeur environnementale du renouvelable en Europe. Au moment de la rédaction de cette thèse, le charbon y était toujours majoritairement moins cher que le gaz, hormis en Angleterre comme montré par Gugler et al. (2021). Avec un prix du carbone ayant considérablement augmenté depuis 2021, il est probable que le gaz ait gagné en compétitivité de façon suffisante par rapport au charbon. Mettre à jour les valeurs environnementales ayant été mesurées avant cette augmentation est important pour un soutien optimal aux technologies propres. Un autre travail qu'il reste à faire est d'évaluer l'impact de

---

<sup>31</sup>Réduction en anglais. Cela caractérise un générateur réduisant sa production stratégiquement ou pour répondre à des contraintes du réseaux.

l'augmentation de la capacité renouvelable sur sa propre valeur environnementale. Nous n'avons malheureusement pas pu le faire du fait du manque de granularité et de variabilité de nos données.

Enfin, le troisième chapitre suggère la mise en place de politiques de transfert fonction du degré d'opposition afin de compenser la perte de bien-être des résidents à proximité de nouvelles éoliennes. Privilégier les zones où l'opposition est la plus faible, toutes choses égales par ailleurs, est également conseillé. Cela permettrait de réduire les coûts, tant en termes de temps que de mesures compensatoires. En outre, nous proposons, dans la mesure du possible, de soutenir l'extension des parcs éoliens existants plutôt que l'installation de la première turbine dans une zone jusque-là non concernée. En plus d'éviter un impact plus élevé sur les prix de l'immobilier, cela permettrait également de tirer parti des infrastructures de raccordement au réseau existantes, évitant ainsi la nécessité de construire de nouvelles installations avec les coûts économiques et environnementaux associés. Pour de futurs travaux portant sur ce sujet, la méthode utilisée pour prendre en compte l'endogénéité du placement des turbines est conseillée. L'instrument employé dans ce papier est spécifique au marché Allemand, mais une stratégie similaire<sup>32</sup> doit être considérée pour l'obtention d'un résultat non biaisé.

---

<sup>32</sup>Voir aussi [Quentel \(2023\)](#) pour une autre idée d'instrument astucieuse.



## General Introduction

This introduction is structured as follows. I begin by presenting the main environmental challenge that the deployment of renewable energies aims to address: climate change. Next, I discuss the responsibility of the electricity sector, the importance of renewable energies, and what is meant by their *environmental value*. The three central concepts of this manuscript - *electricity market integration*, *fuel switching*, and *NIMBYism* - are then defined. Finally, I outline the objectives, methodologies, and contributions of this dissertation.

## Greenhouse gas emissions and climate change

### Climate change: a major risk

The challenge is both immense and pressing. Anthropogenic greenhouse gas (GHG) emissions must be reduced. Otherwise, the consequences are well established: global warming, extreme weather events, sixth extinction, forced population displacements, and more. The picture is grim, but solutions are known. To set the stage, let us review the current situation and trends.

It is now recognized that climate change is due to human activities ([IPCC, 2023b](#)). Its implications are also clearly documented, particularly in the *Impacts, Adaptation and Vulnerability* section of the Intergovernmental Panel on Climate Change (IPCC) Sixth Assessment Report ([IPCC, 2023a](#)), which is a key reference. These include negative impacts already observed on human physical and mental health, increased frequency of heatwaves and wildfires, and accelerated virus proliferation. If it were not clear enough that the situation is critical, the World Economic Forum has analyzed and ranked the main global risks ([WEF, 2024](#)). Each is associated with a category: economic, environmental, geopolitical, societal, or technological. Over a ten-year horizon, the top four risks are all environmental, namely extreme weather events, biodiversity loss, ecosystem collapse, and natural resource shortages as shown in [Figure 7](#). Regarding the direct impact on human lives, the World Health Organization (WHO) estimates that between 2030 and 2050, climate change will cause an additional 250,000 deaths per year ([WHO, 2021](#)). The direct cost of health damages is also projected to be between 2 and 4 billion dollars per year by 2030.



Figure 7: Global Risks Ranked by Severity in the Short and Long Term



Notes: This graph is from the World Economic Forum’s Global Risks Report. The ranking is based on a survey of 1,500 global experts from academia, government, industry, and civil society. Responses were collected between September and October 2023.

## Emissions: where we are, where we are going, where we need to go

Mitigating these risks must be a major concern of our century. But where are we now, and where are we going?

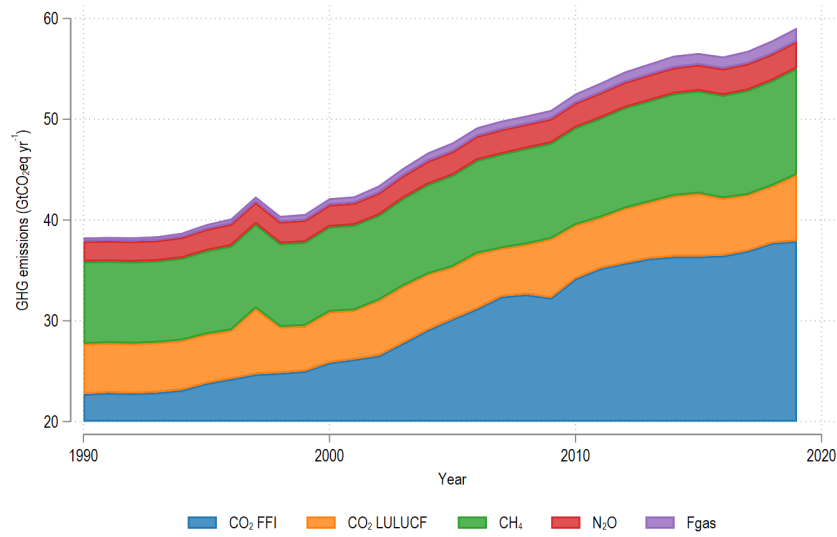
Let us start with the cause. Global warming is due to the concentration of several molecules in the atmosphere<sup>33</sup>, whose warming potentials are expressed in carbon equivalents<sup>34</sup>. Figure 8 shows the evolution of global emissions of the main molecules between 1990 and 2019. They are constantly increasing, with nearly 60 billion tonnes of CO<sub>2</sub> equivalent (GtCO<sub>2</sub>eq) emitted in 2019. In 2020, a reduction occurred but is attributed to the Covid-19 pandemic (Le Quéré et al., 2021), followed by a rebound in 2021 (IEA, 2021b). The global trend is clear: emissions continue to rise relentlessly.

In response, the IPCC provides the pathways consistent with limiting warming to 1.5°C with little or no overshoot in its special report on the consequences of global warming of 1.5°C (IPCC, 2018). For most projections, this requires reducing emissions by 45% by

<sup>33</sup>The main ones emitted by human activity and reported by the United Nations Framework Convention on Climate Change (UNFCCC) include CO<sub>2</sub> from the combustion of fossil fuels and industrial processes (CO<sub>2</sub>-FFI); net CO<sub>2</sub> emissions from land use, land use change, and forestry (CO<sub>2</sub>-LULUCF); methane (CH<sub>4</sub>); nitrous oxide (N<sub>2</sub>O); and fluorinated gases (F-gases) including hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), sulfur hexafluoride (SF<sub>6</sub>), and nitrogen trifluoride (NF<sub>3</sub>).

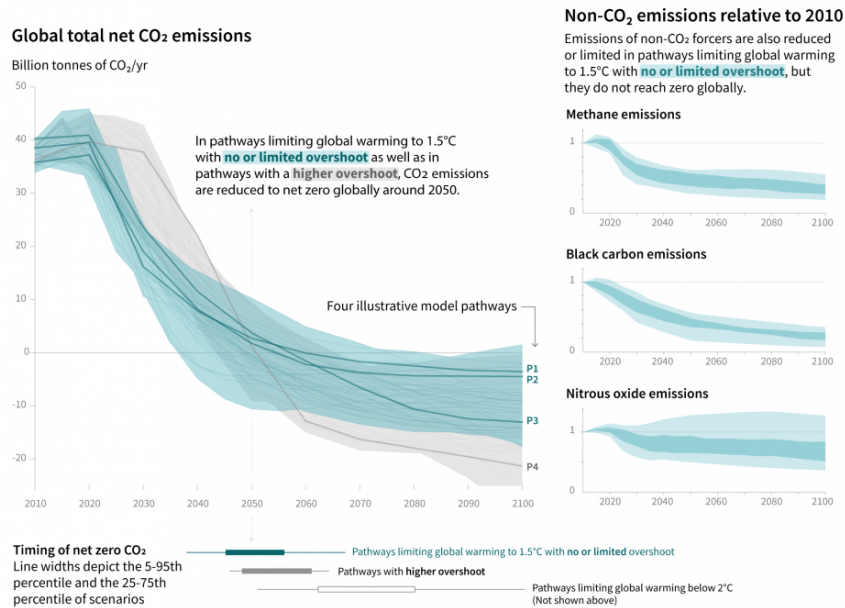
<sup>34</sup>CO<sub>2</sub> equivalent compares the effects of different greenhouse gases on global warming, using CO<sub>2</sub> as the reference, which has a global warming potential (GWP) set at 1. Thus, GWP quantifies the impact of each gas relative to CO<sub>2</sub>. For example, the GWP of methane (CH<sub>4</sub>) is estimated at 28 times that of CO<sub>2</sub> over 100 years, so a ton of methane is equivalent to 28 tons of CO<sub>2</sub> in emission inventories.

Figure 8: Net GHG Emissions 1990-2019



Notes: This figure shows the evolution over time of GHG emissions in CO<sub>2</sub> equivalent. The data are sourced from the EDGAR database (Minx et al., 2021).

Figure 9: Trajectories of global emissions compatible with limiting warming to 1.5°C



Notes: This figure, directly extracted from the Special Report 1.5 (IPCC, 2018), shows the general characteristics of the evolution of anthropogenic net emissions that limit global warming to 1.5°C with little or no overshoot.

2030 compared to 2010, and reaching net zero emissions by 2050. For a 2°C warming limit, the reduction needs to be 25% by 2030, with net zero emissions achieved before

2070. Figure 9 illustrates these trajectories.

The current trend of increasing emissions—*where we are going*—is thus starkly at odds with the IPCC’s recommendations—*where we need to go*.

## Sectoral responsibility for GHG emissions

Where do anthropogenic CO<sub>2</sub> emissions come from? Which sectors are responsible for their growth? These are the first questions to ask to find mitigation pathways. The prime villain is not hard to find. Most emissions released into the atmosphere are due to the combustion process<sup>35</sup>. And coal is by far the fuel bearing the largest share of responsibility. In 2021, its combustion was responsible for the emission of 15 GtCO<sub>2</sub> into the atmosphere (44% of total emissions), followed by oil with 11 GtCO<sub>2</sub> (32% of total emissions), natural gas with 7 GtCO<sub>2</sub> (22% of total emissions), and biofuels with 0.5 GtCO<sub>2</sub> (1.6% of total emissions). These fuels are respectively responsible for generating 27%, 29%, 23%, and 10% of total energy (IEA, 2023). Coal is therefore also the fuel with the highest carbon intensity, meaning the most emissions per unit of final energy produced.

The contribution of different economic sectors is illustrated in Figure 10. The leading sector contributing to global emissions is electricity and heat production. Moreover, it is also the primary sector responsible for the increase their levels. In 1990, it accounted for 26% of GHG emissions, ahead of agriculture at 15%, transportation at 14%, and manufacturing at 12%. By 2020, nearly 31% of emissions were due to electricity production. And here too, coal dominates. Figure 11 shows global electricity generation by source over time from 1990 to 2023. Although its share in total generation has decreased in recent years with the rise of natural gas and renewable energy, coal is still far ahead, and its consumption continues to rise.

Of course, this trend is global. Some countries already have decarbonized electricity, such as the Nordic countries or France. OECD countries’ coal consumption has even started to decline in the past decade (IEA, 2021a). But others remain heavily dependent on it, with China leading the list<sup>36</sup>.

Why are fossil fuel-based electricity production and thus emissions increasing? The answer lies in economic growth and rising global demand. The wealth of developed countries increased by an average of 2% per year during the twentieth century. Between 1950 and 1998 only, global GDP increased sixfold, more than ever before (Maddison, 2006).

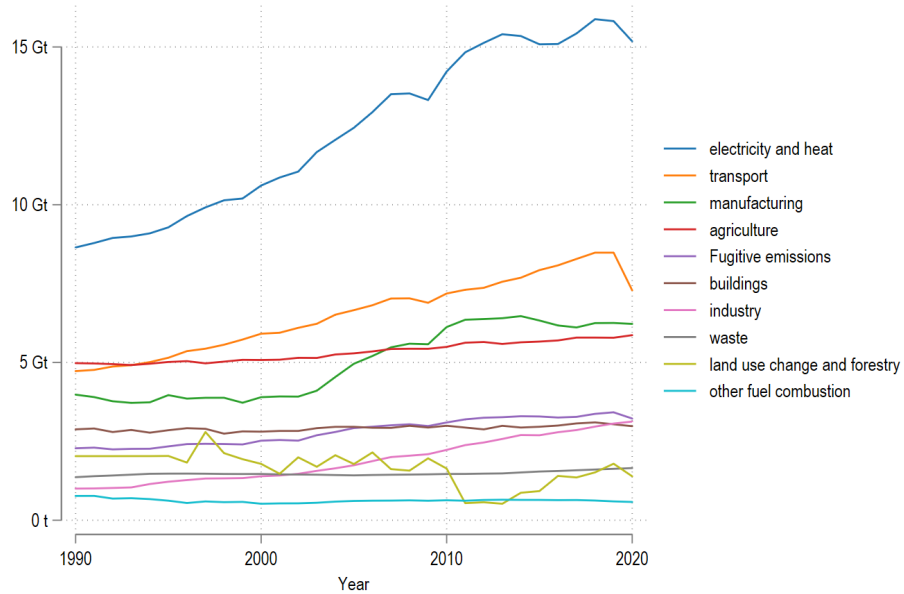
---

<sup>35</sup>Equation 4 describes the classical combustion reaction using methane as an example. For each molecule of methane burned, one molecule of CO<sub>2</sub> is emitted.



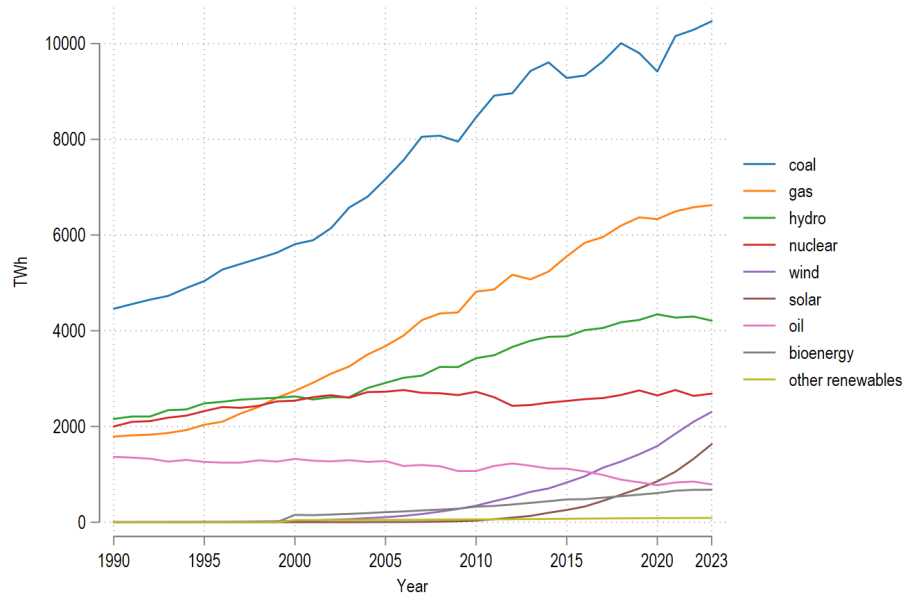
<sup>36</sup>China alone accounted for over 50% of global coal consumption in 2021 (IEA, 2021a).

Figure 10: Distribution of GHG emissions by sector 1990-2020



Notes: This figure shows the evolution of emissions by sector over time. The data are from ClimateWatch (ClimateWatch, 2023). The sector nomenclature is based on that of the IPCC.

Figure 11: Electricity generation by source 1990-2023



Notes: This figure shows the evolution of annual global electricity generation in TWh by source. The data are from Ember (2024). They are collected from multiple sources (EIA, Eurostat, Energy Institute, UN).

At the root of this economic growth lies population growth. And by 2050, the world population is expected to rise from 7 to 9 billion. This increase almost corresponds to the

entire population back in 1950. The trend is deeply rooted: as the population grows, the economy expands, and electricity consumption, still predominantly carbon-based, follows. The challenge for mitigation is thus to phase out polluting fossil fuels, particularly coal, while continuing to satisfy the escalating demand.

## Renewable energy

### A progression that must continue

One of the main solutions chosen by most leading global powers is the massive deployment of renewable energies - offshore and onshore wind, photovoltaic, and bio-energy<sup>37</sup>. This thesis focuses on the first two.

Figure 11 shows the rapid progression of wind electricity production starting in the 2000s and photovoltaic after 2010. Although their shares in total production remain low at 7.8% and 5.5% respectively in 2023, they are constantly increasing. The slopes of their growth are also the steepest. Leading international institutions on this subject recommend continuing or even accelerating this strong progression. The IPCC states that all pathways to emissions reduction illustrated in Figure 9 require the rapid replacement of fossil fuels with renewable energies, improved energy efficiency, and the development of CO<sub>2</sub> capture methods (IPCC, 2023). The International Energy Agency (IEA) and the International Renewable Energy Agency (IRENA) both advocate tripling renewable generation by 2030 (IEA, 2021c; IRENA, 2023). The IEA even proposes an eightfold increase in renewables by 2050 in its Net Zero report studying the optimal way to achieve net zero emissions by 2050. This expansion would lead to renewables comprising 90% of total power generation, effectively phasing out the majority of polluting fossil fuels. According to them, this increase can mainly come from wind and photovoltaic power. These recommendations have been incorporated into the final agreement of COP 28<sup>38</sup>. The 133 signatory countries particularly *note* those from the IEA and IRENA and *commit* to work together to triple renewable generation by 2030, while taking into account the current heterogeneous progress of different countries and local circumstances.

---

<sup>37</sup>Hydropower is also considered renewable, but the possibility of increasing its capacity in the future is relatively low. I am also not discussing nuclear energy, energy conservation, and energy efficiency here, although they are certainly part of the solutions to achieve net-zero emissions (see, for example, IEA (2021c)).

<sup>38</sup>See <https://www.cop28.com/en/global-renewables-and-energy-efficiency-pledge> for the official communication. The link was last accessed on 29/05/2024.

## Ambitious policies

In line with the aforementioned ambitions, major global powers have developed bold plans to encourage the continued deployment of renewable energies. It is noteworthy that these nations are also the main contributors to both past and present emissions. Among them, China and the United States lead the charge towards clean energy. These two countries are the biggest spenders, investing €83 billion and €56 billion respectively in 2019<sup>39</sup>. President Biden has set a target for 80% of U.S. electricity production to be decarbonized by 2030, and 100% by 2035 (WP, 2020). Additionally, the *Inflation Reduction Act* (IRA) passed by the US Congress in 2022, allocates \$370 billion to accelerate the energy transition. Similarly, China aims to achieve 24% renewable energy consumption by 2030, as outlined in its latest five-year plan (UNDP, 2021). Europe, also seeking to increase its energy independence to reduce reliance on Russian gas, aims to achieve 45% renewable energy in its electricity production by 2030 under the REPowerEU plan (EC, 2022). It is currently at 22%. This plan builds on the "Fit for 55" package supporting the goal of reducing emissions by 55% by 2030 through a doubling of the share of renewables. This initiative also aims for carbon neutrality by 2050, in line with the European Green Deal. To give an order of magnitude, the total funding dedicated to this initiative amounts to 225 billion euros<sup>40</sup>.

Significant funds are thus dedicated to promoting renewable energies. But how are they used in practice? Various instruments have been implemented since the mid-2000s. The main ones include: *feed-in tariffs*, which provide renewable energy producers with a fixed income per unit of electricity produced. The amount is independent of the market price. *Feed-in premiums* grant producers a fixed or variable bonus in addition to the market price at which they sell their electricity. *Tenders* are a type of auction where the state issues a call and selects the most cost-effective proposals. Developers who win the auction are then paid the requested price. Other increasingly popular price instruments include *contracts for difference* and *power purchase agreements*. In addition to direct subsidies, tax credits and renewable portfolio standards<sup>41</sup> are also implemented.

Without delving into details, the use of these instruments aims to correct market failures. They address issues such as the positive spillover effects of research and development, learning effects, and economies of scale. An initially higher price is justified to stimulate innovation, given its public good nature. Since the benefits of innovation cannot be fully appropriated, the level of investment would be too low without public support (Fischer and Newell, 2008). The price disparity with fossil fuels when environmental costs

---

<sup>39</sup>Source: Bloomberg

<sup>40</sup>€72 billion in grants and €225 billion in loans.

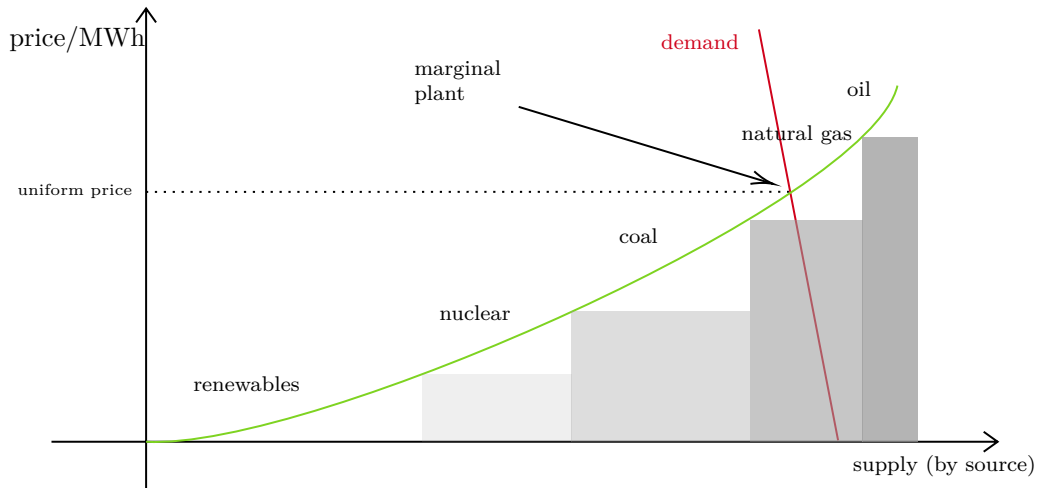
<sup>41</sup>These standards, mainly applied in the United States, require electricity providers to produce a certain proportion of their electricity from renewable sources.

are not internalized is also somewhat accounted for. However, it should be noted that these instruments do not directly account for the actual amount of emissions avoided by renewable energies. This quantity, referred to as the *environmental value* of renewables, is the focus of the first two chapters.

## Environmental value

The idea is simple: how many tonnes of CO<sub>2</sub> are marginally avoided by generating renewable energy? To give an intuition of how this value is determined, let us schematically and simplistically recall the functioning of wholesale electricity markets (see, for example, [Glachant et al. \(2021\)](#) for a detailed explanation). On the generation side, producers are characterized by different technologies and types of fuels used, each with a given capacity and marginal cost<sup>42</sup>. Typically, they submit a series of bids to the market each day. If the market is competitive, the bid prices correspond to the marginal costs. The supply curve or *merit order* is then composed of the quantities offered by producers ordered by increasing marginal costs. Demand also participates in the market and is generally inelastic. For each period, typically one hour of the day, producers are dispatched in order until the supply and demand curves intersect. The auction is uniform, meaning the market price corresponds to the marginal cost of the last producer called upon. This last producer is referred to as the *marginal* producer. Figure 12 schematically illustrates this mechanism.

Figure 12: Illustration of the intersection of supply and demand curves for a given hour.



Notes: This figure illustrates the classic merit order. The marginal plant is the last one called upon to meet demand. Author's illustration.

Now that we have in mind this ordering by increasing marginal costs, let us return

---

<sup>42</sup>The marginal cost is the cost of producing one additional unit of electricity. It depends on variable operation and maintenance costs, energy efficiency, fuel price, fuel carbon content, and carbon price ([Cullen and Mansur, 2017](#)).

to the notion of the environmental value of renewables. These have negligible marginal costs and are therefore at the far left of the merit order. They are thus injected as a priority. Schematically, one additional unit of renewable energy shifts the supply curve to the right. This results in a decrease in the generation from the marginal plant. If demand is perfectly inelastic, this reduction is one-for-one. And if the marginal plant is a thermal power plant<sup>43</sup>, the reduction in its production can be associated with a reduction of a quantity  $x$  of emissions. This  $x$  represents the environmental value<sup>44</sup>.

$$+1 \text{ MWh of renewable} \Rightarrow -x \text{ tCO}_2 \quad (5)$$

An example to illustrate the importance of this concept. Imagine a market **A** where all thermal generation is coal-based, and a market **B** with only gas plants. Demand is perfectly inelastic in both markets. One MWh of renewable in country **A** would reduce coal-based production by one MWh, and thus emissions by 0.9 tonnes<sup>45</sup>. In contrast, this reduction would be only 0.4 tonnes in country **B**. The environmental value is therefore very different in the two cases due to the varying carbon intensities of the marginal plants. And this heterogeneity is indeed observed in the literature. But what is the point of measuring this value *ex-post* or predicting it *ex-ante*? As mentioned above, support mechanisms for renewables do not directly take it into account. One of the main recommendations of this thesis<sup>46</sup> is, on the contrary, to consider this heterogeneity. Generation-based subsidies will continue to play an important role in accelerating new investments and the deployment of renewable energies. Regional differences in electricity mixes and the environmental values of local renewables will also persist for some time, at least until complete decarbonization. Designing incentive policies that reflect these differences can help direct new investments to the regions and technologies that are most environmentally efficient.

## A note on the *waterbed effect*

This idea of providing greater subsidies to renewable energies with a higher environmental value is valid for regions without emission quotas. It is debatable in the opposite case. If a carbon market is in place, such as the European carbon market or Emissions Trading System (ETS), an additional instrument aiming to reducing emissions will result in their

<sup>43</sup>That is, one using coal, gas, or oil as fuel.

<sup>44</sup>This concept is sometimes referred to as the marginal abatement effect. It is utilized in numerous papers. Some foundational examples include Cullen (2013); Fell and Linn (2013), and Novan (2015).

<sup>45</sup>0.9 and 0.4 are the average carbon intensities for coal and gas plants in the United States in 2022. Source: U.S. Energy Information Administration, State Electricity Profiles, U.S. Profile, Table 5 (net generation) and 7 (emissions). <https://www.eia.gov/tools/faqs/faq.php?id=74&t=11>. Last accessed on 30/05/2024.

<sup>46</sup>See Chapter 2.



increase elsewhere. This phenomenon is figuratively called the *waterbed effect*. Indeed, since total emissions at the end of the period are fixed<sup>47</sup>, an additional policy cannot impact the overall volume of emissions. In the case of **Chapter 2**, this is not an issue as the markets studied are in the United States, in regions without a carbon market. However, a more in-depth discussion on this topic is provided in **Chapter 1**, which focuses on European data.

I make two remarks there. First, European countries each have their own emission reduction ambitions, which they report to the European Commission, particularly through the National Greenhouse Gas Emission Inventory and the National Energy and Climate Plans (NECPs). Second, the Market Stability Reserve (MSR) of the ETS was introduced in 2019 to address this issue. The MSR regulates the supply of quotas by removing them from the market when they are too numerous and re-injecting them when they are too few, thus stabilizing the market. This mechanism allows for puncturing the waterbed, ensuring a real reduction in total emissions. [Perino \(2018\)](#) and [Rosendahl \(2019\)](#) provide a detailed discussion of this issue.

## Changes in the environmental value

The fact that the environmental value depends on the type of fuel used by the marginal producer implies that it can vary according to various parameters. Regionally, according to local electricity mixes ([Cullen and Mansur, 2017](#); [Fell and Johnson, 2020](#)), within a market depending on the level of demand at a given time ([Novan, 2015](#)) and the very amount of renewable energy produced ([Gugler et al., 2021](#)), with the level of market integration ([Fell et al. \(2021\)](#); [Gonzales et al. \(2022\)](#), **Chapter 1** of this dissertation), or with changes in the relative marginal costs of the different technologies in the mix (**Chapter 2** of this dissertation). These last two factors are the main focus of my work. Here is a brief description of how they can impact the environmental value of renewables.

Market integration refers to the process of pooling electricity supply and demand between different price zones, thereby allowing for the overall maximization of economic surplus of these zones. When interconnection capacities between two price zones are not congested<sup>48</sup>, this leads to price convergence. An algorithm simultaneously determines prices and implicitly allocates cross-border interconnection capacities. The zone with the cheapest production exports, and the zone with the most expensive production imports, until price parity is reached. Schematically, this reduces demand in the importing country

---

<sup>47</sup>The typical exercise is one year. For example, in 2021, the number of permits was 1,571,583,007. One permit allows for the emission of one ton of CO<sub>2</sub>.

<sup>48</sup>Congestion in electrical interconnections refers to a situation where the physical capacity of the transmission lines is too low to carry the desired load of electricity between regions, leading to disparities in electricity prices across these areas.

and increases it in the exporting country. The marginal producers are then not the same as if the countries were in autarky, which can modify the environmental value of renewables. This phenomenon is central to **Chapter 1**.

So far, we have reasoned with what can be called a *static* merit order. The order of producers' dispatch was always the same because marginal costs were assumed to be stable. However, they can of course vary based on their aforementioned parameters, leading to *fuel switching*. This term refers to the fact that fuels change places within the merit order. To clarify, the marginal cost equation writes as follows:

$$MC = O\&M + HR \times P_{fuel} + HR \times \frac{CO_2}{btu} \times P_{CO_2} \quad (6)$$

where  $MC$  is the marginal cost,  $O\&M$  are the variable operation and maintenance costs,  $HR$  is the plant's heat rate,  $P_{fuel}$  is the fuel price,  $\frac{CO_2}{btu}$  is the carbon content of the fuel, and  $P_{CO_2}$  is the carbon price.

The two parameters that can evolve over time and cause *fuel switching* are the fuel price and the  $CO_2$  price. Let us take an example. In a fictional market, demand is 2 MWh.  $O\&M$  costs are equal for gas and coal, and there is no carbon price. A producer using coal offers 1 MWh at 10 euros and another using natural gas offers 1 MWh at 20 euros. The marginal plant is thus a gas plant, and an additional unit of renewable energy would avoid the emissions associated with this fuel. But if the gas price drops enough for the gas producer to offer production at 5 euros per MWh without a change in the price of coal, there is *fuel switching*. The marginal plant changes, and the renewable energy avoids coal emissions. Similarly, the same phenomenon can occur with fixed fuel prices but an increase in the carbon price. This would reduce the relative competitiveness of coal and could lead to the same result. This interaction between the relative prices of fuels and the environmental value of renewables is the main subject of **Chapter 2**.

## Not in my backyard!

The environmental value represents only one dimension of the external benefits of renewable energy deployment. Others, such as learning effects or positive impacts on human health through the reduction of local pollutants, are difficult to quantify. However, there are also negative externalities, and failing to account for them can lead to poor resource allocation. In particular, wind turbine deployment is increasingly accused of causing visual and noise disturbances (Quentel, 2023), affecting biodiversity by disturbing birds and bats (Kumara et al., 2022), or harming marine fauna for offshore turbines (Bergström et al., 2014). The peculiarity of these externalities is that they are local, while clean energy aims to solve a global problem, namely climate change. There is thus a tension:

most people support decarbonization and renewable energy deployment, but not in their immediate vicinity. In any case, not in their backyard, as expressed by the now-famous English slogan *Not In My Backyard*<sup>49</sup>.

Monetarily evaluating this aversion of households affected by the degradation of their local environment caused by nearby wind turbine construction is necessary. [Douenne and Fabre \(2020, 2022\)](#) and [Dechezleprêtre et al. \(2022\)](#) have shown that perceived costs and the fairness of climate policies are important determinants of public support for the climate transition. In the case of renewable energy infrastructure, declining local community support can lead to friction in their deployment and delay the energy transition ([Jarvis, 2021](#)). To avoid this, concentrating new projects in areas with the least opposition and monetarily compensating affected populations may be a solution. **Chapter 3** addresses this issue.

## This dissertation

This dissertation comprises three independent empirical research papers focusing on the influence of electricity market integration on the environmental value of renewables (**Chapter 1**), the impact of relative fuel prices and CO<sub>2</sub> prices on this value (**Chapter 2**), and the assessment of the perceived local disamenities by households living near wind farms through induced property prices changes (**Chapter 3**). The methods employed utilize data from three different contexts: Spain and France (**Chapter 1**), the United States (**Chapter 2**), and Germany (**Chapter 3**).

The objective of this manuscript is to measure external effects of renewable energy deployment that are not internalized by the market. This involves examining how the amount of CO<sub>2</sub> they marginally avoid varies regionally and with other factors (**Chapters 1 and 2**) and estimating the negative perception of proximity to wind turbines through revealed preference (**Chapter 3**).

Below, I provide a summary of the contribution of each chapter, followed by a description of the various methodological approaches and data used. Finally, I outline some policy recommendations and suggestions for future research.

## Contributions by chapter

The first chapter title is *The impact of electricity market integration on the cost of CO<sub>2</sub> emissions abatement through renewable energy promotion*. It examines how electricity

---

<sup>49</sup>This term was popularized by Mike Davis in his book *City of Quartz*. He uses this acronym to describe the local mobilizations of wealthy homeowners against development projects in late twentieth-century Los Angeles.

market integration can influence the environmental value of renewable energies and ultimately alter the cost of avoiding an additional tonne of CO<sub>2</sub> emissions. Specifically, I evaluate the causal impact of expanding the electricity interconnection between France and Spain on the amount of CO<sub>2</sub> avoided each hour by Spanish wind power in both countries, on fossil fuel generation, and on wholesale electricity prices. The *regression discontinuity in time* (RDiT) method is used. The main finding is that emissions avoided in Spain due to Spanish wind power decreased post-expansion, while those avoided in France increased<sup>50</sup>. This is explained by a smaller reduction in coal-based generation in Spain in favor of a greater reduction in natural gas-based generation, which is marginally less emitting, in France. Prices in France also decrease more with wind generation as interconnection capacity increases<sup>51</sup>. The evolving impact of Spanish wind power on the economic surpluses of both countries suggests that the current market functioning may incentivize free-riding behavior, taking undue advantage of clean energy subsidy policies in neighboring countries.

The main contribution of this chapter is to add to the scarce empirical literature evaluating the impact of electricity market integration on renewable energy deployment. A novelty of this paper is its focus on the connection between two countries. The two most related articles, by [Fell et al. \(2021\)](#) and [Gonzales et al. \(2022\)](#), examine connections between two regions within a single country — specifically, Texas in the United States for [Fell et al. \(2021\)](#) and Chile for [Gonzales et al. \(2022\)](#). Considering two countries involves reflecting on distributive issues, particularly in terms of allocation of emission abatement costs. Who pays what and who benefits is a very different question here than in the case of intra-national market integration. A second important novelty is the integration of two "dirty" zones<sup>52</sup>. In the case of the two previously cited papers, it is the connection of a "clean" zone concentrating a large majority of renewable energy and a "dirty" zone that takes place. There is no ambiguity about the effect of integration on the environmental value of renewables.

The second chapter, titled *How fuel switching impacts the environmental value of renewable energy*, is a joint work with Sven Heim and Mario Liebensteiner. We quantify the regional CO<sub>2</sub> emissions reductions attributable to solar and wind energy generation in the United States during the low natural gas price period induced by the shale gas revolution. We also map how the intensity of these reductions varies according to a

---

<sup>50</sup>Precisely, 25.35 megatonnes of CO<sub>2</sub> were avoided annually in Spain pre-expansion compared to 20.15 megatonnes post-expansion. In France, the reduction was 0.34 megatonnes pre-expansion versus 2.06 megatonnes post-expansion.

<sup>51</sup>On average, €0.77/MWh pre-expansion and €1.72/MWh post-expansion. In Spain, the effect was a decrease of €13/MWh and €10/MWh, respectively.

<sup>52</sup>Both are dependent on polluting generation at the margin.

hypothetical CO<sub>2</sub> price, determined by revealed preferences. To account for the selection problem due to the fact that plants do not produce continuously, we use Heckman's two-step method. Zero production occurs when plants are under maintenance or if they shut down for economic reasons.

This study contributes to several growing areas in the economic literature. First, we add to works evaluating *ex-post* the environmental value of renewables in general. Second, our subject is closely related to studies on the interaction between different public policy instruments. We highlight an important context where two price instruments, here incentives for renewable energy deployment and a carbon tax, do not necessarily add up to offer greater emissions reductions. The combined policy effect may even be less effective than the carbon tax alone. Empirically, obtaining this result was made possible by using data over a long period following the shale gas revolution. Thus, we were able to innovate by taking advantage of unprecedented variations in relative gas and coal prices.

The third chapter, titled *Wind Turbines and Local Economies: Effects on Housing, Tourism, and Municipality Income*, is also a joint work with Sven Heim and Mario Liebensteiner. We examine to what extent households experience disamenities due to nearby wind turbine deployment. This is done using granular German data over a long period. We study the internalization of these disamenities using the hedonic method by exploiting variations in property prices. This chapter contributes to the literature in several ways. First, we have access to an unprecedentedly detailed database for German municipalities, including property prices and key socio-economic data. To our knowledge, we are the first to use this database along with [Quentel \(2023\)](#), who exploited it for his recent job market paper. Secondly, we address the potential endogeneity problem of wind turbine siting using an instrumental variables approach that leverages quasi-experimental variations in profitability induced by subsidies. Specifically, we take advantage of exogenous longitudinal and temporal variations in expected revenues for wind farm developers.

## Data and methods used

Conducting these empirical studies posed significant challenges in data collection and in choosing robust econometric methods to causally address the various research questions of this manuscript.

### Data

The first two chapters evaluating the environmental value of renewables, though in different contexts and based on different parameters, require similar data. As the equation

5 shows, CO<sub>2</sub> emissions and renewable production data are necessary. Controlling for confounding factors also requires key variables from electricity markets: demand, thermal generation by fuel type, fuel prices, and CO<sub>2</sub> prices if they exist. Ideally, these data should be as granular as possible, typically hourly to match the common frequency of electricity markets, and for each generator or power plant.

Unfortunately, I had to work outside this ideal framework in both cases. For **Chapter 1**, I was able to collect hourly data from the French and Spanish electricity markets covering a one-year period before and one year after October 2015, the date marking the availability of additional interconnection capacity between the two countries. This means that the dataset consists of about 17,500 observations. The analyzed period is relatively short to minimize the risk of also capturing market adjustments caused by the interconnection expansion, such as investments in new plants. Production and demand data for Spain and France come from their respective transmission system operators, *Red Eléctrica* (REE) and *Réseau de transport d'électricité* (RTE). Coal, natural gas, and carbon (ETS) prices are obtained from *Bloomberg*. Natural gas and CO<sub>2</sub> prices are daily, while coal prices are monthly. I also use hourly temperature data from the *European Climate Assessment and Dataset* and an industrial production index from the *OECD* to instrument demand. Hourly emissions by fuel type are not directly available; they are calculated using emission coefficients. These are available for each year for both Spain and France and are calculated from IEA energy data following the 2006 IPCC Guidelines for National Greenhouse Gas Inventories. The main limitation of the final dataset is the absence of fuel costs for each plant.

For **Chapter 2**, on the other hand, we were able to collect detailed longitudinal data. We combine monthly plant-level data from January 2009 to December 2022 for three regions, encompassing energy production from natural gas, coal, and renewable sources. These three regions are associated with distinct independent system operators (ISOs): the Electric Reliability Council of Texas (ERCOT), the Midcontinent Independent System Operator (MISO), and the Southwest Power Pool (SPP). Net production data come from the EIA<sup>53</sup> Form 923. This form also provides information on the type and amount of fuel used. Each plant is then associated with the ISO to which it belongs using EIA Form 860M. In total, we have data for 432 coal and gas plants for SPP, 399 for ERCOT, and 1217 for MISO. Emissions are also not directly measured but can be obtained for each plant. To do this, we multiply the monthly amount of fuel consumed in MMBtu, provided by EIA Form 923, by the corresponding carbon content of the fuel. We use values provided by the US Environmental Protection Agency. The heat rate in MMBtu/MWh for each plant is obtained by dividing the monthly amount of fuel used in MMBtu by

---

<sup>53</sup>US Energy Information Administration.

the net monthly production in MWh. This value is then multiplied by the monthly fuel expenses provided by EIA Form 923, giving the coal and gas prices for each plant in dollars per MWh of electricity produced. Regional gas and coal prices are also calculated by taking the weighted average of the product of the heat rate and fuel expenses at the plant level. For renewable energy production, monthly wind and solar production data are also obtained from EIA Form 930. For this chapter, the main limitation of the data is that they are monthly and not hourly, which does not allow us to discuss the hourly heterogeneity of our results. This limitation is discussed in detail in the text.

Finally, the data used in **Chapter 3** are unique. They come from the RWI-GEO-RED database of the Ruhr Research Data Center at the Rhine-Westphalia Institute for Economic Research (FDZ Ruhr). The data include property prices, the number of wind turbines and their capacity, as well as local socio-economic characteristics such as population density, average purchasing power, and average age for 8,039 postal codes over the period from 2011 to 2014.

## Methods

The method used in the first chapter is suited to studying shocks with high-frequency time series. It is precisely explained by [Hausman and Rapson \(2017\)](#), who provides important recommendations for its credible use. This strategy is gaining popularity, particularly for studying the effects of environmental public policies impacting a group of individuals or companies indiscriminately. Generally, obtaining a control group and using the difference-in-differences method is rendered impossible due to the absence of longitudinal variation. The idea is inspired by the classical regression discontinuity technique. Its advantage lies in using high-frequency data to incorporate flexible controls and apply a higher-order polynomial time trend. The order is selected based on the Bayesian Information Criterion. The underlying concept of this approach is that the dependent variable would have evolved continuously around the treatment date in the absence of the treatment, and the polynomial trend accounts for this possibility.

In the second chapter, I take advantage of the panel structure of the data to use the fixed-effects method. Naively estimating the model directly via ordinary least squares (OLS) would yield biased results. Indeed, we observe periods of temporary inactivity as well as permanent plant closures (i.e., periods of zero production until the end of the sample). Applying OLS would not account for this selection problem. Permanent closures and zero production periods would only be captured by the extensive margin. The latter refers to plants that cease production temporarily or permanently due to variations in fuel prices or renewable energy injection (as well as other control variables), while the intensive margin refers to variations in emissions from plants (and thus variations in

electricity production) when they are operational. For this reason, we apply the Heckman two-step model<sup>54</sup> to estimate the full effect, including responses on the intensive margin (production conditional on operation) and the extensive margin (on/off decision).

Finally, the third chapter uses the hedonic pricing method to evaluate the impact of wind turbines on property prices. This method is widely used in the literature to estimate the implicit prices of characteristics within a class of products. [Freeman III et al. \(2014\)](#) provide a comprehensive description. The concept is based on the idea that if a class of products, in our case properties in Germany, contains enough items with varying characteristics, it is possible to estimate an implicit relationship that determines the product's price based on the quantities of its various characteristics. This relationship is called the hedonic price function. The partial derivative of this function with respect to one of its characteristics then gives its implicit marginal price. This method is particularly useful because it allows decomposing the price of a composite good into a series of implicit prices for each of its characteristics. For properties, these characteristics can include size, proximity to infrastructure, environmental quality, etc. Using this approach, we can isolate and quantify the impact of each characteristic on property prices.

## **Policy recommendations and avenues for future research**

Mitigating emissions from thermal generation is a priority to meet the Paris Agreement targets. The massive deployment of renewable energies is one of the globally implemented actions to move in this direction. The first chapter shows that the environmental efficiency of unilateral clean energy subsidy policies can be influenced by market integration and that the markets of connected countries can also be impacted. This underscores the importance of coordinated European energy policy. I do not suggest that all strategic decisions be centralized at the European Commission level, but there is a need for increased proactive monitoring and dialogue to assess the costs and implications of national decisions. In particular, a policy reform that reduces electricity prices in a neighboring country can create uncertainty regarding the construction of new power plants and affect the future structure of the European energy mix. This could lead to uncertainty about the return on investment for new facilities, resulting in underinvestment and challenges related to supply security. Therefore, I recommend establishing regulatory frameworks to ensure that decisions with significant cross-border impacts undergo thorough community discussions before implementation. This will better coordinate energy policies and maximize environmental benefits while minimizing economic risks. Future research could evaluate the impacts of integration on other key issues, such as market power. The literature has shown that energy system actors can make harmful anti-competitive strategic

---

<sup>54</sup>See [Heckman \(1976\)](#) for a detailed description of the method.



decisions, such as curtailment<sup>55</sup>, and manipulate prices to their benefit (Bergler et al., 2017). How this market power evolves with market integration is an important question yet to be empirically studied.

The conclusions of the second chapter call for an ex-ante analysis of the potential regional environmental value of renewables and its evolution over time. Understanding geographic variations and the influence of fuel or CO<sub>2</sub> prices is crucial for designing optimal support policies aimed at rapidly reducing emissions. Based on our empirical observations, two strategic recommendations are proposed. The first, which we call *Location, location, location*, is to more vigorously promote renewables in regions where their environmental value is higher. The second, *Think ahead*, is to anticipate future changes in regional environmental values and favor areas where these values are likely to increase. Future research could use a similar method to measure the influence of fuel switching on the environmental value of renewables in Europe. At the time of writing this dissertation, coal was still generally cheaper than gas in Europe, except in England as shown by Gugler et al. (2021). With a carbon price that has significantly increased since 2021, it is likely that gas has gained sufficient competitiveness over coal. Updating the environmental values measured before this increase is important for optimal support of clean technologies. Another task that remains is to evaluate the impact of increasing renewable capacity on its own environmental value. Unfortunately, we could not do this due to the lack of granularity and variability in our data.

Finally, the third chapter leads us to recommend implementing transfer policies based on the degree of opposition to compensate for the welfare loss of residents near new wind turbines. Favoring areas with the least opposition, all else being equal, is also advised. This could reduce costs in terms of time and compensation measures. Additionally, we propose, where possible, supporting the expansion of existing wind farms rather than installing the first turbine in a previously undeveloped area. Besides avoiding a higher impact on property prices, this would also take advantage of existing grid connection infrastructure, thereby avoiding the need to build new facilities with associated economic and environmental costs. For future research on this topic, the method used to account for the endogeneity of turbine placement is recommended. The instrument employed in this paper is specific to the German market, but a similar strategy<sup>56</sup> should be considered to obtain unbiased results.

---

<sup>55</sup>Curtailment refers to a generator reducing its production strategically or in response to grid constraints.

<sup>56</sup>See also Quentel (2023) for another clever instrument idea.





---

# Chapter 1

## The impact of electricity market integration on the cost of CO<sub>2</sub> emissions abatement through renewable energy promotion

### Abstract

The integration of electricity markets is widely promoted for its positive impact on competition and energy security. However, little is known about its consequences on emissions and on the optimal deployment of renewable energies. In this paper, I exploit the sudden and substantial expansion of the Spanish-French electricity interconnector to causally estimate the impact of integration on the quantity and location of CO<sub>2</sub> emissions avoided by Spanish wind production, as well as its impact on the electricity prices of both countries. I find that integration has increased the amount of emissions avoided in France but decreased that avoided in Spain for each additional megawatt-hour of Spanish wind. The increase in France does not offset the decrease in Spain, resulting in a reduced environmental value of Spanish wind. For the effect on prices, the previously non-significant impact on French prices before the expansion becomes significant afterwards, highlighting a cross-border merit order effect. I then calculate the cost of reducing one tonne of CO<sub>2</sub> for the Spanish consumer through the wind energy subsidy program. Due to the price effect, there is a net gain of 26.1€/tCO<sub>2</sub> which drops to 3.6€/tCO<sub>2</sub> following the expansion. On the other hand, the French consumer benefits for free from the abatement of 2 megatonnes of CO<sub>2</sub> annually, financed at a cost of 143€/tCO<sub>2</sub> by the Spanish taxpayer post-expansion. This suggests that the current operation of the markets might incentivize freeriding on neighboring countries' subsidies for renewable electricity. Finally, I calculate the marginal impact of wind generation on welfare, considering the decrease in electricity generators' profits due to the price effect and the gains related to emissions abatement. The subsidy policy is welfare improving starting from a social cost of carbon of 60€/tCO<sub>2</sub> pre-expansion and 70€/tCO<sub>2</sub> post-expansion.

## Résumé

L'intégration des marchés de l'électricité est largement promue pour son impact positif sur la concurrence et la sécurité énergétique. Cependant, on connaît peu de choses sur ses conséquences concernant les émissions et le déploiement optimal des énergies renouvelables. Dans cet article, j'utilise l'expansion soudaine et substantielle de l'interconnexion électrique entre l'Espagne et la France pour estimer de manière causale l'impact de l'intégration sur la quantité et la localisation des émissions de CO<sub>2</sub> évitées par la production éolienne espagnole, ainsi que son impact sur les prix de l'électricité des deux pays. Je constate que l'intégration a augmenté la quantité d'émissions évitées en France mais a diminué celle évitée en Espagne pour chaque mégawattheure supplémentaire d'éolien espagnol. L'augmentation en France ne compense pas la diminution en Espagne, ce qui entraîne une baisse de la valeur environnementale de l'éolien espagnol. Concernant l'effet sur les prix, l'impact auparavant non significatif sur les prix français avant l'expansion devient significatif par la suite, mettant en évidence un effet d'ordre de mérite transfrontalier. Je calcule ensuite le coût de réduction d'une tonne de CO<sub>2</sub> pour le consommateur espagnol à travers le programme de subvention de l'énergie éolienne. En raison de l'effet prix, il y a un gain net de 26,1€/tCO<sub>2</sub> qui a été réduit à 3,6€/tCO<sub>2</sub> suite à l'expansion. D'autre part, le consommateur français bénéficie gratuitement de l'abattement de 2 mégatonnes de CO<sub>2</sub> annuellement, financé à un coût de 143€/tCO<sub>2</sub> par le contribuable espagnol après l'expansion. Cela suggère que le fonctionnement actuel des marchés pourrait inciter à profiter indûment des subventions des pays voisins pour l'électricité renouvelable. Enfin, je calcule l'impact marginal de la génération éolienne sur le bien-être, en tenant compte de la diminution des profits des producteurs d'électricité due à l'effet prix et des gains liés à l'abattement des émissions. La politique de subvention est bénéfique pour le bien-être à partir d'un coût social du carbone de 60€/tCO<sub>2</sub> avant l'expansion et de 70€/tCO<sub>2</sub> après l'expansion.

**Keywords:** Renewable energy, Wind power, Market integration, Decarbonization.

**JEL classification codes:** D61, Q40, Q42, Q52

I am indebted to my advisors François Lévêque and Sven Heim for their continued guidance and support. I would also like to thank Mario Liebensteiner, Mar Reguant, Mathias Reynaert, Nicolas Astier, Filippo D'Arcangelo, Pello Aspuru, Takahiko Kiso, Dorothée Charlier and Guillaume Wald for useful comments and suggestions. This paper has also benefited from comments received at the Toulouse Conference on the Economics of Energy and Climate 2024, the MCEE 2024, the PSE Doctorissimes 2024, the FAERE Doctoral Workshop 2024, the WEP 2023, the Dauphine PhD Workshop and the YEEES 2023. I thank Mar Reguant and her team for their hospitality at Barcelona School of Economics where part of this research was conducted.

## 1.1 Introduction

Integrating national electricity markets by expanding cross-border electricity interconnection capacity offers many significant advantages. Relaxing transmission constraints enhances competition and reduces gaming incentives (Borenstein et al., 2000), fosters price convergence among connected regions (Horst Keppler et al., 2016), and facilitates cost-effective dispatch of existing generation capacities across regions (Brunekreeft et al., 2005). According to the Agency for the Cooperation of Energy Regulators (ACER, 2022), the benefits associated with improving the integration of European electricity markets over the past decade are estimated at 34 billion euros annually. These benefits, along with the imperative to foster competition in electricity markets, strongly support the need for further developments in interconnections.

While the above benefits are undeniable, the integration of national electricity markets also has less clear implications when it comes to assessing the environmental and market value of renewable energy built in a country with interconnector capacity to another. Recent literature has begun to explore these nuanced issues. Empirical studies have assessed how increased electricity interconnection between a region with significant renewable capacity and another with polluting thermal generation impacts emissions and market prices (Fell et al., 2021; Gonzales et al., 2022). However, there is limited evidence for cases where two regions, and especially two countries, with polluting generation are connected.

This paper studies the impact of a sudden increase in interconnection capacity between France and Spain, two countries that both have thermal generation and renewable energy, on the value of renewable electricity. Specifically, I estimate the impact of the 2015 expansion of the interconnection between France and Spain on a) the environmental value of the Spanish wind energy and b) the electricity prices in the two countries. The environmental value of renewable energy is defined as the number of tonnes of CO<sub>2</sub> emissions avoided per additional megawatt-hour of renewable energy generated. Throughout this paper, I refer to this concept as "the environmental value of renewable energy" or "the marginal abatement effect of CO<sub>2</sub>".

While wind energy, whose marginal cost is close to zero, substitutes for polluting electricity generation in the country of origin, cross-border interconnectors can generate spillover effects that mitigate the substitution effect and lead to a shift to the interconnected country. The sudden and substantial expansion of Spanish-French interconnection capacity allows me to causally estimate how market integration shifts the CO<sub>2</sub> marginal abatement effect of Spanish wind energy on Spanish emissions and the cross-border marginal abatement effect of the same wind energy on French emissions.

Additionally, I explore the influence of the interconnection on the merit order effect and cross-border merit order effect of Spanish wind energy, i.e., the impact of wind energy on electricity prices in Spain and France. I assemble data from the French and Spanish electricity markets which combines hourly generation at the technology level, emissions, fuel prices, CO<sub>2</sub> prices, weather conditions and a measure of each country's overall economic output from 2014 to 2016. Technically, I employ a Regression-Discontinuity-in-Time approach. This quasi-experimental design enables me to measure the local treatment effect while accounting for the possibility that my outcome variable would have changed smoothly around the treatment date in the absence of treatment. A challenge with identifying the merit order effect and cross-border merit order effect of Spanish renewable energy is the reverse causal relation between load and prices. To circumvent this challenge, I apply IV-techniques leveraging variation in temperature, industrial production and hours of daylight at the country level. My analysis thus employs a similar strategy to [Grossi et al. \(2017\)](#).

The main results of my study are the following. Firstly, doubling the interconnection capacity between the two countries has reduced the domestic CO<sub>2</sub> marginal abatement effect of Spanish wind energy by 30%, from 0.573 tCO<sub>2</sub>/MWh to 0.398 tCO<sub>2</sub>/MWh because of less coal generation offset. For context, the average CO<sub>2</sub> emissions from the Spanish electricity mix over the given period amount to 0.215 tCO<sub>2</sub>/MWh. Therefore, the environmental value of wind power is still higher than the average emissions. Conversely, it has increased the cross-border CO<sub>2</sub> marginal abatement effect of Spanish wind generation on French emissions from 0.006 tCO<sub>2</sub>/MWh to 0.045 tCO<sub>2</sub>/MWh, thereby compensating part of the domestic decrease, but not all of it. This indicates that even when accounting for the emissions avoided across the border, market integration has resulted in a decrease in the environmental value of Spanish wind energy.

Secondly, I show how the effect of Spanish wind energy on electricity wholesale prices has changed due to the expansion of the interconnector. Prior to the expansion of the interconnection capacity, an additional gigawatt-hour of wind energy generated in Spain led to an average decrease in electricity prices of €2.7 per MWh in Spain and €0.12 per MWh in France, respectively. These values represent 5 and 0.3 percent of the average wholesale price over the period. Following the expansion of this interconnection, the domestic price effect in Spain decreased to €1.7 per MWh for each additional GWh of wind energy, while it increased across the border. The impact of Spanish wind energy on reducing French electricity prices became more pronounced, with each additional GWh of wind generation in Spain reducing French prices by €0.27 per MWh, equivalent to 0.8 percent of the average price.

Then, I calculate the cost per tonne of CO<sub>2</sub> avoided through the wind subsidy system

in Spain, as well as the net cost borne by the Spanish consumer who pays for this subsidy. The cost slightly increased after the expansion, from 112 euros to 143 euros (whether in Spain or France). Additionally, taking into account the price effect in Spain, I find that the Spanish consumer benefited from a net gain of 26.1 euros per tonne of CO<sub>2</sub> avoided pre-expansion, which decreased to 3.6 euros post-expansion.

Finally, the marginal impact of wind generation on welfare is computed. In addition to the impact on consumer surplus, I consider the profit loss of generators in both countries due to the price effect, and the gains related to the reduction of CO<sub>2</sub> emissions. I find that the break-even point at which subsidizing wind power in Spain becomes welfare improving occurs for a social cost of carbon of approximately €60/tCO<sub>2</sub> pre-expansion and €70/tCO<sub>2</sub> post-expansion.

These results are robust to a variety of specifications, including controlling for wind generation in neighbouring Germany, varied temporal fixed effects and the use of a global polynomial approach or alternatively a local linear approach.

To the best of my knowledge, this paper provides the first estimate of the impact of increased electricity interconnection between two countries with thermal polluting generation on the value of renewable energy. Previous literature has examined how renewable electricity reduces CO<sub>2</sub> emissions by displacing thermal generation (Cullen, 2013; Fell and Linn, 2013; Kaffine et al., 2013; Novan, 2015; Holladay and LaRiviere, 2017; Callaway et al., 2018; Sexton et al., 2018; Abrell et al., 2019b; Gugler et al., 2021; Petersen et al., 2022) and impact market prices (Prol et al., 2020; Bushnell and Novan, 2021; Abrell and Kosch, 2022; Peña et al., 2022; Petersen et al., 2022) in a given market. For the papers on the the environmental value of renewable energy, they all find that renewable electricity offsets CO<sub>2</sub> emissions, and that this effect varies depending on the structure of the electricity mix. The issue of emissions offset in connected countries has not been empirically addressed, except by Abrell and Kosch (2022). They demonstrated that the promotion of renewable energy in Germany effectively reduces emissions in neighboring countries. As for the papers on the impact of renewable energy on electricity prices, they have garnered interest for a more extended period than those focused on the effects on emissions. This phenomenon is commonly referred to as the "merit order effect". It has been widely demonstrated that electricity market prices in a given market area decrease with the increase in renewable generation.

This effect on prices in interconnected importing countries is also of interest. It is likely that these prices too are influenced downward, as lower local prices due to the domestic merit order effect stimulate exports. This intuition has been empirically verified by Phan and Roques (2015), Grossi et al. (2018) and Abrell and Kosch (2022) for the case of Germany and its neighboring countries. An important point is that this anticipated price



decrease is enabled by renewable energy support programs funded by consumers in the country of origin of the electricity. The question of who benefits from the policies funded in a specific country thus arises. Moreover, a negative effect for producers in neighboring countries is the reduction in their profits due to the contamination of their market prices. In this case study, I aim to quantify these effects and investigate whether they have been modified by the available interconnection capacity.

Other studies have examined theoretically the role of transmission expansion on wholesale electricity markets (Borenstein et al., 1999; Joskow and Tirole, 2000, 2005). A more recent segment of the literature, to which our study is closely related, has focused on the ex-post evaluation of the consequences of expanding interconnections between regions abundant in renewable resources and demand centers with carbon-intensive production (Fell et al., 2021; Gonzales et al., 2022). The former has found that relaxing transmission constraints between these two types of regions increases the environmental value of renewables by displacing carbon-intensive generation. The latter has found that market integration leads to price convergence between two regions, an increase in renewable generation, and a reduction in emissions. I differ from these studies in several respects. I examine the expansion of interconnection capacity between two countries rather than within a single country among different regions. Therefore, the issues related to cost allocation and emissions reduction are distinct. Each country has its own climate pledge and makes decisions regarding investments in renewables independently. Furthermore, France and Spain consistently have thermal generation at the margin with coal or gas. Hence, I am not studying the connection of a region with nearly entirely decarbonized generation with a region with polluting production. Instead, I investigate the interconnection of two regions, each with both zero-carbon and carbon-intensive assets and different price structures. Improved integration results in the ability to exchange more electricity but also relocates generation to the country with the lowest cost. However, the level of pollution from a power plant is not necessarily correlated with its marginal cost. Therefore, while must take wind energy offsets the costlier generation between two zones when there is no congestion, its effect on emissions can be suboptimal. For instance, it may lead to the avoidance of more expensive but less polluting gas generation rather than coal generation. Additionally, there could be an incentive for one country to freeride on the renewable energy subsidy policies of neighboring countries, while on the other hand, there might be a decrease in the effectiveness of domestic subsidies that are intended to achieve national climate targets. I take advantage of my unique setup to investigate this hypothesis.

This paper holds implications that extend beyond the specific case of France and Spain, with broader relevance to energy policy and the transition to renewable energy sources. By analyzing the effects of interconnection on CO<sub>2</sub> emissions and electricity prices, this

research contributes to the understanding of the potential benefits and challenges associated with cross-border cooperation and market integration in achieving environmental and economic objectives. Furthermore, it sheds light on the dynamics between renewable energy deployment, market interconnections, and the effective reduction of greenhouse gas emissions.

The rest of the paper is organized as follows. Section 2 provides background on European policy promoting electricity market integration and presents a simple conceptual framework. Section 3 describes our data. Section 4 outlines our identification strategies and results. Section 5 presents the welfare approach. Section 6 discusses the results and their implications. Section 7 concludes.

## 1.2 Background and Conceptual Framework

This section provides background and clarifications on the main concepts addressed in this paper. It begins by documenting the commonly expected benefits associated with the integration of electricity markets. Next, it reviews the literature on the environmental value of renewables and the merit order effect. Subsequently, it describes the Spanish wind energy subsidy system. Finally, it develops a simple conceptual model to offer insight into the anticipated effects and their potential ambiguity.

### 1.2.1 Benefits of electricity markets integration

Establishing a well-integrated European electricity market is a key objective for promoting the energy transition, integrating renewable energy sources, enhancing energy security, and reducing wholesale prices. This process involves pooling electricity supply and demand across different price zones, thereby enabling overall maximization of the economic value of these zones. When the interconnection capacities between two price zones are not congested, meaning that the power flowing through the interconnections is less than their physical capacity, market coupling leads to price convergence between these zones. An algorithm simultaneously determines prices and implicitly allocates cross-border capacities. If the interconnection capacity allows, the country with the least expensive generation exports while the one with the costlier generation imports until price parity is achieved. However, if the capacity between the two zones is insufficient, price convergence is not guaranteed.

Since mid-2014, prior to the start of our study, the interconnection capacity between France and Spain has been implicitly allocated. This means that it is jointly allocated with energy exchanges. In practice, for spot markets, market participants in each zone submit their daily buy and sell order books to their Nominated Electricity Market Operator

(NEMO) before noon. The Transmission System Operators (TSOs) provide information about exchange capacities at the borders and allocation constraints to the Regional Coordination Centers, which calculate cross-border exchange capacities for each region. The NEMOs then execute the EUPHEMIA algorithm, which calculates prices and simultaneously allocates cross-border capacities across all of Europe, maximizing the total economic value. The capacity of cross-border electricity interconnections is a limiting factor for full market integration, meaning constant verification of the "Law of One Price". Therefore, the EU has set a target for member countries to achieve 15% interconnection of their annual production by 2030 (Commission, 2017).

The integration of electricity markets through the development of new electric interconnection capacities is strongly promoted at the European level. As an example, a communication from the European Commission in March 2023 states: "To achieve its climate and energy goals, Europe needs to improve cross-border electricity interconnections. Connecting Europe's electricity systems will allow the EU to boost its security of electricity supply and to integrate more renewables into energy markets", and "An integrated EU energy market is the most cost-effective way to ensure secure, sustainable, and affordable energy supplies to EU citizens. Through common energy market rules and cross-border infrastructure, energy can be produced in one EU country and delivered to consumers in another". The arguments for promoting integration, which are of interest in this paper, relate to achieving climate goals through facilitating the deployment of renewable energies. The intuition for deploying more renewables stems from the argument that increased exchange possibilities between zones would lead to harnessing reductions in the temporal fluctuation of distant sources. Specifically, additional transmission capacity would facilitate the diffusion of renewable energy when the wind blows or the sun shines. There would also be a reciprocal impact: a region with abundant renewable capacity could access cost-effective thermal generation from another zone on windless or sunless days. This is particularly pertinent for our case study, as Spain is one of the leading countries in Europe in terms of wind power capacity. Indeed, with 23 GW of capacity, Spain ranks as the fifth-largest producer worldwide and the second in Europe, trailing only behind Germany.

While these policies are vigorously advocated at the European level, the reception at the national level is more nuanced. The increase in interconnection capacity between France and Spain from 1400 MW to 2800 MW in 2015 involved an investment of approximately 700 million euros. Moreover, it is projected to reach 5000 MW in 2026 through the European Biscay Gulf project, estimated to cost 2850 million euros, with substantial European support of 578 million euros (CRE, 2023)<sup>1</sup>. However, disagreements emerged

---

<sup>1</sup><https://www.cre.fr/actualites/la-cre-et-la-cnmc-parviennent-a-un-accord-sur-la-repartition-du->

between the two nations regarding this project. According to a Reuters article <sup>2</sup>, negotiations on the distribution of construction costs for the interconnection took place. Initially, France, being a predominant exporter to Spain, saw Spain agree to bear some of the French side's costs. This decision was influenced by Spain's anticipation of a decrease in its wholesale electricity prices by importing French electricity. Additionally, Spain likely views this project as essential to integrate its heavily invested renewable energy into a broader European grid. Notably, climate considerations are not central in this discourse. But the increasing Spanish wind power capacity and the challenges in the French nuclear sector have reshaped the dynamics. France now has less to gain from selling electricity to a region whose prices have converged towards its own, resulting in a narrower price spread. Conversely, Spain's expectation of significant price reductions is less likely. The key takeaway is that while the European Commission's arguments highlight communal European benefits from greater integration, national political debates reveal an awareness of potential winners and losers at the national level. The cost-benefit analysis of these projects is highly dependent on the contexts of national electricity markets. This paper contributes to the discourse on the distribution of environmental costs and benefits of market integration for consumers and producers in both countries.

These contemporary political considerations resonate in the economic literature. Empirical papers have extensively studied the impact of trade in general on the environment. Intuitively, two opposing effects are identified. The pollution haven hypothesis suggests that developing countries with low incomes become more polluted through international trade due to the relocation of polluting production activities to these countries. Given their generally less stringent environmental regulations and less advanced technologies, the net result on emissions could be negative. Conversely, the Factor Endowment Theory posits that capital-intensive polluting production activities will relocate to capital-abundant countries, namely wealthier nations. Empirical results vary depending on the environmental aspect and case studies, showing either positive or negative impacts of free trade on the environment. To cite a few seminal papers, starting with those finding a positive impact: [Antweiler et al. \(2001\)](#) demonstrated that for sulfur dioxide, a country's increased exposure to free international markets leads to a slight modification of its national pollution intensity while significantly increasing national production and income. This increase in production and income, leading to improved production techniques, results in a beneficial final effect on emissions: opening to international markets with a 1 percent increase in production and income causes, on average, a 1 percent decrease in

---

financement-du-projet-d-interconnexion-electrique-entre-la-france-et-l-espagne-com, last access on the 05/03/2024

<sup>2</sup><https://www.reuters.com/business/energy/breakthrough-close-france-spain-undersea-electricity-link-sources-2023-03-02/>, last access on the 05/01/2024.

national emissions. [Copeland and Taylor \(2004\)](#) argue similarly, finding little evidence to support the pollution-haven hypothesis, at least not as a primary determinant in the evolution of emissions related to free trade. They thus advise against using protectionism to improve environmental quality. Alternatively, [Managi et al. \(2009\)](#), accounting for the endogeneity of trade and income – differentiating themselves from Antweiler and Copeland – measured a negative effect of trade on SO<sub>2</sub> and CO<sub>2</sub> emissions in non-OECD countries but a positive effect in OECD countries, supporting the pollution-haven hypothesis. Hence, the environmental impact of trade openness is both empirically well-documented and significant in the context of combating climate change and local pollution when making trade policy decisions. However, the part of this literature concerning electricity markets is still in its early stages.

Economic papers on electricity markets and trade have primarily focused on the aspect of competition enhancement. The literature has highlighted the positive effects of market integration through enhanced interconnection capacity on competition. Theoretical papers have shown that if the interconnection capacity between two price zones is insufficient, large players can strategically congest transmission lines within their dominant zone. This phenomenon can be mitigated by relatively low-cost investments, considering the substantial benefits associated with improved competition ([Borenstein et al., 1999, 2000](#)). This has been empirically validated by [Wolak \(2015\)](#) and [Ryan \(2021\)](#). Using data from Alberta’s electricity market, [Wolak \(2015\)](#) measured a net positive benefit on competition resulting from the expansion of transmission capacity, which led strategic suppliers to anticipate less congestion. Similarly, using data from India, [Ryan \(2021\)](#) assessed a 22 percent market surplus increase for the Indian electricity market with an expansion of transmission capacity.

Another segment of the literature focuses on the impact of increasing interconnection capacity on CO<sub>2</sub> emissions using simulation techniques. Early works by [Denny et al. \(2010\)](#) demonstrated that increasing interconnection between Ireland and Great Britain would lead to a reduction in CO<sub>2</sub> emissions in Ireland but an increase in Great Britain, resulting in no overall change in aggregate emissions. Similarly, [Yang \(2022\)](#) finds that establishing interconnections in line with the EU2030 target increases CO<sub>2</sub> emissions for the France-Spain and Germany-Poland pairs. From a methodological perspective, these papers provide significant insights but remain models that suffer from simplifications necessary for their resolution. Typically, they struggle to reflect the complexities of power system operations, particularly due to potential uneconomic dispatch or congestion constraints. They nonetheless challenge the argument that more interconnection is a means to achieving European climate objectives.

Analysis of the link between market integration and the environmental efficiency of

renewables or the merit order effect are also scarce. The studies by [Fell et al. \(2021\)](#) and [Gonzales et al. \(2022\)](#) are the closest to my research in this regard. They conducted ex-post measurements of environmental benefits resulting from the expansion of transmission capacity between a region dominated by renewable energy and one dominated by thermal energy. They also measured greater price convergence. My study differs in several ways. While [Fell et al. \(2021\)](#) focused on Texas and [Gonzales et al. \(2022\)](#) on Chile, examining market integration within a single country, my research investigates market integration between two distinct countries - France and Spain. This cross-border aspect introduces distributive questions regarding renewable energy subsidies, which are addressed in my work. Additionally, both Fell and Gonzales study the expansion of transmission capacity between a "clean" zone with predominantly renewable generation and a "dirty" zone with polluting thermal generation. In contrast, this study involves the expansion between two zones where thermal generation is marginal. Consequently, the outcomes in my case may not align with their findings, underscoring the importance of this research in understanding the nuanced effects of market integration.

### 1.2.2 The environmental value of renewable electricity

As described above, the literature on the influence of market integration on the environmental value of renewable energies is still nascent. In contrast, substantial research exists on their environmental value within isolated markets. As summarized in Table 1.A2 in annexes, there is a consensus that emissions savings are notable and vary depending on regional energy mixes and time-specific factors. Generally, studies indicate that 0.4 to 0.9 tonnes of CO<sub>2</sub> are avoided for each additional MWh of wind or solar power, consistent with the offset of emissions from natural gas or coal plants. The primary motive for promoting renewable energies centers on reducing emissions from conventional electricity generation. This consideration becomes pivotal in policy-making, particularly when deciding on subsidies for specific technologies in particular areas. It is crucial to consider how many tonnes of CO<sub>2</sub> will be avoided and, ultimately, to determine the cost per tonne of CO<sub>2</sub> avoided. Such an approach allows for a comparative analysis of the efficiency of various clean technologies in different locations.

The two papers most closely related to mine are [Abrell et al. \(2019b\)](#) and [Petersen et al. \(2022\)](#). Both studies focus on the case of Spain. [Abrell et al. \(2019b\)](#) find a marginal abatement effect of wind in Spain between 0.250 and 0.786 tCO<sub>2</sub>/MWh. They do not directly account for the emissions actually abated in France by Spanish wind power, but make assumptions about this effect. The value of 0.250 tCO<sub>2</sub>/MWh is found considering only domestic abatement. Assuming that 100 percent of Spanish exports avoid coal generation, they report an average marginal CO<sub>2</sub> abatement effect of 0.786 tCO<sub>2</sub>/MWh, their

upper bound. Assuming that exports avoid gas generation, they find 0.463 tCO<sub>2</sub>/MWh. Therefore, the true value likely lies between these two. While these results are interesting, they do not directly account for the impact on the French mix. [Petersen et al. \(2022\)](#) also estimate a marginal impact of an additional MWh of wind energy on emissions to be about 0.500 tCO<sub>2</sub>, which is twice as high as Abrell's finding. The reason could be the study period: 2014-2015 for [Abrell et al. \(2019b\)](#) versus 2008-2019 for [Petersen et al. \(2022\)](#). Two hypotheses to explain this: predominantly offsetting hydro during Abrell's study period, or a change in the carbon intensity of the marginal plant between the two periods, possibly driven by the end of Petersen's study period. Regardless, [Petersen et al. \(2022\)](#), not accounting for exports, also observe that the marginal abatement effect at high levels of wind penetration is only 66 percent of its value at low levels of penetration. Their hypotheses for this are either a lower substitution of coal or wind curtailment. They add that they do not quantify the emissions avoided abroad through exports, which could compensate for the value they identify at high levels of penetration. Notably, both studies have limitations in directly accounting for the cross-border environmental impacts. My research aims to build on these findings by exploring the cross-border environmental impacts of renewable energy between France and Spain. Intuitively, and in line with Petersen's argument regarding the potential offsetting of marginal abatement at high levels of wind generation, I anticipate that Spanish wind power not only facilitates emissions reduction within Spain but also contributes to lowering emissions in France by fostering exportation. I formalize this intuition in section [1.2.5](#).

### 1.2.3 Merit order effect

In order to fully address the distributive aspects, especially in cases where a subsidy in one country might have effects in another, it is essential to consider the price effect of wind generation. Renewable energies are known to exert a deflationary influence on wholesale electricity prices. Table [1.A2](#) in the annexes provides a non-exhaustive review of the literature measuring this effect. Similar to the environmental value, most studies focus on the merit order effect within a single market. The extent of the effect depends on the steepness of the supply curve; the steeper it is, the more significant the expected impact. [Abrell et al. \(2019b\)](#) and [Petersen et al. \(2022\)](#) also examine the merit order effect in Spain, finding an average impact of around -2 €/MWh for each additional GWh of wind generation. Intuitively, I expect that this merit order effect may also influence prices in France, underscoring the potential for significant cross-border economic impacts of renewable energy policies.

### 1.2.4 Wind power promotion in Spain

The massive deployment of renewable energies is a necessity to limit global warming to below 1.5°C. All models that maintain temperatures within the 1.5-2°C threshold involve a rapid decrease in emissions from fossil fuel energy production and a substitution with renewable energy ([Intergovernmental Panel On Climate Change \(Ippc\), 2023](#)). Recognizing this challenge, the European Commission passed the revised Renewable Energy Directive in 2023, setting a target of 42.5% renewable energy in the EU mix by 2050 for climate neutrality – essentially doubling the proportion of renewable energy. During my study period of 2014-2016, this directive was not yet in effect. However, the ambition starting from 2001 with the Energy 2020 strategy, was already to reach 20% renewable energy by 2020<sup>3</sup>.

In this context, Spain has been a European leader in experimenting with a succession of support mechanisms. The initial generation-based subsidy mechanisms like Feed-in-Premiums and Feed-in-Tariffs were discontinued and replaced in June 2014. Before the study period, the Spanish government introduced a capacity-based remuneration mechanism, retroactively applied to all facilities that had not yet recovered their investment costs, mainly those installed after 2004 ([Petersen et al., 2022](#)). Consequently, during this period, the net financial support for wind power, which is of particular interest to us, was 64.60 € per MWh of wind output ([Abrell et al., 2019b](#))<sup>4</sup>.

The goal being CO<sub>2</sub> emission abatement, it is crucial to determine the cost to the Spanish taxpayer per tonne of CO<sub>2</sub> avoided. The location of this tonne, whether in France or Spain, is also relevant. However, caution must be exercised in discussing this aspect. Each EU member state has its own pledges for emission reduction. If one country reduces its emissions due to a public policy financed by another country, the issue arises of which country should claim this reduction. Typically, observing that the country reducing emissions thanks to foreign investment reports the abatement as part of its pledge would underscore the incentive to freeride on the renewable energy subsidy policies of a more enterprising neighboring country.

However, in terms of emission levels, this debate holds limited significance for two reasons. First, CO<sub>2</sub> is a global pollutant. Regardless of where it is emitted or avoided, the final effect on atmospheric concentration remains the same. Secondly, electricity production is covered by the EU Emissions Trading System. Hence, supplementary policies like renewable subsidies represent an overlapping climate policy that affects who emits but not the aggregate emissions. This is known as the waterbed effect<sup>5</sup>. Therefore, while

---

<sup>3</sup>Additionally, member countries had to report their progress biennially to the Commission.

<sup>4</sup><https://www.cnmec.es/estadistica/informacion-mensual-de-estadisticas-sobre-las-ventas-de-renovables-cogeneracion-y-46> for the data

<sup>5</sup>See [Perino \(2018\)](#) and [Rosendahl \(2019\)](#) for some considerations on the EU ETS waterbed effect.



assessing the change in the environmental value of wind energy with market integration may appear less pertinent, evaluating the impact on consumer surplus and the program costs of carbon abatement remains critical. The underlying question is who pays and who benefits. Who pays is clear in the context of this study. Who benefits must be measured.

### 1.2.5 Conceptual Framework

This section provides insight into how an increase in transmission capacity can impact the effect of renewable generation on prices and emissions. Building on the model used by [Joskow and Tirole \(2005\)](#) and [Fell and Kaffine \(2018\)](#), I extend it to consider two regions with thermal capacity, one of which includes renewables, and a negative externality represented by CO<sub>2</sub> emissions. By employing this model, potential variations in the marginal CO<sub>2</sub> abatement effect of wind energy and its influence on prices are illustrated based on various fuel price scenarios, the CO<sub>2</sub> price, the capacities of different technologies in each region, and the level of transmission capacity between the regions. Two scenarios are considered: "congested" when the interconnection is constrained and "uncongested" when it is not. A highly simplified model is used for illustration purposes, which will help us gain insight into the ambiguity of expected results. Let us consider Spain as a country rich in wind power capacity, producing  $W$  units of wind energy at zero marginal cost. Spain also has thermal generation  $F_s$ , composed of coal and gas power plants.  $M_c(F_s)$  is the marginal cost of the marginal thermal plant. For simplicity, assume that France has nuclear and thermal generation  $F_f$ , with the marginal cost of the marginal power plant being  $M_c(F_f)$ . Recall that the cost of the marginal power plant corresponds to the market price. The electricity demands of both countries are considered fixed, with values  $L_f$  and  $L_s$ . Finally, let us assume that in autarky (self-sufficiency), the marginal Spanish power plant is cheaper than the French one. I will relax this hypothesis later.

Therefore, I focus on the hours when Spain is exporting to France. Both countries can exchange a volume  $Q$  with  $|Q| \leq K$ , where  $K$  represents the transmission constraint. Thus,  $F_s = L_s - W + Q$  and  $F_f = L_f - Q$ . Assuming perfect competition, the uncongested regime verifies:

$$MC_s(L_s - W + Q) = MC_f(L_f - Q) \quad (1.1)$$

A first observation is that compared to the case of autarky where  $Q = 0$ , the price in Spain has increased, and the price in France has decreased until they are equal. From equation 1.1, it can be deduced that an exogenous marginal increase in wind generation alters the exchanges between the two countries and their respective thermal generations by the following quantities:

$$\frac{dQ}{dW} = \frac{MC'_s}{MC'_f + MC'_s}; \frac{dF_s}{dW} = -\frac{MC'_f}{MC'_f + MC'_s}; \frac{dF_f}{dW} = -\frac{MC'_s}{MC'_f + MC'_s} \quad (1.2)$$

Therefore, a marginal increase in Spanish wind generation leads to an increase in the flow from Spain to France and a decrease in thermal generation in both countries, according to the relative slopes of the country marginal cost curves. Market prices and emissions related to thermal generation decrease in both countries with this marginal increase in wind power. Conversely, if the interconnection is congested with  $Q = K$ , the prices in the two countries will differ:

$$MC_s(L_s - W + K) + \eta(K) = MC_f(L_e - K) \quad (1.3)$$

where  $\eta(K) > 0$  is the shadow cost of the transmission constraint. The effects of a marginal increase in wind generation is now:

$$\frac{dQ}{dRE} = 0; \frac{dF_s}{dRE} = -1; \frac{dF_f}{dRE} = 0 \quad (1.4)$$

With a congestion constraint, the additional wind generation offsets thermal generation in Spain only and reduces prices there only. The question then is: in which scenario is the environmental value of renewables and the price reduction due to them the greatest? For the emission effect, it depends on the carbon intensity of the marginal power plants in each country and in each regime. Depending on the relative prices of coal and gas, the price of CO<sub>2</sub>, and the demands of the two countries, two cases are possible. The first scenario involves a marginal gas power plant in both Spain and France, and the second scenario involves a marginal coal power plant in Spain and a marginal gas power plant in France. In the first scenario, assuming that the carbon intensity of gas power plants in both countries is the same, the emissions avoided by an additional unit of wind power would be the same for both the congested and uncongested regimes. As for the price effect, the reduction in the average price depends on the relative slopes of the two supply curves. In other words, the effect of transitioning from one regime to another can be positive or negative in terms of the price effect of renewables. In the second scenario, an additional unit of wind power would reduce coal generation in Spain by the same amount, while in the uncongested case, the reduction in thermal generation due to the additional wind unit would be shared between gas generation in France and coal generation in Spain. Given that coal emit twice as much CO<sub>2</sub> as gas on average, the environmental value of wind power would be higher in the congested regime. The reasoning for the price effect is the same as in the first scenario: it depends on the relative slopes of the supply curves.

Increasing interconnection capacity effectively reduces the probability of a given hour being in the "congested" regime. As the simple model above suggests, the impact of such

a policy on the value of renewables is ambiguous. Thus, I aim to quantify these effects in the case of the capacity increase between France and Spain in 2015. Furthermore, the electrical system is complex, and modeling emissions reduction *ex ante*, especially due to non-economic dispatch, would be challenging. Using real-world data in this case is necessary.

## 1.3 Data

I collected hourly data from the French and Spanish electricity markets, covering a period of one year before and one year after October 2015, which marks the availability of additional interconnection capacity. This results in a dataset of roughly 17,500 observations. The analyzed time period is rather short in order to minimize the risk of also capturing market adjustments caused by the interconnector expansion, e.g. investments in new power plants. Generation data for Spain and France are obtained from their respective transmission system operators, REE and RTE. Prices for coal, natural gas, and the EU ETS (Emissions Trading System) are obtained from Bloomberg. Prices for natural gas and for CO<sub>2</sub> are at the daily level whereas prices for coal are at the monthly level. Hourly temperature data are sourced from the European Climate Assessment and Dataset website, while the production index is constructed by the OECD. I calculate the coal over gas cost ratio by taking into account the CO<sub>2</sub> price.

### 1.3.1 Electricity mix in Spain and in France

This subsection presents the composition of the French and Spanish electricity mixes. The two countries differ in their installed capacities as indicated in Table 1.1.

The first observation is that the installed capacity by technology type remained stable over the studied period. This stability suggests that potential construction or decommissioning of production assets does not influence my results. The details of the plant portfolios of the two countries, starting with Spain, are the following. In order of magnitude, the largest share of installed capacity in Spain is gas plants, representing 26 percent. The country also has a significant portion of its total capacity coming from wind at 22 percent. Next are hydro and coal with 16 and 10 percent, respectively. Solar represents 4 percent of the total capacity. Table 1.4 provides the annual generation values before and after the increase in transmission capacity for both countries. Due to the heterogeneity of load factors, the order of importance of technologies shifts. The most significant portion of production comes from nuclear and coal plants used for base-load, with average load factors of 81 and 53 percent, respectively. Following this comes wind, and finally natural gas, which is used for peak-load with a very low load factor of 12 percent. This

Table 1.1: Installed capacity (MW)

	Spain		France	
	Before expansion	After expansion	Before expansion	After expansion
Natural Gas	28,268	28,268	6,121	6,121
Coal	10,962	10,030	4,810	2,930
Nuclear	7,573	7,573	63,130	63,130
Hydro	17,043	17,050	10,314	10,325
Pumped storage	3,331	3,331	4,965	4,965
Wind	22,920	22,971	10,322	11,761
Solar	4,684	4,689	6,191	6,772
Total capacity	105,657	104,557	121,039	121,350

*Note:* Data are taken from REE for Spain and from RTE for France. "Before expansion" is the 12 months average installed capacity before October 2015, "After expansion" the 12 months average value after October 2015.

Table 1.2: Annual generation (TWh)

	Spain		France	
	Before expansion	After expansion	Before expansion	After expansion
Natural Gas	32	32	14	22
Coal	52	47	8	8
Nuclear	54	56	415	416
Hydro	28	36	68	59
Pumped storage	2	3	-	-
Wind	48	48	17	21
Solar	8	8	5	7
Total consumption	267	261	540	546

*Note:* Data are taken from REE for Spain and from RTE for France. 12 months total generation by technology before and after October 2015.

underlines the overcapacity of gas plants in Spain over this period. For Spanish wind and solar, the important observation is that generation is almost the same in both periods, which means, apart from possible curtailments, that the weather conditions are similar across both periods.

Turning to the case of France, its mix is dominated by nuclear power, which is far ahead in installed capacity, accounting for 52 percent of the country's total capacity and 76 percent of total generation. During the period studied, no major maintenance issues significantly impacting the availability of these plants were reported. In terms of capacity, hydro, wind, solar, gas, and finally coal follow in that order. Of course, due to the intermittency of renewables, the order of importance in generation differs again. Thermal generation is used on the margin in France for about 5 percent of total generation.

But these only 5 percent are responsible for almost all of the emissions from the French mix, with about 25 Mt annually over the period<sup>6</sup>. Biomass and fuel used as backup are responsible for a negligible part of these emissions. For scale, these 25 Mt represent one-twentieth of the country's total emissions. Although both countries have different energy mixes, they share the common feature of resorting to polluting fossil fuels at least marginally, be it natural gas or coal.

Connecting these two countries consequently differs from the cases studied by [Fell et al. \(2021\)](#) and [Gonzales et al. \(2022\)](#). In contrast to these papers, which assess the impact of connecting a "clean" zone dominated by zero-emission renewable energies with a "dirty" zone dominated by polluting thermal power, the France-Spain case involves connecting two "dirty" zones, as shown by the descriptive statistics. Although the carbon intensity of the French electricity mix is relatively low, it is the marginal carbon intensity, typically from coal or gas, that matters when it comes to quantifying the environmental value of renewable energy.

This analysis primarily focuses on the impact of Spanish wind energy for several key reasons. Firstly, the output from photovoltaic generation during the period in question is relatively low in both countries. Secondly, the solar generation exhibits minimal variation, being highly predictable and closely correlated with hourly seasonality. This aspect becomes particularly problematic given our control for demand, which is strongly correlated with solar generation. Lastly, our analysis of photovoltaics is further constrained by the high correlation of solar generation between France and Spain (see figure 1.A2 in annexes). These factors collectively make it quite complex to distinctly identify the impact of solar energy on prices and emissions in both countries quite complex. However, this limitation is mitigated by the relatively low level of solar generation during the period under study.

Another argument pertains to the impact of each country's type of renewable electricity generation on cross-border trade. It is expected that volatile renewable energy generation leads to imports during periods of low generation and to exports when generation is high. To explore the impact of renewable generation on energy trade between France and Spain, I regress the exports on renewable generation, including demand and time-fixed effects to account for possible changes in available capacities by technology, and seasonal, daily, and hourly cycles (see in appendix table 1.A3). The findings shows that Spanish solar power has a weak and non-significant effect on Spanish exports. French solar power also has non-significant low effect on exports from France to Spain. Finally, French wind power exhibits a significantly positive marginal effect, but it is twice as weak as that of Spanish wind power. Given that total Spanish wind generation is two to three times higher than in France, this paper focuses solely on Spanish wind generation.

---

<sup>6</sup><https://analysesetdonnees.rte-france.com/bilan-electrique-emission-ges>

Throughout the remainder of the paper, the focus is on the impact of volatile wind generation on carbon-based assets such as coal and gas plants. Hydro generation is excluded from the analysis as it can dynamically influence the results and not contemporaneously. These considerations are left for exploration in future work.

### 1.3.2 Emissions

Hourly CO<sub>2</sub> emissions by country are calculated by multiplying the generation by each fuel type with its emission coefficient. These coefficients are available for each year for both Spain and France ([International Energy Agency, 2016](#)). They are calculated using the IEA energy data and in accordance with the 2006 IPCC Guidelines for National Greenhouse Gas Inventories <sup>7</sup>. On average, emissions per MWh from electricity generation using coal are slightly higher in France than in Spain, with 1.187 tCO<sub>2</sub>/MWh compared to 947 tCO<sub>2</sub>/MWh. The opposite holds true for natural gas, with an average of 313 tCO<sub>2</sub>/MWh in France and 349 tCO<sub>2</sub>/MWh in Spain.

### 1.3.3 Wind generation and load

Figure 1.1 illustrates the average hourly variations in electricity demand in both countries and wind generation in Spain. Figure 1.A1 in the annex presents the average monthly variations, calculated as the monthly averages of hourly data. The initial observation is that both demand levels and wind generation exhibit substantial hourly variation. This suggests that the marginal impact of wind generation on thermal generation depends on the time of day. Typically, demand is lower at night and in the early morning in both countries. On a monthly horizon, it is lower in spring and autumn in Spain due to the use of air conditioning in the summer months, and in summer in France. If wind is generated during these times, it is the base-load generators with relatively low marginal costs that are more likely to be displaced. Conversely, during peak demand periods, wind energy is more likely to replace generators with relatively higher marginal costs. Another observation is that there is more wind generation in the afternoon and early night, as well as in winter, which corresponds to the demand peak in France. A key point for analysis using a discontinuity method is that wind generation did not change over time, as shown in Table 1.2. It remains the same pre and post expansion.

When comparing demand variations between the two countries, the most significant observation is the difference in spread between off-peak and peak demand months. Winter and summer demand in Spain is about 15 percent higher than in autumn and spring, which is relatively small. In contrast, in France, the difference between summer and winter is

---

<sup>7</sup>See: <http://www.ipcc-nggip.iges.or.jp/public/2006gl/vol2.html>

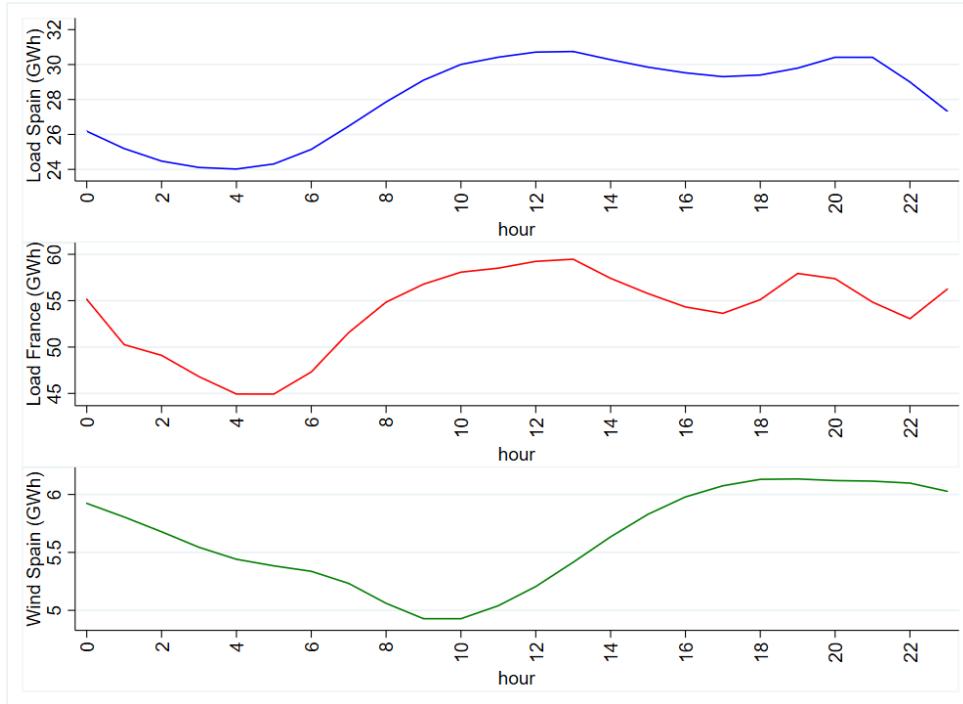


Figure 1.1: Average daily electricity demand in Spain and France and Wind generation in Spain (GWh)

about 66 percent, due to the high winter demand for heating, which is predominantly electric.

### 1.3.4 Cost ratio

To account for potential changes in the merit order of generation units, the coal-to-gas cost ratio is incorporated into the analysis. This cost ratio is calculated as the ratio of the prices of each fuel in €/MWh of electricity produced, considering the CO<sub>2</sub> price. This involves multiplying the price of the EU ETS in €/tCO<sub>2</sub> by the emission coefficient of each type of fuel in tCO<sub>2</sub>/MWh. On average, the coal-to-gas cost ratio is 0.36 pre-expansion and 0.52 post-expansion. Therefore, the marginal cost of coal is lower than that of natural gas during the sample period. This suggests that coal plants are more likely to be dispatched before gas plants to meet the base-load. Consequently, one would expect a greater environmental value from an additional GWh of wind energy when demand is low, particularly in the case of Spain, which has a significant portion of its generation produced from coal as shown in section 1.3.1. It is noteworthy that there is a decoupling between marginal costs and emission factors. The most polluting plants are dispatched before the less polluting ones.

## 1.4 Empirical Analyses

This section is structured as follows. The identification strategy for both the CO<sub>2</sub> marginal abatement effect and the CO<sub>2</sub> cross-border marginal abatement effect is outlined. The results and their heterogeneity are then presented and discussed. The same structure is subsequently applied to the merit order effect and the cross-border merit order effect. Finally, robustness tests are presented.

### 1.4.1 Marginal abatement effect and cross-border marginal abatement effect

#### 1.4.1.1 Econometric framework

I use the method of Regression Discontinuity in Time (RDiT) as described by [Hausman and Rapson \(2017\)](#). Its advantage over a traditional event study lies in leveraging high-frequency data to incorporate flexible controls by utilizing higher-order time trend polynomials before and after the treatment. The concept underlying this approach is that the dependent variable, whether emissions or thermal generation in this context, would have changed smoothly around the treatment date in the absence of the treatment. Specifically, what I do is the following:

First, I regress the dependent variables *emissions in Spain* ( $e_t^s$ ) and *emissions in France* ( $e_t^f$ ) on *wind generation in Spain* ( $Wind_t^s$ ) with an indicator for observations after October 24th 2015, various control variables and a flexible n-th order polynomial time trend  $g(t)$ :

$$e_t^s = \alpha_0 1\{t \geq 10/2015\} + \alpha_1 Wind_t^s + \alpha_2 Wind_t^s \times 1\{t \geq 10/2015\} + \sum_j \theta_j f_j(\mathbf{X}_t) + \alpha_3 \mathbf{Cal}_t + g(t) + u_t \quad (1.5)$$

$$e_t^f = \beta_0 1\{t \geq 10/2015\} + \beta_1 Wind_t^s + \beta_2 Wind_t^s \times 1\{t \geq 10/2015\} + \sum_j \kappa_j f_j(\mathbf{X}_t) + \beta_3 \mathbf{Cal}_t + g(t) + u_t \quad (1.6)$$

where  $e_t^{spain}$  and  $e_t^{france}$  are hourly CO<sub>2</sub> emissions in tonnes,  $Wind_t^s$  is hourly wind generation in Spain in MWh, and  $1\{t \geq 10/2015\}$  is an indicator that takes the value one if the observation corresponds to an hour after October 24th 2015 and is zero otherwise.  $\mathbf{X}_t$  is a set of controls for load in France and in Spain ( $L_t^s$  and  $L_t^f$ ),  $CR_t$  the coal over gas price ratio to control for changes in fuel cost and the wind generation in France  $Wind_t^f$ . All these controls are fully interacted with  $1\{t \geq 10/2015\}$ .  $\mathbf{Cal}_t$  is a vector of calendar variables including hour of day, day of week and month-of-year fixed effects to



control for possible changes in the generation mix as well as for the impact of seasonal and daily cycles.  $g(t)$  is a  $n$ -th order polynomial time trend. Our coefficients of interest for equation 1.5 are  $\alpha_1$ , representing the CO<sub>2</sub> marginal abatement effect of spanish wind generation before the interconnection expansion, and  $\alpha_2$  representing its change after the expansion. For equation 1.6,  $\beta_1$ , represents the cross-border CO<sub>2</sub> marginal abatement effect of spanish wind generation on french emissions before the interconnection expansion, and  $\beta_2$  representing its change after the expansion. The expected sign of  $\alpha_1$  and  $\beta_1$  is negative as wind generation with zero marginal cost is expected to offset some polluting thermal plants in both countries.  $\beta_2$  is also expected to be negative as more electricity is being sent from Spain to France after the interconnection capacity increase. The sign of  $\alpha_2$  is ambiguous. As detailed in Section 1.2.5, it could be positive under certain settings. The analysis specifically investigates how, due to exports to France when Spain produces a significant amount of wind energy, less Spanish thermal generation is offset as a result of increased interconnection between the two countries.

Then, to disentangle the effect of  $Wind_t^s$  on each major polluting source of electricity  $i$ , I employ the hourly generation by fuel type in each country  $c$  as the dependent variable, which is regressed against its key determinants:

$$g_{i,t}^c = \gamma_{0i}^c 1\{t \geq 10/2015\} + \gamma_{1i}^c Wind_t^s + \gamma_{2i}^c Wind_t^s \times 1\{t \geq 10/2015\} + \sum_j \lambda_{ji}^c f_j(\mathbf{X}_t) + \gamma_{3i}^c Cal_t + g(t) + u_{i,t} \quad (1.7)$$

where  $g_{i,t}^{country}$  is coal or gas generation in Spain or in France. The coefficients of interest in this regression are  $\gamma_{1i}^c$  and  $\gamma_{2i}^c$  and they capture the marginal effect of Spanish wind energy on different polluting electricity sources in both countries and its evolution post expansion. Following the same reasoning as for the previous regressions, the expected sign of  $\gamma_{1coal}^{spain}$ ,  $\gamma_{1gas}^{spain}$ ,  $\gamma_{1coal}^{france}$  and  $\gamma_{1gas}^{france}$  is negative, that of  $\gamma_{2coal}^{france}$ ,  $\gamma_{2gas}^{france}$  is also negative, and those of  $\gamma_{2coal}^{spain}$  and  $\gamma_{2gas}^{spain}$  are ambiguous.

#### 1.4.1.2 Results and discussion

The estimation results of equations 1.5 and 1.6 are presented in Table 1.3. Before the expansion of the interconnection, Spanish wind energy offsets 0.573 tonnes of CO<sub>2</sub> per MWh in Spain and a negligible amount in France. The treatment effect alligns with those found by Abrell et al. (2019b) and Petersen et al. (2022), as discussed in Section 2.2.2. After the interconnection expansion, the amount of CO<sub>2</sub> avoided in Spain per MWh of wind generation decreased by 0.175 tonnes of CO<sub>2</sub> per MWh and increased by 0.045 tonnes of CO<sub>2</sub> per MWh in France. In total, the marginal abatement effect of Spanish

wind energy on CO<sub>2</sub> has decreased from 0.579 to 0.449 tCO<sub>2</sub>/MWh. This implies that it has become more expensive to avoid a tonne of CO<sub>2</sub>.

Table 1.3: Emissions regression results

Variable	Spanish emissions	French emissions
	(1)	(1)
Wind Spain	-0.573*** (0.030)	-0.006 (0.002)
Wind Spain $\times 1\{t \geq 10/2015\}$	0.175*** (0.033)	-0.045** (0.019)
Wind France	-0.059 (0.046)	-0.164*** (0.012)
Load Spain	0.425*** (0.017)	0.026*** (0.009)
Load France	0.061*** (0.009)	0.121*** (0.006)
Cost Ratio	-897.041*** (101.017)	-609.179*** (204.564)
Hours of day FE	YES	YES
Day of week FE	YES	YES
Month of Year FE	YES	YES
Fully interacted	YES	YES
N	29,228	29,228
R-squared	0.850	0.807

*Note:* Results for equations 1.5 and 1.6. BIC-chosen global polynomial. Coefficients can be interpreted as tCO<sub>2</sub>/MWh. Newey–West standard errors in parentheses. \*\*\* p<0.01, \*\* p<0.05, \* p<0.1

To provide a rough estimate, I calculate the average annual effect and examine how it is impacted by the expansion of interconnection by multiplying the marginal effects with the annual averages of wind generation before and after the expansion. On average and per year, 0.34 MtCO<sub>2</sub> were avoided in France due to Spanish wind power before the expansion, and this increased to 2.06 MtCO<sub>2</sub> after the expansion. This represents 6 percent of the emissions from the electricity mix and is thus non-negligible. Regarding the domestic effect, 25.35 MtCO<sub>2</sub> per year were avoided in Spain due to domestic wind power. This figure declined to 20.15 MtCO<sub>2</sub> per year following the expansion. Overall, the enhanced emission reductions in France do not compensate for the reduction Spain attributable to Spanish wind energy.

The increase in the cross-border abatement effect was expected, as the flows to France have doubled and congestion between the two countries has decreased due to the additional interconnection capacity. However, how can we explain the decrease in the amount of emissions abated in Spain through wind energy? This decrease can be attributed to the

hours when Spain exports to France. During these hours, it is not only the generation from the most expensive power plant in Spain that is reduced with an increase in wind generation. Part is exported if the interconnection is not congested to offset generation in France as shown by equation 1.2. This raises the question of which electricity sources in Spain would have been offset in the case of autarky.

Table 1.4: Generation per fuel type regression results

Variable	Spanish generation		French generation	
	Gas	Coal	Gas	Coal
Wind Spain	-0.245*** (0.018)	-0.463*** (0.032)	-0.009 (0.010)	-0.003 (0.002)
Wind Spain $\times 1\{t \geq 10/2015\}$	-0.030*** (0.003)	0.164*** (0.035)	-0.044*** (0.017)	-0.025* (0.015)
Wind France	-0.067 (0.042)	-0.026 (0.017)	-0.202*** (0.017)	-0.064*** (0.009)
Load Spain	0.372*** (0.018)	0.261*** (0.018)	0.025** (0.011)	0.014** (0.006)
Load France	0.064*** (0.010)	0.032*** (0.009)	0.137*** (0.007)	0.053*** (0.004)
Cost Ratio	4947.951*** (1047.109)	-4227.808*** (1298.578)	114.929 (82.653)	-176.617 (494.902)
Hour FE	YES	YES	YES	YES
Month of Year FE	YES	YES	YES	YES
Fully interacted	YES	YES	YES	YES
N	29,228	29,228	29,228	29,228
R-squared	0.850	0.884	0.857	0.807

*Note:* Coefficients can be interpreted as MWh of thermal generation / MWh of wind generation. BIC-chosen global polynomial. Newey–West standard errors in parentheses.  $p < 0.01$ , \*\*  $p < 0.05$ , \*  $p < 0.1$

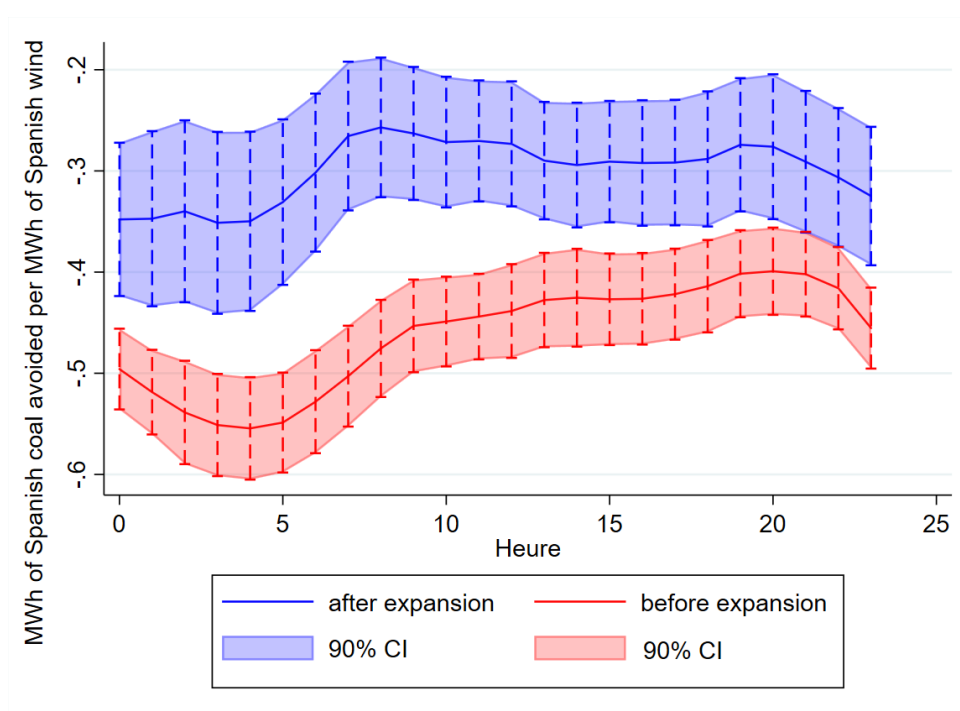
In summary, the enhanced market integration between France and Spain has caused a significant decrease in total CO<sub>2</sub> emissions abatement. The generation regressions are utilized to analyze this effect. Table 1.4 presents the results of regression 1.7. Examining the effect of Spanish wind energy on different types of generation shows that it displaces less domestic coal generation - typically the most polluting - following the interconnection expansion. Each MWh of Spanish wind energy displaces 0.164 less MWh of domestic coal and 0.030 more gas than before, explaining the negative effect on emissions reduction. This shift can be attributed to coal being more frequently at the margin than gas when Spain exports electricity to France. As for the generation displaced on the other side of the border, each MWh of Spanish wind energy displaces an additional 0.044 MWh of gas generation and 0.025 MWh of coal compared to before, which explains the increase in the cross-border CO<sub>2</sub> abatement effect. These findings indicate that the expansion of

the interconnection capacity leads to a greater reduction in gas generation compared to coal generation, which is suboptimal for the cumulative emissions of both regions. The magnitudes observed align with the findings documented in the literature, as discussed in Section 2.2.2.

### 1.4.1.3 Heterogeneous effects

As noted in Section 1.3.1, the proportion of each type of generation varies throughout the day, and different conventional generators are marginal at varying times. To further explore the impact of the interconnection expansion on the environmental value of Spanish wind energy, the hour-by-hour heterogeneity in the displacement of each type of technology is examined. The displacement of coal in Spain and gas in France is of particular interest since the variation in marginal CO<sub>2</sub> emissions primarily originates from these sources, as discussed in Section 1.4.1. Figure 1.2 plots the marginal impact of Spanish wind energy on coal generation in Spain hour by hour before and after the interconnection expansion.

Figure 1.2: Hour-by-hour Spanish coal replacement per MWh of Spanish Wind Power

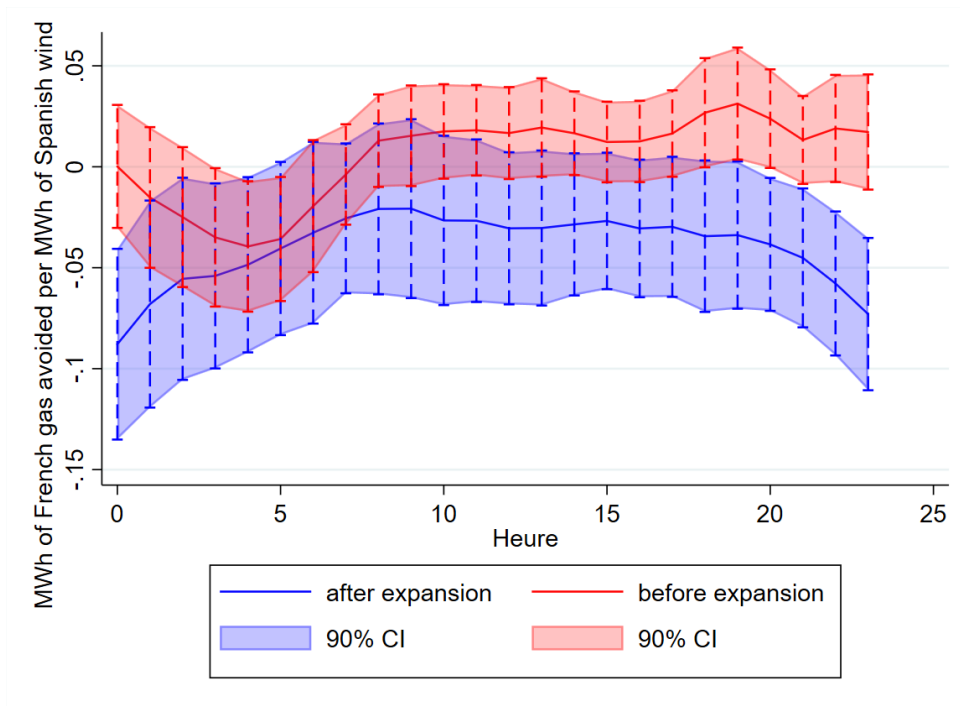


The initial observation is that the effect is not constant throughout the day. Consistent with existing literature (Kaffine et al., 2013; Novan, 2015; Fell and Kaffine, 2018), coal is predominantly displaced during low-demand hours. The coal displacement then decreases as domestic demand rises. Comparing this replacement before and after the expansion of the interconnection capacity shows that indeed less coal is displaced afterward. This

change is mainly driven by low-demand hours at night, which is consistent with the period when coal, being cheaper than gas, is more likely to be marginal. The gap between the two curves then narrows during peak-load hours when gas is marginal.

Regarding gas generation displaced in France by Spanish wind energy, the effect also varies throughout the day. Figure 1.3 plots the replacement effect of gas generation in France by Spanish wind generation.

Figure 1.3: Hour-by-hour French gas replacement per MWh of Spanish Wind Power



Before the expansion, it is almost always insignificant. The observed minimum at night could be explained by the periods of low demand in both countries coupled with significant wind generation in Spain, likely triggering exports. However, the effect remains very weak. After the expansion, the analysis is less clear than for the domestic case, with coefficients not often significantly different from the pre-expansion case. Nevertheless, the inverted U-shape of the curve mirrors the inverse of the average hourly wind generation curve displayed in figure 1.1. It seems that the more wind generation there is in Spain, the more gas is displaced in France. This interpretation should be taken cautiously, given the low significance of the hourly coefficients.

## 1.4.2 Merit order effect

### 1.4.2.1 Econometric framework

Last, I regress French and Spanish (country  $c$ ) spot prices on the variable of interest  $Wind_t^s$ , along with a set of control variables that affect wholesale prices to investigate the cross-border merit order effect and its evolution with the interconnection:

$$p_t^c = \delta_0^c 1\{t \geq 10/2015\} + \delta_1^c Wind_t^s + \delta_2^c Wind_t^s \times 1\{t \geq 10/2015\} + \sum_j \mu_j^c f_j(\mathbf{X}_t) + \delta_3^c \mathbf{Cal}_t + g(t) + u_t \quad (1.8)$$

Here,  $\mathbf{X}_t$  is slightly different compared to the previous equations. It is a set of controls for load in France and in Spain ( $L_t^s$  and  $L_t^f$ ),  $p_t^{coal}$  the price of coal per MWh generated,  $p_t^{gas}$  the price of gas per MWh and  $p_t^{euets}$  the price of CO<sub>2</sub> per tonne. Unlike previous regressions where the cost ratio was employed to account for potential fuel switching, here fuel prices are considered in their actual levels. The reason is that the cost ratio was utilized to control for potential fuel switching. Here, it is directly the price in level of the marginal plant that explains variations in electricity wholesale prices.

There may be concerns about endogeneity of wind generation due to curtailment issues. As detailed in the background section, the focus is on the period post-June 2014, following the regulation that introduced the capacity-based subsidy scheme. Under this framework, the incentive for wind generators to offer their production during periods of wind oversupply has been logically reduced.

Correctly identifying the impact of Spanish wind energy on prices in both countries requires accurate modeling of the supply curves. Our variable of interest is wind generation, but the potential endogeneity issue brought about by including demand as a control must be addressed. While electricity demand is often considered perfectly inelastic, the development of demand-side management tools raises concerns about demand reacting to price signals, leading to reverse causality. Therefore, I employ temperature, squared temperature, a national industrial production index, and hours of sunshine as instrumental variables. These instruments are expected to provide an exogenous variation in demand, isolating it from contemporaneous price effects. This results in the following first-stage regressions:

$$L_t^c = \rho_0^c \mathbf{Inst}_t + \rho_1^c 1\{t \geq 10/2015\} + \rho_2^c Wind_t^s + \rho_3^c Wind_t^s \times 1\{t \geq 10/2015\} + \sum_j \rho_j^c f_j(\mathbf{X}_t) + \rho_4^c \mathbf{Cal}_t + g(t) + u_t \quad (1.9)$$

The Kleibergen-Paap Wald F-statistic always exceeds the weak identification (ID) critical values from Stock-Yogo which suggests that load is identified by the instruments.

As the shape of the supply curve is unknown and likely non-linear, it is modeled as flexibly as possible through the estimation of a semiparametric partially linear regression model using Robinson's (1988) double residual method. The model is structured as the partially linear regression that follows:

$$P_c = \theta_0 + \mathbf{Z}_c\theta + m(L_c) + \eta_c \quad (1.10)$$

In this equation,  $P_c$  represents the spot prices in country  $c$ ,  $\mathbf{Z}_c$  denotes the row vector of control variables, and  $\theta_0$  is the intercept term. Variable  $L_c$  is load and enters in a non-linear way via the non-binding function  $m$ .  $\eta_i$  is the disturbance term, assumed to have  $E(\eta|L) = 0$ . The double residual methodology applies conditional expectation on both sides of the equation, yielding:

$$E(P_c|L_c) = \theta_0 + E(\mathbf{Z}_c|L_c)\theta + m(L_c) \quad (1.11)$$

By subtracting Equation 1.10 from Equation 1.11, we get:

$$P_c - E(P_c|L_c) = (\mathbf{Z}_c - E(\mathbf{Z}_c|L_c))\theta + m(L_c) + \eta_c \quad (1.12)$$

where  $P_c - E(P_c|L_c) = \eta_{1c}$  and  $Z_{kc} - E(Z_{kc}|L_c) = \eta_{2c}$  represent the residuals, indexed by  $k = 1, \dots, K$  for the control variables that enter the model parametrically. A two-step procedure is first used to obtain estimates of the conditional expectations  $E_n(P_c|L_c)$  and  $E_n(Z_c|L_c)$  through non-parametric kernel estimations of the form  $P_c = m_P(L_c) + \eta_{1c}$  and  $Z_{kc} = m_{Z_k}(L_c) + \eta_{2c}$ .

These estimated conditional expectations are then inserted into Equation 1.12, to consistently estimate the parameter vector  $\theta$  without explicitly modelling  $m(L_i)$  using a standard non-intercept ordinary least squares regression, resulting in  $\hat{\theta} = (\hat{\eta}'_2\hat{\eta}_2)^{-1}(\hat{\eta}'_2\hat{\eta}_1)$ . Finally,  $m(L)$  is estimated by regressing  $(P - Z\hat{\theta})$  on  $L$  non-parametrically.

The endogenous nature of the non-parametrically modelled variable  $L$ , however, yields  $E(\eta|L) \neq 0$ . Since standard IV-techniques such as 2SLS and general method of moments (GMM) are not feasible in the context of endogenous variables that are non-linear in parameters, a two-step residual inclusion control function is applied, adding the residuals  $\nu$  fitted in the linear prediction of  $L$  in Equation 1.9 as control function to the semi-parametric regression model described in Equation 1.11 (see [Blundell and Powell \(2004\)](#); [Imbens and Wooldridge \(2009\)](#)).

## 1.4.2.2 Results and discussion

The results of regression 1.8 are presented in Table 1.5. The domestic merit order effect decreased with the increase in interconnection, dropping from a reduction of 2.4 €/MWh per GWh of wind generation to 1.9 €/MWh per GWh.

Table 1.5: Merit order effect

Variable	Spanish prices	French prices
	(1)	(1)
Wind Spain	-0.00235*** (0.00012)	-0.00012 (0.00023)
Wind Spain $\times 1\{t \geq 10/2015\}$	0.00052** (0.00016)	-0.00015*** (0.000024)
Wind France	-0.00005 (0.00014)	-0.0015*** (0.000072)
Gas price	1.233*** (0.048)	2.248*** (0.122)
Coal price	10.268*** (1.314)	2.075 (3.284)
EU ETS	1.74*** (0.135)	-0.2 (0.338)
Hours FE	YES	YES
Day of week FE	YES	YES
Month of Year FE	YES	YES
N	29,228	29,228
R-squared	0.810	0.815
F-test (1st stage)	78.092	71.561

*Note:* Results for equations 1.8. BIC-chosen global polynomial. Coefficients can be interpreted as €/MWh per MWh of wind generation. Newey–West standard errors in parentheses.  $p < 0.01$ , \*\*  $p < 0.05$ , \*  $p < 0.1$

By multiplying these values by the average hourly wind generation for each period, it is determined that wind power reduced the average Spanish wholesale electricity price by 13 €/MWh before the expansion and 10 €/MWh afterwards. Furthermore, the marginal effect of Spanish wind energy on French prices has increased after October 2015. Multiplying the marginal effect of Spanish wind energy on French prices by the average hourly wind generation for each period reveals that the spot price has decreased on average by a non significant 0.77€/MWh before October 2015 and by a substantial 1.72€/MWh thereafter. For reference, the average wholesale prices were 39€/MWh in France and 50€/MWh in Spain before expansion, and 33€/MWh and 38€/MWh after. Consequently, the deployment of Spanish wind energy has led to a decrease in French prices, and this decrease has intensified with the expansion of exchanges between the two countries. This outcome



highlights that Spain's renewable energy subsidy system has effectively lowered electricity prices in France, enhancing consumer surplus while adversely affecting the revenue surplus of electricity producers. This dual impact is further explored in the subsequent section.

### 1.4.3 Robustness checks

I explore the robustness of my estimates under several alternative specifications. Initially, as an alternative to the polynomial approach, the local linear approach is tested with a rectangular kernel and a 30-day span in both the pre and post periods, in line with the recommendations suggested by [Hausman and Rapson \(2017\)](#). The coefficients obtained Table 1.A4 in the appendix are consistent with those from my primary specification, which I retain for subsequent robustness tests.

In the primary specification, all controls are interacted with the indicator variable for the expansion. The regressions are also estimated without this interaction, and the coefficients closely align with those from my main specification as shown Table 1.A5 in the appendix.

Maintaining the polynomial form of the Regression-Discontinuity-in-Time method, I experiment with different sets of temporal fixed effects. Load-hours fixed effects are employed to allow the impact of demand on emissions to vary by the time of day.

Lastly, the data are aggregated to the daily level to account for potential dynamic effects of wind generation. This adjustment considers the possibility that wind generation at time  $t$  might affect emissions at time  $t+n$ . Possible mechanisms for this include ramping activities or the use of hydro reservoirs. If hydro is utilized to store electricity generated by wind, the emissions abated later when this stored energy is released can be attributed to wind energy, thereby contributing to its environmental value. The estimates under this specification are also consistent, as shown Table 1.A6.

## 1.5 The cost of reducing CO<sub>2</sub> emissions

The previous analyses have shown that the environmental value of Spanish wind energy has decreased on an aggregate level with the increase in interconnection capacity, but it has increased for France. Since wind energy is subsidized with the aim of reducing CO<sub>2</sub> emissions, I compute the cost of abating one tonne of CO<sub>2</sub> through wind energy. This calculation employs a straightforward back-of-the-envelope approach.

Net financial support is defined as the subsidy paid to renewable electricity producers minus the income received from selling their production on the market. This value, derived

from CNMC (2018) data<sup>8</sup>, was 64.60 euros per MWh over the period. The program's cost is then calculated as follows:

$$\text{program cost} = \text{financial support}/\text{CO}_2 \text{ offset} \quad (1.13)$$

This equation directly relates the financial support for wind energy to the quantity of CO<sub>2</sub> emissions it offsets, providing a measure of economic efficiency in terms of environmental benefit.

The calculated cost of promoting wind energy is 112 euros per tonne of CO<sub>2</sub> avoided prior the interconnection expansion and 143 euros afterwards. This result is consistent with the literature, yet remains higher than the commonly accepted values of the social cost of carbon. However, this does not take into account the benefits of wind energy to those who finance it, namely the consumers, through the price effect. The subsequent question is how much does this cost the consumers? I assume that the wind subsidy is entirely paid by them. The price they pay to avoid CO<sub>2</sub> emissions thus corresponds to the price paid for each MWh of subsidized wind energy minus the merit order effect, relative to the amount of CO<sub>2</sub> emissions avoided. The back-of-the-envelope calculation is as follows:

$$\text{consumer cost} = (\Delta E)^{-1} \sum_t (F_e \times \text{Wind}^{\text{Spain}} - \bar{D}_t \times |\Delta p^{\text{Spain}}|) \quad (1.14)$$

With  $\Delta p$  the price effect,  $F_e \times \text{Wind}^{\text{Spain}}$  the net financial support for wind generation and  $\Delta E$  the emissions offset.

Spanish consumers were paying -26.1 euros per tonne of CO<sub>2</sub> avoided before the expansion and -3.6 euros after. They benefit from a net gain as the decrease in electricity prices due to the merit order effect overcompensates for the increase due to subsidy payments. However, this gain has been reduced and is approaching zero. This is due to slightly lower price effect and wind generation over the year post-expansion. Nevertheless, the French consumers pay nothing and thus benefit for free from the annual abatement of 2 mega tonnes of CO<sub>2</sub> post expansion, which are financed at a rate of 143 euros per tonne by the Spanish consumer.

## 1.6 Marginal impact of wind generation on welfare

The section above details the cost to the consumers, who ultimately finance the policy, of abating a tonne of CO<sub>2</sub>. While the price effect compensates for the subsidy cost,

<sup>8</sup><https://www.cnmc.es/estadistica/informacion-mensual-de-estadisticas-sobre-las-ventas-de-renovables-cogeneracion-y-46>

it impacts not only consumers but also producers. Recall that the day-ahead market operates with a uniform price auction. All called producers receive the price offered by the most expensive marginal plant times the quantity of electricity offered. Hence, wind power tends to decrease electricity producers' profits. Another impact of wind energy on surplus, not accounted for above, is the benefit from reduced CO<sub>2</sub> emissions. To incorporate these aspects and provide a more comprehensive view of wind energy's effect on welfare, the results from Sections 1.4.1.2 and 1.4.2.2 are used to estimate the marginal impact of Spanish wind generation on economic welfare in France and Spain.

### 1.6.1 Decomposition of Economic Surplus:

Following the methodology proposed by Petersen et al. (2022) for surplus decomposition, I consider its breakdown in each country. The marginal impact of Spanish wind generation on surplus can be decomposed as follows:

$$\begin{aligned} \Delta EconomicSurplus &= \Delta ConsumerSurplus_{Spain} + \Delta ConsumerSurplus_{France} \\ &+ \Delta ProducerSurplus_{Spain} + \Delta ProducerSurplus_{France} \\ &+ \Delta EmissionsBenefits \end{aligned} \quad (1.15)$$

The change in consumer surplus differs between Spanish and French consumers as explained above. The Spanish consumer pays for the subsidy but benefits from the price effect, calculated as the change in market price multiplied by average demand. The French consumer benefits from the price effect but pays nothing in return. I calculate the change in consumer surplus for each country before and after the interconnection expansion.

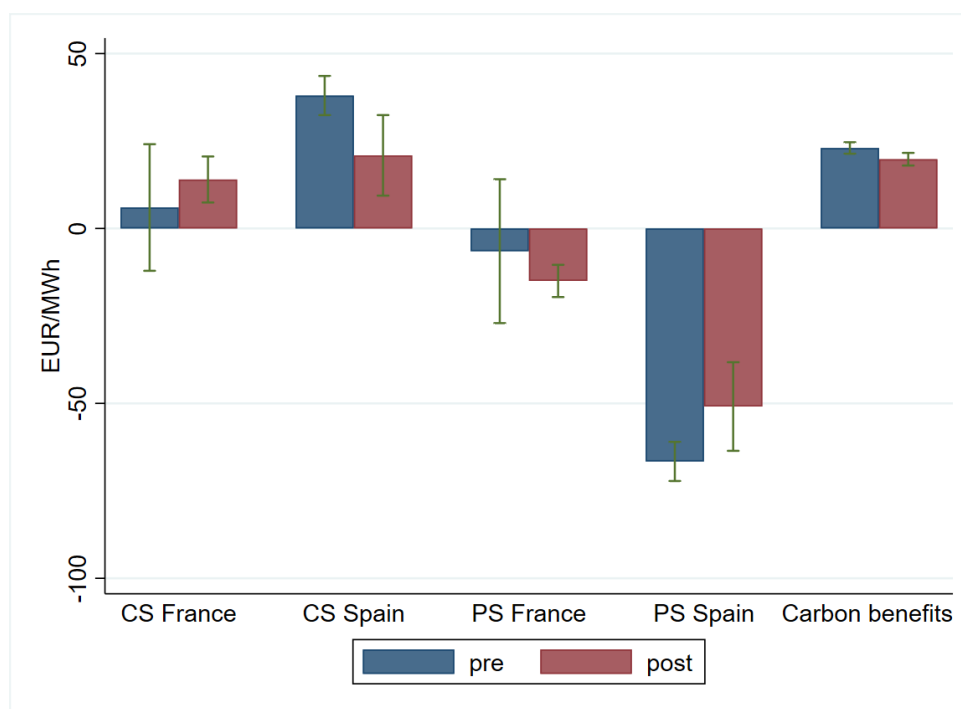
The change in producers' surplus comprises two effects. The price effect refers to the change in rents for units whose output is not affected. They sell the same amount of energy but at a lower price. Additionally, the producer surplus is affected by the replacement effect, which corresponds to the foregone rents for units whose output is affected. For a marginal increase in wind generation, this equates to  $\frac{\partial p}{\partial W}$ .

Finally, the change in Emissions Benefits must be considered. Given that the Spanish electricity market is subject to the EU ETS, a portion of the emissions benefits is already accounted for. Therefore, I regress net emissions costs ( $(SCC - p_{CO_2}) \times emissions$ ) using the same identification strategy as for equation 1.5. I directly calculate the change in the emission benefits of the two countries combined.

## 1.6.2 Results

Figure 1.4 presents the results of calculating the marginal impact of Spanish wind energy on economic surplus. As an illustrative example, the social cost of carbon chosen for calculating emission benefits is set at 50 €/tCO<sub>2</sub>. This value will be varied in subsequent analyses. The objective is to compare how the winners and losers of the wind subsidy are distributed between producers and consumers, as well as between countries. Pre-expansion, the impact of wind on the welfare of French consumers and electricity producers is not significant. In Spain, consumers gain and producers lose, resulting in a net loss without taking into account emission savings. Post-expansion, the gains for French consumers are offset by losses for French producers. In Spain, the gains for consumers and the losses for producers are both reduced.

Figure 1.4: Marginal Surplus Effects of Spanish Wind



Note: This figure shows the impacts of wind on consumer surplus (CS) and producer surplus (PS) in France and in Spain before and after the interconnection expansion as well as the impact on emission benefits with a SCC of 50€/tCO<sub>2</sub>. Calculations based on marginal estimates from equations 1.5, 1.6 and 1.8.

To assess the complete effect on surplus, the reduction in emissions must be considered. This value depends on the social cost of carbon, which is highly debated. For instance, Nordhaus (2017) suggests recent estimates indicate damages of approximately \$30–100. At 50€/tCO<sub>2</sub>, as shown in figure 1.4, the carbon benefits are insufficient to offset the producers' loss, making the marginal effect of wind on total surplus negative. Furthermore,

the carbon benefits slightly decrease after the expansion of the interconnection.

Figure 1.A3 in the annex plots the total effect on surplus from wind energy as a function of the social cost of carbon. The break-even point at which the policy becomes net beneficial is approximately 60€/tCO<sub>2</sub> before expansion and rises to around 70€/tCO<sub>2</sub> after. It should be noted that these two values of the social cost of carbon break-even points fall within the range recommended by climate scientists and economists. Still, the political implication of this result is that a social cost of carbon about 15 percent higher is required after the expansion for marginal Spanish wind energy production to be welfare positive.

## 1.7 Policy discussion

The integration and harmonization of national electricity markets within Europe is a priority for the European Commission, something not questioned in this paper. However, member states retain significant latitude in decisions related to their national energy mixes and policies. The desire to maintain energy sovereignty is strong, and often leads to energy policy decisions being made unilaterally, without coordination with other member states. In the context of significant and increasing market integration, such unilateral national policies can impact interconnected markets. This is indeed what is found in this paper, aligning with the literature on market integration and unilateral policies. For instance, the increase in renewable capacity is the mirror's reflection of reduction in nuclear generation. While I find that Spanish wind energy has decreased French prices, enhancing consumer surplus and reducing profits for French generators, other papers, such as those studying the impact of nuclear plant closures in Germany following Fukushima ([Grossi et al., 2017, 2018](#); [Jarvis et al., 2019](#)), typically show that phase-outs increased prices in connected countries, especially where interconnection capacity is high or number of congestion hours is low.

These examples present a real political challenge. The externalities of unilateral policy decisions by a member state imposed on others through market integration underscore the importance of coordinated European energy policy. While I do not propose that all strategic decisions should be centralized at the European Commission level, there is a clear need for more proactive monitoring and dialogue to assess national decisions' costs and implications. I add that this paper only considers short-term effects. Price changes contaminating connected countries can have longer-term effects, particularly impacting investment decisions. Various aspects of the economy are likely to be impacted and should be taken into consideration. From a macroeconomic perspective, a decrease in electricity prices increases the available income for consumers, which directly impacts real purchasing

power and thus industrial production and GDP growth in both countries. Also, and specifically with respect to national power systems, a unilateral policy reform lowering prices in a neighboring country can create uncertainty about the construction of new power plants. Unilateral policy reforms can affect the future structure of the European energy mix and potentially create insecurity regarding the return on investment of new plants, potentially leading to under investment and consequent challenges to supply security. Thus, I advocate for the establishment of regulatory frameworks to ensure that decisions with significant cross-border impacts are subjected to comprehensive community-level discussions before implementation.

## 1.8 Conclusion

Using a Regression Discontinuity in Time design, this paper shows that the increase in interconnection capacity between France and Spain has led to a decrease in the domestic environmental value of Spanish wind energy, primarily due to reduced displacement of coal generation. However, it has increased this environmental value for France. Nevertheless, this increase does not compensate for the domestic decrease. France and Spain have the particularity of frequently relying on conventional generation at the margin. Market integration has the effect of relocating generation to where it is cheapest but not necessarily where it is the least polluting.

On the other hand, the well-known depressing effect of domestic renewable energy sources on prices contaminates foreign prices, and this effect becomes even more significant with increased exchange capacity. This is in line with what is found in the literature. Back-of-the-envelope calculations indicate that the program cost of carbon abatement has slightly increased with the construction of the additional interconnection capacity, rising from 112 euros per tonne to 143 euros. This cost is entirely borne by the Spanish consumer who, however, also benefits from the price effect. Once this effect is deducted, I find that the Spanish consumer gains: the merit order effect more than compensates for the cost of promoting wind energy. The gain has decreased, from 26.1 euros earned per tonne of CO<sub>2</sub> avoided to 3.6 euros. In any case, the French consumer benefits for free from both the emission abatement due to Spanish wind generation, and from the price effect, which raises questions about the distributive stakes.

To determine whether subsidising wind power is beneficial for society in the short run, it is necessary to consider the expenses incurred for the renewable energy promotion program and assess the gain associated with the reduction in CO<sub>2</sub> emissions. Moreover, the impact on generator profits must be taken into consideration. Indeed, prices decrease in France, therefore the revenue of generators is affected as well. Simultaneously, I observe

that domestic prices in Spain decreased less after the increase in interconnection, which can be beneficial for Spanish generators. There is a significant issue here regarding who bears the costs and who benefits. After accounting for changes in the profits of generators and gains related to CO<sub>2</sub> emissions reduction, the Spanish wind subsidy policy is found to be welfare improving for a social cost of carbon of approximately €60/tCO<sub>2</sub> pre-expansion and €70/tCO<sub>2</sub> post-expansion.

This paper has implications that extend beyond the specific case of France and Spain. It suggests that a precise evaluation of the expected environmental and economic benefits related to the integration of European price zones should be conducted systematically. This should be the case, for example, for future increases in interconnection capacity between countries with varying degrees of polluting generation.

## 1.A Appendices

### 1.A.1 Literature

Table 1.A1: Emissions Offsets Due to Renewable Electricity

Paper	Region	Emissions Offsets
<a href="#">Cullen (2013)</a>	Texas	0.430 tCO <sub>2</sub> /MWh (wind)
<a href="#">Fell and Linn (2013)</a>	Texas	0.512-0.514 tCO <sub>2</sub> /MWh (wind) 0.745 tCO <sub>2</sub> /MWh (solar)
<a href="#">Kaffine et al. (2013)</a>	Texas	0.523 tCO <sub>2</sub> /MWh (wind)
<a href="#">Graff Zivin et al. (2014)</a>	WECC and Eastern interconnection (US)	0.370 tCO <sub>2</sub> /MWh (solar, WECC)  0.555 tCO <sub>2</sub> /MWh (solar, Eastern)
<a href="#">Novan (2015)</a>	Texas	0.63 tCO <sub>2</sub> /MWh (wind)
<a href="#">Holladay and LaRiviere (2017)</a>	US regions	2044-5745 tCO <sub>2</sub> /MW of installed wind capacity per year 1006-2131 tCO <sub>2</sub> /MW of installed solar capacity per year
<a href="#">Callaway et al. (2018)</a>	US regions	0.566-0.811 tCO <sub>2</sub> /MWh (wind) 0.587-0.791 tCO <sub>2</sub> /MWh (solar)
<a href="#">Abrell et al. (2019b)</a>	Germany and Spain	0.175-0.530 tCO <sub>2</sub> /MWh (wind, Germany) 0.233-0.600 tCO <sub>2</sub> /MWh (solar, Germany) 0.250-0.786 tCO <sub>2</sub> /MWh (wind, Spain) 0.168-0.797 tCO <sub>2</sub> /MWh (solar, Spain)
<a href="#">Gugler et al. (2021)</a>	Germany and Great Britain	0.386 tCO <sub>2</sub> /MWh (wind, Germany) 0.934 tCO <sub>2</sub> /MWh (wind, GB)
<a href="#">Petersen et al. (2022)</a>	Spain	0.500 tCO <sub>2</sub> /MWh (wind, Spain)



Table 1.A2: Merit order effect

<b>Paper</b>	<b>Region</b>	<b>Merit Order Effect</b>
<a href="#">Bode and Groscurth (2006)</a>	Germany	0.55-0.61 €/MWh per additional 1GW of renewable capacity
<a href="#">De Miera et al. (2008)</a>	Spain	4.75-12.44 €/MWh (average price reduction, wind)
<a href="#">Sensfuß et al. (2008)</a>	Germany	1.7-7.83€/MWh (average price reduction, renewables)
<a href="#">Gelabert et al. (2011)</a>	Spain	2€/MWh (marginal price reduction from a 1GWh increase of renewable generation)
<a href="#">Traber and Kemfert (2011)</a>	Germany	3.7€/MWh (average price reduction, wind)
<a href="#">Woo et al. (2011)</a>	Texas	1.5-6.1 \$/MWh (marginal price reduction from a 1GWh increase wind generation)
<a href="#">Würzburg et al. (2013)</a>	Austria and Germany	7.6 €/MWh (average price reduction, renewables)
<a href="#">Clò et al. (2015)</a>	Italy	2.3€/MWh (marginal price reduction from a 1GWh increase of solar generation) 4.2€/MWh (marginal price reduction from a 1GWh increase of wind generation)
<a href="#">Woo et al. (2016)</a>	California	4.0-5.3 \$/MWh (marginal price reduction from a 1GWh increase of solar generation) 3.3-3.4 \$/MWh (marginal price reduction from a 1GWh increase of wind generation)
<a href="#">Abrell et al. (2019b)</a>	Germany and Spain	1.2 €/MWh (marginal price reduction from a 1GWh increase of wind generation, Germany) 2.6 €/MWh (marginal price reduction from a 1GWh increase of wind generation, Spain)
<a href="#">Macedo et al. (2020)</a>	Portugal	Price decreases by 0.06% when wind generation increases by 1%
<a href="#">Bushnell and Novan (2021)</a>	California	~0.4 \$/MWh (marginal price reduction from a daily 1GWh increase of renewable generation)
<a href="#">Mwampashi et al. (2021)</a>	Australia	1.3 AUD/MWh (marginal price reduction from a 1GWh increase of wind generation)
Continued on next page		

Table 1.A2 continued from previous page

<b>Paper</b>	<b>Region</b>	<b>Merit Order Effect</b>
<a href="#">Peña et al. (2022)</a>	Spain	Wind plant remuneration decrease by 0.655€/MWh when wind penetration increases by 1%
<a href="#">Petersen et al. (2022)</a>	Spain	~2 €/MWh (marginal price reduction from a 1GWh increase of wind generation)

## 1.A.2 Additional Tables

Table 1.A3: Effects of RE on exports (MWh exports per MWh of RE)

	(1)	(2)
	Spain to France	France to Spain
$\beta_{Wind}$	0.07*** (0.01)	0.04*** (0.01)
$\beta_{Solar}$	0.007 (0.053)	0.05 (0.03)
Exports <sub>Wind</sub>	3.3*** (0.48)	0.76*** (0.19)
Exports <sub>Solar</sub>	0.05 (0.42)	0.3 (0.2)

*Note:*  $\beta$  coefficients indicate the marginal effect of wind and solar energy on exports from Spain to France and from France to Spain. Exports is the yearly average impact of wind and solar on exports measured in TWh and calculated by  $Exports = \beta \bar{RE}$  with  $\bar{RE}$  being wind or solar average yearly generation.

Table 1.A4: Emissions regression results - Augmented local linear

Variable	Spanish emissions	French emissions
	(1)	(1)
Wind Spain	-0.468*** (0.010)	0.019 (0.011)
Wind Spain $\times 1\{t \geq 10/2015\}$	0.073** (0.018)	-0.042** (0.006)
Wind France	0.015 (0.025)	-0.084* (0.025)
Load Spain	0.173** (0.038)	0.008 (0.026)
Load France	-0.003 (0.030)	0.119** (0.015)
Cost Ratio	-298.249 (5943.883)	-522.500 (1598.030)
Hours of day FE	YES	YES
Day of week FE	YES	YES
Month of Year FE	YES	YES
Fully interacted	YES	YES
$N$	1464	1464
R-squared	0.787	0.605

*Note:* Results for equations 1.5 and 1.6. Augmented local linear: the impacts of seasonality controls are estimated using the two-years data window and the residuals are saved. Then a local linear specification is estimated using the residuals within a narrow 30 days band-width. Coefficients can be interpreted as tCO<sub>2</sub>/MWh. Newey–West standard errors in parentheses. \*\*\* p<0.01, \*\* p<0.05, \* p<0.1

Table 1.A5: Emissions regression results - Control variables are not interacted with the indicator

Variable	Spanish emissions	French emissions
	(1)	(1)
Wind Spain	-0.537*** (0.025)	0.013 (0.011)
Wind Spain $\times 1\{t \geq 10/2015\}$	0.167*** (0.040)	-0.035** (0.017)
Wind France	-0.025 (0.021)	-0.198*** (0.016)
Load Spain	0.499*** (0.022)	0.035 (0.021)
Load France	-0.002 (0.012)	0.120*** (0.009)
Cost Ratio	-767.032*** (103.045)	-501.011*** (252.223)
Hours of day FE	YES	YES
Day of week FE	YES	YES
Month of Year FE	YES	YES
Fully interacted	NO	NO
N	29,228	29,228
R-squared	0.899	0.838

*Note:* Results for equations 1.5 and 1.6. BIC-chosen global polynomial. Controls are not interacted with the indicator variable. Coefficients can be interpreted as tCO<sub>2</sub>/MWh. Newey–West standard errors in parentheses. \*\*\* p<0.01, \*\* p<0.05, \* p<0.1

Table 1.A6: Emissions regression results - Daily aggregation

Variable	Spanish emissions	French emissions
	(1)	(1)
Wind Spain	-0.580*** (0.025)	0.026 (0.016)
Wind Spain $\times 1\{t \geq 10/2015\}$	0.167*** (0.040)	-0.081** (0.020)
Wind France	-0.031 (0.026)	-0.230*** (0.019)
Load Spain	0.645*** (0.031)	0.098*** (0.025)
Load France	-0.003 (0.013)	0.135*** (0.010)
Cost Ratio	-52328.4 (68773.74)	-56546.94 (41971.92)
Day of week FE	YES	YES
Month of Year FE	YES	YES
Fully interacted	YES	YES
N	703	703
R-squared	0.921	0.867

*Note:* Results for equations 1.5 and 1.6 with daily aggregation. BIC-chosen global polynomial. All controls are interacted with the indicator variable. Coefficients can be interpreted as tCO<sub>2</sub>/MWh. Newey–West standard errors in parentheses. \*\*\* p<0.01, \*\* p<0.05, \* p<0.1

### 1.A.3 Additional Figures

Figure 1.A1: Average monthly electricity demand in Spain and France and Wind generation in Spain (GWh)

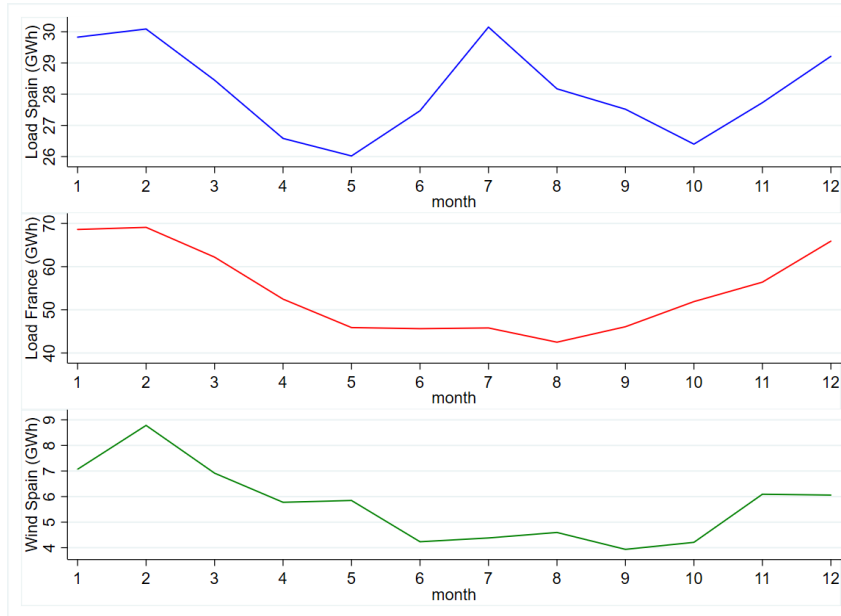


Figure 1.A2: Average daily photovoltaic generation in Spain and France (GWh)

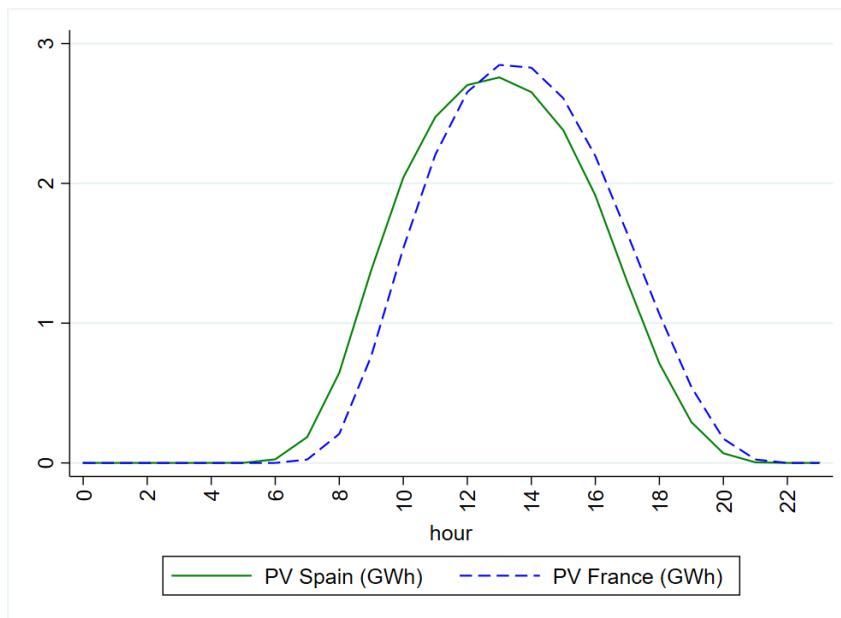
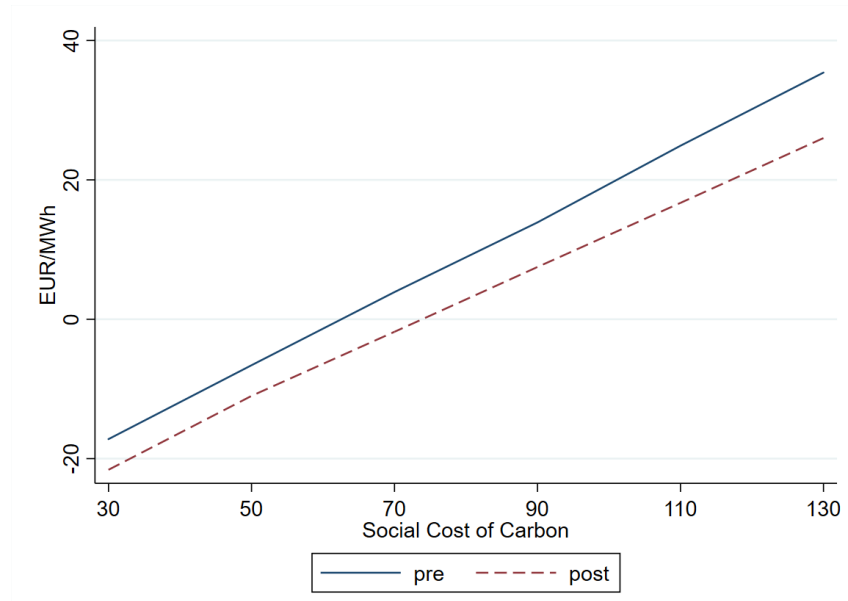


Figure 1.A3: Marginal Surplus Effects of Wind with varying Social Cost of Carbon



Note: This figure illustrates effect of a marginal increase in wind generation on economic surplus as a function of the social cost of carbon. The figure shows the break-even social costs of carbon of wind promotion before and after expansion.





# Chapter 2

## How fuel switching impacts the environmental value of renewable energy

*co-written with Sven Heim (Mines Paris - PSL, ZEW) and Mario Liebensteiner (FAU)*

### Abstract

This paper examines the environmental value of renewable energy in the United States, focusing on how this value fluctuates with changes in coal and gas prices following the shale gas revolution. Utilizing an extensive dataset covering the post-shale gas boom period, we employ an econometric framework that integrates an interaction term between the coal-to-gas cost ratio and renewable energy generation. Our analysis reveals significant regional variations in the environmental benefits of renewables, which are heavily influenced by the relative fuel prices. For interpretability, the cost ratio is also mapped to a fictional carbon price. We find that lower carbon prices typically see renewables displacing gas generation, yielding relatively modest environmental benefits. As carbon price increases, coal generation becomes the marginal technology, enhancing the environmental value of renewables until a threshold is reached. Beyond this point, coal becomes uneconomical, and the environmental value decreases as gas takes over as the marginal generator. We propose policy recommendations that advocate for differential subsidies for renewable energy based on regional environmental values and potential future increases in their effectiveness due to changes in fuel prices and carbon pricing.

### Résumé

Cet article examine la valeur environnementale des énergies renouvelables aux États-Unis, et la manière dont cette valeur fluctue en fonction des variations des prix du charbon et du gaz après la révolution du gaz de schiste. En utilisant une base de données couvrant la période suivant cette révolution, nous employons une méthode économétrique intégrant un terme d'interaction entre le ratio de coût charbon-gaz et la production d'énergie renouvelable. Notre analyse révèle des variations régionales significatives des bénéfices environnementaux des énergies renouvelables, fortement influencées par les prix relatifs des combustibles. Pour une meilleure interprétation, le ratio de coût est également associé à un prix du carbone fictif. Nous constatons que des prix carbone plus bas amènent généralement les renouvelables à remplacer la production d'électricité au gaz, offrant des bénéfices environnementaux relativement modestes. À mesure que le prix du carbone augmente, la production au charbon devient la technologie marginale, augmentant la valeur environnementale des renouvelables jusqu'à atteindre un seuil. Au-delà de ce point, le charbon n'est plus compétitif, et la valeur environnementale diminue à mesure que le gaz prend le relais en tant que générateur marginal. Nous recommandons la mise en place de politiques de subventions différentielles pour les énergies renouvelables, basées sur les valeurs environnementales régionales et les potentielles augmentations futures de leur efficacité en raison des variations des prix des combustibles et du prix du carbone.

**Keywords:** Renewable energy, Shale gas boom, Decarbonization.

**JEL classification codes:** D61, Q40, Q42, Q52

**Acknowledgements:** I thank my two co-authors Sven Heim and Mario Liebensteiner for their work and ideas. Participants to the FAEE PhD workshop, the IEAA International conference, the YEEES seminar, the EEM conference, the Dauphine PhD workshop and the JDD provided useful comments and suggestions.

## 2.1 Introduction

Around the world, renewable energies are deployed to displace conventional greenhouse-gas emitting power stations. The environmental value of each additional unit of renewable electricity depends on how many CO<sub>2</sub> equivalents it offsets<sup>1</sup>. Given that different sources of thermal energy<sup>2</sup> have different emission factors, it becomes imperative to comprehend the circumstances under which renewable energies displace specific technologies, and how policy interventions can shape the environmental efficacy of renewable energy.

The aim of this study is to assess the environmental value of renewable energy for variations in coal and gas prices in the United States by means of an ex-post econometric framework. These variations in fuel prices are also mapped to a hypothetical CO<sub>2</sub> price to enhance interpretability and to extend the conclusions to areas where such a pricing mechanism is in place.

The underlying idea is that variable renewable energies, such as wind and solar power, can feed in electricity at zero marginal costs upon resource availability (solar radiation and wind speed), thereby being dispatched before any other technology with higher marginal costs. Hence, the commodity prices of coal and gas essentially determine which conventional source of electricity generation operates at the margin, where supply meets demand. This marginal technology would be displaced first by an additional unit of renewable energy, with gas plants emitting significantly fewer CO<sub>2</sub> equivalents per unit of electricity than hard coal or lignite power plants. Therefore, it is the carbon intensity of the marginal power plant, rather than the average carbon intensity of the electrical mix, that determines the marginal abatement effect (and consequently the environmental value<sup>3</sup>) of renewable energies (e.g., [Cullen, 2013](#); [Novan, 2015](#); [Fell and Kaffine, 2018](#); [Gugler et al., 2021](#)).

**Context:** Historically, in the United States, the commodity price of coal was typically lower than that of natural gas, so that coal plants were used for base-load and had lower marginal costs than the more flexible gas plants, which were used to supply peak-load. Under such circumstances, renewable energies primarily offset gas-fired power plants ([Cullen, 2013](#)), whereas coal-based electricity remained largely unaffected ([Liebensteiner and Wrienz, 2020](#), show this for European power plants).

The U.S. electricity mix underwent significant disruption with the shale gas boom, facilitated by newly discovered hydraulic fracturing techniques, during the period of 2005

---

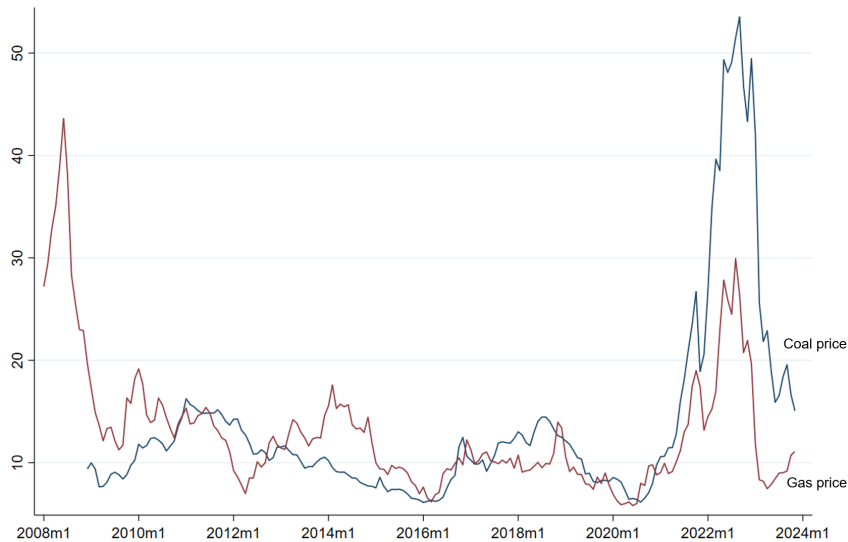
<sup>1</sup>Formally, the environmental value is  $x$  in "+ 1 MWh of renewable energy offsets  $x$  tons of CO<sub>2</sub>".

<sup>2</sup>e.g., lignite, hard coal, natural gas.

<sup>3</sup>Going forward, we refer to this concept interchangeably as the marginal CO<sub>2</sub> abatement effect or the environmental value of renewable energies.

to 2010. This boom resulted in a decline in natural gas prices. Figure 2.1 illustrates the commodity price trends of coal and natural gas since 2008<sup>4</sup>, revealing that natural gas frequently became cheaper than coal.

Figure 2.1: Commodity price developments (\$/MWh)



Notes: This graph shows monthly price developments of the natural gas Henry Hub future and the Newcastle coal future, converted to \$/MWh.

Consequently, coal generation decreased significantly since about 2005 and was partly replaced by gas, as shown in Figure 2.2. Natural gas even became the primary source of electricity in 2015. This phenomenon is called *fuel switching*.

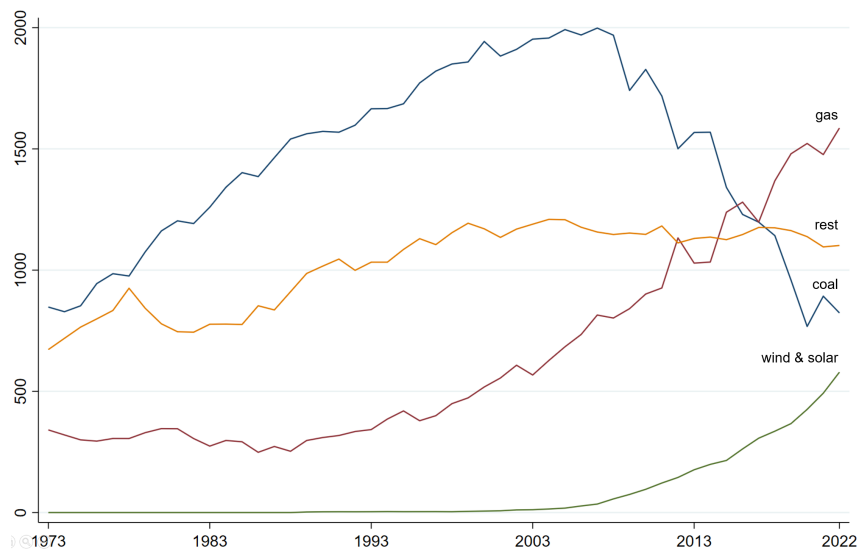
The substitution of coal by gas plants led to a decrease of the average carbon intensity of the U.S. electricity sector. Figure 2.3 indeed illustrates the decline in annual emissions from the electricity mix, driven by the reduction in emissions associated with coal-fired power plants. It is noteworthy that although gas is surpassing coal as the primary source of electricity generation, coal remains the leading contributor to emissions due to its higher carbon intensity.

Another transformative factor in the U.S. electricity mix is the increased adoption of renewable energy, driven by policies promoting solar and wind power (Abdmouleh et al., 2015). These energies are promoted precisely for their environmental value. Therefore, understanding and measuring how this value is determined is crucial for informing future climate-policy decisions.

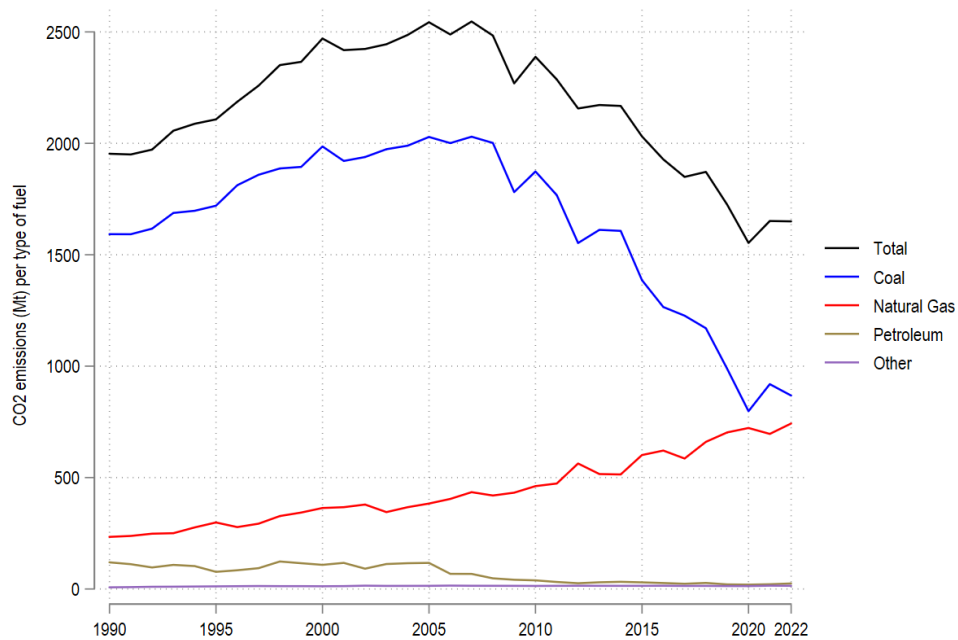
**Results:** This paper documents the interaction between renewable electricity generation and fuel prices in the context of the post-shale gas boom in the U.S. electricity system. We measure how the effect of an additional MWh of renewable energy generation

<sup>4</sup>The time series does not extend further back.

Figure 2.2: U.S. electricity production by source (TWh)



*Notes:* This graph displays the temporal evolution of annual electricity generation by fuel type. It shows a decline in coal generation in favor of natural gas and renewable energy production. Source: EIA 2023.

Figure 2.3: U.S. CO<sub>2</sub> emissions by source (Mt)

*Notes:* This graph illustrates the temporal evolution of CO<sub>2</sub> emissions from electricity generation by fuel type. It reveals a decrease in total emissions driven by a faster decline in coal-related emissions than the increase in those associated with gas. Source: EIA 2023.

on greenhouse gas (GHG) emissions varies with the coal-to-gas cost ratio. This ratio controls for potential fuel switching between coal and gas generation. Furthermore, our econometric model identifies which fuel is displaced by renewable energy, thereby determining the source of emission reductions. Fluctuations in the cost ratio are also mapped to variations in a hypothetical CO<sub>2</sub> price. The purpose is to utilize shifts in fuel prices to assess the combined impact of a carbon price and the promotion of renewable energies in a revealed preference approach. The underlying question is whether these policies are complementary or not.

The findings reveal that the environmental value of renewables varies regionally, by up to a factor of two. Specifically, each additional MWh of renewables abates between 0.4 tCO<sub>2</sub> and 0.9 tCO<sub>2</sub>, depending on the region analyzed. Moreover, these regional values themselves fluctuate according to the associated cost ratio/carbon price. As the carbon price rises, the environmental value of renewables starts to increase because gas generation at the margin for low prices is replaced by coal generation. Above a threshold value, the environmental value decreases as coal becomes uneconomical and ceases production.

These results provide insights into the interaction between relative fuel prices or CO<sub>2</sub> prices and renewable energy generation in reducing CO<sub>2</sub> emissions. This interaction can either be complementary or not. According to our results, policymakers aiming to maximize the effectiveness of their energy transition strategies should increase subsidies for renewables in proportion to their regional environmental value, and even more so in anticipation of future increases under an appropriate CO<sub>2</sub> price level.

**Contributions:** This study makes several significant contributions to the existing economic literature, particularly in the realm of evaluating the environmental value of renewable energies. This literature often aims to compare the environmental benefits of wind or solar power with the costs associated with their development. For instance, a growing number of studies, mainly focused on Texas (Cullen, 2013; Kaffine et al., 2013; Novan, 2015), have demonstrated that wind power reduces CO<sub>2</sub> emissions within a range between the carbon intensity of gas-fired and coal-fired power plants. These studies have also revealed a heterogeneity in the results, both regionally and based on the time of day or period of year. Geographic heterogeneity is driven by differences in the composition of electric power mixes. Temporal heterogeneity, related to the time of the day or month of the year, is driven by variations in electricity demand and, consequently, the use of different marginal plants. However, the study period of these papers corresponds to what can be called the "old mix", where the coal over gas cost ratio was well below 1, hence coal was used for baseload generation and gas for peak load. The mix under study is generally *static*. As such, it involves a scheduling of power plants that does not vary, i.e., without

fuel switching.

Subsequently, several studies have explicitly used the shale gas boom as a natural experiment to investigate how cheap natural gas has decreased the average emissions of the electricity mix (Cullen and Mansur, 2017), changed the marginal emissions profile in different regions (Holladay and LaRiviere, 2017; Linn and Muehlenbachs, 2018), pushed coal-fired generation out of the merit order, and lowered emissions, especially where wind generation is significant (Fell and Kaffine, 2018).

These two streams of literature — the one studying the environmental value of renewables in the context of the "old mix", where coal generation was almost systematically used for base load, and the other examining how the electricity mix has evolved with the sharp drop in gas prices — point to the following intuition: wind power primarily displaces gas-fired generation, which operates at the margin, and the lower gas prices led to an increased share of gas-fired power plants in the mix, at the expense of coal-fired plants.

Our study enhances this literature in several ways. Unlike previous studies that focused on the environmental value of renewables over short periods, often as brief as two years (Cullen, 2013; Kaffine et al., 2013; Novan, 2015), we employ an extensive 12-year dataset. This extended period allows us to use real data on renewable energy generation, eliminating the need for simulations like in Holladay and LaRiviere (2017). Most importantly, we move away from the context of a stable mix without fuel switching and take into account power plant decommissions. The time span covered by our data enables us to explore variations in the environmental value of renewables, particularly considering gas and coal price levels. To this end, we introduce an interaction term between the coal-gas cost ratio and renewable generation, a methodology inspired by Fell and Kaffine (2018) and Gugler et al. (2021). Additionally, unlike previous studies examining the impact of the shale gas boom, our analysis does not solely concentrate on the immediate effect of this shock on the environmental value of renewables. Instead, we focus on how this value evolves in the period that follows, which we refer to as the *low gas prices* period. During this time, numerous coal-fired plants closed due to their economic inviability. To address this issue, we leverage a methodology that accounts for possible selection biases.

The remainder of the paper is organised as follows. Section 2 gives some background on the US electricity market and its recent developments. Section 3 presents a conceptual framework that encompasses the channels through which renewables offset emissions. Section 4 describes the data we use. Section 5 details our identification strategy. Section 6 and 7 presents the results and discuss them. Section 8 concludes.



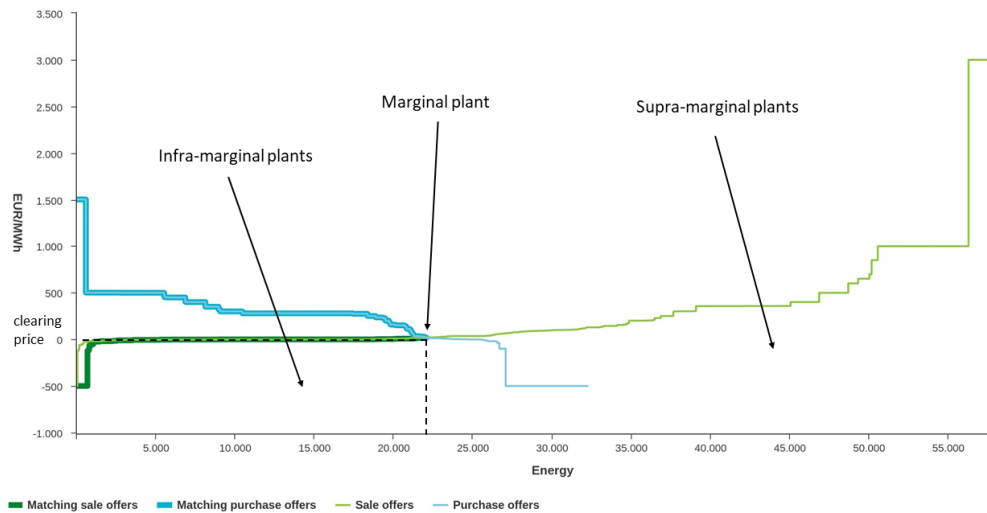
## 2.2 Background

In this section, we provide background information on the functioning of the electricity market and its recent developments that impact the environmental value of renewable energies.

### 2.2.1 Electricity markets

In the United States, the standard market design is the integrated market (Cramton, 2017), based on the Wholesale Power Market Platform developed by the US Federal Energy Regulatory Commission (FERC). For the day-ahead market, which is our focus, electricity prices are determined by the regional Independent System Operator (ISO), to which generation and consumption bids are submitted for every hour of the next day. The ISO optimizes welfare under network and resource constraints and determines prices at each location. Roughly speaking, market clearing prices are determined at the intersections of supply and demand curves. The supply curve is established considering the supply bids in ascending order, forming what is known as the *merit order* illustrated Figure 2.4.

Figure 2.4: Merit order



*Notes:* This graph illustrates the supply and demand bid curves for a given hour. The *marginal* plant is located where demand and supply intersect. To the left of this point, all cheaper, *infra-marginal* plants are called upon. To the right, the *supra-marginal* plants are uneconomical and not utilized. They are out of the merit order. Source: OMIE 2024.

Under the commonly made assumption of a competitive market environment, the merit order curve reflects the marginal costs of the available power plants. These plants

are dispatched in sequence until demand is met. The market clearing price corresponds to the supply bid of the last power plant<sup>5</sup> that is needed to meet demand. *Infra-marginal* plants, i.e. those with a marginal cost lower than the market clearing price, receive a rent corresponding to the difference between the market clearing price and their own marginal costs multiplied by the quantity of electricity sold. Plants that are out of the merit order<sup>6</sup>, i.e. with a marginal cost higher than the clearing price, are not dispatched and receive nothing.

Two key points should be noted here. First, the order in which plants are dispatched depends on their marginal costs. These costs include fuel costs and CO<sub>2</sub> prices, if applicable<sup>7</sup>. They vary over time, and plants can shift positions in the merit order with variations in fuel prices. This change in position is referred to as *fuel switching*. Second, there are three types of plants for a given market outcome: *infra-marginal* plants with a capacity factor (hourly generation in MWh divided by capacity in MW) close to one<sup>8</sup>, *marginal* plants with a maximum capacity factor of one, and *supra-marginal* plants that are out of merit with a capacity factor of zero. A plant falls into a particular category based on the price of its fuel relative to that of other plants, the available capacities of each plant, and the level of demand. Of course, a plant can change its category over time due to fuel switching. We discuss this further in Section 3.3.

The central idea is that the environmental value of renewable energies corresponds to the carbon intensity of the marginal plant. For instance, one MWh of renewable energy at a near-zero marginal cost shifts the supply curve to the right, reducing the generation of the marginal plant by one MWh and avoiding its associated CO<sub>2</sub> emissions. Due to the market design explained above, the marginal plant is the one with the cheapest possible generation. Unfortunately, it is not necessarily the least polluting option. Historically, coal-fired plants were used for baseload due to their relatively low fuel costs under minimal or nonexistent carbon pricing. Gas-fired plants were subsequently dispatched. Given that typical coal-fired plants have a GHG emission intensity about twice that of gas plants, a decoupling exists between carbon intensity and marginal costs. This configuration may be suboptimal from a welfare perspective that internalizes emissions, as it fails to account for the environmental costs associated with higher emissions from coal.

In the following subsections, we first detail the findings from the literature on the environmental value of renewables. The papers reviewed here do not consider the possibility

---

<sup>5</sup>This unit is commonly called the *marginal* plant.

<sup>6</sup>Also called *supra-marginal* plants.

<sup>7</sup>In the US, a carbon market exists only in California and for the Regional Greenhouse Gas Initiative (RGGI) region, which includes the states of Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Pennsylvania, Rhode Island, and Vermont. This constitutes a small part of the country, and the RGGI initiative features a relatively low and stable carbon price.

<sup>8</sup>Technical but not economic constraints explain why the capacity factor can differ from one.

of fuel switching. The assumption of a stable scheduling of generators in the merit order<sup>9</sup> is implicitly made, justified by the short study periods and the stability of fuel prices. We then summarize the studies conducted on the impact of fuel switching related to the shale gas boom on the US mix. We finally describe our contribution to the literature which examines the interaction between the environmental value of renewable energies and fuel prices.

### 2.2.2 The environmental value of renewable electricity - *Static merit order*

Renewable energy is central to limiting global warming below 2°C ([Intergovernmental Panel On Climate Change \(Ippc\), 2023](#)) and is thus widely promoted. In particular, photovoltaic and wind energy are deployed with the aim of decarbonizing electricity production. The United States has set the ambitious goal of achieving a fully decarbonized electrical system by 2035 through its "US 2030 GHG Pollution Target plan"<sup>10</sup>. This plan has the interim target to reduce emissions by 50–52% compared to 2005 levels by 2030. To achieve this objective, the country stands as a global leader in renewable electricity investment, with a whopping \$56 billion invested in renewable energies in 2019 alone. These investments are primarily directed towards solar photovoltaic and wind technologies, the costs of which have significantly decreased ([Jayadev et al., 2020](#)). Additionally, various regional policies have been implemented to achieve the same goal. These include renewable portfolio standards (RPS)<sup>11</sup> adopted by nearly every state, carbon markets in California and the Regional Greenhouse Gas Initiative (RGGI) area, and various subsidies and tax credits. Consequently, between 2001 and 2019, photovoltaic production increased from 0.5 TWh to 70 TWh, and wind production surged from 7 TWh to almost 300 TWh.

A growing body of research thus focuses on evaluating the effectiveness of these energy sources in decarbonizing the electrical mix. As outlined above, renewables' CO<sub>2</sub> marginal abatement factor depends on the available thermal capacities, their dispatch order, and ultimately the technology of the marginal plant. The literature that has delved into this topic primarily utilizes empirical or optimization methods. These papers have mainly focused on a single region, often Texas ([Cullen, 2013](#); [Kaffine et al., 2013](#); [Novan, 2015](#)) or Germany ([Gugler et al., 2021](#)). Due to data limitations, other studies use simulated data for wind or photovoltaic production employing wind or insolation data ([Holladay and LaRiviere, 2017](#); [Millstein et al., 2017](#); [Callaway et al., 2018](#)). In all these cases, the envi-

---

<sup>9</sup>What we call *static* merit order.

<sup>10</sup><https://www.whitehouse.gov/wp-content/uploads/2021/10/us-long-term-strategy.pdf>, last access on the 15/04/2024.

<sup>11</sup>The RPS requires that electricity utilities produce a given proportion of their electricity from renewable energy sources.

ronmental value of renewables is calculated based on the marginal emission factor of the electricity mix, and for a plant scheduling considered as stable in a first approximation<sup>12</sup>. Typically, their identification strategy takes the following form:

$$e_{i,t} = \beta RE_{i,t} + D_i + D_t + \epsilon_{i,t} \quad (2.1)$$

Where  $e_{i,t}$  represents emissions at spatial resolution  $i$  and temporal resolution  $t$ ,  $RE_{i,t}$  denotes renewable electricity generation, and  $D_i$  and  $D_t$  are sets of fixed effects. In particular, the fact that the studied periods are short and devoid of significant commodity price fluctuations does not necessitate controlling for an interaction with the fuel cost ratio.  $\beta$  is the estimate of the average environmental value.

Let us begin with the findings for Texas. This state has been extensively analyzed due to the early availability of data and its electrical grid's isolation from neighboring states<sup>13</sup>. [Cullen \(2013\)](#) demonstrated that the marginal abatement effect of wind power was 0.47 tCO<sub>2</sub>/MWh over 2005–2007, with an average carbon intensity of the electricity mix being 0.74 tCO<sub>2</sub>/MWh. Comparing these two values indicates that during this period, the hours with wind energy production generally correspond to those when the carbon intensity of the marginal plant is below the average carbon intensity of the mix. This typically occurs when electricity generation is dominated by coal for the base-load, which drives the average intensity higher, but with a gas plant operating at the margin. For the period 2007–2009, [Kaffine et al. \(2013\)](#) estimated a similar marginal abatement effect of 0.52 tCO<sub>2</sub>/MWh. [Novan \(2015\)](#) found a marginal abatement effect of wind electricity of 0.63 tCO<sub>2</sub>/MWh over 2007–2011. From these findings, it can be concluded that wind power significantly reduces CO<sub>2</sub> emissions. However, its abatement effectiveness varies over time, depending on the average carbon intensity of the marginal plant during the period under investigation.

Regional disparities are also observed, as highlighted by [Callaway et al. \(2018\)](#) and [Fell and Johnson \(2020\)](#). Using market data for around ten representative American regions during 2018–2020, [Fell and Johnson \(2020\)](#) found that the marginal abatement effect of solar electricity varied significantly: between 0.28 tCO<sub>2</sub>/MWh in California and 0.62 tCO<sub>2</sub>/MWh in the Southeast region. For wind, the heterogeneity turned out to be even more pronounced, ranging from 0.17 tCO<sub>2</sub>/MWh in the New York region to 0.65 tCO<sub>2</sub>/MWh in the Midwest. The results in [Callaway et al. \(2018\)](#) are similar.

These regional differences are explained by the type of fuel typically at the margin in the area. By examining the technology actually displaced by renewables in each case,

---

<sup>12</sup>Meaning without rearrangement of the merit order due to fuel price shocks (with the exception of [Gugler et al. \(2021\)](#) where they control for fuel switching that happens for the UK case).

<sup>13</sup>There is none or almost none interconnection with other states.

the authors also validated that the marginal abatement factor is most pronounced where wind electricity replaces coal-fired generation.

But this does not mean that renewables deployed in a region predominantly dominated by coal generation necessarily avoid a lot of emissions. Recall that it is the carbon intensity of the marginal plant only that determines marginal abatement. This is by definition different from the average mix intensity, which has been extensively studied. Their values can even differ greatly. To illustrate this point, consider two scenarios: one where the energy mix is 99% clean but the marginal plant is highly polluting, and another where the mix is uniformly 100% moderately polluting. The environmental effectiveness of renewable generation would be substantially greater in the first scenario, suggesting a stronger case for targeted renewable subsidies.

The German case perfectly illustrates this idea. The country's electricity mix is dominated by coal, accounting for 35% of its capacity and 78% of its CO<sub>2</sub> emissions. However, (Gugler et al., 2021) estimated 0.38 tCO<sub>2</sub> avoided per additional MWh of wind energy in Germany for the period 2017-2018. It is slightly less for solar energy: 0.27 tCO<sub>2</sub>/MWh. During this period, gas was mostly at the margin.

In conclusion, these studies have measured empirically the abatement effectiveness of wind and solar power with a *static merit order*. Their results depend on which supply technology is displaced at the margin but they do not consider the fact that marginal emissions rates can change over time. Given that variations in the marginal costs of thermal power plants can influence their position in the merit order, it is not immediately clear what the impact of changes in the merit order would be on previous findings. In section 2.5, we thus apply an interaction term between the coal-to-gas marginal cost ratio and renewable energy infeed to assess its effect on marginal abatement. This approach is inspired by the methodologies employed in Gugler et al. (2021)'s analysis of Germany and England, and Fell and Kaffine (2018)'s study in the United States. We particularly build on the paper by Fell and Kaffine (2018), which to the best of our knowledge is the pioneering work in assessing the combined effect of declining gas prices and increasing wind generation on declining coal generation in the U.S. Although very similar in methodology to this paper, we quantify the total impact on emissions: while coal and its associated emissions indeed dropped sharply in the decade following the shale gas boom, it was replaced by gas. To capture the full effect, it is essential to consider the contribution to the environmental value of renewables that comes from avoiding gas-fired generation.

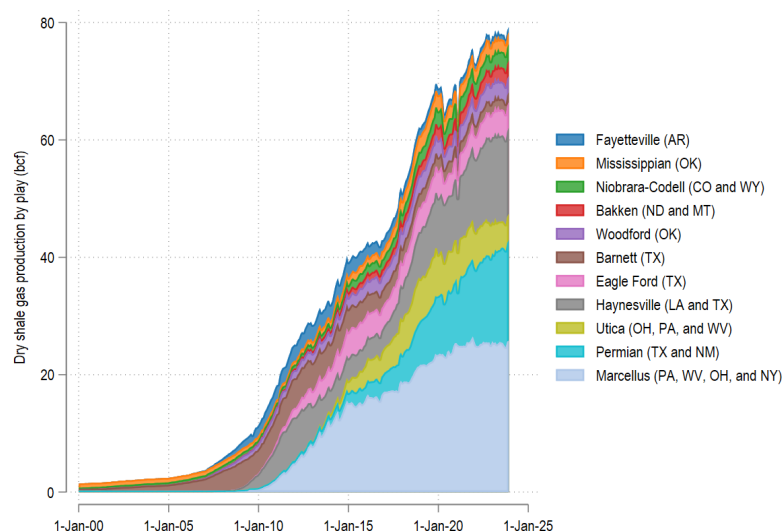
The following subsection provides a more detailed description of how this phenomenon of fuel switching occurred, fundamentally changing the structure of electricity supply in the US, and discusses the initial findings from the literature that used this shock as a natural experiment.

### 2.2.3 U.S. electricity mix and fuel switching

Fossil fuels still dominate the U.S. electricity supply mix, constituting approximately 60% of total production. The country remains heavily reliant on both natural gas and coal as shown by Figure 2.2 in the introduction. However, during the last two decades, the supply of electricity has undergone significant change. The "old mix" from the early 2000s was predominantly coal-driven, accounting for 1750 TWh in 2001, equivalent to 50% of total generation. Simultaneously, natural gas was utilized for 700 TWh, constituting 17% of total generation.

In 2008, the discovery of hydraulic fracturing disrupted the energy market. Figure 2.5 shows that shale gas production increased fivefold between 2010 and 2018.

Figure 2.5: Monthly dry shale gas production in the US by play in billions cubic feet



*Notes:* This graph displays the evolution of shale gas production by play. The onset of the shale gas boom is observed in 2008, marked by the beginning of a massive increase in exploitation. The data are sourced from the EIA.

This led to a plummeting gas prices, whereas coal prices remained stagnant as shown in Figure 2.1. These developments resulted in a massive substitution of coal by gas in the production of electricity with a significant increase in gas generation (Joskow, 2013) and a decline in coal generation (Fell and Kaffine, 2018). Specifically, coal generation peaked in 2007 and declined steadily thereafter. In 2015, gas generation surpassed coal generation for the first time. By 2019, coal generation accounted for only 880 TWh<sup>14</sup>, while gas generation amounted to almost 1600 TWh<sup>15</sup>.

This fuel switch occurred swiftly due to the availability of gas plant capacity. Indeed,

<sup>14</sup>23% of total generation

<sup>15</sup>38% of total generation

over-investment in gas plants took place between 1998 and 2005 (Lafrancois, 2012). Their total capacity had already exceeded that of coal in 2002, with the construction of over 200 GW. However, even with this capacity increase, generation did not follow at the time. The reason was that although the plants were built, gas prices remained too high to compete with coal, and a significant proportion of newly constructed gas plants were uneconomic. With the shale gas boom and the rapid decline in gas prices, the available capacity could be utilized immediately without waiting for new plant construction.

The American mix was thus revolutionized with the shale gas boom. Literature has delved into the impact of the induced fuel switching on CO<sub>2</sub> emissions. It is important because the power sector is a major contributor to US emissions, accounting for 32% of total US energy-related CO<sub>2</sub> emissions in 2019 (EIA, 2021). Despite stable total demand since 2008, Figure 2.3 shows that emissions peaked and have been steadily decreasing since. In the US, the average carbon intensity of a coal plant is 1.0 tonne of CO<sub>2</sub> per MWh, whereas it is 0.4 tonne for a gas plant. Gas and coal are the two primary polluters of the electricity mix, contributing to 93% of emissions despite representing only 60% of generation. Therefore, the literature commonly associates the emission decline with the phenomenon of fuel switching between gas and coal. Studies are divided between ex-post and ex-ante evaluations of the effect of fuel switching on emissions.

The first strand employs econometric models to conduct ex-post assessments of the effect of falling gas prices and fuel switching between coal and gas on average power system emissions (de Gouw et al. (2014), Knittel et al. (2015), Kim and Kim (2016), Cullen and Mansur (2017), Linn and Muehlenbachs (2018), Zhou and Huang (2021)). It should be noted that some papers use variations in CO<sub>2</sub> prices in areas where they exist. This is equivalent to variations in the ratio between coal and gas prices under the conditions described by Cullen and Mansur (2017), which we detail in the discussion section. The main findings from the literature are diverse, but there is a consensus that lower gas prices lead to a decrease in coal-fired generation and total CO<sub>2</sub> emissions.

This last result is not self-evident. The model presented by Acemoglu et al. (2023) indeed shows that in the short term, two opposing effects of the shale gas boom on emissions exist. On the one hand, the *substitution effect* corresponds to fuel switching from coal to gas that leads to a decrease in emissions. On the other hand, the *scale effect* describes how the shale gas boom makes overall electricity generation cheaper, which could lead to an increase in consumption and thus emissions if demand is elastic.

Let us review some results from this literature for the United States. de Gouw et al. (2014) show that emissions in 2012 were 23% lower than in 1997 due to fuel switching between coal and gas. During 2008-2012, when gas prices dropped by 70%, Cullen (2013) documents a 10% reduction in emissions from electricity generation in the short term.

Over the same period, the magnitude found by [Knittel et al. \(2015\)](#) is slightly higher, with a reduction of 19%-33%. This range is due to heterogeneity found according to the type of producer: on average 33% for investor-owned utilities and 19% for independent power producers. This difference is explained by the availability of gas plants to quickly replace coal generation at the time of the price shock. This idle capacity is more significant for investor-owned utilities in non-restructured markets due to the Averch-Johnson effect<sup>16</sup>. Although uneconomic before the shale gas boom, relatively more investment had taken place in gas capacity. Finally, let us mention [Linn and Muehlenbachs \(2018\)](#) who use data from the electricity mix between 2001 and 2012. They calculated that a 10% change in gas prices implied an average change of 0.93% in the carbon intensity of the mix. They also showed that this phenomenon was regionally heterogeneous, and regions with a significant coal-to-gas shift experienced the most reductions. To wrap up, the *substitution effect* described by [Acemoglu et al. \(2023\)](#) is the dominant factor here.

Other papers found similar results in other countries. In England, coal generation decreased by three-quarters and was replaced by gas due to the implementation of the Carbon Price Support, a carbon price for the power market. This led to a 55% reduction in CO<sub>2</sub> emissions in the country ([Gugler et al., 2021](#)).

The second strand of the literature explores the enabling conditions for coal to gas fuel switching and its associated CO<sub>2</sub> reduction potential using forecast models and ex-ante modelling ([Delarue and D'haeseleer \(2008\)](#), [Lafrancois \(2012\)](#), [Wilson and Staffell \(2018\)](#), [Rehfeldt et al. \(2020\)](#)). Their main findings are detailed in the Appendix 2.A.1.

The consensus from both ex post literature and forecasting models indicates that fuel switching has the potential, in most cases, to reduce total and average emissions associated with electricity generation.

Our paper is related to this body of literature but shifts the focus towards marginal emissions, specifically the carbon intensity of the marginal power plant at times when renewable electricity is generated.

In the following section, we develop a concise model that highlights the ambiguity surrounding the carbon intensity of the marginal plant<sup>17</sup>. This ambiguity, particularly how it changes with fuel prices, underscores the need for the subsequent empirical analysis.

---

<sup>16</sup>The Averch-Johnson effect is a regulatory phenomenon where regulated companies overinvest in capital to maximize their profitability, which is allowed to increase with the asset base.

<sup>17</sup>Despite the fact that the effect of the shale gas boom on the average carbon intensity of the mix is clearly negative.



## 2.3 Conceptual framework

In this section, we adapt the conceptual framework developed by [Gillingham et al. \(2021\)](#) to assess the environmental impact of electric vehicles and its variation with carbon pricing. However, our focus diverges as we concentrate on the supply side of electricity, rather than on demand. The model intentionally maintains simplicity to provide a clear understanding of the expected effects. Notably, we do not incorporate intricate operations such as non-economic dispatch and congestion constraints. Furthermore, this analysis assumes a purely inelastic demand.

The *initial model* corresponds to the conventional dispatch order prevalent during the high gas prices period before the shale gas boom. The merit order or electricity supply curve is composed, in sequence, of must-take generation sources (renewable electricity and nuclear) with a capacity of  $Cap_R$ , followed by coal-fired power plants utilized for base-load generation with a capacity of  $Cap_C$ . Subsequently, gas-fired power plants are included with a capacity of  $Cap_{NG}$ . Coal-fired power plants used for base-load generation have a constant marginal cost, whereas gas-fired power plants utilized for peak-load have an increasing marginal cost<sup>18</sup>. Initially, the marginal cost  $MC_C$  of coal plants is lower than that of gas plants  $MC_{NG}$ .  $e_{NG}$  and  $e_C$  are respectively the carbon intensities of natural gas and coal. For simplicity, we suppose that they are constant. Relaxing this simplification can be done. The demand  $D_0$  is such that gas is initially the marginal source. Diagrams 2.A4 in the Appendix illustrate the initial situation and each sub-case.

The key insight from our adaptation lies in recognizing that the carbon intensity of the marginal plant will shift when the cost ratio between coal and gas changes. This parameter drives the dynamics of our conceptual model. It is essential to note that while this model captures the fundamental interactions, it deliberately omits complex operational nuances for the sake of conceptual clarity.

### 2.3.1 Supply function

The quantity of electricity supplied by each technology based on the market price of electricity is as follows:

- $S_R(P) = Cap_R$

---

<sup>18</sup>This simplification in the model is justified by the fact that in reality, the segment of the merit order consisting of coal-fired plants is relatively flat compared to that of gas-fired plants, where efficiency varies considerably. This variation ranges from newer generation plants with relatively low marginal costs to older, obsolete plants whose costs can skyrocket.

$$\bullet S_C(P) = \begin{cases} 0 & \text{if } P < MC_C \\ [0, Cap_C] & \text{if } P = MC_C \\ Cap_C & \text{if } P \geq MC_C \end{cases}$$

$$\bullet S_{NG}(P) = \begin{cases} 0 & \text{if } P < MC_{NG}(0) \\ y(P) & \text{if } P \geq MC_{NG}(0) \end{cases}$$

With  $MC_{NG}(0)$  representing the minimum marginal cost of natural gas generation, and  $y(P)$  indicating the supply of gas-fired power plants with increasing marginal cost once the market price of electricity is high enough for them to be dispatched. The aggregated supply function is therefore:

$$S(P) = Cap_R + S_C(P) + S_{NG}(P) \quad (2.2)$$

$P^*$  the equilibrium price is determined by:

$$D_0 = S(P^*) \quad (2.3)$$

Diagram 2.A4a illustrates this initial state.

### 2.3.2 How does the carbon intensity of the marginal plant vary?

Let suppose that the price of gas decreases by  $\Delta p_g$  while the price of coal is constant. This equates to an increase in the coal over gas cost ratio. Natural gas generation is dispatched if the market price is higher than  $MC_{NG} - \Delta p_g$ , i.e., when  $P + \Delta p_g$  is higher than its initial marginal cost. Supplies from the different technologies become the following:

$$\bullet \hat{S}_R(P) = S_R(P)$$

$$\bullet \hat{S}_C(P) = S_C(P)$$

$$\bullet \hat{S}_{NG}(P) = S_{NG}(P + \Delta p_g)$$

And the new equilibrium price  $P^{**}$  is defined as follow:

$$D_0 = Cap_R + S_C(P^{**}) + S_{NG}(P^{**} + \Delta p_g) \quad (2.4)$$

Initially,  $P^* > MC_{NG}$  and  $MC_{NG}(0) > MC_C$ , indicating that the marginal power plant relies on natural gas. With the decrease in gas prices, three scenarios are possible depending on its magnitude:

1) Small decrease of the gas price, no fuel switching at the margin (2.A4b)

The decrease of the gas price is small and the marginal plant is still a natural gas peaker. It happens if

$$\Delta p_g < MC_{NG}(D_0 - Cap_R - Cap_C) - MC_C \quad (2.5)$$

In this scenario, some gas power plants may now have a marginal cost lower than that of coal and are therefore dispatched first, but the last unit of demand is still served by gas. Therefore, the carbon intensity of the marginal power plant is  $e_{NG}$ .

2) Moderate decrease of the gas price, coal is pushed to the margin (2.A4c)

If the decrease of the gas price is important enough, the coal generation is pushed to the margin. It occurs if

$$\Delta p_g \in [MC_{NG}(D_0 - Cap_R) - MC_C, MC_{NG}(D_0 - Cap_R - Cap_C) - MC_C] \quad (2.6)$$

And the carbon intensity of the marginal power plant is  $e_C$ , that is higher than  $e_{NG}$ .

3) High decrease of the gas price, coal becomes supra marginal (2.A4d)

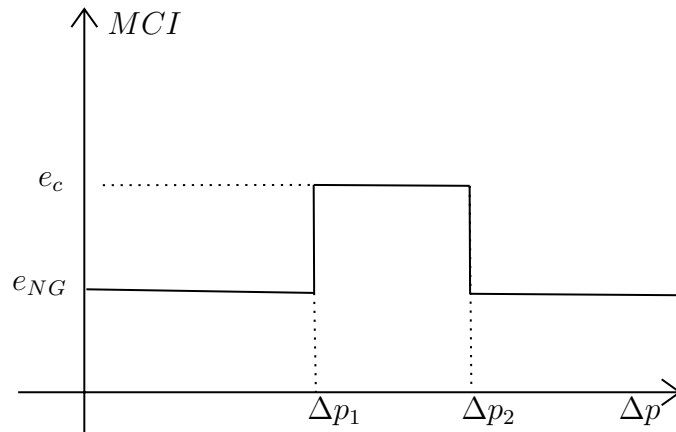
The decrease of the gas price is important enough for the coal to be pushed outside of the merit order. Coal is now supra marginal and no coal plants are used to meet demand. It is the case if

$$\Delta p_g \geq MC_{NG}(D_0 - Cap_R) - MC_C \quad (2.7)$$

Here, the intensity of the marginal plant is again  $e_{NG}$ . Coal power plants are no longer used for average demand but are reserved for rare high-demand situations or are decommissioned. Of course, for both the moderate decrease and high decrease scenarios, the average electricity generation carbon intensity decreases. This is directly beneficial for the environment. However, the environmental value of renewables varies. It is the highest for an additional MWh of renewable energy in the case of a moderate decrease. Figure 2.6 summarizes how the marginal carbon intensity varies.

This cute model does not directly illustrate the evolution of the environmental value of renewables, which relates to the carbon intensity of the marginal plant when renewables are generating. However, it does provide an insight into the expected effect. This difference also suggests that the marginal effects of demand and renewables on emissions measured in the empirical section might differ.

Figure 2.6: Marginal carbon intensity as a function of the price of gas



Notes: Until point  $\Delta p_1 = MC_{NG}(D_0 - Cap_R) - MC_C$ , the marginal plant is powered by gas with a relatively low carbon intensity. Between points  $\Delta p_1$  and  $\Delta p_2 = MC_{NG}(D_0 - Cap_R - Cap_C) - MC_C$ , it is powered by coal with a higher carbon intensity, and after point  $\Delta p_2$ , coal is out of merit and the marginal intensity reverts to that of gas.

In the Appendix 2.A.2, an extension of this conceptual part is presented, taking into account the effect of the increase in renewable electricity capacity. This could serve as a basis for future work. We are currently unable to empirically explore this aspect due to insufficient variation in renewable capacity at different gas price levels, which precludes precise evaluation of this treatment. Hourly data might enable this assessment.

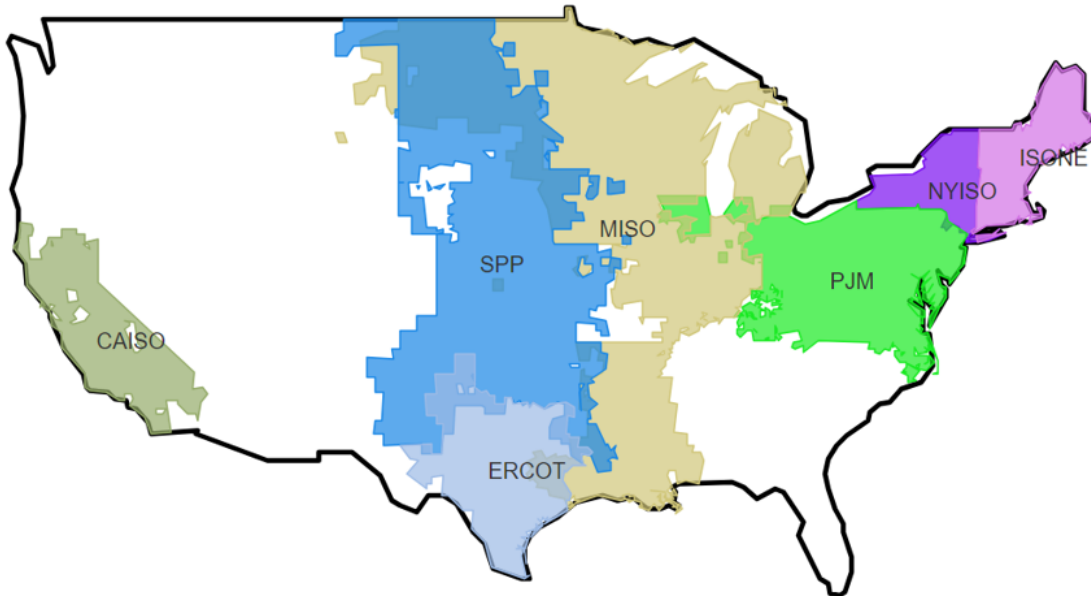
## 2.4 Data

We combine monthly plant-level data from January 2009 to December 2022 for three regions, encompassing natural gas, coal, and renewable energy generation. These three regions are associated with distinct Independent System Operators (ISOs): the Electric Reliability Council of Texas (ERCOT), the Midcontinent Independent System Operator (MISO), and the Southwest Power Pool (SPP)<sup>19</sup>.

We selected these regions because they are areas where potential fuel switching between gas and coal may occur. Indeed, other regions with renewable sources, such as the West Coast or the Northeast, already had very little coal generation as of January 2009. We initiate our analysis in 2009 to scrutinize the evolution of the environmental value of electricity in the post-shale gas boom era, a period we term the "Low Natural Gas Prices" era. This choice aligns with [Holladay and LaRiviere \(2017\)](#), who, employing a structural break model, identified December 2008 as the onset of the sustained decline in natural gas prices following the advent of fracking technologies. This section outlines the data sources, calculation steps, and key variables used in our analysis.

<sup>19</sup>Refer to the map 2.7 for locations.

Figure 2.7: Independent system operators map



### 2.4.1 Dependent Variables

The first dependent variables are derived from net generation data at the plant level from EIA Form 923. These are monthly plant-level data with information on the type and quantity of fuel used. Each plant is associated with the ISO to which it belongs using EIA Form 860M. In total, we have data for 432 coal and gas power plants for SPP, 399 for ERCOT, and 1217 for MISO, which is the largest market. The three regions have more gas plants than coal plants, but the latter are larger in size. Table 2.1 reports the mean and standard deviation of the variables used for each region. The first part shows that coal plants have a much higher average monthly net generation than gas plants. However, gas plants are more numerous in all three regions. Coal generation remains higher on average than gas generation over the period in all regions except ERCOT, where gas predominates.

To calculate the emissions from each plant, we multiply the monthly fuel quantity consumed in MMBtu provided by EIA Form 923 by the corresponding fuel's carbon content. We use values provided by the U.S. Environmental Protection Agency: 228.6 lbs/MMBtu for anthracite, 205.6 lbs/MMBtu for bituminous, 216.13 lbs/MMBtu for lignite, 214.13 lbs/MMBtu for subbituminous, and 117 lbs/MMBtu for natural gas. We then convert to metric tons by dividing by 2205.

Table 2.1: Summary Statistics

Variable	Units	SPP	ERCOT	MISO
<i>1. Dependent variables</i>				
Coal generation	GWh	169.98 (124.45)	409.97 (256.33)	101.34 (130.48)
Natural gas generation	GWh	16.47 (22.63)	67.88 (50.68)	22.66 (30.92)
CO <sub>2</sub> emissions	ktCO <sub>2</sub>	36.35 (53.87)	63.03 (77.33)	35.98 (69.72)
<i>2. Control variables</i>				
Coal-gas cost ratio		0.59 (0.23)	0.78 (0.27)	0.70 (0.26)
RE generation	GWh	12733.55 (7186.29)	7046.49 (3848.71)	11362.58 (5983.17)
Load	GWh	90061.02 (13833.97)	44582.46 (8850.85)	153519.8 (22038.36)
<i>3. Emissions rate</i>				
Emissions rate coal	tCO <sub>2</sub> /MWh	1.13 (0.06)	1.05 (0.022)	1.19 (0.18)
Emissions rate gas	tCO <sub>2</sub> /MWh	0.54 (0.09)	0.48 (0.01)	0.49 (0.05)
Average emissions rate	tCO <sub>2</sub> /MWh	0.64 (0.09)	0.52 (0.01)	0.65 (0.09)
<i>4. Other</i>				
Number of plants		432	399	1217
Number of coal plants		84	24	334
Number of gas plants		348	375	883

Notes: Means and standard deviations in parentheses for each ISO over the entire sample.

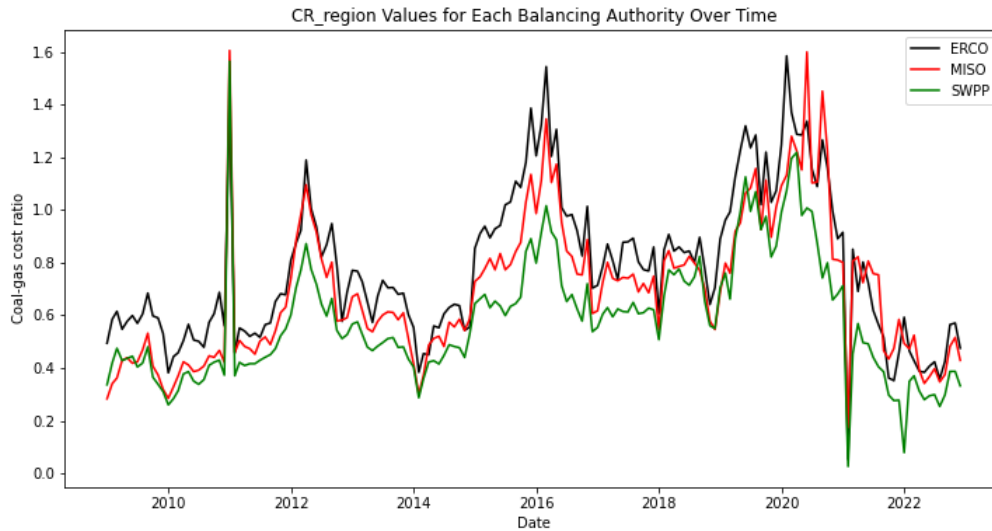
## 2.4.2 Control variables

The heat rate in MMBtu/MWh for each plant is obtained by dividing the monthly fuel quantity used in MMBtu by its monthly net generation in MWh. This value is then multiplied by the monthly fuel expenditures given by EIA Form 923, yielding the coal and gas prices for each plant in dollar per MWh of generated electricity. Regional gas and coal prices are also calculated by taking the monthly generation-weighted average product of plant-level heat rate and fuel expenditures.

The coal-over-gas cost ratio  $CR_{i,t}$  is calculated as follows: for coal plants, we divide their own monthly coal cost by the regional gas cost. For gas plants, we divide the regional coal cost by the plant's gas cost. Table 2.1 shows that the cost ratio faced by the plants is heterogeneous across regions. It is significantly lower in SPP. Since the coal price is similar and stable in all three regions, the differences in the level of the cost ratio

and its variations are primarily due to spatial and temporal variations in natural gas prices. These differences are likely attributable to the presence of wells in the region<sup>20</sup>. Additionally, the average ratio is below one, indicating that coal is less expensive than gas per MWh produced. Examining temporal variations with Figure 2.8, we observe significant fluctuations in the ratio. There is a co-movement for the three regions, but

Figure 2.8: Ratio of coal over gas fuel costs in each region during 2009-2022



*Notes: This graph displays the temporal evolution of the coal-to-gas cost ratio. It is calculated using the fuel prices in dollars per MWh of final electricity, allowing for direct comparisons. The cost ratio fluctuates significantly over time, crossing above and below 1, indicating that fuel switching is likely. No clear trend is observed during this period following the shale gas boom.*

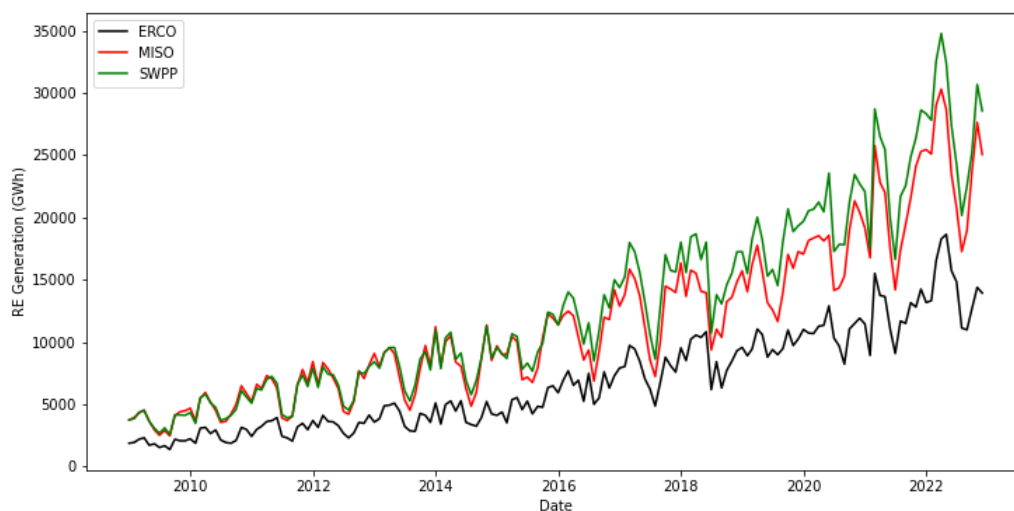
the cost ration in SPP consistently remains lower meaning gas is more expensive than in other regions as coal prices are similar. The ratio rises above 1 for 25% of the observed months, indicating that during these periods, coal is on average more expensive than gas per MWh of electricity produced. The rest of the time, the ratio is below 1, and coal is more cost-effective. We leverage these substantial variations over time for our empirical strategy.

For renewable generation, we gathered monthly wind and photovoltaic generation data using EIA Form 930.  $RE_{i,t}$  represents renewable electricity generation as the sum of wind and photovoltaic in GWh in the region of thermal power plant  $i$  for month  $t$ . Renewable generation is substantial in SPP and ERCOT, accounting for an average of 14% and 16% of regional demand, respectively. It is less in MISO, serving only 7% demand due to a

<sup>20</sup>See [https://www.eia.gov/dnav/ng/ng\\_prod\\_wells\\_s1\\_a.htm](https://www.eia.gov/dnav/ng/ng_prod_wells_s1_a.htm) for number and locations of producing gas wells in the US.

smaller number of wind turbines. Regarding temporal variations, Figure 2.9 illustrates a consistent evolution since the start of our observation period.

Figure 2.9: Renewable electricity monthly generation per region during 2009-2022 (GWh)



To control for regional electricity demand, we use the variable  $Load_{it}$ , representing the energy demanded in the region of power plant  $i$  during month  $t$  in GWh. Mean load values have remained relatively constant during the period studied.

## 2.5 Methodology

### 2.5.1 Identification strategy

We examine the marginal response of thermal power plant generation and  $CO_2$  emissions to increases in renewable electricity generation ( $RE_{i,t}$ ), changes in the coal-to-gas cost ratio ( $CR_{i,t}$ ) to control for possible fuel switching, electricity demand ( $L_{i,t}$ ), and the interactions among these factors. Particularly, we focus on how the impact of renewables on emissions varies with the cost ratio. The conceptual framework anticipates that the environmental value of renewables shifts with the relative prices of coal and gas, a relationship we aim to delineate.

The right-hand side (RHS) variables in our model, including both gas and coal prices for the cost ratio, demand, and renewable energy generation, are treated as exogenous. Gas price fluctuations are primarily influenced by supply shocks from the shale gas boom and its utilization in sectors other than electricity generation, which accounts for only



38 percent of its total consumption. Similarly, coal prices are predominantly determined by long-term contracts. Renewable generation is considered exogenous as it directly depends on variable weather conditions. We assume inelastic electricity demand, a standard hypothesis recently validated by [Hirth et al. \(2023\)](#).

The interactions between the cost ratio and renewable generation ( $RE_{i,t} \times CR_{i,t}$ ) are included to assess potential complementarity between these variables in relation to conventional generation fluctuations and CO<sub>2</sub> emissions. To account for non-linear relationships with terms of higher order than one, a flexible functional form is employed. Specifically, control variables are included at their levels, squared, and cubic forms, along with their interactions. We account for plant-level fixed effects with  $D_i$  to control for constant unobserved heterogeneity between units.  $D_t$  represents month-of-year and year time fixed effects to capture monthly patterns and seasonality as well as a linear time trend.

It should be noted that over the studied period, new power plants are built and start to operate, while others are temporally inactive for maintenance reason, or definitely retired. Without taking these capacity modifications into consideration, we would find biased estimates. Therefore, we need to estimate both the extensive margin, i.e. the on/off decision, and the intensive margin which is our dependant variable variations conditional on the plant being operational. To do so, we use a Heckman two-steps model that delivers the full effect of the control variables. It accounts for both the extensive and the intensive margins. This model first captures the decision to operate the plant or not. Then, it measures the effect of the control variables on the outcome variable, conditional on operating. The first stage estimates the selection equation with a probit regression (2.8) to determine the inverse Mills ratio  $\hat{\lambda} = \phi(\cdot)/\psi(\cdot)$ , with  $\phi$  the density function and  $\psi$  the cumulative distribution function, that measures the probability of operation for each plant  $i$ . We include lagged load variables as they are expected to affect  $z_{it}$ , and  $u_{it}$  is the mean-zero error term. More specifically, the selection equation writes as follows:

$$z_{i,t} = \beta_{CR}CR_{i,t} + \beta_{RE}RE_{i,t} + \sum_{j=1}^3 \sum_{k=1}^3 \beta_{RE^j.CR^k} RE_{i,t}^j CR_{i,t}^k + \sum_{n=0}^2 \beta_{L_{t-k}} L_{i,t-k} + D_i + D_t + u_{i,t} \quad (2.8)$$

with

$$z_{i,t} = \begin{cases} 1 & \text{if } y_{i,t} \geq 0 \\ 0 & \text{if } y_{i,t} = 0 \end{cases} \quad (2.9)$$

In the second stage, what would have been the naive equation is corrected with  $\hat{\lambda}$  to measure the intensive effect of RE infeed and of the cost ratio on  $y_{i,t}$ , i.e. the effect

conditional on operating. The intensity equation estimated with OLS is:

$$y_{i,t} = \beta_{CR}CR_{i,t} + \beta_{RE}RE_{i,t} + \sum_{j=1}^3 \sum_{k=1}^3 \beta_{REj.CRk} RE_{i,t}^j CR_{i,t}^k + \beta_L L_{i,t} + D_i + D_t + \beta_{\hat{\lambda}} \hat{\lambda}_{i,t} + u_{i,t} \quad (2.10)$$

These regressions are run with two different dependent variables, generation and  $CO_2$  emissions. For both cases, separate regressions are estimated for coal and gas-fired power plants generation and for each region.

Lastly, we calculate the marginal abatement effect of renewable generation, holding other variables at their means except the cost ratio that can vary.

## 2.5.2 Mapping of the cost ratio to carbon price

To map the variations in the cost ratio to changes in a fictional price of  $CO_2$ , we follow the method described by [Cullen and Mansur \(2017\)](#). The aim is to use quasi-experimental variations in the cost ratio to identify the potential impact of a carbon price that can also lead to fuel switching. For the US, this approach provides an insight into what might happen if such a price were introduced. It is also useful for extending our analysis to other areas, such as Europe, which is subject to the EU ETS, and to infer recommendations for these regions from our findings. The computational details and conditions for the validity of this method are provided in the [Appendix 2.A.3](#). Simply put, the concept is as follows. Due to their differing emission rates, instituting a carbon price would increase the marginal costs of coal-fired plants more than those of gas-fired plants, resulting in an increase in the coal over gas cost ratio. The idea is to start with a baseline for the prices of coal and natural gas and assess how much a given carbon price would increase the cost ratio.

For instance, if the price of coal is \$27.45 per MWh and that of gas is \$53.47 per MWh<sup>21</sup>, a carbon price of \$10 would increase the cost ratio from 0.51 to 0.65. [Table 2.2](#) illustrates this mapping between the carbon price and cost ratio for a carbon price range from \$0 to \$120 per tonne of  $CO_2$ .

<sup>21</sup>These values correspond to their long-run average costs estimated by the EIA (2012).

Table 2.2: Mapping cost ratio to carbon price

Carbon price	Gas price			Coal price			Cost ratio
	Raw price	Carbon	Total	Raw price	Carbon	Total	
<b>0</b>	53.47	0	53.47	27.45	0	27.45	<b>0.51</b>
<b>10</b>	53.47	5	58.47	27.45	11	38.45	<b>0.65</b>
<b>20</b>	53.47	10	63.47	27.45	22	49.45	<b>0.77</b>
<b>30</b>	53.47	15	68.47	27.45	33	60.45	<b>0.88</b>
<b>40</b>	53.47	20	73.47	27.45	44	71.45	<b>0.97</b>
<b>50</b>	53.47	25	78.47	27.45	55	82.45	<b>1.05</b>
<b>60</b>	53.47	30	83.47	27.45	66	93.45	<b>1.11</b>
<b>70</b>	53.47	35	88.47	27.45	77	104.45	<b>1.18</b>
<b>80</b>	53.47	40	93.47	27.45	88	115.45	<b>1.23</b>
<b>90</b>	53.47	45	98.47	27.45	99	126.45	<b>1.28</b>
<b>100</b>	53.47	50	103.47	27.45	110	137.45	<b>1.32</b>
<b>110</b>	53.47	55	108.47	27.45	121	148.45	<b>1.36</b>
<b>120</b>	53.47	60	113.47	27.45	132	159.45	<b>1.40</b>

*Notes:* Carbon price in \$/tonne CO<sub>2</sub>. Natural gas and coal raw prices are expressed in \$/MWh of electricity generated. 'Carbon' refers to the average carbon cost of a gas or coal power plant for each carbon price level. This is calculated by multiplying the carbon price by the average carbon intensity in tCO<sub>2</sub>/MWh. The totals obtained for both are then divided to derive the cost ratio. Following [Cullen and Mansur \(2017\)](#), the assumption that variable operating and maintenance costs are equal for both types of generators is made.

## 2.6 Results

This section presents the results obtained, first with the net generation per fuel as the dependent variable, followed by emissions. The coefficients derived represent the average effect of an additional GWh of renewable energy in a given ISO and of a variation in the cost ratio on a corresponding ISO plant. To enhance interpretability, these coefficients are also multiplied by the number of corresponding plants.

### 2.6.1 Electricity generation

Table [2.3](#) presents the regression estimates<sup>22</sup> on net generation.

<sup>22</sup>Marginal effects only are reported first. They are computed by averaging remaining covariates.

Table 2.3: Effect of the coal over gas cost ratio and renewable energy generation on fossil fuel generation

	SPP		ERCOT		MISO	
	Coal	Gas	Coal	Gas	Coal	Gas
Cost ratio	-34.8*** (10.1)	5.54*** (1.2)	-103*** (22.3)	6.95*** (1.51)	-17.4*** (3.37)	5.53*** (.776)
Renewables	-.00691*** (.00204)	-.000853*** (.000132)	-.00389 (.0027)	-.00224*** (.000307)	-.0028** (.00122)	-.0000925 (.000202)
Demand	.0028*** (.000519)	.000998*** (.000139)	.00574* (.0031)	.00238*** (.000288)	.00217*** (.000401)	.00074*** (.0000814)
Plant FE	Y	Y	Y	Y	Y	Y
Month FE	Y	Y	Y	Y	Y	Y
Year FE	Y	Y	Y	Y	Y	Y
State specific trends	Y	Y	Y	Y	Y	Y
Observations	9948	50844	3120	38388	39660	113472

Standard errors in parentheses

\*  $p < 0.1$ , \*\*  $p < 0.05$ , \*\*\*  $p < 0.01$

*Notes:* The dependent variable is the net generation of a power plant in GWh. Iso level monthly renewable generation and demand in GWh. The plant-level cost ratio is dimensionless. Standard errors clustered at the plant level in parenthesis. \*\*\* $p < 1\%$ , \*\* $p < 5\%$ , \* $p < 10\%$ .

The coefficient estimates on the cost ratio between coal and gas indicate a significantly negative impact on coal-based generation and a positive impact on gas-based generation. This is intuitive, as a higher coal price relative to the gas price increases the marginal costs of coal generation, making gas generation relatively cheaper.

In response to an increase in the cost ratio by one standard deviation<sup>23</sup>, the average coal plant in SPP reduces its production by 8.0 GWh per month, in ERCOT by 27 GWh, and in MISO by 4.5 GWh. Conversely, the average gas plant increases its production by 1.27 GWh per month in SPP, 1.87 GWh in ERCOT, and 1.43 GWh in MISO.

Moreover, both coal- and gas-fired electricity production react negatively to an increase in renewable electricity infeed by one GWh.

The average coal plant in SPP decreases its output by 69.1 MWh, in ERCOT by a

<sup>23</sup>For SPP, ERCOT, and MISO, this is respectively 0.23, 0.27, and 0.26.

non significant 3.89 MWh, and in MISO by 2.8 MWh. This translates to an aggregate reduction in coal-fired electricity output across all coal plants<sup>24</sup> by 0.58 GWh in SPP, a non significant 0.09 GWh in ERCOT, and 0.93 GWh in MISO. All aggregate effects are also reported Table 2.5.

Regarding gas generation, the average plant decreases its output by 0.853 MWh in SPP, 2.24 MWh in ERCOT, and a non-significant 0.09 MWh in MISO. The corresponding aggregate effects across all gas plants<sup>25</sup> result in a decrease of 0.29 GWh in SPP, 0.84 GWh in ERCOT, and a non-significant 0.05 GWh in MISO.

Evaluated across all fossil-fuelled power plants, a change in renewable-based electricity by one GWh is associated with an output decreases by 0.87 GWh in SPP, 0.93 GWh in ERCOT and 0.98 GWh in MISO. The order of magnitude of our results provides confidence in our estimates: 1 GWh of renewable energy nearly avoids 1 GWh of thermal generation. A possible explanation for a value differing from 1-to-1 could be the offset of other technologies such as hydro or nuclear. Since these technologies are carbon-free, the effect on emissions would not be biased. Another explanation might be the incompleteness of our sample with missing fossil fuel units. Yet another possibility is that even though regions are almost entirely isolated, a small amount of electricity can still be exchanged with neighboring regions. Thus, the difference between our results and a 1-to-1 ratio could be related to exports, and thereby avoiding polluting generation in other regions. In any case, our results are still close to 1, and we do not concern ourselves further with these possibilities.

The effect of demand on the net generation of each fuel type is positive and of the same order of magnitude as that of renewables. The difference in values is due to the discrepancy between the hourly patterns of renewable energy and those of electricity demand. A detailed examination of this difference requires hourly data, which we leave for future research.

## 2.6.2 Environmental value of renewable generation

The electricity substitution effects highlighted in the previous subsection naturally also translate into changes in CO<sub>2</sub> emissions, which are presented in Table 2.4.

We find that a higher cost ratio decreases total fossil-based emissions. Specifically, in response to a one-standard-deviation increase in the cost ratio, emissions from the average fossil-fueled plant decrease by 0.85 kt CO<sub>2</sub> in SPP, 1.50 kt CO<sub>2</sub> in ERCOT and 0.69 kt CO<sub>2</sub> in MISO. This reduction in emissions illustrates that the decrease in gas prices has made coal less competitive, which has lowered the average emissions of the mix due to

---

<sup>24</sup>There are 84 in SPP; 24 in ERCOT, 334 in MISO.

<sup>25</sup>There are 348 in SPP; 375 in ERCOT, and 883 in MISO.

Table 2.4: Effect of the coal over gas cost ratio and renewable energy generation on emissions

	<i>Emissions (ktCO<sub>2</sub>)</i>		
	(1) SPP	(2) ERCOT	(3) MISO
Cost ratio	-3.72* (1.91)	-5.56** (2.61)	-2.66*** (1.02)
Renewables	-.00141*** (.000354)	-.00103*** (.000259)	-.000756** (.000315)
Demand	.000888*** (.000115)	.00151*** (.000285)	.000873*** (.000117)
Plant FE	Y	Y	Y
Month FE	Y	Y	Y
Year FE	Y	Y	Y
State specific trends	Y	Y	Y
Observations	60792	41508	153132

*Notes:* The dependent variable is the emissions of a power plant in ktCO<sub>2</sub>. Iso level monthly renewable generation and demand in GWh. The plant-level cost ratio is dimensionless. Standard errors clustered at the plant level in parenthesis. \*\*\* $p < 1\%$ , \*\* $p < 5\%$ , \* $p < 10\%$ .

the higher carbon intensity of coal.

Moreover, one additional GWh of renewable electricity offsets on average 1.41 tCO<sub>2</sub> from a fossil-fueled plant in SPP, 1.03 tCO<sub>2</sub> in ERCOT, and 0.75 tCO<sub>2</sub> in MISO. Aggregating for each region, this corresponds to an average environmental value of renewable energy of 0.60 ktCO<sub>2</sub>/GWh in SPP, 0.40 ktCO<sub>2</sub>/GWh in ERCOT, and 0.91 ktCO<sub>2</sub>/GWh in MISO. These values are consistent with the results from the previous subsection. The environmental value of renewables is highest in MISO<sup>26</sup>, which is the region where the most coal generation is offset. This is followed by SPP, where 0.60 ktCO<sub>2</sub>/GWh corresponds to a mix where renewable generation alternatively offsets coal or gas. Further exploration of the specific times each type of generation is offset requires hourly data. Finally, ERCOT<sup>27</sup> has the lowest average environmental value. Gas is predominantly marginal at the time of renewable production. This is consistent with previous estimates for Texas<sup>2829</sup>

The environmental value of renewable energies thus varies significantly across regions, by as much as a factor of two, which is substantial. Subsidizing 1 MWh of renewable

<sup>26</sup>In this region, the carbon intensity of coal is 1.19 tCO<sub>2</sub>/MWh.

<sup>27</sup>In this region, the carbon intensity of gas is 0.48 tCO<sub>2</sub>/MWh.

<sup>28</sup>Texas corresponds to ERCOT.

<sup>29</sup>Between 0.47 tCO<sub>2</sub>/MWh and 0.63 tCO<sub>2</sub> according to the papers and periods studied (Cullen, 2013; Kaffine et al., 2013; Novan, 2015). The results of these studies are detailed in Section ??

energy in a the MISO area abates nearly one tonne of CO<sub>2</sub>, but only 0.4 tons in a region like ERCOT. This raises the question of whether to adjust the level of subsidies based on this difference in efficiency. This issue is further discussed in Section 2.7.

Table 2.5: Aggregate effect of renewable energy deployment

<i>Aggregate effect on</i>	(1)	(2)	(3)
	SPP	ERCOT	MISO
Coal generation	-0.58*** (0.17)	-0.09 (0.06)	-0.93** (0.40)
Gas generation	-0.29*** (0.04)	-0.84*** (0.11)	-0.05 (0.12)
Emissions	-0.60*** (0.15)	-0.40*** (0.10)	-0.91** (0.38)

*Notes:* This table displays the aggregated effect of renewable energy (RE) on generation by fuel type and emissions for each region. This corresponds to the coefficients from Tables 2.3 and 2.4 multiplied by the number of plants concerned in the ISO. The values for the effect on generation can be interpreted as the number of MWh avoided in the ISO for each additional MWh of renewable energy. Those for the effect on emissions represent the number of tons of CO<sub>2</sub> avoided per additional MWh of renewable energy. These values are suitable for comparison with the literature. Standard errors clustered at the plant level in parenthesis. \*\*\* $p < 1\%$ , \*\* $p < 5\%$ , \* $p < 10\%$ .

### 2.6.3 Heterogeneity in the environmental value of renewable generation as a function of the cost ratio

The preceding results shed light on the regional heterogeneity of the environmental efficiency of renewables for an average cost ratio. This subsection presents estimates from regression 2.10 with varying cost ratios and associated carbon prices. The value of marginal emissions avoided per additional unit of renewable is obtained using the following derivative:

$$MEA(RE, CR) = \frac{\partial e(RE, CR)}{\partial RE} \tag{2.11}$$

with all other variables at their means.

As renewable generation interacts with the cost ratio, the squared cost ratio, and the cubed cost ratio, the marginal effect is a nonlinear function of the cost ratio. Figure 2.10 displays the estimates for each ISO as a function of the carbon price, which is mapped to the cost ratio using the method introduced in subsection 2.5.2. Table 2.A1 in the Appendix

provides the correspondence with the cost ratio, the precise values of the estimates, and the standard errors. All coefficients are significant at least at the 5% level.

The figure reads as follows. It shows the estimates of the average monthly CO<sub>2</sub> offset in tonnes by an additional MWh of renewable energy for a power plant on the left y-axis, and of the coal generation and gas generation offset on the right y-axis.

The first is for the SPP region. The marginal effect of renewables there is negative and decreases with the carbon price. In the absence of a carbon price<sup>30</sup> mechanism, it is -1.38 tCO<sub>2</sub> per GWh of additional renewable generation. This corresponds to an aggregated effect across all power plants in the region of -0.59 tCO<sub>2</sub>/MWh. As the carbon price increases (the relative price of gas decreases), the value rises to -2.32 tCO<sub>2</sub>/GWh i.e., in aggregate, -1.0 tCO<sub>2</sub>/MWh for a carbon price of \$120/tCO<sub>2</sub>. The carbon price pushes coal plants to the margin, which are then offset by renewable generation. In this region, there is therefore a complementarity between policies subsidizing renewables and the fictional carbon price. This corresponds to a switch from case from "1) Small decrease of the gas price, no fuel switching at the margin" to "2) Moderate decrease of the gas price, coal is pushed to the margin" in the conceptual section 3.3.

The pattern for ERCOT is similar. The generation offset curves illustrate the fuel switching implied by an increase in the CO<sub>2</sub> price. The environmental value of renewables is -0.998 tCO<sub>2</sub>/GWh or in aggregate -0.39 tCO<sub>2</sub>/MWh for a carbon price of zero and increases up to -1.31 tCO<sub>2</sub>/GWh or in aggregate -0.52 tCO<sub>2</sub>/MWh for \$120/tCO<sub>2</sub><sup>31</sup>.

MISO illustrates the transition from "1) Small decrease of the gas price, no fuel switching at the margin" to "2) Moderate decrease of the gas price, coal is pushed to the margin" then to "3) High decrease of the gas price, coal becomes supra marginal". For a carbon price of \$0/tCO<sub>2</sub>, 0.651 tCO<sub>2</sub>/GWh or 0.79 tCO<sub>2</sub>/MWh in aggregate are avoided. As the carbon price increases, coal becomes increasingly marginal when renewables produce. A maximum is reached for a carbon price of \$40/tCO<sub>2</sub><sup>32</sup> with a maximum marginal abatement of -0.827 tCO<sub>2</sub>/GWh or -1.0 tCO<sub>2</sub>/MWh in aggregate. Coal is at this level of carbon price on the margin most of the time when renewables produce. Then the environmental value decreases to -0.640 tCO<sub>2</sub>/GWh i.e., in aggregate -0.77 tCO<sub>2</sub>/MWh. Coal becomes too uneconomical compared to gas and is increasingly often out of merit. In MISO, the complementarity between support for renewables and a high carbon price is thus more

---

<sup>30</sup>Here, we consider the carbon price and gas price interchangeably. A low carbon price corresponds to a high gas price (high gas price era, pre-shale gas boom), while a high carbon price corresponds to a low gas price (low gas price era, post-shale gas boom).

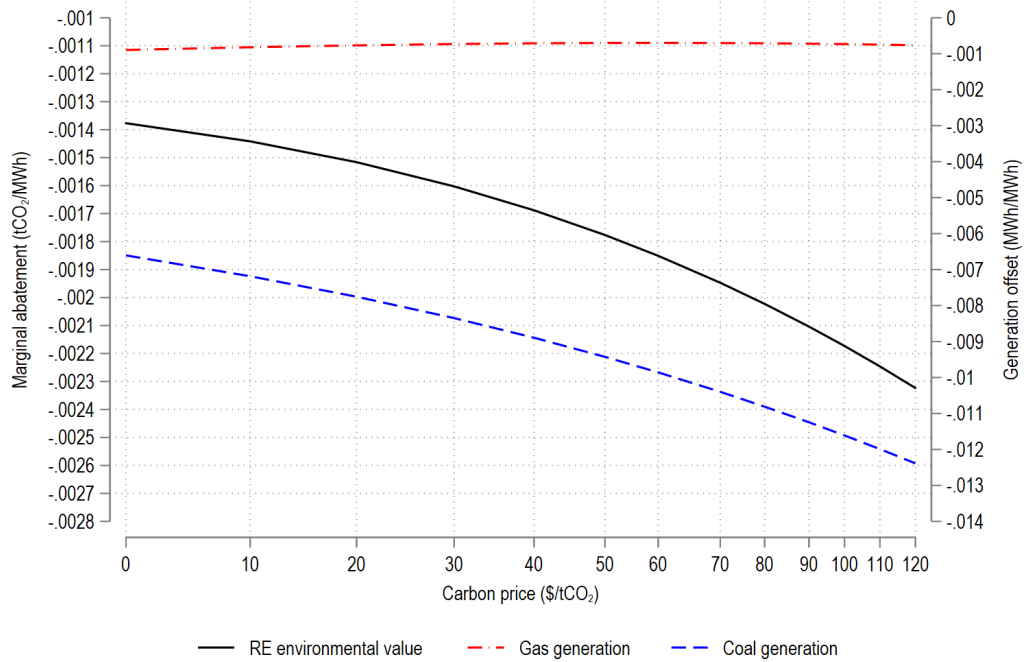
<sup>31</sup>The curves for the generation effect can be misleading. It is indeed the marginal effect on a power plant that is calculated. There are 24 coal plants and 375 gas plants in ERCOT, and it is predominantly the gas plants that remain on the margin when renewables are producing, which explains the environmental value close to the carbon intensity of a gas plant.

<sup>32</sup>This corresponds to a cost ratio of 0.97. For reference, the average cost ratio in MISO is 0.70.

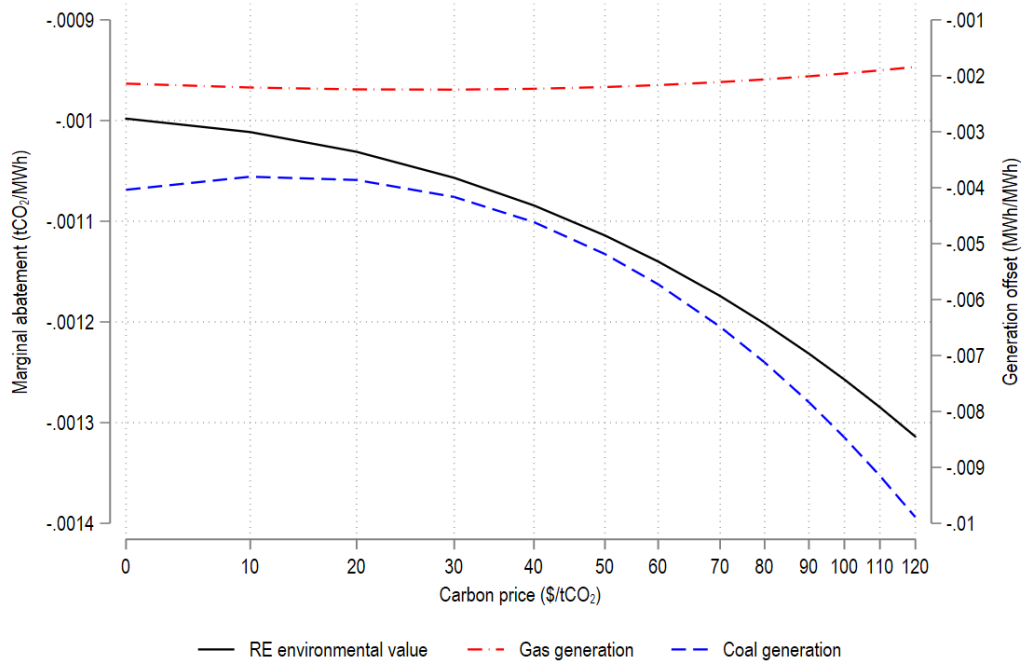


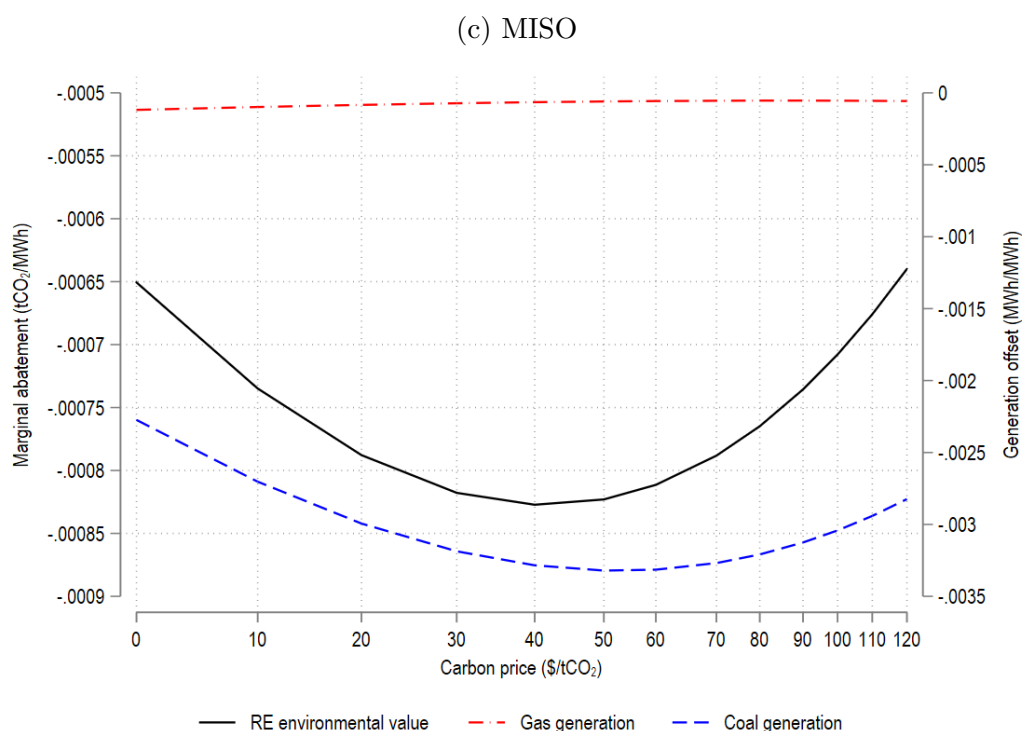
Figure 2.10: Renewable generation environmental value with varying carbon price

(a) SPP



(b) ERCOT





*Notes:* The environmental value is read from the left y-axis, and the fossil fuel generation offset from the right y-axis. The carbon price is derived from the mapping explained in subsection 2.5.2. Tables with coefficients, standard errors, and corresponding cost ratios are provided in the Appendix. The values should be interpreted as the average effect on a plant in the region of a marginal increase in renewable generation for a given carbon price.

nanced. Their interaction becomes negative in terms of emission reductions beyond the threshold mentioned above.

These results illustrate that the CO<sub>2</sub> marginal abatement effect changes over time, driven by shifts in the merit order. Specifically, the presence of a carbon price can make the deployment of renewables more or less effective. Therefore, considering only a short-term value for the design of public support policies, while overlooking this co-dependence, can be sub-optimal.

## 2.7 Discussion

This section derives from our findings two policy recommendations aimed at enhancing the deployment efficiency of renewable energies for emission reduction. These recommendations are termed *Location, Location, Location* and *Think One Step Ahead*.

### 2.7.1 Location, Location, Location - Geographic Differentiation in Renewable Energy Policy

The results of this paper corroborate the existing literature presented in subsection 2.6.2 and highlight significant regional disparities in the environmental benefits of renewable energies. Policy implications can be drawn from this heterogeneity. Since the primary goal of renewables is to reduce CO<sub>2</sub> emissions, we propose prioritizing deployment in regions where renewables have the highest environmental value. Subsidy policies should consider this variability to maximize effectiveness.

This first recommendation echoes the geographically differentiated support strategies advocated by Callaway et al. (2018) and Fell and Johnson (2020). The title of this subsection, which is also given to the associated recommendation — *Location, Location, Location* — is drawn from the very telling title of Callaway et al. (2018)’s paper. Their decision criterion for the level of incentive corresponds to the ranking of environmental values calculated in this paper in subsection 2.6.2. Specifically, renewable energy subsidies should be more significant in regions like MISO, followed by SPP and ERCOT, reflecting each area’s respective environmental benefit ranking.

We join Callaway et al. (2018) and Fell and Johnson (2020) in this recommendation but add a nuance. The ordering of regions based on the previous reflection only is valid in the short run with stable power mix and energy prices. We complement this recommendation — *Location, Location, Location* — by including considerations related to changes in environmental value due to shifts in relative fuel prices — *Think One Step Ahead*.

### 2.7.2 Think One Step Ahead

Beyond regional differentiation, we advocate for forward-looking policy designs that anticipate shifts in environmental values driven by market dynamics. Specifically, are there more or less polluting infra-marginal assets that could become marginal with changes in fuel prices, CO<sub>2</sub> prices, or increase in renewable capacity<sup>33</sup>? For the regions studied in this paper, this implies assessing if there remains any infra marginal coal generation.

For instance, consider the infra-marginal coal assets in a region like MISO. Here, maintaining high subsidies until these assets become marginal —triggered by a carbon price reaching \$40/tCO<sub>2</sub>— and then gradually reducing support can optimize emission reductions over time. The reduction should occur once the minimum is passed in anticipation of a convergence towards an abatement on the order of the carbon intensity of gas plants replacing coal plants for base-load as time progresses. This approach not

---

<sup>33</sup>Considerations on this last aspect, which we do not assess empirically in this paper, are formalized in Section 2.A.2 in the Appendix.

only aligns with short-term environmental efficiency but also adapts to long-term goals, ensuring that renewable energies provide maximum benefit as energy markets evolve.

### 2.7.3 Policy Implications for Other Countries

Mapping the variations of the cost ratio with a fictional carbon price allows us to discuss implications for regions with similar prices and electricity mixes<sup>34</sup>. For example, in Europe, electricity generation is subject to the EU ETS. Until now, little or no fuel switching has been observed as discussed in [Gugler et al. \(2021\)](#). Generally, gas generation is more expensive than coal.

To illustrate how the recommendations *Location, Location, Location* and *Think One Step Ahead* can differ, let us take Spain and Germany as examples. They are leaders in Europe in the deployment of renewables and rely on conventional generation at the margin<sup>35</sup>. In both countries, the marginal plant is mostly gas-powered. Thus, the short-term environmental value of renewable is the same in both countries. The recommendation *Location, Location, Location* suggests a similar level of subsidy in both countries. But Spain has already almost completely phased out coal generation. Therefore, an increase in carbon price<sup>36</sup> would not increase the environmental value of renewable. This corresponds to the part of the curve in [Figure 2.10c](#) above \$40/tCO<sub>2</sub><sup>37</sup>. On the other hand, Germany still uses a significant part of infra-marginal coal generation. An increase in the carbon price would thus increasingly push coal to the margin. This matches the cases observed in SPP [Figure 2.10a](#) and ERCOT [Figure 2.10b](#), and for MISO to the left of the \$40/tCO<sub>2</sub> threshold [Figure 2.10c](#).

The recommendation *Think One Step Ahead* thus proposes to relatively favor the deployment of renewable energy in Germany more than in Spain. The precise optimal design of a support policy corresponding to this recommendation is left for future work. Of course, European countries have energy sovereignty and decide their mixes and strategies for promoting renewable. However, we argue that community-level consultations must take place for optimal deployment.

### 2.7.4 Avenues for future research

This analysis primarily addresses the synergies between carbon pricing and renewable deployment concerning CO<sub>2</sub> emissions. Other aspects such as impacts on electricity prices, local pollution, grid stability, or increased congestion are beyond this study's scope but

<sup>34</sup>i.e., thermal generation with heterogeneous carbon intensity

<sup>35</sup>See [Abrell et al. \(2019a\)](#) for a precise description of electricity generation in both countries.

<sup>36</sup>Or renewable capacity as shown in the conceptual part.

<sup>37</sup>This value is specific to the mix of this region and may be very different for others.

represent avenues for future research. Thus, our recommendations should be viewed as part of a broader strategic framework aiming to compile a comprehensive study of the costs and benefits associated with deployment. It still requires further empirical validation and theoretical expansion.

## 2.8 Conclusion

The United States leads in deploying renewable energies aimed at combating climate change. The environmental value of these energies primarily depends on the carbon intensity of the technologies they replace, dictated by the sorting of power plants in the merit order.

This study examines the variability in environmental value — both regional and induced by shifts in relative prices of coal and natural gas following the shale gas revolution. These price changes, mapped to fictive CO<sub>2</sub> price variations for better interpretability, lead to fuel switching, thus rearranging the merit order and altering the regional environmental values of renewables.

We find that from low to moderate carbon prices, renewables tend to offset gas generation, yielding a relatively low environmental value. As the carbon price increases, fuel switching initially pushes coal to the margin, enhancing the environmental value. This highlights a synergy between two policies aimed at reducing emissions, namely, promoting renewable energies and implementing a carbon pricing strategy. However, if the carbon price is too high, coal becomes uneconomic (out of merit), diminishing the environmental value as renewables replace lower-emission gas generation instead of coal generation, indicating a threshold where these policies are no longer complementary.

Understanding both geographic variations and the impact of fuel or CO<sub>2</sub> prices is crucial for designing optimal support policies to reduce emissions swiftly and cost-effectively. Based on our empirical observations, we propose two strategic recommendations:

**Location, Location, Location:** More vigorously promote renewable energies in regions where their environmental values are highest.

**Think One Step Ahead:** Anticipate future changes in regional environmental values and prioritize areas where these values are likely to increase.

By aligning renewable energy support with these dynamic environmental values, policymakers can more effectively leverage renewables as a pivotal tool in the global effort to mitigate climate change.

## 2.A Appendices

### 2.A.1 Fuel switching enabling conditions

In coal-reliant countries, [Wilson and Staffell \(2018\)](#) demonstrate that fuel switching in the power sector from coal to natural gas generation could deliver rapid carbon savings on the order of 1 GtCO<sub>2</sub> per year globally. This represents 3 percent of the world's annual CO<sub>2</sub> emissions, which is highly significant. Even if this potential is highly sensitive to the electricity mix of each country<sup>38</sup>, it can be assessed regionally. They also show that the enabling conditions for rapid fuel switching are the presence of spare generation, fuel supply chain capacity, low enough natural gas prices and political will with a carbon price introduction for example. Sufficient idle capacity in gas-fired power plants is required for the switch to natural gas to be possible. This is actually what has been observed in the case of the United States where rapid coal to gas fuel switching happened. Globally, they assess that 40-50 percent of the coal-based electricity generation could be switched to gas. On average, each MWh switched from coal to natural gas reduces CO<sub>2</sub> emissions by 59 percent. In 2012, the potential reduction in CO<sub>2</sub> emissions in the electricity sector due to fuel switching was estimated at 23-42%. This would lead to an overall reduction of US CO<sub>2</sub> emissions by 9-17 percent, as reported by [Lafrancois \(2012\)](#). He also agrees that the limiting factor in this process is the existing capital stock in natural gas-fired power plants.

Significant CO<sub>2</sub> reduction potential exists also in the electricity sectors in Germany, Spain, and Italy in Europe, as stated by [Delarue and D'haeseleer \(2008\)](#). Accordingly, [Rehfeldt et al. \(2020\)](#) assessed the fuel switching potential for medium-term emission reduction. Their primary conclusion is that energy costs play the most significant role in determining the choice of technology. Their results are thus in line with the empirical literature. They have calculated that, under the condition of significant economic pressures<sup>39</sup>, combining fuel switching and energy efficiency measures could achieve emission reductions of about 50 percent by 2030.

### 2.A.2 Conceptual framework extension: Effect of the increase in renewable electricity capacity

In this section, we denote  $\Delta_{CRE}$  as an increase in renewable capacity. We are interested in the overall impact of this increase on emissions for each sub-case of gas price changes. We already know that marginally, an additional unit of renewable energy reduces emissions

---

<sup>38</sup>renewables, nuclear, gas, coal

<sup>39</sup>300 euro/ton of CO<sub>2</sub>

by  $e_{NG}$  in the 'small decrease' scenario (case 1) and 'high decrease' scenario (case 3), while it reduces them by  $e_C$  in the 'moderate decrease' scenario (case 2). Let us express the total CO<sub>2</sub> abatement effect of  $\Delta_{CRE}$  for each sub-case.

1) Small decrease of the gas price, no fuel switching [2.A1](#)

Let us define  $\alpha_1 = D_0 - (Cap_R + Cap_C + S_{NG}(MC_C))$  the quantity of energy supplied from natural gas plants with a marginal cost higher than that of coal plants. Possibly,  $S_{NG}(MC_C)$  is already dispatched before coal generation. The case with no fuel switching occurs when  $S_{NG}(MC_C) = 0$ .  $\beta_1 = D_0 - (Cap_R + S_{NG}(MC_C))$  is the previous quantity  $\alpha_1$  plus the electricity produced using coal. Lastly,  $\gamma = D_0 - Cap_R$  is the total electricity coming from gas and coal to meet the demand  $D_0$ . The total amount of CO<sub>2</sub> mitigated, depending on the magnitude of the increase in renewable capacity, will be:

- If  $\Delta_{CRE} < \alpha_1$  :  $\Delta Emissions = \Delta_{CRE} \times e_{NG}$
- If  $\beta_1 \geq \Delta_{CRE} \geq \alpha_1$  :  $\Delta Emissions = \alpha_1 \times e_{NG} + (\Delta_{CRE} - \alpha_1) \times e_C$
- If  $\gamma \geq \Delta_{CRE} \geq \beta_1$  :  $\Delta Emissions = (\Delta_{CRE} - Cap_C) \times e_{NG} + Cap_C \times e_C$
- If  $\Delta_{CRE} > \gamma$  :  $\Delta Emissions = (\gamma - Cap_C) \times e_{NG} + Cap_C \times e_C$

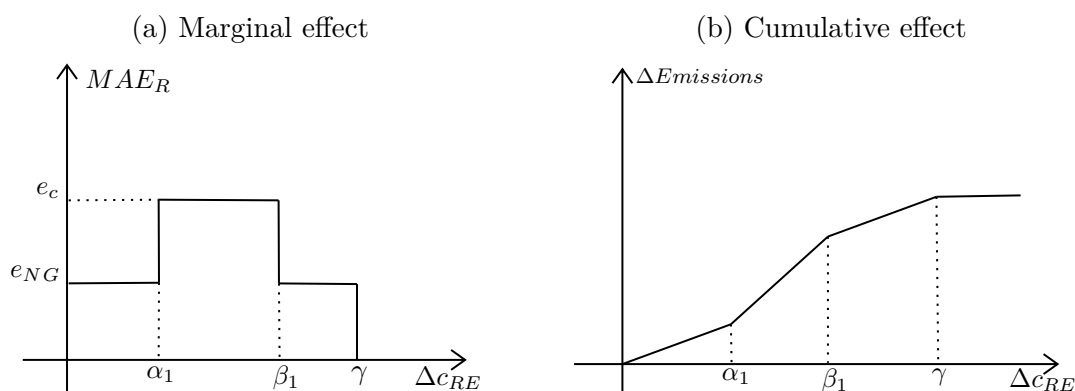
The first units of added generation offset natural gas peakers and their associated emissions. Within this range, the environmental value of renewable energy is  $e_{NG}$ . Then, some coal is offset if enough renewable capacity is deployed. The environmental value of renewable energy has increased to  $e_C$ . After the coal power plants, some gas power plants that had switched with coal due to a lower marginal cost are rendered uneconomical by the addition of capacity. The environmental value decreases back to  $e_{NG}$ . When the additional capacity is significant enough to meet the demand, the marginal abatement effect drops to zero.

2) Moderate decrease of the gas price [2.A2](#)

In this scenario, the moderate decrease in gas prices makes gas power plants competitive enough for coal to be pushed to the margin. The quantity of CO<sub>2</sub> avoided by additional renewable energy is now:

- If  $\Delta_{CRE} < \beta_1$  :  $\Delta Emissions = \Delta_{CRE} \times e_C$
- If  $\gamma \geq \Delta_{CRE} \geq \alpha_1$  :  $\Delta Emissions = \beta_1 \times e_C + (\Delta_{CRE} - \beta_1) \times e_{NG}$

Figure 2.A1: Effect of additional RE capacity for a small decrease of the gas price

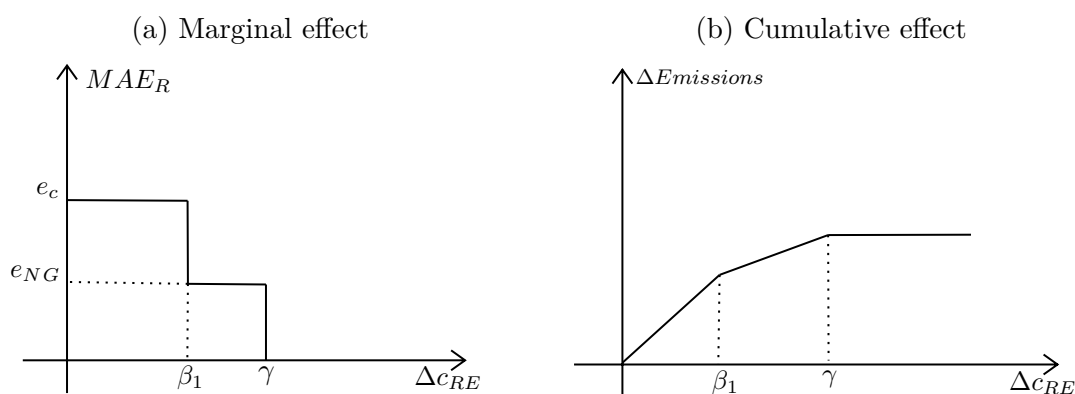


Notes: This graph shows marginal and cumulative effect of a renewable capacity increase for a small decrease of the gas price.

- If  $\Delta C_{RE} > \gamma$ :  $\Delta Emissions = \beta_1 \times e_c + (\gamma - \beta_1) \times e_{NG}$

At first, renewable energy offsets coal, which is marginal. Its environmental value is therefore  $e_C$ . With the increase in renewable capacity, coal is completely pushed out of the merit order, and renewable energy offsets gas power plants. Its environmental value decreases to  $e_{NG}$ . Above  $\gamma$ , all the possible abatement solutions have been exhausted.

Figure 2.A2: Effect of additional RE capacity for a small decrease of the gas price



Notes: This graph shows marginal and cumulative effect of a renewable capacity increase for a moderate decrease of the gas price.

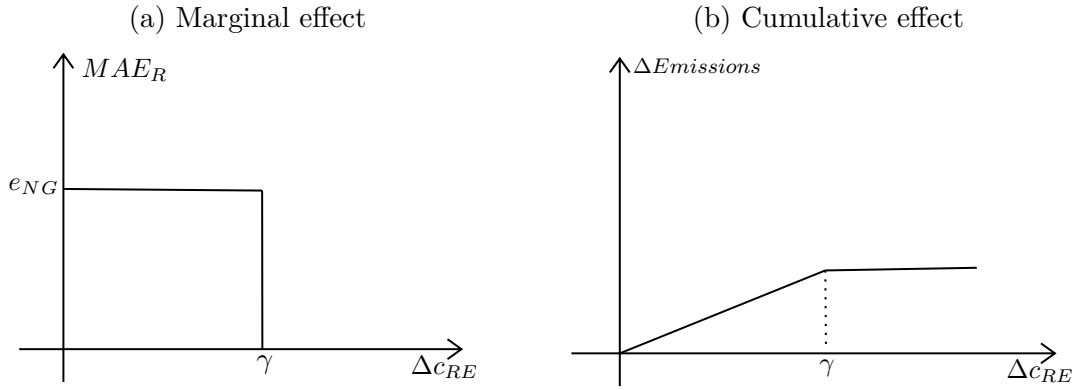
### 3) High decrease of the gas price [2.A3](#)

In the last scenario, coal is pushed out of the merit order due to the decrease in gas prices. It becomes apparent here that having a sufficient capacity of gas power plants is a key factor for coal to become uneconomical. The only polluting source that is offset is gas power plants.



- If  $\Delta c_{RE} < \gamma$  :  $\Delta Emissions = \Delta c_{RE} \times e_{NG}$
- If  $\Delta c_{RE} \geq \gamma$  :  $\Delta Emissions = \gamma \times e_{NG}$

Figure 2.A3: Effect of additional RE capacity for a small decrease of the gas price



Notes: This graph shows marginal and cumulative effect of a renewable capacity increase for a high decrease of the gas price.

What can be gathered from this simple model, which offers insights into the expected effects, is that the environmental value of renewable energy varies with the relative price of gas compared to coal, the installed renewable capacity, and their interaction. Specifically, the terms  $\Delta p_g$  and  $\Delta c_{RE}$  highlighted in this conceptual section will correspond to the control variables fuel cost ratio (CR) and RE in the econometric part of our analysis. We will empirically assess how these terms impact the emissions of the electricity mix.

The key takeaways of this simplified model are the following. If the average demand and fuel prices are such that a gas power plant is marginal and coal is infra-marginal, the environmental value of renewable energy increases and then decreases with its installed capacity. If the relative price of gas is low enough for the marginal power plant to be gas-based, the environmental value will initially be higher than in the previous case but will only decrease over time. In the last case, where the drop in gas prices is such that coal is no longer dispatched, the environmental value will be low initially and will decrease with the added capacity.

### 2.A.3 Mapping cost ratios with carbon prices

This section outlines the method proposed by [Cullen and Mansur \(2017\)](#) for mapping a carbon price to variations in the coal over gas cost ratio, along with its validity conditions. The concept is as follows: The marginal cost corresponding to the bid of a coal or gas power plant is the sum of the fuel price required to produce one unit of electricity multiplied by the heat rate, the price of CO<sub>2</sub> (if applicable) multiplied by the emissions

associated with producing an additional unit of electricity, and the variable operating and maintenance costs. Since coal generation emits significantly more CO<sub>2</sub> per unit of electricity produced than gas generation, a variation in the part related to the CO<sub>2</sub> price more significantly affects the marginal cost of the former. Assuming equal variable operating and maintenance costs for each type of plant, this implies that an increase in the carbon price is equivalent to an increase in the coal-to-gas cost ratio.

It should be noted that this equivalence requires the verification of certain conditions.

The first is that marginal costs actually determine the production decisions of power plants. This condition is met in a competitive market environment without frictions such as market power exertion.

A second condition is that technical differences in plants that affect speeds and the ease of ramping up and down do not alter the competitive order of merit.

A final condition is that stakeholders react similarly to a variation in fuel price due to a change in commodity price and to a change in carbon price. [Fabra and Reguant \(2014\)](#) have demonstrated that the reaction is indeed similar in the case of the Spanish market.

## 2.A.4 Additional Tables

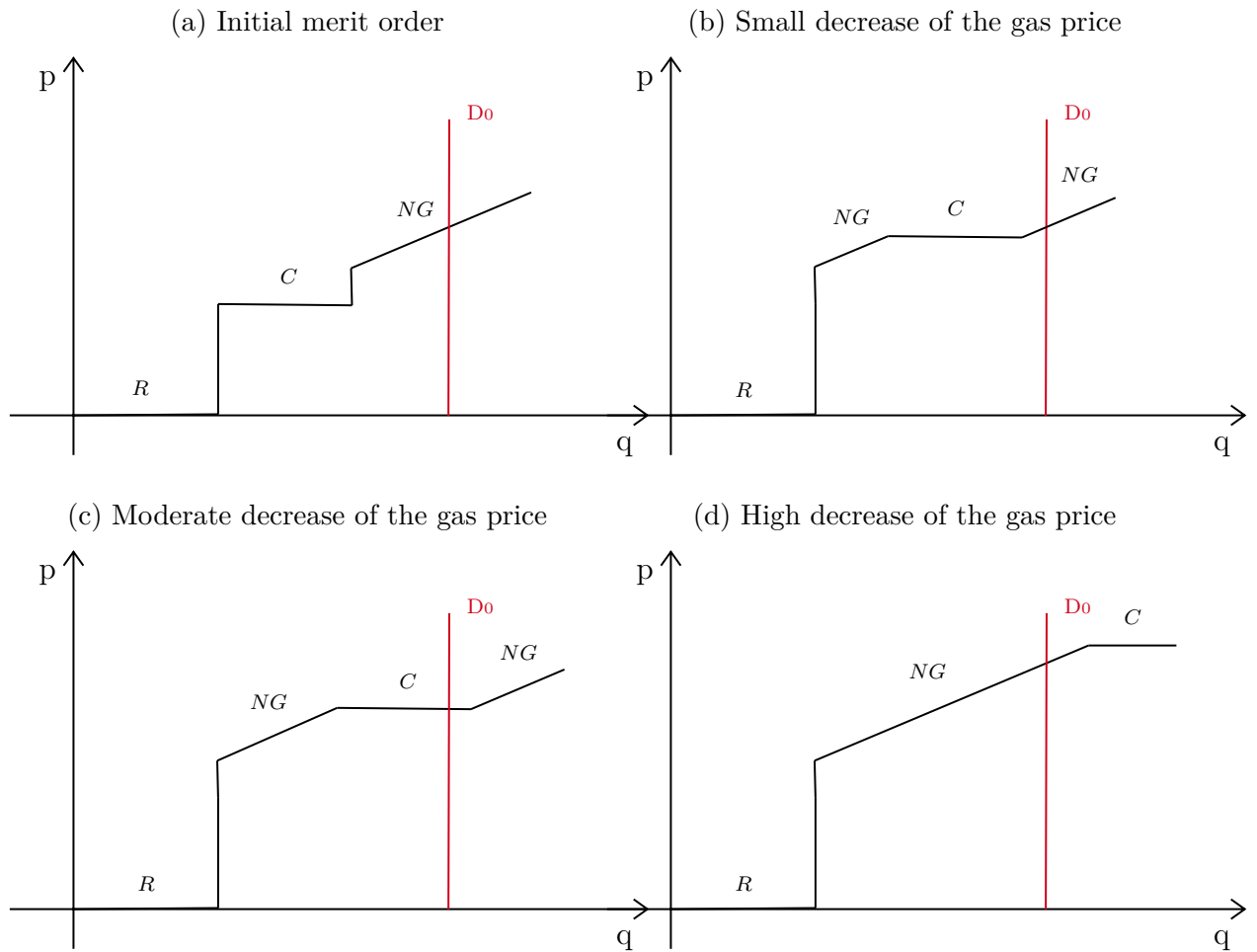
Table 2.A1: RE environmental value with varying cost ratio (carbon price)

Carbon price	Cost ratio	SPP	ERCOT	MISO
0	0.51	-.00138*** (.000342)	-.000998*** (.000253)	-.000651** (.00032)
10	0.65	-.00144*** (.000367)	-.00101*** (.000252)	-.000735** (.000316)
20	0.77	-.00152*** (.000395)	-.00103*** (.000259)	-.000788** (.000314)
30	0.88	-.00160*** (.000428)	-.00106*** (.000271)	-.000818*** (.000315)
40	0.97	-.00169*** (.000461)	-.00108*** (.000286)	-.000827*** (.000316)
50	1.05	-.00178*** (.000495)	-.00111*** (.000305)	-.000823*** (.000317)
60	1.11	-.00185*** (.000524)	-.00114*** (.000323)	-.000811** (.000317)
70	1.18	-.00195*** (.000562)	-.00117*** (.000348)	-.000788** (.000318)
80	1.23	-.00202*** (.000591)	-.00120*** (.000369)	-.000765** (.000318)
90	1.28	-.00210*** (.000624)	-.00123*** (.000393)	-.000736** (.000318)
100	1.32	-.00217*** (.000651)	-.00126*** (.000414)	-.000708** (.000319)
110	1.36	-.00225*** (.000681)	-.00128*** (.000438)	-.000676** (.000319)
120	1.40	-.00232*** (.000712)	-.00131*** (.000464)	-.000640** (.000319)
Observations		60792	41508	153132

*Notes:* The estimates are calculated for representative values of the cost ratio and at means for other control variables. They are interpretable as tCO<sub>2</sub> avoided per additional MWh of RE generation for a given ISO's plant. For reference, the average cost ratio values were 0.59 in SPP, 0.78 in ERCOT, and 0.70 in MISO during the specified period. The associated carbon price is calculated using the method detailed in subsection 2.5.2. Plant level cost ratio Standard errors clustered at the plant level in parenthesis. \*\*\* $p < 1%$ , \*\* $p < 5%$ , \* $p < 10%$ .

## 2.A.5 Additional Figures

Figure 2.A4: Illustration of the impact of a change in the price of gas on the marginal plant



*Notes: Each panel represents a scenario of the merit order adjustment in response to changes in gas prices. The first diagram illustrates the initial state of the energy mix. The second depicts a scenario where the gas price drops sufficiently to trigger fuel switching, but not enough for coal to become the marginal source. The third shows a case where there is enough fuel switching for coal to be at the margin. The last diagram represents a scenario where there is so much fuel switching that coal becomes supra-marginal.*



# Chapter 3

## Wind Turbines and Local Economies: Effects on Housing, Tourism, and Municipality Income

*co-written with Sven Heim (Mines Paris - PSL, ZEW) and Mario Liebensteiner (FAU)*

### Abstract

Wind turbines offer significant environmental benefits but also create negative local externalities, such as noise and visual pollution, which can lead to local tensions and community resistance to the energy transition. This paper investigates both the negative and positive externalities of wind turbine siting in Germany. Utilizing an instrumental variables approach, we find that wind turbine siting decreases house purchase prices by 1.9% in affected municipalities, with this adverse effect being most pronounced for the first turbines installed. Additionally, the siting of wind turbines reduces local tourism and leads to fewer building permits being issued for apartments and houses, exacerbating the housing shortage. On the positive side, each installed wind turbine increases a municipality's local tax capacity by 1.8% through their contribution to local commercial tax income. Our findings suggest that the negative externalities can be mitigated by investing the increased tax revenue into local amenities and services, thereby compensating for the adverse effects of wind turbines.

Résumé

Les éoliennes offrent des avantages environnementaux significatifs mais créent également des externalités locales négatives, telles que le bruit et la pollution visuelle, pouvant mener à des tensions locales et une résistance communautaire à la transition énergétique. Cet article examine à la fois les externalités négatives et positives de l'implantation des éoliennes en Allemagne. En utilisant une approche de variables instrumentales, nous constatons que l'implantation des éoliennes diminue les prix d'achat des maisons de 1,9 % dans les municipalités affectées, cet effet adverse étant plus prononcé pour les premières turbines installées. De plus, l'implantation des éoliennes réduit le tourisme local et entraîne une diminution des permis de construire délivrés pour les appartements et les maisons, aggravant la pénurie de logements. Du côté positif, chaque éolienne installée augmente de 1,8 % la capacité fiscale d'une municipalité grâce à sa contribution aux revenus fiscaux commerciaux locaux. Nos résultats suggèrent que les externalités négatives peuvent être atténuées en investissant les revenus fiscaux accrus dans les équipements et services locaux, compensant ainsi les effets adverses des éoliennes.

**Keywords:** Wind power, Hedonic pricing, NIMBY, Local disamenities

**JEL classification codes:** D61, Q40, Q42, Q52

## 3.1 Introduction

The transition from conventional thermal power plants to decentralized renewable energy sources is a key challenge in achieving the climate ambitions of developed countries. While most renewable energy technologies, including biomass, biogas, and hydropower, have limited deployment potential in many countries, wind and solar power offer much greater potential. However, unlike conventional large-scale power plants, wind and solar installations are significantly smaller and distributed across the country.

Despite the significant benefits of abating greenhouse-gas emissions and local pollutants, the construction of wind turbines sometimes faces local opposition, commonly referred to as the "Not In My BackYard" (NIMBY) syndrome (Van Der Horst, 2007). That is, people generally support the deployment of renewable energies, but within their vicinity, they do not want to endure the associated negative local externalities. In this regard, the literature documents adverse health effects related to living in proximity to wind turbines, via noise and visual pollution (Ata Teneler and Hassoy, 2023; Knopper and Ollson, 2011), and negatively influencing households' wellbeing (Krekel and Zerrahn, 2017).

In this paper, we empirically assess these externalities by examining the induced variations in house prices and related outcomes in Germany. If disamenities, such as noise and visual pollution of landscapes, are indeed perceived negatively by households, the deployment of new wind turbines should lead to a decrease in house prices. Measuring this effect is particularly interesting because NIMBYism can hinder the deployment of wind turbines and, consequently, the replacement of polluting power plants. Quantifying the effect of wind turbines on house prices enables the implementation of targeted compensation measures to mitigate the impact on affected local communities. Additionally, assessing the effect's heterogeneity can guide the strategic placement of future wind turbines. In this study, we focus on Germany, which serves as an excellent case study for this ex post evaluation due to its leading and pioneering role in the deployment of wind energy.

We utilize a unique dataset combining house prices and the number and capacity of wind turbines in German municipalities between 2008 to 2017. A key challenge in identifying the causal effect of wind turbine proximity on house prices is the potential reverse causality, because property prices in a municipality may also determine wind turbine investments. This could be, for example, that investors may construct wind turbines in cheaper areas. To circumvent a potential endogeneity bias, our analysis leverages variation in the deployment of wind turbines, induced by changes in the government's incentive scheme, which determines the revenue of a wind turbine investment. Using this



instrument, we can causally identify the effect of interest.

Our principal finding is that wind turbine placements negatively affect house prices within their proximity. We find that a wind turbine placement deters the average house price in a municipality by 1.9%. The effect is, however, not linear. Our estimates indicate that the first wind turbine placements have a significantly large effect of -5.3% on the house prices, whereas the effects of additional wind turbines in areas which other wind turbines are already populated turn out statistically insignificant.

Moreover, we find that wind turbine siting not only depresses house prices but also affects apartment rents and hotel overnight stays, highlighting that the negative externalities extend to other outcomes as well. This latter effect suggests that the negative externalities of wind turbines are experienced not only by local residents but also by tourists. Additionally, we show that the number of building permits for apartments and houses issued by a municipality falls in response to a wind turbine siting. This suggests a trade-off between allocating new land parcels for building new houses and apartments or for wind turbine siting. Therefore, policymakers should account for these negative impacts in their cost-benefit analyses when making decisions about wind power deployment.

Besides estimating the adverse effects of wind turbine investments, we also demonstrate that the number of wind turbines and the size of wind turbines significantly increase a municipality's tax income. Hence, in addition to their environmental benefits, wind turbines provide positive impacts on municipal finances, which help mitigate the negative externalities of visual and noise pollution. Municipalities may use the additional tax income to invest in local infrastructure, such as child care, medical and educational services, public transportation, and recreational facilities, to alleviate the local adverse effects of wind turbine sitings. Such targeted investments could help, *ceteris paribus*, increase housing prices and attract tourism.

This study contributes on the local impacts of wind energy deployment. As we discuss in more detail in Sections 3.2.2 and 3.2.3, several studies investigated the effect of wind turbine deployment on land or housing prices. Among them are [Jarvis \(2021\)](#) and [Gibbons \(2015\)](#) for Great Britain, [Dröes and Koster \(2016\)](#) and [Dröes and Koster \(2021\)](#) for the Netherlands, [Sunak and Madlener \(2016\)](#) and [Sunak and Madlener \(2017\)](#) for the German state North-Westphalia, and [Quentel \(2023\)](#) for Germany. These studies find negative effects of wind turbine proximity on housing or property prices, whereas the effects vary greatly. Yet, some papers find no significant effect or in some occasions even a positive effect, depending on the context, as summarized in a literature review by [Parsons and Heintzelman \(2022\)](#). Hence, an often made assumption that there is necessarily a negative effect of wind turbine deployment, regardless of the context, can lead to poor policy decisions.

In contrast to previous studies, this paper offers several new contributions. We combine multiple detailed datasets covering the entire country of Germany over a recent period, including crucial socioeconomic data. Moreover, we not only estimate the adverse effects of wind turbine proximity on house prices, but also on apartment rents, hotel overnight stays, and building permits. Additionally, we demonstrate that wind turbines benefit municipalities through increased tax income. We also show that the first wind turbine has the greatest negative externality. Furthermore, we apply a credible instrumental variables approach to identify the effect of interest.

The rest of the paper is organized as follows. Section 3.2 provides a brief background on wind power promotion in Germany and local opposition. Section 3.3 proposes a simple conceptual model as a pillar for our empirical approach. Section 3.4 describes our data. Section 3.5 outlines our empirical strategy. Section 3.6 presents the results and Section 3.6.3 provides robustness tests. Section 3.7 concludes.

## 3.2 Institutional background

In this section, we provide background information on the promotion and evolution of wind power in Germany over the past 20 years. We also discuss the dilemma between global benefits related to the reduction of greenhouse gas emissions and local disamenities, including visual and noise pollution. Finally, we review the literature assessing the costs to local residents of wind turbines and our contribution.

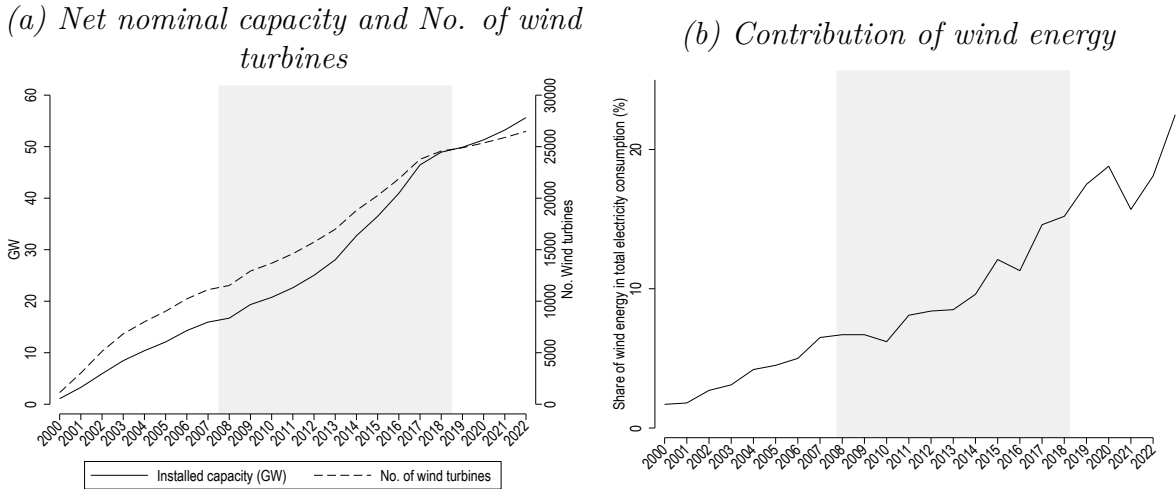
### 3.2.1 Wind energy expansion in Germany

Germany is a leading country in the deployment of renewable energies, driven by a dual purpose. The primary goal is to reduce CO<sub>2</sub> emissions from the electricity sector to meet climate objectives. The second goal is the implementation of the *Atomausstieg*, the decision to phase out nuclear made in 2002 under Gerhard Schröder (and then confirmed again under Angela Merkel following the Fukushima nuclear accident in March 2011). Thus, the promotion of renewables aims not only to replace thermal power plants but also to compensate for the rapid closure of German nuclear facilities. Given the country's significant wind potential compared to its relatively low sunlight exposure, wind energy has been the most vigorously promoted renewable source (Abrell et al., 2019a).

Over the past 20 years, installed capacity has increased rapidly and steadily, as shown in Figure 3.1. It has risen more than tenfold, from 6 GW in 2000 to 61 GW in 2023, with an average annual growth rate of 2.5 GW. Additionally, to achieve carbon-neutral electricity production before 2050, the 2021 Renewable Energies Act sets the ambition to reach 65 percent of production from renewable sources by 2030 (IEA, 2024). Thus,

the increase in renewable energy capacity will continue in the future, underscoring the importance of evaluating its impact.

Figure 3.1: Development of wind energy in Germany, 2000–2022



Notes: a) Aggregate installed wind power capacity and number of wind turbines in Germany, 2000–2022. Own computation based on individual wind turbine information available at the Market Master Data Register by the German Federal Network Agency (BNetzA, 2024). b) Calculation based on data from the German Federal Ministry for Economic Affairs and Energy (BMWi, 2023). The shaded area indicates the sample period of our analysis in both panels.

To achieve its ambitions, Germany has implemented generous support policies for renewables. The country introduced a feed-in support system that guarantees renewable energy producers a fixed subsidy payment per megawatt-hour, which is independent of and above the market price. Moreover, renewable energy facilities enjoy prioritized and guaranteed infeed, before any other conventional power stations.

In recent years, after the end of our sample period in 2017, a feed-in premium system was established. Wind generators are now responsible themselves for selling their electricity on the market, still with priority, and receive a premium on top of the actual market price. Since, this regulatory change does not coincide with our study period, so it does not influence the results.

The feed-in tariff during our sample period was structured as follows: its level depends on the technology and capacity, resulting in different subsidy levels for photovoltaic, wind, and other technologies. The feed-in tariff is granted for a duration of 20 years following the construction of a given project.

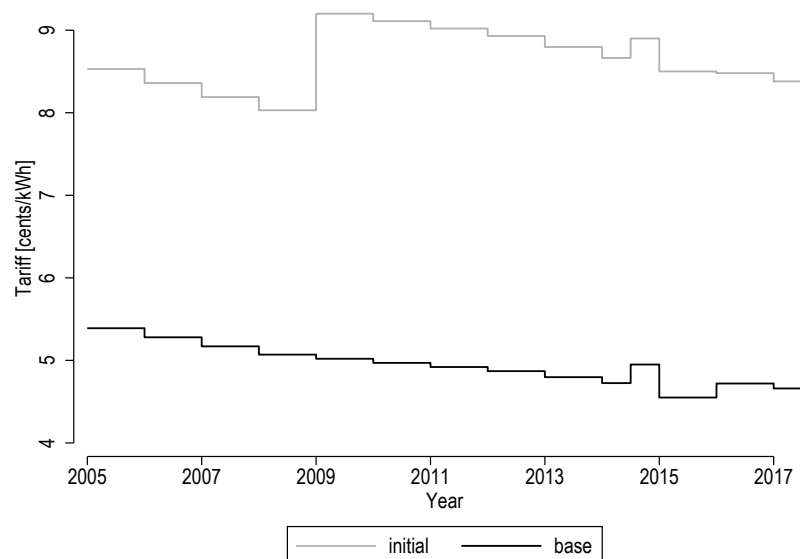
A key element in the deployment of renewables is geographic diversification. This is crucial for two reasons. Firstly, it helps mitigate the production intermittency renewable energy sources. By multiplying distant sources, temporal fluctuations in energy

production are reduced, resulting in a smoother average electricity output. Secondly, diversification of locations addresses congestion problems. Without rapid and adequate grid development, it would be impossible to circulate electricity produced by thousands of wind turbines in a confined area.

To encourage wind turbine installations in areas with suboptimal wind potential, feed-in tariffs vary geographically. These tariffs are determined by a "reference yield model" and are inversely proportional to wind potential. The model calculates tariffs by dividing the potential of each location by a reference potential, also known as the "yield ratio". The subsidy then evolves over time, starting with a high initial tariff for the first 5 years after the turbine's construction plus a period dependent on the yield ratio, before dropping to a lower base tariff. Typically, the higher the wind potential, the quicker this reduction occurs.

It is noteworthy that this subsidy system introduces significant cross-sectional heterogeneity in subsidies and, consequently, in the expected profits from wind turbines. Furthermore, both the initial and base tariffs were adjusted during our study period, with several consecutive decreases. Until 2012, a feed-in tariff was only granted to wind turbines in locations with a yield ratio of at least 60 percent. In 2012, the subsidy scheme was extended to the entirety of Germany, allowing wind turbines in any location to qualify for feed-in tariffs. Figure 3.2 illustrates how these tariffs have evolved over time.

Figure 3.2: Development of feed-in tariffs for wind, 2005-2017



*Notes: Data from the German Transmission System Operators (2019).*

We leverage this temporal and cross-sectional variation introduced by the workings and changes in the feed-in tariff scheme for our identification strategy. It is important to note that these variations only pertain to new turbines, while the subsidy scheme that was valid in the year of the installation at the beginning remaining applies for a period of 20 years.

### 3.2.2 Benefits versus local opposition

The promotion of wind energy in Germany is motivated by environmental and nuclear safety concerns. By replacing thermal generation, wind power mitigates the emission of CO<sub>2</sub> and local pollutants such as SO<sub>2</sub>, NO<sub>x</sub>, and particulate matter (Cullen, 2013). This reduction in CO<sub>2</sub> emissions benefits the entire world, as a ton of CO<sub>2</sub> emitted anywhere contributes equally to climate change (Nordhaus, 2019).

However, this is not the case with local pollutants. Generating less electricity with conventional thermal power plants directly benefits populations living near these plants by reducing the likelihood of smog, haze, or respiratory illnesses and lung diseases (see, e.g., Deschenes et al., 2017; Holland et al., 2020; Jarvis et al., 2022). Thus, it is shown that phasing out coal has a significant impact on the local environment and health benefits that more than offset the costs of this phase-out in most regions of the world, even without considering the global benefits from slowing climate change (Rauner et al., 2020).

Moreover, the deployment of wind energy also serves to compensate for Germany's decision to phase out nuclear energy. In response to the Fukushima accident, the German Bundestag decided to abandon this technology for safety reasons. The rationale is that the use of nuclear energy involves the risk of dangerous radioactive radiation for humans and the environment. The German society concluded that the risks of this technology outweigh its benefits and thus decided on the phase-out (Grossi et al., 2017). Hence, besides environmental value, wind turbines also mitigate citizens' perceived safety concerns related to nuclear energy.

The benefits of wind energy deployment stand against the negative local externalities. This has led to increasingly publicized opposition from local residents (Spiegel, 2011; Financial Times, 2019; The Economist, 2021; The New York Times, 2022). The arguments advanced include visual pollution, noise, damage to biodiversity, and even a local loss of jobs in the conventional electricity producing industry. Zerrahn (2017) provides a comprehensive literature review on wind power and its negative local environmental externalities. Additionally, the massive deployment of decentralized renewables also requires the construction of many new high-voltage power lines, which themselves have adverse visual and biodiversity consequences.

In Germany, 97 percent of the 28,000 wind turbines installed are within two kilome-

ters of a residential area. Resident resistance, often expressed through petitions with thousands of signatures against nearby projects (Spiegel, 2011), does not aim to halt the energy transition but to relocate it out of their sight. Polls even show that popular support for wind energy remains high in general, despite significant wind energy deployment in Germany (Financial Times, 2019). Thus, there is a tension between aggregate benefits and local costs.

It is crucial to understand the local costs of renewable energy infrastructures to prevent local opposition from hindering the achievement of climate goals. Highlighting this tension, environmental protection organizations such as Greenpeace are even signing petitions urging the government to relax animal protection laws to facilitate the installation of more wind turbines (Recharge, 2024).

Delays in project implementation due to administrative and legal challenges not only postpone deployment schedules but also escalate costs for developers. Such delays and increased expenses could jeopardize Germany's renewable energy goals. Industry stakeholders report that it can take 5 to 7 years to determine whether a wind turbine installation project is feasible, and that they are increasingly taken to court even when approved by the authorities.

### 3.2.3 Valuing the costs to local residents

To implement appropriate policies to address these local objections, it is not only crucial to understand the benefits but also to credibly estimate the disamenities associated with wind energy deployment.

The literature has highlighted several local externalities affecting households near wind turbines (Zerrahn, 2017).<sup>1</sup> With an average height of around 100 meters during our study period, wind turbines can be visible from a significant distance depending on the topology. For instance, Gibbons (2015) demonstrated through a quasi-experimental research design in England and Wales that each additional wind turbine reduces house prices by 6.5 percent within 1 km and by 5.5 to 6 percent within 2 km if they are visible.

However, most studies do not distinguish between types of nuisances and use the hedonic price method to assess if households value non-market amenities. The concept, which we further explain in Section 3.3, is that the local impacts of wind projects are reflected in house prices. In a literature review of hedonic price studies, Parsons and Heintzelman (2022) highlights that most studies showed a significantly negative effect of wind turbine deployment on property prices. However, the magnitudes vary greatly,

---

<sup>1</sup>The papers reviewed in Zerrahn (2017) describe and measure, among other things, the negative impact of wind turbines on wildlife, including a decrease in bird and bat populations, noise pollution—though no causally measured health effects—and landscape deterioration. Regarding positive externalities, there is some evidence of increased local employment and GDP.

underscoring the context-specific nature of these impacts. Most studies also show that turbines are located in areas where land prices are lower, all else being equal. This supports the endogeneity problem described in detail in the methodology section.

Key findings from the reviewed literature are as follows. [Vyn and McCullough \(2014\)](#)'s study in Southern Ontario, Canada, indicates a property value decrease of 3 to 5% for an additional turbine within a distance of less than 1km, with a full view. The study notes large standard errors, attributed to a small sample size. In the Netherlands, [Dröes and Koster \(2016\)](#) applied a difference-in-difference methodology over the period 1985-2019, demonstrating a 1.4% decrease in house prices within 2km of a turbine, with a substantial observational dataset supporting these findings. In North-Westphalia, Germany, [Sunak and Madlener \(2016\)](#) reported a 9-14% decrease in property prices. With more observations, they showed for the same area a decrease of 12.5% if the additional turbine is less than 1km away and visible ([Sunak and Madlener, 2017](#)). This effect decreases with distance and converges towards zero after 4-5km. In Denmark, [Jensen et al. \(2018\)](#) found that onshore wind turbines within 3 km led to price reductions of 0.2 to 1.1% for primary residences and 1.1 to 2.1% for vacation homes. This disparity is likely due to a higher valuation of landscape views associated with secondary residences. Moreover, [Jarvis \(2021\)](#) highlights an average 4-5% reduction in residential property values at a 2 km distance from a wind project, diminishing with increased distance and nullifying beyond 4km. The effect is notably more pronounced in wealthier neighborhoods. Closely related to our study is [Quentel \(2023\)](#), estimating the impact of wind turbine proximity on German house prices. His primary finding is that a wind turbine decreases the house price by 2.1%, using also an instrumental variables (IV) approach, which exploits variation in wind turbine height and varying wind conditions by altitude. This results is in line with our main estimate, whereas our study differs in sample period, IV approach, highlighting a non-linear impact of wind turbine placements, using alternative outcome variables, and showing that municipalities earn tax income for wind turbines.

Overall, we contribute to the related literature in several ways. We employ an IV strategy by exploiting variations in the expected revenue from wind generators to deal with the endogeneity of treatment. Moreover, we combine different granular datasets for the whole of Germany, allowing us to gain insight from a pioneering country in renewable energy deployment. Our findings demonstrate a non-linear impact of wind turbine placement, where the first turbine has the strongest adverse effect on house sale prices. Additionally, we estimate that wind turbines not only deter house prices, but also apartment rental prices and hotel overnight stays. Furthermore, we estimate that municipalities issue fewer building permits for housing in favor of wind turbine sitings. This aligns with our finding that municipalities generate more tax income from larger wind turbine investments in

their area. Several robustness tests support our primary estimates.

### 3.3 Conceptual framework

As a pillar for our empirical approach, this section provides a brief conceptual framework. The hedonic price method is widely used in the literature to estimate the explicit prices of characteristics within a class of products. [Freeman III et al. \(2014\)](#) offers a comprehensive description of this methodology. The concept is that if a class of products, for us a house in Germany, contains enough items with different characteristics, then it is possible to estimate an implicit relationship that gives the product's price based on the quantities of its various characteristics. This relationship is the hedonic price function. The partial derivative of this hedonic price function with respect to any of its characteristics then gives its marginal implicit price.

More formally, a product from a class of products can be described by a vector  $\mathbf{Q} = (q_1, \dots, q_n)$  of its characteristics. For a parcel of land, this corresponds to the present value of the stream of benefits and costs derivable from the land.  $\mathbf{Q}$  may include structural attributes, air quality, the view of a beautiful landscape, neighborhood quality, and other attributes. The hedonic price function  $p(q_1, \dots, q_n)$  gives the product's price at equilibrium as a function of its characteristics. Let us detail how this function is generated.

Assume that each individual only buys one unit of the product class. The individual's utility derived from this purchase is:

$$u = u(z, \mathbf{Q}), \quad (3.1)$$

with  $z$  being the numeraire good. By substituting the budget constraint  $p(\mathbf{Q}) + z = I$ , with  $I$  being the available income, we can rewrite the utility function as:

$$u = u(I - p(\mathbf{Q}), \mathbf{Q}) \quad (3.2)$$

Utility maximization requires the individual to choose the level of each  $q_k$  with  $k \in \llbracket 1, n \rrbracket$  that solves the following maximization problem:

$$\begin{aligned} \max_{q_k, z} \quad & u = u(I - p(\mathbf{Q}), \mathbf{Q}) \\ \text{s.t.} \quad & p(\mathbf{Q}) + z = I \end{aligned} \quad (3.3)$$

The Lagrangian for the full problem is:

$$\mathcal{L} = u(I - p(\mathbf{Q}), \mathbf{Q}) + \delta[p(\mathbf{Q}) + z - I] \quad (3.4)$$



The first-order conditions yield that the individual must choose each  $q_k$  to satisfy:

$$\frac{(\partial u / \partial q_k)}{(\partial u / \partial z)} = \frac{\partial p}{\partial q_k} \quad (3.5)$$

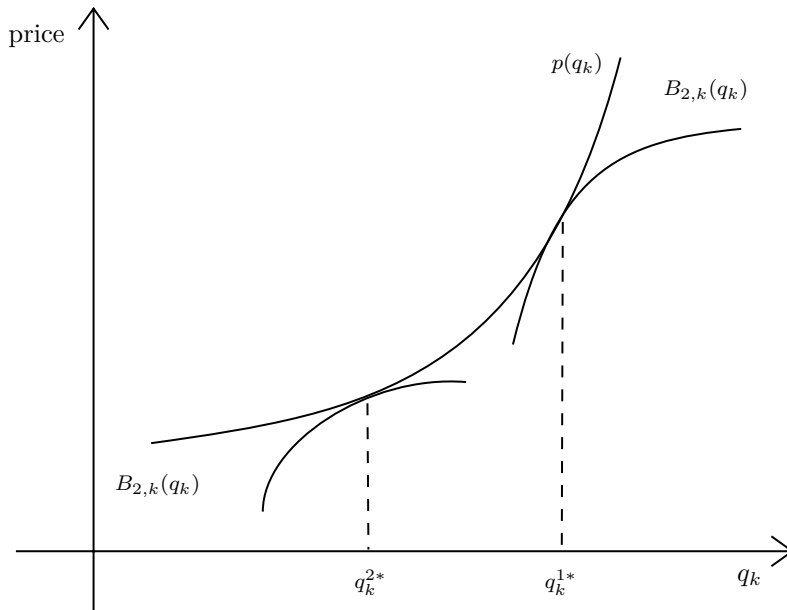
Thus, the marginal willingness to pay for  $q_k$  must be equal to the cost of purchasing more of  $q_k$ . However, as noted by Rosen (1974),  $p(\mathbf{Q})$  is what the individual must pay for the vector of characteristics  $\mathbf{Q}$ . This is different from what the individual would be willing to pay for  $\mathbf{Q}$  because he/she has the alternative of the numeraire good  $z$ . The individual therefore defines  $B(I, \mathbf{Q}, u^*)$  as the bid function, implicitly solving:

$$u[I - B(I, \mathbf{Q}, u^*)] = u^*, \quad (3.6)$$

with  $u^*$  being the solution of the individual's maximization problem.

Let us now focus on the attribute  $q_k$  for two distinct types of individuals. Let  $B_{1,k}(q_k) = B_1(I_1, q_k, \mathbf{Q}_{-k}^{1*}, u^{1*})$  and  $B_{2,k}(q_k) = B_2(I_2, q_k, \mathbf{Q}_{-k}^{2*}, u^{2*})$  be the bid functions for the characteristic  $k$  of two individuals of types 1 and 2. Individuals of type 1 value the environmental quality related to the characteristic  $k$  more than individuals of type 2.  $B_{1,k}(q_k)$  and  $B_{2,k}(q_k)$  are obtained by fixing all characteristics other than  $q_k$  to their optimal levels  $\mathbf{Q}_{-k}^{1*}$  and  $\mathbf{Q}_{-k}^{2*}$ . In the  $(p, q_k)$  plane,  $B_{1,k}(q_k)$  and  $B_{2,k}(q_k)$  are the indifference curves of the two types of individuals, as shown in Figure 3.3.

Figure 3.3: Bid curves of buyers



Given the hedonic price function, the two types of individuals choose  $q_k^{1*}$  and  $q_k^{2*}$  respectively. At each point of the hedonic price function, the marginal price of  $q_k$  is equal

to the marginal willingness to pay of individuals that have chosen this location. In the case of disamenities related to the construction of wind turbines, this model predicts that each type of negatively valued nuisance implies that the concerned houses must have a lower price than equivalent ones without the nuisance.

As noted by [Davis \(2011\)](#), the assumption is made that the hedonic price function does not shift with the decrease in environmental quality. In our case, we argue that this approximation is correct because even though the number of wind turbines is significant, only a small part of the land market is affected, making a significant alteration unlikely.

## 3.4 Data

This section describes the dataset underpinning our empirical analysis. In summary, it includes house prices, the number of wind turbines and their capacity, as well as local socioeconomic characteristics like population density, unemployment, and citizens' average age at the municipality level ('Gemeindeverband', corresponding to the European LAU 1-level) during the period from 2008 to 2017.<sup>2</sup> [Table 3.1](#) summarises the primary data employed in our analysis.

### 3.4.1 House prices

We use an index of house purchase prices per German municipality, developed by [Klick and Schaffner \(2021\)](#), which uses the RWI-GEO-REDX dataset ([Boelmann et al., 2019](#)) on house sale offers from the largest real estate internet platform in Germany, "ImmobilienScout24". The index is created via annual cross-sectional hedonic price regressions, which control for typical house properties, such as size, rooms, floors, vintage, type of hose, furnishing, energy consumption, etc., and characteristics of the property, such as property size and location.

The underlying model is:

$$\ln(y_{igt_0}) = \theta X_{igt_0} + u_{gt_0} + \epsilon_{igt_0}, \quad (3.7)$$

where  $i$  denotes the individual house,  $g$  the municipality, and  $t_0$  is the respective year of the cross sectional regression.  $X$  captures house and property characteristics.  $u$  are municipality fixed effects, and  $\epsilon$  is the error term. Variation at the municipality level of the index is derived from the municipality fixed effects  $u$  of the regressions. The house price

---

<sup>2</sup>Germany has 4,639 municipalities (Gemeindeverband, corresponding to the European LAU 1-level) in total, of which we observe 3,430 in our data, because house prices are not reported for municipalities with less than 50 house transactions per year. The median size of a municipality is 47 km<sup>2</sup>, which corresponds to a radius of approximately 3.8 km.

Table 3.1: Summary statistics of main variables

	Mean	SD	Min	Max
<i>Dependent variable</i>				
ln(house price index)	-0.10	0.43	-2.63	1.94
<i>Variables of interest</i>				
Number of wind turbines	5.65	14.02	0.00	257.00
Net wind turbine capacity (MW)	8.88	25.34	0.00	689.24
<i>Control variables</i>				
Age	44.05	2.17	36.29	53.71
Employment	55.97	5.28	20.36	77.35
Population density	364.77	441.63	14.99	4708.36
<i>Instrumental variables</i>				
Expected revenue of a WT	0.90	0.31	0.27	2.25
Ineligible	0.18	0.38	0.00	1.00
Ineligible $\times$ Wind potential	0.38	0.83	0.00	2.59
Obs.	26,657			

Notes: Descriptive statistics for municipality-level data. Annual data for 2008 – 2017.

index is only available for municipalities with at least 50 house purchases in a given year. Otherwise, the data is removed from the sample for data protection reasons. Thus, out of the 4,654 municipalities in Germany, we are left with an average of 2,742 municipalities per year.

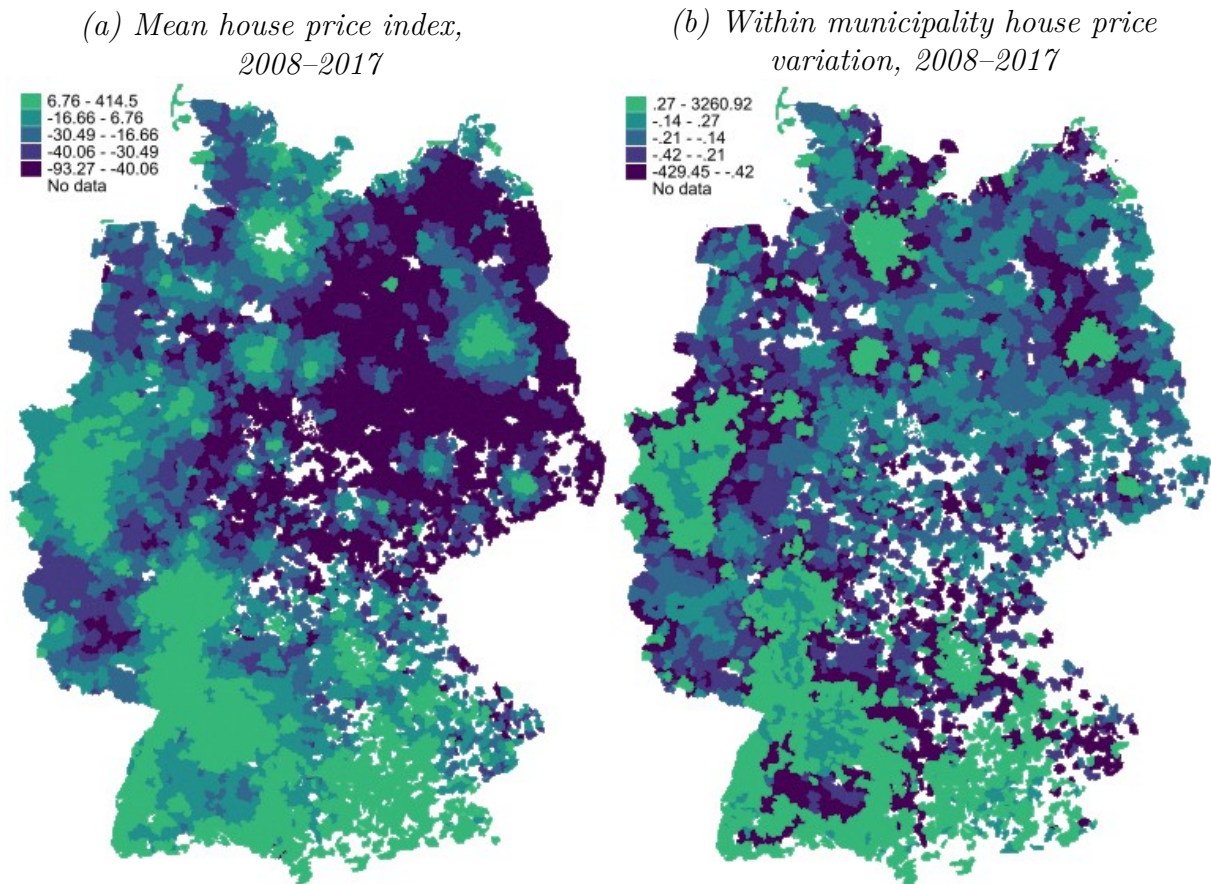
Figure 3.4a shows that there are significant regional disparities with higher prices in the southwest, west, and northwest. These regions correspond to former West Germany. Besides higher land parcel prices, other variables remain significantly different between the former GDR and West Germany: in the West, the population is younger, wealthier, and less rural.

Figure 3.4b shows the within variation of house prices. It is calculated as the ratio of within and between standard deviations and expressed as a percentage. The figure shows that prices also varied within zip codes with an average variation of about 10 percent.

### 3.4.2 Wind turbines

Data regarding the number and capacity of wind turbines within each municipality were sourced from the Marktstammdatenregister (Market Master Data Register) by the German Federal Network Agency (BNetzA, 2024). The Marktstammdatenregister contains, as a central register, data on all generation plants that are connected via the electricity

Figure 3.4: Means and within municipality variation of the house price index 2008–2017



Notes: These graphs show the mean (a) and the within variation (b) of the house price index per municipality. The white areas represent missing data, i.e. municipalities with less than 50 house transactions per year.

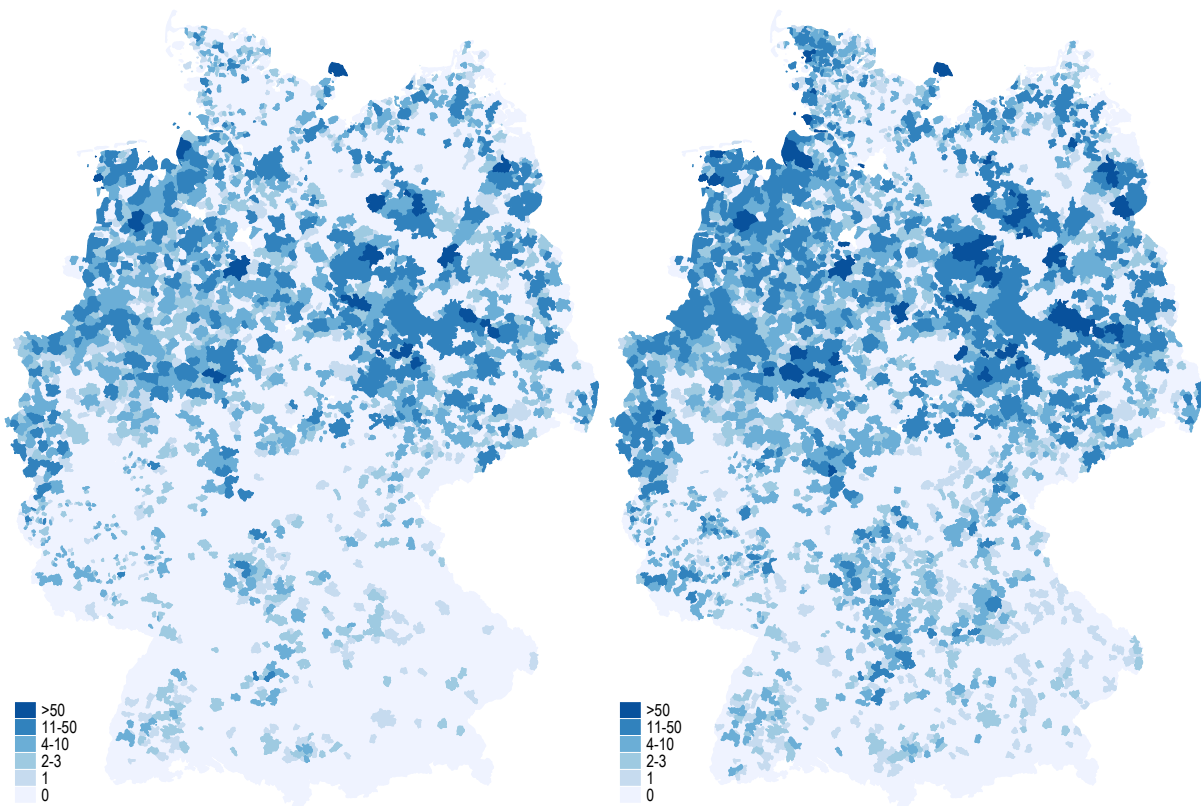
and gas networks. For each wind turbine it contains information on the turbine's net capacity, geo-coordinates, commissioning date, height, rotor diameter. During the sample period 2008 to 2017, the average number of wind turbines is 5.65 and the average aggregate net capacity is 8.88 MW. Over the decade we study, the number of wind turbines in Germany increased sharply from 14,167 in 2008 to 26,344 in 2017, and the installed capacity rose from 18.8GW to 48.6GW.

Figure 3.5 shows their geographical distribution of wind turbines across Germany in 2008 and 2017. They are predominantly placed in the north of the country. While one might initially think that this corresponds to where wind conditions are most favorable, as shown in Figure 3.6. This is not exactly the case. The distribution of wind turbines in the country rather corresponds to places where the expected revenue from the feed-in tariff is high and property prices are low, as shown in Figure 3.7a.

Figure 3.5: Development of wind turbines in Germany between 2008 and 2017

(a) *Wind turbines in 2008*

(b) *Wind turbines in 2017*



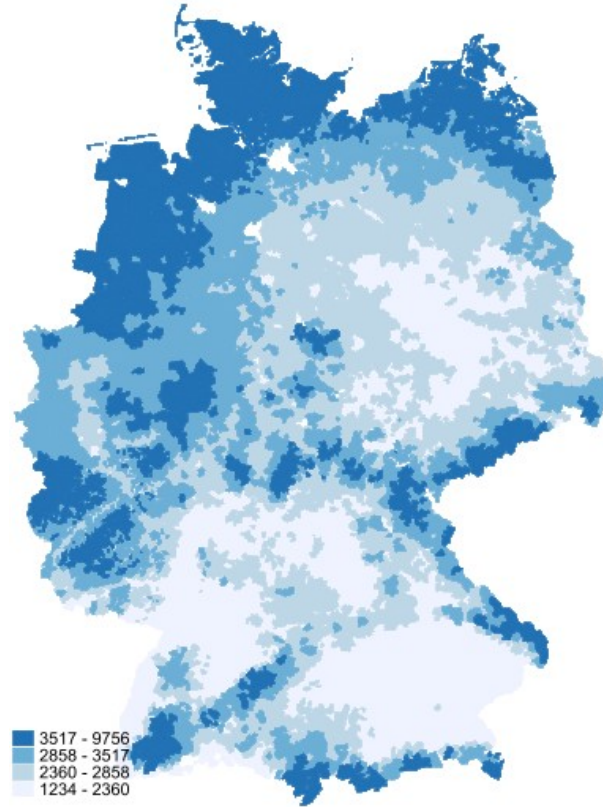
*Notes: This graphs show the number of turbines per municipality in 2008 (a) and 2017 (b). The average number of turbines per municipality is 5.7, but the graph displays significant regional heterogeneity, with some municipalities in the north having more than 50 turbines.*

### 3.4.3 Expected revenue

During the sample period 2008–2017, the remuneration per unit of electricity produced by wind turbines was not uniform across Germany. The applied feed-in tariff aimed to encourage deployment across the entire territory to limit congestion problems and smooth the temporal profile of intermittent non-dispatchable wind production. As already outlined in more detail in Section 3.2.1, the regional distribution of feed-in tariffs was set according to a "reference yield model".

This remuneration scheme implies larger payments per megawatt-hour (MWh) of electricity output for wind turbines placed in locations with lower wind profiles (i.e., where the wind blows less strongly and regularly). We therefore calculate the expected revenue per wind turbine using local wind potential data from the German Meteorological Office and the amount and duration of the initial and base tariffs obtained from the German

Figure 3.6: Wind power potential in Germany



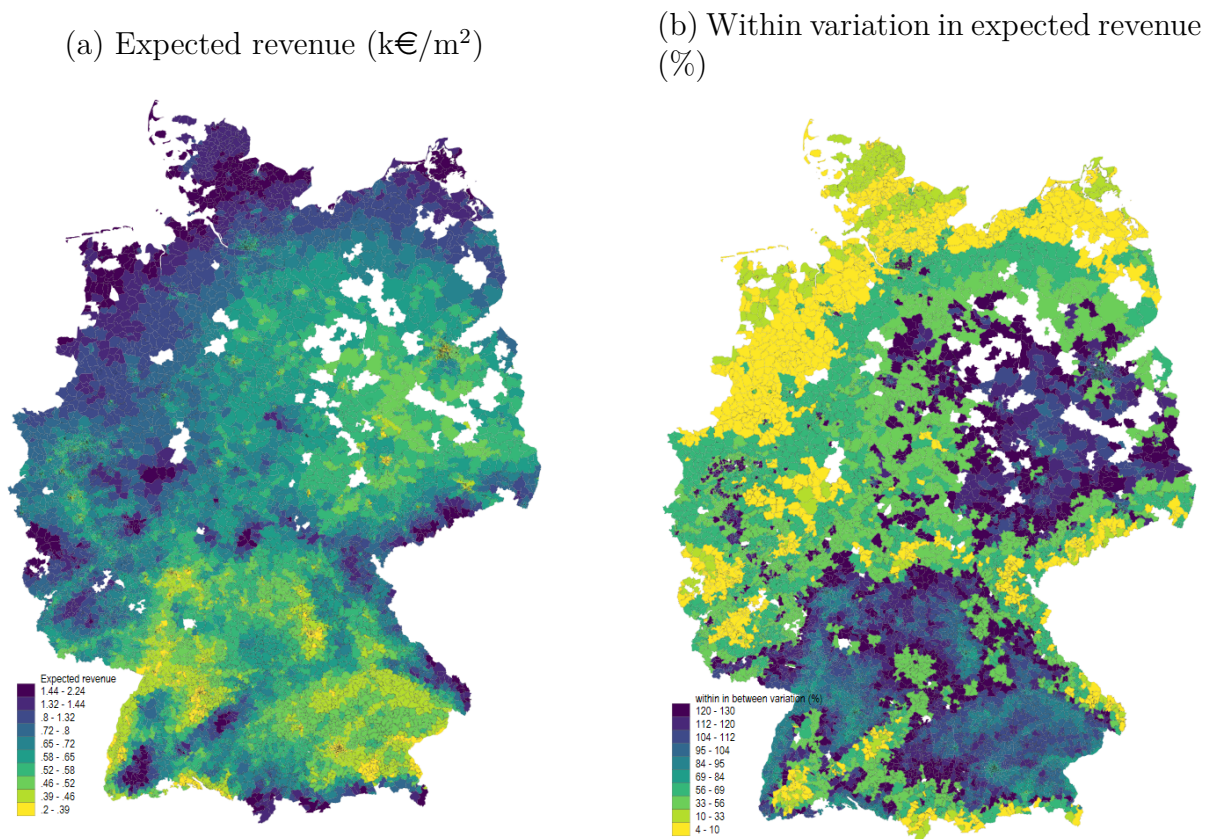
TSOs. The expected revenue ( $ER$ ) for each turbine is calculated as follows:

$$ER_{i,t} = (FIT_{init,t} \times n_{init,i} + FIT_{base,t} \times n_{base,i}) \times POTENTIAL_{i,t}, \quad (3.8)$$

where  $FIT_{init,t}$  represents the initial tariff for year  $t$ ,  $n_{init,i}$  the initial tariff period for municipality  $i$ ,  $FIT_{base,t}$  the base tariff for year  $t$ , and  $n_{base,i}$  the duration of the base tariff for municipality  $i$ .  $FIT_{init,t}$  is always higher than  $FIT_{base,t}$  and varies over time with successive reforms, introducing temporal variation to the expected revenue.

The values of the initial and base tariffs vary over time but are fixed for each wind turbine at the rates in effect at the time of construction, remaining constant for a duration of 20 years. Hence,  $n_{init,i} + n_{base,i} = 20$  years. The windless the location, the longer  $n_{init,i}$  is.  $POTENTIAL_i$  is the annual wind potential at municipality  $i$ . Specifically, the initial period is 5 years plus an additional duration based on the yield ratio. A low-yield location can benefit from the initial tariff for a longer period than a high-yield location. Most amendments during the sample period resulted in tariff reductions. Moreover, a reform in 2012 extended the subsidy's reach to all of Germany. Before that, only locations with more than 60 percent of the reference yield were eligible. Expected revenues are measured in €1,000 per square meter ( $m^2$ ) of rotor surface. The sample average is about €900 per

Figure 3.7: Expected revenue and within variations



*Notes: The figure on the left displays municipality level expected revenues. They are average values over the entire sample. The figure on the right shows the within variation in expected revenue, calculated as the ratio of within to between standard deviations, expressed as a percentage. The white areas represent missing data, although these are minimal.*

m<sup>2</sup>, ranging from €273 to €1,2252.

Figure 3.7a shows the average expected revenue of a wind turbine per municipality. It exhibits similar patterns to the number of wind turbines per municipality illustrated in Figure 3.5. This supports the intuition that higher expected revenues lead to the construction of more turbines. Moreover, Figure 3.7b presents evidence for substantial within variation in expected revenues over the sample period. The within variation is explained by the evolution of the tariff for wind turbines installed in different years, as it is fixed for the first 20 years of the installation. Most of the German municipalities display a within variation of about 50 percent. Areas with a variation of more than 100 percent are those where the eligibility threshold was removed in 2012.

### 3.4.4 Control variables

As socioeconomic control variables, we collected data on municipalities' average age of the residents, population density, and the local employment rate from [www.inkar.de](http://www.inkar.de), a database on spatial and urban development in Germany, provided by the German Federal Institute for Research on Building, Urban Affairs, and Spatial Development (BBSR, 2024).

## 3.5 Identification strategy

This section details our baseline estimates for the effect of wind turbine construction on house prices. We model this relationship using the following regression equation:

$$\log(P_{i,t}) = \beta \cdot WT_{i,t} + \gamma \cdot \mathbf{X}_{i,t} + \xi_i + \phi_t + \varepsilon_{i,t}, \quad (3.9)$$

where the dependent variable  $\log(P_{i,t})$  represents the logarithm of the average house price in municipality  $i$  in year  $t$ .  $WT_{i,t}$  measures the number of wind turbines within the municipality and  $\beta$  is the parameter of interest.

The vector of control variables  $\mathbf{X}_{i,t}$  encapsulates time-varying socioeconomic characteristics, specifically average local employment rate, population density, and the average age of the population. The municipality fixed effects  $\xi_i$  absorb any time-invariant characteristics specific to each municipality, such as local preferences and profitability. Moreover, the year fixed effects  $\phi_t$  control for annual aggregate shocks that influence both house prices and wind turbine deployment. To account for spatial correlation in the error term, we cluster the standard errors  $u_{i,t}$  at the municipality level in all specifications.

Although time and municipality fixed effects can effectively control for constant time and municipality-specific characteristics, concerns about potential endogeneity between the outcome variable and the variable of interest persist. This may lead to estimation bias of the parameter of interest  $\hat{\beta}$  if we estimate equation 3.9 by OLS. Several reasons underpin this concern. Firstly, property prices likely influence the siting decisions for new wind turbines. Developers aiming to maximize expected revenue may prefer less expensive areas, all else being equal, leading to reverse causality. If this were the case, the OLS estimates would be biased toward zero.

Additionally, unobserved preferences for wind turbines might not be stable over time, as households could change their views on the technology's presence in their vicinity, for example, due to media coverage. There may also be other unobserved changes over time that affect wind turbine deployment and preferences. For instance, if wind turbines generate monetary benefits for the municipality, which are then used to improve local infrastructure, this could increase the value of houses. We will discuss this in more detail



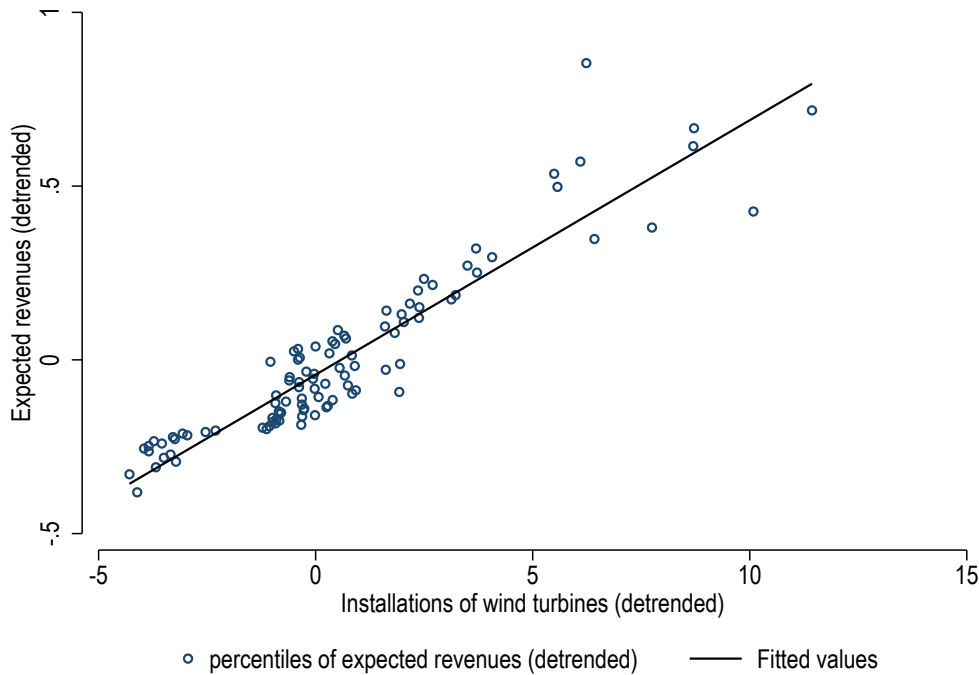
later. Lastly, the variable  $WT_{i,t}$  does not directly measure population exposure to wind turbines. We calculate  $W_{i,t}$  based on the distance to the municipality center, potentially introducing measurement error.

To address these potential sources of endogeneity bias, we employ an instrumental variables strategy, leveraging quasi-experimental spatial and year-to-year variations in variables determining the expected local revenues for wind turbines, in the spirit of [Ger-meshausen et al. \(2023\)](#).

As discussed in Section 3.4.3, the reference yield model introduces exogenous variation on the revenues wind turbines expect to receive across municipalities and years. This is because both the cross-sectional variation in the feed-in tariff, which depends on local wind potential, and the yearly adjustments to the feed-in tariff scheme, which are based on policy targets for distributing wind turbines across Germany, are plausibly independent of other local characteristic changes, such as house prices. Another source of exogenous variation is introduced by a policy change in the coverage of the reference yield model. While before 2012, only wind turbines in locations exceeding a certain wind potential (i.e.,  $\geq 60\%$  of the reference yield) were eligible for feed-in tariffs, from 2012 on, all locations were covered by the subsidy scheme. The reduction of the eligibility threshold concerned a large part of the German land area and led to significant revenue increases.

Thus, we are confident that the profitability of a wind turbines based on feed-in-tariffs set by the reference yield scheme are uncorrelated to shocks to house prices. The other condition that needs to hold for the IV is that our instrument is relevant. In our case this means that anticipated revenues according to the reference yield scheme shift the siting decisions of new wind turbines. This assumption is testable and holds as we will show in the result section. The plot of the two variables, expected revenues and wind turbines, in Figure 3.8 also demonstrates a strong positive correlation between the number of wind turbines in a municipality and the expected revenue there according to the reference yield scheme.

Figure 3.8: Expected revenues and wind turbine installations correlation



*Notes: The figure plots expected revenues from the reference yield scheme (defined in eq. 3.8) against the number of newly installed wind turbines, after residualizing both variables with respect to year dummies. This procedure corrects for both cost reductions in wind turbine construction and reductions in the feed-in tariffs over time.*

Thus, using data from the expected revenues of wind turbines, we apply the following specification for the first stage regression model:

$$\begin{aligned}
 WT_{i,t} = & \gamma_1 \times ER_{i,t} + \gamma_2 \times INELIGIBLE_{i,t} + \gamma_3 \times INELIGIBLE_{i,t} \\
 & \times POTENTIAL_i + \Gamma \mathbf{X}_{i,t} + \mu_i + \nu_t + \epsilon_{i,t}
 \end{aligned} \tag{3.10}$$

$ER_{i,t}$  represents the expected revenue for wind turbines located in municipality  $i$  for year  $t$ . As detailed in section 3.4.3, locations with a yield ratio below 60 percent became eligible for the feed-in tariff only since the year 2012. For these municipalities,  $ER_{i,t} = 0$  before 2012. Hence,  $INELIGIBLE_{i,t}$  is a dummy equal to 1 before 2012 when  $ER_{i,t} = 0$  and 0 otherwise. Moreover,  $INELIGIBLE_{i,t} \times POTENTIAL_i$  captures heterogeneous investment incentives in ineligible locations.

## 3.6 Results

We apply a GMM estimator for our IV regressions. This is similar to a two-stage least squares approach, but has the beneficial feature that GMM applies a weighting matrix for our three instrumental variables. Local variations in the expected revenue of a wind turbine serve as a strong predictor of both the number and capacity of wind turbines installed within a municipality. Table 3.2 presents the outcomes of the first-stage regression.

An expected revenue increase in rotor surface significantly increases the number of wind turbines. Additionally, the coefficient of the dummy variable "Ineligible" is positive and statistically significant. This indicates that wind turbines which were not eligible for a feed-in tariff before 2012 – and thus had a value of zero for the *ER* variable – still had positive revenues, even though outside of the feed-in tariff system, as reflected by this variable's coefficient. Furthermore, the coefficient on the interaction term "Ineligible x Wind potential" is statistically insignificant but enhances the overall instrumentation performance by increasing the first-stage F statistic, thereby strengthening the predictive power of our instruments.

Table 3.2: First-stage regression estimates, IV-GMM

Dependent variable is <i>No. wind turbines</i>	
Expected revenue of a WT (k€/m <sup>2</sup> of rotor surface)	3.503*** (0.654)
Ineligible	4.269*** (0.499)
Ineligible × Wind potential	-0.096 (0.317)
Year FE	yes
Municipality FE	yes
Socioeconomic controls	yes
Obs.	26,657

Notes: First stage estimates. Standard errors clustered at the municipality level in parenthesis. \*\*\* $p < 1\%$ , \*\* $p < 5\%$ , \* $p < 10\%$ .

### 3.6.1 Main results

Table 3.3 presents the primary OLS and IV estimates for the impact of the number of wind turbines on house prices. Columns (1) and (3) omit socioeconomic control variables, while columns (2) and (4) include them. Evidently, the IV estimates yield significantly more pronounced effects (i.e., difference about 35%–40%) than the OLS estimates. This is expected and indicates that neglecting the endogeneity bias results in estimates biased

toward zero. Hence, neglecting endogeneity would significantly underestimate the true impact of wind turbines on house prices.

The first-stage F-statistic of 60 and 44 for the two IV specifications suggest that weak instruments are not a concern in this analysis. Moreover, the Durbin-Wu-Hausman test rejects exogeneity of  $WT$ , substantiating our decision to employ an instrumental variable approach. Consequently, our interpretations of the results rely on the IV estimates for the remainder of the paper.

The IV estimates, both excluding (column (1)) and including socioeconomic control variables (column (2)), are reasonably close. Our preferred baseline specification is the fully specified model in column (2), which shows that the placement of a wind turbine decreases house prices in a municipality by 1.9%, indicating a significant negative externality on nearby house owners.

To contextualize the magnitude of our findings, we compare them with existing literature. [Quentel \(2023\)](#) also found a 2.1 percent decrease in house prices for each additional wind turbine within a 3 km radius using an alternative instrumental variable. Although our study varies in the dependent variable, location, time horizon, and IV strategy, it is noteworthy that our results align with this study. Moreover, [Sunak and Madlener \(2016\)](#) and [Sunak and Madlener \(2017\)](#), focusing on a single German state, North Rhine-Westphalia, estimated a 9% to 14% reduction in house prices per additional wind turbine, also indicating a negative, yet more pronounced effect of wind turbines. Our findings also align with [Parsons and Heintzelman \(2022\)](#)'s review of studies on the effect of wind power projects on property values, which generally find a negative impact.

### 3.6.2 Effect of first vs. additional wind turbines

One concern with the aforementioned estimate is that the first wind turbine might have a significantly more pronounced adverse effect on house prices than subsequent turbines. For example, the impact of increasing the number of wind turbines from four to five might be less substantial compared to installing the first turbine in an area previously free of such structures. The initial turbine may be perceived as more disruptive than additional ones in an already affected zone. A natural way to test this hypothesis would be to include a squared term in the model to assess a potential non-linear relationship. However, this approach is challenging in our IV framework because the squared term would also be endogenous and require appropriate instrumentation. We attempted to instrument the squared term using the squared original instruments, but they proved too weak for identification.

To address this concern, we take a different approach. We restrict our model to compare municipalities with no wind turbines in 2007 to those that already had at least

Table 3.3: Effect of wind turbine deployment on house prices

	Dependent variable is $\ln(\text{house price index})$			
	IV-GMM		OLS	
	(1)	(2)	(3)	(4)
No. wind turbines	-0.0295*** (0.0030)	-0.0191*** (0.0029)	-0.0009*** (0.0003)	-0.0004* (0.0002)
Year FE	yes	yes	yes	yes
Municipality FE	yes	yes	yes	yes
Socioeconomic controls		yes		yes
Durbin-Wu-Hausman test	0.00	0.00		
First stage F stat.	59.72	43.63		
Obs.	27,016	26,657	27,077	26,660

Notes: The dependent variable is the logged municipality level house price index. The adoption of wind turbines is instrumented for with the expected revenue according to the reference yield subsidy scheme in Columns (1) and (2). The IV estimator is two-step feasible GMM. Columns (3) and (4) give the corresponding OLS estimates. Standard errors clustered at the municipality level in parenthesis. \*\*\* $p < 1\%$ , \*\* $p < 5\%$ , \* $p < 10\%$ .

one wind turbine sited in 2007. This allows us to test the effect of the placement of the first wind turbines relative to locations where additional wind turbines were placed.

Columns (1) and (2) of Table 3.4 present the respective estimates. We find a pronounced negative effect of placing a wind turbine in a municipality that initially had no wind turbines. In such cases, the first wind turbine reduces house prices in the neighborhood by 5.5%. This is a significant effect in economic terms. However, in municipalities that already had installed wind turbines, the placement of an additional turbine has no statistically significant effect on house prices.

Given that the first-stage F statistic of the model in column (1) is rather low and below the generally accepted rule of thumb value of 10, the estimates may be suffering from weak instrumentation. Hence, we re-estimate the model using the continuously updating GMM estimator (CUE) (Hansen et al., 1996) which is more robust to weak instruments.

Columns (3) and (4) of Table 3.4 report the GMM-CUE estimates. The estimates remain robust, showing that the first wind turbine reduces house prices by 5.6%, whereas additional wind turbines do not alter house prices.

There are several potential explanations for this finding. Once the visual landscape is adversely impacted or noise becomes noticeable, each additional turbine likely has a diminishing marginal impact. It may also be the case that residents become accustomed to wind turbines, finding additional ones less disturbing. This findings generates some useful information for policymakers, which will discuss later.

Table 3.4: Effect of first WT vs. effect of additional WTs

	Dependent variable is $\ln(\text{house price index})$			
	IV-GMM		IV-GMM-CUE	
	(1) No WTs in 2007	(2) WTs in 2007	(3) No WTs in 2007	(4) WTs in 2007
No. wind turbines	-0.0546*** (0.0177)	0.0025 (0.0034)	-0.0560*** (0.0174)	0.0026 (0.0034)
Year FE	yes	yes	yes	yes
Municipality FE	yes	yes	yes	yes
Socioeconomic controls	yes	yes	yes	yes
Durbin-Wu-Hausman test	0.00	0.48	0.00	0.48
First stage F stat.	7.99	8.97	7.99	8.97
Obs.	2,985	10,700	2,985	10,700

Notes: The dependent variable is the logged municipality level house price index. The adoption of wind turbines is instrumented for with the expected revenue according to the reference yield subsidy scheme. The IV estimator in Columns (1) and (2) is two-step feasible GMM. In Columns (3) and (4) the continuously updating GMM estimator (CUE) is applied which is more robust to weak instruments. Standard errors clustered at the municipality level in parenthesis. \*\*\* $p < 1\%$ , \*\* $p < 5\%$ , \* $p < 10\%$ .

### 3.6.3 Robustness tests

To assess the robustness and plausibility of our findings on the impact of wind turbine installations on house prices, we conduct several tests, which are presented in the following three subsections.

#### 3.6.3.1 Effect of future wind turbine placements on contemporaneous house prices

A potential concern of our IV strategy may be that the areas that received subsidies were also the ones building turbines for other reasons. To address this concern, we first conduct a placebo test. We estimate the effect of wind turbines built in the year after next on the current house price index. The idea is that the siting of wind turbines should have no effect on house prices before they were actually built.

Column (1) of Table 3.5 provides the estimates of this placebo test. Indeed, the coefficient estimate is statistically not different from zero, as expected. Since the two-periods lag reduces the number of observations, we further check in column (2) of Table 3.5 if the sample selection potentially drives this result. We thus re-estimate our original, contemporaneous model for the same sample, as in column (1). It turns out that we still find a significantly negative impact of wind turbine placement on house price and that the magnitude of the effect (-1.6%) remains similar to the baseline estimate (-1.9%).

Table 3.5: Placebo test with lagged dependent variable

	(1) Lagged ln(house price index)	(2) ln(house price index)
No. wind turbines	-0.0029 (0.0026)	-0.0158*** (0.0031)
Year FE	yes	yes
Municipality FE	yes	yes
Socioeconomic controls	yes	yes
Durbin-Wu-Hausman test	0.29	0.00
First stage F stat.	33.35	33.35
Obs.	18,442	18,442

Notes: The dependent variable in Column (1) is the log municipality level house price index lagged by two periods. The dependent variable in Column (2) is also the log municipality level house price index but without lags, but the same sample as in Column (1) is applied in order to allow for a better comparison. In both columns the adoption of wind turbines is instrumented for with the expected revenue according to the reference yield subsidy scheme. The IV estimator in both columns is two-step feasible GMM. Standard errors clustered at the municipality level in parenthesis. \*\*\* $p < 1\%$ , \*\* $p < 5\%$ , \* $p < 10\%$ .

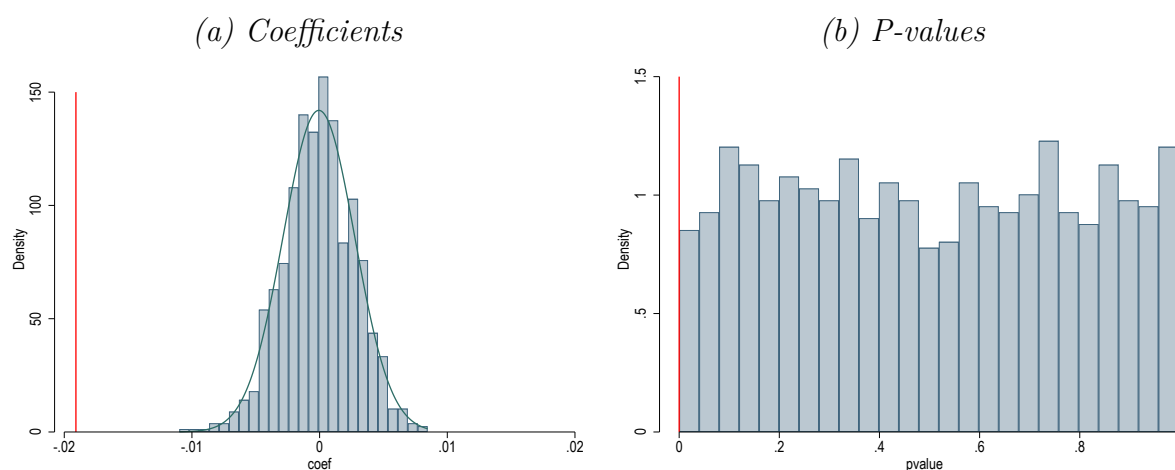
Thus, this placebo test supports the notion that our findings are causal .

### 3.6.3.2 Randomized siting of wind turbines

We further conduct another placebo test in the form of random treatment assignment. We randomly assign the number of wind turbines in a given municipality  $i$  to another municipality  $j$  and re-estimate our main regression specification, as introduced in equation 3.9. The instruments are also assigned to municipality  $j$ . We replicate this random assignment 1,000 times.

The left-hand side of Figure 3.9 displays the density function of the obtained coefficients. They are normally distributed and centered around zero. For comparison, the red line indicates our primary estimate (-0.0191), which does not overlap with the coefficients from the placebo estimations. Moreover, the right-hand side of Figure 3.9 provides a distribution of the p-values, showing that the lion's share of the point estimates are statistically insignificant at conventional levels. By contrast, our primary estimate is statistically significant with a p-value less than 0.00. This placebo test suggests that our primary estimate is not driven by chance.

Figure 3.9: Placebo test



*Notes: The red vertical lines indicate estimation results from Column (2) in Table 3.3, with a point estimate of -0.0191 ( $p = 0.00$ ). The black line presents a normal distribution. The Durbin-Wu-Hausman's p-value in the placebo test is  $p = 0.50$  (not shown here).*

### 3.6.3.3 Alternative time periods

As a third robustness check, we test if our findings may be driven by the specific time period we analyze. For this purpose, we restrict the initial sample period 2008–2017 to alternative periods by excluding one or two years from each end. Table 3.6 presents the estimates for the period 2009–2016 (column (1)) and 2010–2015 (column(2)).



In both specifications, the estimates effect of wind turbine placement on house prices stays similar in magnitude: -1.7% during the period 2009–2016 and -1.6% during the period 2010–2015. These estimates support the notion that our main results are not driven by a specific circumstance in time.

Table 3.6: Robustness: Alternative time periods

	Dependent variable is $\ln(\text{house price index})$	
	2009 – 2016 (1)	2010 – 2015 (2)
No. wind turbines	-0.0170*** (0.0035)	-0.0160*** (0.0045)
Year FE	yes	yes
Municipality FE	yes	yes
Socioeconomic controls	yes	yes
Durbin-Wu-Hausman test	0.00	0.00
First stage F stat.	40.13	37.37
Obs.	21,156	15,688

Notes: The dependent variable is the log municipality level house price index. In Column (1) the observation period is shortened to 2009–2016 and in Column (2) it is shortened to 2010–2015. The adoption of wind turbines is instrumented for with the expected revenue according to the reference yield subsidy scheme. The IV estimator is two-step feasible GMM. Standard errors clustered at the municipality level in parenthesis. \*\*\* $p < 1\%$ , \*\* $p < 5\%$ , \* $p < 10\%$ .

### 3.6.4 Different outcome variables

Besides investigating the effect of wind turbine placements on house prices, we also employ alternative outcome variables in the regressions. Table 3.7 provides estimates on apartment rental prices (column (1)), the number of overnight stays in hotels (column (2)), and the number of building permits for apartments and houses (column (3)). All outcome variables are introduced in logarithms to allow for percentage interpretations of the coefficient estimates.

We find that wind turbines have a statistically significant and adverse economic effect on all three outcome variables. Column (1) indicates that a wind turbine placement reduces the apartment rent in its neighborhood by 2.1%. Moreover, column (2) provides an estimate that a wind turbine in the neighborhood reduces hotel overnight stays by 1.5%. This suggests that wind turbines exert a negative externality on tourism. The effects on apartment rents and hotel overnight stays can be directly explained via wind turbines' negative externalities in the form of visual landscape and noise pollution. Finally, column (3) indicates that the number of building permits for apartments and houses issued by a

municipality falls by 2.2% in response to a wind turbine placement. An explanation for this effect is that municipalities may face a trade-off between allocating new land parcels for building new houses and apartments or for wind turbine siting.

Table 3.7: Alternative outcome variables

	(1)	(2)	(3)
	Apartment rent	Hotel accommodation	Building permits
No. wind turbines	-0.0213*** (0.0030)	-0.0152** (0.0076)	-0.0216** (0.0085)
Year FE	yes	yes	yes
Municipality FE	yes	yes	yes
Socioeconomic controls	yes	yes	yes
Durbin-Wu-Hausman test	0.00	0.03	0.00
First stage F stat.	28.37	40.03	74.16
Obs.	16,316	28,563	43,445

Notes: The dependent variable in Column (1) is the log apartment rent price index, in Column (2) the log number of guest overnight stays in accommodation establishments, in Column (3) the log number of building permits for apartments and houses. The observation unit is the municipality level in all columns. The adoption of wind turbines is instrumented for with the expected revenue according to the reference yield subsidy scheme. The IV estimator is two-step feasible GMM. Standard errors clustered at the municipality level in parenthesis. \*\*\* $p < 1\%$ , \*\* $p < 5\%$ , \* $p < 10\%$ .

Altogether, the empirical results presented so far indicate significant adverse effects of wind turbines, which policymakers must consider in their cost-benefit calculations when deciding on wind power deployment.

### 3.6.5 Commercial taxes

Despite the adverse effects we found so far, wind power deployment can also be financially beneficial for German municipalities through increased commercial tax income. The commercial taxes depend on the number and capacity of wind turbines. Column (1) of Table 3.8 provides estimates on the impact of wind turbine placements in a municipality on the logarithm of commercial tax income, showing that for each additional wind turbine, commercial taxes increase by 2%. Since commercial taxes constitute the bulk of a municipality's total tax capacity, we observe an effect of similar magnitude when total tax capacity is used as the dependent variable as shown in Column (3) of Table 3.8.

Notably, wind turbines have become significantly larger over time. While the average wind turbine had a capacity of 1 MW in 2000, it grew to almost 4 MW by 2022, as shown in Figure 3.10a. During the sample period from 2008 to 2017, the average wind turbine capacity increased from about 2 MW to about 3 MW. Similarly, Figure 3.10b depicts trends in wind turbines' hub height and rotor diameter, both of which have grown

Table 3.8: WTs and commercial taxes

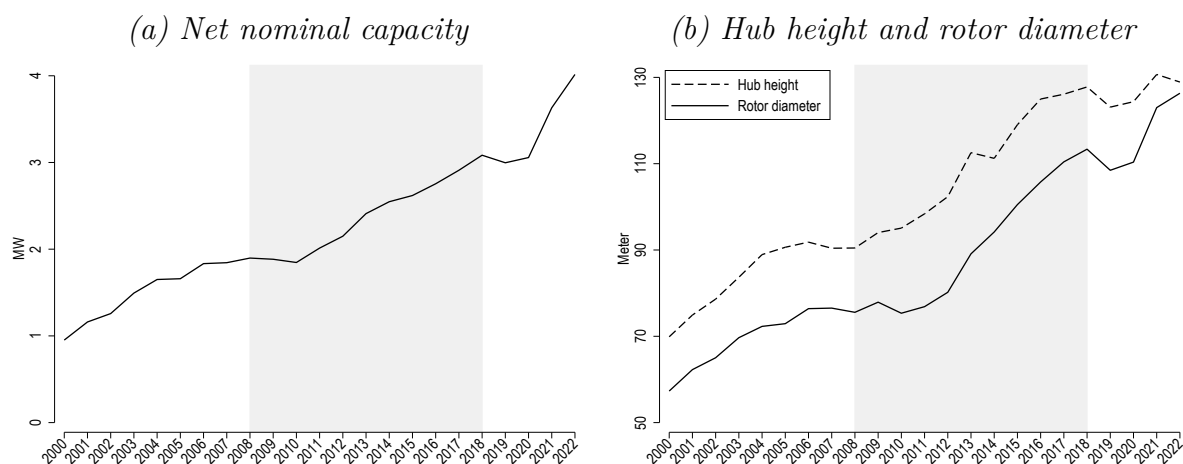
	Commercial taxes		Total tax capacity	
	(1)	(2)	(3)	(4)
No. wind turbines	0.0201*** (0.0058)		0.0181*** (0.0055)	
Net wind turbine capacity (MW)		0.0083*** (0.0023)		0.0072*** (0.0021)
Year FE	yes	yes	yes	yes
Municipality FE	yes	yes	yes	yes
Socioeconomic controls	yes	yes	yes	yes
Durbin-Wu-Hausman test	0.00	0.00	0.00	0.00
First stage F stat.	74.03	69.27	74.19	69.44
Obs.	43,355	43,355	43,424	43,424

Notes: The dependent variable is log municipality level commercial taxes in columns 1 and 2 and the total tax capacity in columns 3 and 4. The adoption of wind turbines is instrumented for with the expected revenue according to the reference yield subsidy scheme. The IV estimator is two-step feasible GMM. Standard errors clustered at the municipality level in parenthesis. \*\*\* $p < 1\%$ , \*\* $p < 5\%$ , \* $p < 10\%$ .

substantially. In 2000, the average hub height was about 70 meters and the average rotor diameter was about 60 meters. By 2022, these metrics increased to nearly 130 meters and 125 meters, respectively. These increases in size have a significant impact on municipal tax income.

To account for this, we also estimate the effect per MW of installed net capacity of wind turbines in a municipality on commercial taxes, as shown in columns (2) and (4) of Table 3.8. The estimates indicate that commercial taxes increase by 0.8% per additional MW of net turbine capacity. For instance, a wind turbine built in 2017 has a 50% greater effect on a municipality's commercial tax income than one built in 2008.

Figure 3.10: Development of wind turbine characteristics over time



Notes: The shaded area indicates the sample period of the econometric analysis.

### 3.7 Discussion and Policy Recommendations

Germany is a global leader in renewable energy deployment, particularly wind energy, with investments in wind turbines expected to accelerate in the coming years according to government goals. Despite strong promotion by national and European authorities, as well as international institutions advocating for climate change mitigation, negative perceptions among local populations may hinder the expansion of wind turbines.

Our findings indicate that new wind turbine installations in a municipality decrease local real estate values, including house purchase prices, apartment rents, tourism, and building permits, by approximately 2% on average. Conversely, wind turbines increase local tax capacity due to their subjection to commercial taxes.

To mitigate these negative effects, the additional tax revenue from wind turbines could be utilized to enhance local infrastructure and amenities. Investments in public services, such as parks, transportation, and community facilities, could improve the quality of life and potentially offset the decline in property values.

Moreover, the results show that the initial wind turbine has a more substantial negative impact on property values compared to subsequent turbines in areas already hosting wind farms. Therefore, a strategic policy could involve clustering wind turbines in locations with existing installations. This approach leverages the diminishing marginal negative effect on property values while maintaining the linear positive effect on tax capacity.

The dual impacts of wind turbines—negative externalities on property values and tourism versus positive effects on local tax revenues—should be considered. Policies providing incentives for property owners and investing in local infrastructure might support renewable energy adoption while addressing community concerns.

Effective community engagement is crucial. Transparent communication about the benefits and drawbacks of wind energy projects and involving residents in decision-making processes are essential. Compensation mechanisms, such as direct payments to affected homeowners or subsidies for local development projects, might help mitigate adverse effects and garner community support.





# Bibliography

- Abdmouleh, Z., Alammari, R. A., and Gastli, A. (2015). Review of policies encouraging renewable energy integration & best practices. *Renewable and Sustainable Energy Reviews*, 45:249–262.
- Abrell, J. and Kosch, M. (2022). Cross-country spillovers of renewable energy promotion—The case of Germany. *Resource and Energy Economics*, 68:101293.
- Abrell, J., Kosch, M., and Rausch, S. (2019a). Carbon abatement with renewables: Evaluating wind and solar subsidies in Germany and Spain. *Journal of Public Economics*, 169:172–202.
- Abrell, J., Rausch, S., and Streitberger, C. (2019b). The economics of renewable energy support. *Journal of Public Economics*, 176:94–117.
- Acemoglu, D., Aghion, P., Barrage, L., and Hémous, D. (2023). Climate change, directed innovation, and energy transition: The long-run consequences of the shale gas revolution. Technical report, National Bureau of Economic Research.
- ACER (2022). Final Assessment of the EU Wholesale Electricity Market Design. Technical report, ACER.
- Antweiler, W., Copeland, B. R., and Taylor, M. S. (2001). Is Free Trade Good for the Environment? *American Economic Review*, 91(4):877–908.
- Ata Teneler, A. and Hassoy, H. (2023). Health effects of wind turbines: a review of the literature between 2010-2020. *International journal of environmental health research*, 33(2):143–157.
- BBSR (2024). INKAR: Indikatoren und Karten zur Raum- und Stadtentwicklung. Bundesinstitut für Bau-, Stadt- und Raumforschung (BBSR) (Federal Institute for Research on Building; Urban Affairs and Spatial Development).



- Bergler, J., Heim, S., and Hüschelrath, K. (2017). Strategic capacity withholding through failures in the German-Austrian electricity market. *Energy Policy*, 102:210–221.
- Bergström, L., Kautsky, L., Malm, T., Rosenberg, R., Wahlberg, M., Capetillo, N., and Wilhelmsson, D. (2014). Effects of offshore wind farms on marine wildlife—a generalized impact assessment. *Environmental Research Letters*, 9(3):034012. ISBN: 1748-9326 Publisher: IOP Publishing.
- Blundell, R. W. and Powell, J. L. (2004). Endogeneity in Semiparametric Binary Response Models. *Review of Economic Studies*, 71(3):655–679.
- BMWi (2023). Time Series for the Development of Renewable Energy Sources in Germany. German Federal Ministry for Economic Affairs and Energy (BMWi). Accessed 17th June, 2024.
- BNetzA (2024). Marktstammdatenregister: Market master data register (mastr). German Federal Network Agency (Bundesnetzagentur).
- Bode, S. and Groscurth, H.-M. (2006). The Effect of the German Renewable Energy Act (EEG) on " the Electricity Price". Technical report, HWWA Discussion Paper.
- Boelmann, B., Budde, R., Klick, L., and Schaffner, S. (2019). RWI-GEO-RED: RWI real estate data – houses for sale. RWI Leibniz Institute for Economic Research, DOI: 10.7807/immo:red:hk:v1.
- Borenstein, S., Bushnell, J., and Knittel, C. R. (1999). Market power in electricity markets: Beyond concentration measures. *The Energy Journal*, 20(4). ISBN: 1944-9089 Publisher: International Association for Energy Economics.
- Borenstein, S., Bushnell, J., and Stoft, S. (2000). The Competitive Effects of Transmission Capacity in a Deregulated Electricity Industry. *The RAND Journal of Economics*, 31(2):294.
- Brunekreeft, G., Neuhoff, K., and Newbery, D. (2005). Electricity transmission: An overview of the current debate. *Utilities Policy*, 13(2):73–93.
- Bushnell, J. and Novan, K. (2021). Setting with the Sun: The impacts of renewable energy on conventional generation. *Journal of the Association of Environmental and Resource Economists*, 8(4):759–796. ISBN: 2333-5955 Publisher: The University of Chicago Press Chicago, IL.
- Callaway, D. S., Fowle, M., and McCormick, G. (2018). Location, location, location: The variable value of renewable energy and demand-side efficiency resources. *Journal*

- 
- of the Association of Environmental and Resource Economists*, 5(1):39–75. Publisher: University of Chicago Press Chicago, IL.
- ClimateWatch (2023). Greenhouse gas emissions by sector.
- Clò, S., Cataldi, A., and Zoppoli, P. (2015). The merit-order effect in the Italian power market: The impact of solar and wind generation on national wholesale electricity prices. *Energy Policy*, 77:79–88. Publisher: Elsevier.
- Commission, E. (2017). Towards a sustainable and integrated Europe. Technical report, European Commission.
- Copeland, B. R. and Taylor, M. S. (2004). Trade, Growth, and the Environment. *Journal of Economic Literature*, 42(1):7–71.
- Cramton, P. (2017). Electricity market design. *Oxford Review of Economic Policy*, 33(4):589–612.
- Cullen, J. (2013). Measuring the Environmental Benefits of Wind-Generated Electricity. *American Economic Journal: Economic Policy*, 5(4):107–133.
- Cullen, J. A. and Mansur, E. T. (2017). Inferring Carbon Abatement Costs in Electricity Markets: A Revealed Preference Approach Using the Shale Revolution. *American Economic Journal: Economic Policy*, 9(3):106–133.
- Davis, L. W. (2011). The effect of power plants on local housing values and rents. *Review of Economics and Statistics*, 93(4):1391–1402. ISBN: 0034-6535 Publisher: The MIT Press.
- de Gouw, J. A., Parrish, D. D., Frost, G. J., and Trainer, M. (2014). Reduced emissions of CO<sub>2</sub>, NO<sub>x</sub> and SO<sub>2</sub> from U.S. power plants owing to switch from coal to natural gas with combined cycle technology. *Earth's Future*, 2(2):75–82.
- De Miera, G. S., del Río González, P., and Vizcaíno, I. (2008). Analysing the impact of renewable electricity support schemes on power prices: The case of wind electricity in Spain. *Energy Policy*, 36(9):3345–3359. Publisher: Elsevier.
- Dechezleprêtre, A., Fabre, A., Kruse, T., Planterose, B., Chico, A. S., and Stantcheva, S. (2022). Fighting climate change: International attitudes toward climate policies. Technical report, National Bureau of Economic Research.
- Delarue, E. and D’haeseleer, W. (2008). Greenhouse gas emission reduction by means of fuel switching in electricity generation: Addressing the potentials. *Energy Conversion and Management*, 49(4):843–853.

- Denny, E., Tuohy, A., Meibom, P., Keane, A., Flynn, D., Mullane, A., and O'Malley, M. (2010). The impact of increased interconnection on electricity systems with large penetrations of wind generation: A case study of Ireland and Great Britain. *Energy Policy*, 38(11):6946–6954.
- Deschenes, O., Greenstone, M., and Shapiro, J. S. (2017). Defensive investments and the demand for air quality: Evidence from the NOx budget program. *American Economic Review*, 107(10):2958–2989.
- Douenne, T. and Fabre, A. (2020). French attitudes on climate change, carbon taxation and other climate policies. *Ecological Economics*, 169:106496. Publisher: Elsevier.
- Douenne, T. and Fabre, A. (2022). Yellow vests, pessimistic beliefs, and carbon tax aversion. *American Economic Journal: Economic Policy*, 14(1):81–110. Publisher: American Economic Association 2014 Broadway, Suite 305, Nashville, TN 37203-2425.
- Dröes, M. I. and Koster, H. R. (2021). Wind turbines, solar farms, and house prices. *Energy Policy*, 155:112327.
- Dröes, M. I. and Koster, H. R. (2016). Renewable energy and negative externalities: The effect of wind turbines on house prices. *Journal of Urban Economics*, 96:121–141. ISBN: 0094-1190 Publisher: Elsevier.
- EC (2022). Communication REPowerEU.
- EIA (2021). U.S. Energy Information Administration, Monthly Energy Review, Tables 11.1—11.6. Technical report.
- Ember (2024). Yearly Electricity Data.
- Fabra, N. and Reguant, M. (2014). Pass-through of emissions costs in electricity markets. *American Economic Review*, 104(9):2872–2899. ISBN: 0002-8282 Publisher: American Economic Association 2014 Broadway, Suite 305, Nashville, TN 37203.
- Fell, H. and Johnson, J. X. (2020). Regional disparities in emissions reduction and net trade from renewables. *Nature Sustainability*, 4(4):358–365.
- Fell, H. and Kaffine, D. T. (2018). The Fall of Coal: Joint Impacts of Fuel Prices and Renewables on Generation and Emissions. *American Economic Journal: Economic Policy*, 10(2):90–116.
- Fell, H., Kaffine, D. T., and Novan, K. (2021). Emissions, Transmission, and the Environmental Value of Renewable Energy. *American Economic Journal: Economic Policy*, 13(2):241–272.

- 
- Fell, H. and Linn, J. (2013). Renewable electricity policies, heterogeneity, and cost effectiveness. *Journal of Environmental Economics and Management*, 66(3):688–707.
- Financial Times (2019). Germans fall out of love with wind power.
- Fischer, C. and Newell, R. G. (2008). Environmental and technology policies for climate mitigation. *Journal of environmental economics and management*, 55(2):142–162. Publisher: Elsevier.
- Freeman III, A. M., Herriges, J. A., and Kling, C. L. (2014). *The measurement of environmental and resource values: theory and methods*. Routledge.
- Gelabert, L., Labandeira, X., and Linares, P. (2011). An ex-post analysis of the effect of renewables and cogeneration on Spanish electricity prices. *Energy economics*, 33:S59–S65. Publisher: Elsevier.
- Germeshausen, R., Heim, S., and Wagner, U. J. (2023). Support for renewable energy: The case of wind power. Publisher: CRC TR 224, Discussion Paper.
- Gibbons, S. (2015). Gone with the wind: Valuing the visual impacts of wind turbines through house prices. *Journal of Environmental Economics and Management*, 72:177–196.
- Gillingham, K., Ovaere, M., and Weber, S. (2021). Carbon Policy and the Emissions Implications of Electric Vehicles. Technical Report w28620, National Bureau of Economic Research, Cambridge, MA.
- Glachant, J.-M., Joskow, P. L., and Pollitt, M. G. (2021). *Handbook on electricity markets*. Edward Elgar Publishing.
- Gonzales, L., Ito, K., and Reguant, M. (2022). The Dynamic Impact of Market Integration: Evidence from Renewable Energy Expansion in Chile. Technical Report w30016, National Bureau of Economic Research, Cambridge, MA.
- Graff Zivin, J. S., Kotchen, M. J., and Mansur, E. T. (2014). Spatial and temporal heterogeneity of marginal emissions: Implications for electric cars and other electricity-shifting policies. *Journal of Economic Behavior & Organization*, 107:248–268.
- Grossi, L., Heim, S., Hüscherlath, K., and Waterson, M. (2018). Electricity market integration and the impact of unilateral policy reforms. *Oxford Economic Papers*, 70(3):799–820.

- Grossi, L., Heim, S., and Waterson, M. (2017). The impact of the German response to the Fukushima earthquake. *Energy Economics*, 66:450–465.
- Gugler, K., Haxhimusa, A., and Liebensteiner, M. (2021). Effectiveness of climate policies: Carbon pricing vs. subsidizing renewables. *Journal of Environmental Economics and Management*, 106:102405.
- Hansen, L. P., Heaton, J., and Yaron, A. (1996). Finite-sample properties of some alternative GMM estimators. *Journal of Business & Economic Statistics*, 14(3):262–280.
- Hausman, C. and Rapson, D. (2017). Regression Discontinuity in Time: Considerations for Empirical Applications. Technical Report w23602, National Bureau of Economic Research, Cambridge, MA.
- Heckman, J. J. (1976). The common structure of statistical models of truncation, sample selection and limited dependent variables and a simple estimator for such models. In *Annals of economic and social measurement, volume 5, number 4*, pages 475–492. NBER.
- Hirth, L., Khanna, T., and Ruhnau, O. (2023). How aggregate electricity demand responds to hourly wholesale price fluctuations. *ZBW - Leibniz Information Centre for Economics*.
- Holladay, J. S. and LaRiviere, J. (2017). The impact of cheap natural gas on marginal emissions from electricity generation and implications for energy policy. *Journal of Environmental Economics and Management*, 85:205–227.
- Holland, S. P., Mansur, E. T., Muller, N. Z., and Yates, A. J. (2020). Decompositions and policy consequences of an extraordinary decline in air pollution from electricity generation. *American Economic Journal: Economic Policy*, 12(4):244–274.
- Horst Keppler, J., Phan, S., and Le Pen, Y. (2016). The Impacts of Variable Renewable Production and Market Coupling on the Convergence of French and German Electricity Prices. *The Energy Journal*, 37(3).
- IEA (2021a). Coal Information: Overview.
- IEA (2021b). Global Energy Review 2021. Technical report, Paris.
- IEA (2021c). Net Zero by 2050. Technical report.
- IEA (2023). Greenhouse Gas Emissions from Energy Data Explorer.
- IEA (2024). Germany’s renewables energy act. International Energy Agency.

- Imbens, G. W. and Wooldridge, J. M. (2009). Recent developments in the econometrics of program evaluation. *Journal of economic literature*, 47(1):5–86. ISBN: 0022-0515  
Publisher: American Economic Association.
- Intergovernmental Panel On Climate Change (Ipc), editor (2023). *Climate Change 2022 - Mitigation of Climate Change: Working Group III Contribution to the Sixth Assessment Report of the Intergovernmental Panel on Climate Change*. Cambridge University Press, 1 edition.
- International Energy Agency (2016). *CO<sub>2</sub> Emissions from Fuel Combustion 2016*. CO<sub>2</sub> Emissions from Fuel Combustion. OECD.
- IPCC (2018). Global Warming of 1.5°C. An IPCC Special Report on the impacts of global warming of 1.5°C above pre-industrial levels and related global greenhouse gas emission pathways, in the context of strengthening the global response to the threat of climate change, sustainable development, and efforts to eradicate poverty. Technical report, Cambridge University Press.
- IPCC (2023). Climate Change 2022 - Mitigation of Climate Change: Working Group III Contribution to the Sixth Assessment Report of the Intergovernmental Panel on Climate Change. Technical report, Cambridge University Press.
- IPCC (2023a). Climate Change 2022 – Impacts, Adaptation and Vulnerability: Working Group II Contribution to the Sixth Assessment Report of the Intergovernmental Panel on Climate Change. Technical report, Cambridge University Press.
- IPCC (2023b). IPCC, 2023: Climate Change 2023: Synthesis Report. Contribution of Working Groups I, II and III to the Sixth Assessment Report of the Intergovernmental Panel on Climate Change [Core Writing Team, H. Lee and J. Romero (eds.)]. IPCC, Geneva, Switzerland. Technical report, Intergovernmental Panel on Climate Change (IPCC). Edition: First.
- IRENA (2023). *Tripling renewable power and doubling energy efficiency by 2030 crucial steps towards 1.5°C*. International Renewable Energy Agency, Abu Dhabi. OCLC: 1423377320.
- Jarvis, S. (2021). The economic costs of NIMBYism: evidence from renewable energy projects. Publisher: London School of Economics and Political Science.
- Jarvis, S., Deschenes, O., and Jha, A. (2019). The Private and External Costs of Germany’s Nuclear Phase-Out. Technical Report w26598, National Bureau of Economic Research, Cambridge, MA.

- Jarvis, S., Deschenes, O., and Jha, A. (2022). The private and external costs of Germany's nuclear phase-out. *Journal of the European Economic Association*, 20(3):1311–1346.
- Jayadev, G., Leibowicz, B. D., and Kutanoglu, E. (2020). U.S. electricity infrastructure of the future: Generation and transmission pathways through 2050. *Applied Energy*, 260:114267.
- Jensen, C. U., Panduro, T. E., Lundhede, T. H., Nielsen, A. S. E., Dalsgaard, M., and Thorsen, B. J. (2018). The impact of on-shore and off-shore wind turbine farms on property prices. *Energy policy*, 116:50–59. ISBN: 0301-4215 Publisher: Elsevier.
- Joskow, P. and Tirole, J. (2005). Merchant transmission investment. *The Journal of industrial economics*, 53(2):233–264. ISBN: 0022-1821 Publisher: Wiley Online Library.
- Joskow, P. L. (2013). Natural gas: from shortages to abundance in the United States. *American Economic Review*, 103(3):338–343. ISBN: 0002-8282 Publisher: American Economic Association.
- Joskow, P. L. and Tirole, J. (2000). Transmission rights and market power on electric power networks. *The Rand Journal of Economics*, pages 450–487. ISBN: 0741-6261 Publisher: JSTOR.
- Kaffine, D. T., McBee, B. J., and Lieskovsky, J. (2013). Emissions Savings from Wind Power Generation in Texas. *The Energy Journal*, 34(1):155–175. Publisher: International Association for Energy Economics.
- Kim, M.-K. and Kim, T. (2016). Estimating impact of regional greenhouse gas initiative on coal to gas switching using synthetic control methods. *Energy Economics*, 59:328–335.
- Klick, L. and Schaffner, S. (2021). Regional real estate price indices for germany, 2008–2019: Rwi-geo-redx. *Jahrbücher für Nationalökonomie und Statistik*, 241(1):119–129.
- Knittel, C., Metaxoglou, K., and Trindade, A. (2015). Natural Gas Prices and Coal Displacement: Evidence from Electricity Markets. Technical Report w21627, National Bureau of Economic Research, Cambridge, MA.
- Knopper, L. D. and Ollson, C. A. (2011). Health effects and wind turbines: A review of the literature. *Environmental health*, 10:1–10.
- Krekel, C. and Zerrahn, A. (2017). Does the presence of wind turbines have negative externalities for people in their surroundings? Evidence from well-being data. *Journal of Environmental Economics and Management*, 82:221–238.

- Kumara, H. N., Babu, S., Rao, G. B., Mahato, S., Bhattacharya, M., Rao, N. V. R., Tamiliniyan, D., Parengal, H., Deepak, D., Balakrishnan, A., and Bilaskar, M. (2022). Responses of birds and mammals to long-established wind farms in India. *Scientific Reports*, 12(1):1339.
- Lafrancois, B. A. (2012). A lot left over: Reducing CO<sub>2</sub> emissions in the United States' electric power sector through the use of natural gas. *Energy Policy*, 50:428–435.
- Le Quéré, C., Peters, G. P., Friedlingstein, P., Andrew, R. M., Canadell, J. G., Davis, S. J., Jackson, R. B., and Jones, M. W. (2021). Fossil CO<sub>2</sub> emissions in the post-COVID-19 era. *Nature Climate Change*, 11(3):197–199. Publisher: Nature Publishing Group UK London.
- Liebensteiner, M. and Wrienz, M. (2020). Do intermittent renewables threaten the electricity supply security? *Energy Economics*, 87:104499. ISBN: 0140-9883 Publisher: Elsevier.
- Linn, J. and Muehlenbachs, L. (2018). The heterogeneous impacts of low natural gas prices on consumers and the environment. *Journal of Environmental Economics and Management*, 89:1–28.
- Macedo, D. P., Marques, A. C., and Damette, O. (2020). The impact of the integration of renewable energy sources in the electricity price formation: is the Merit-Order Effect occurring in Portugal? *Utilities Policy*, 66:101080.
- Maddison, A. (2006). *The World Economy: Volume 1: A Millennial Perspective and Volume 2: Historical Statistics*. Development Centre Studies. OECD.
- Managi, S., Hibiki, A., and Tsurumi, T. (2009). Does trade openness improve environmental quality? *Journal of Environmental Economics and Management*, 58(3):346–363.
- Millstein, D., Wiser, R., Bolinger, M., and Barbose, G. (2017). The climate and air-quality benefits of wind and solar power in the United States. *Nature Energy*, 2(9):1–10. ISBN: 2058-7546 Publisher: Nature Publishing Group.
- Minx, J. C., Lamb, W. F., Andrew, R. M., Canadell, J. G., Crippa, M., Döbbeling, N., Forster, P. M., Guizzardi, D., Olivier, J., Peters, G. P., Pongratz, J., Reisinger, A., Rigby, M., Saunio, M., Smith, S. J., Solazzo, E., and Tian, H. (2021). A comprehensive and synthetic dataset for global, regional, and national greenhouse gas emissions by sector 1970–2018 with an extension to 2019. *Earth System Science Data*, 13(11):5213–5252.



- Mwampashi, M. M., Nikitopoulos, C. S., Konstandatos, O., and Rai, A. (2021). Wind generation and the dynamics of electricity prices in Australia. *Energy Economics*, 103:105547. ISBN: 0140-9883 Publisher: Elsevier.
- Nordhaus, W. (2019). Climate change: The ultimate challenge for economics. *American Economic Review*, 109(6):1991–2014. Publisher: American Economic Association 2014 Broadway, Suite 305, Nashville, TN 37203.
- Nordhaus, W. D. (2017). Revisiting the social cost of carbon. *Proceedings of the National Academy of Sciences*, 114(7):1518–1523.
- Novan, K. (2015). Valuing the Wind: Renewable Energy Policies and Air Pollution Avoided. *American Economic Journal: Economic Policy*, 7(3):291–326.
- Parsons, G. and Heintzelman, M. D. (2022). The Effect of Wind Power Projects on Property Values: A Decade (2011–2021) of Hedonic Price Analysis. *International Review of Environmental and Resource Economics*, 16(1):93–170. ISBN: 1932-1465 Publisher: Now Publishers, Inc.
- Perino, G. (2018). New EU ETS Phase 4 rules temporarily puncture waterbed. *Nature Climate Change*, 8(4):262–264.
- Petersen, C., Reguant, M., and Segura, L. (2022). Measuring the Impact of Wind Power and Intermittency. *Available at SSRN 4291672*.
- Peña, J. I., Rodriguez, R., and Mayoral, S. (2022). Cannibalization, depredation, and market remuneration of power plants. *Energy Policy*, 167:113086. ISBN: 0301-4215 Publisher: Elsevier.
- Phan, S. and Roques, F. (2015). Is the depressive effect of renewables on power prices contagious? A cross border econometric analysis. Publisher: JSTOR.
- Prol, J. L., Steininger, K. W., and Zilberman, D. (2020). The cannibalization effect of wind and solar in the California wholesale electricity market. *Energy Economics*, 85:104552. ISBN: 0140-9883 Publisher: Elsevier.
- Quentel, M. (2023). Gone with the Wind: Renewable Energy Infrastructure, Welfare, and Redistribution.
- Rauner, S., Bauer, N., Dirnaichner, A., Dingenen, R. V., Mutel, C., and Luderer, G. (2020). Coal-exit health and environmental damage reductions outweigh economic impacts. *Nature Climate Change*, 10(4):308–312.

- Recharge (2024). German green groups compromise on wildlife to help wind. Bernd Radowitz, 4 September 2019.
- Rehfeldt, M., Fleiter, T., Herbst, A., and Eidelloth, S. (2020). Fuel switching as an option for medium-term emission reduction - A model-based analysis of reactions to price signals and regulatory action in German industry. *Energy Policy*, 147:111889.
- Rosen, S. (1974). Hedonic prices and implicit markets: product differentiation in pure competition. *Journal of political economy*, 82(1):34–55. ISBN: 0022-3808 Publisher: The University of Chicago Press.
- Rosendahl, K. E. (2019). EU ETS and the waterbed effect. *Nature Climate Change*, 9(10):734–735.
- Ryan, N. (2021). The Competitive Effects of Transmission Infrastructure in the Indian Electricity Market. *American Economic Journal: Microeconomics*, 13(2):202–242.
- Sensfuß, F., Ragwitz, M., and Genoese, M. (2008). The merit-order effect: A detailed analysis of the price effect of renewable electricity generation on spot market prices in Germany. *Energy policy*, 36(8):3086–3094. Publisher: Elsevier.
- Sexton, S. E., Kirkpatrick, A. J., Harris, R., and Muller, N. Z. (2018). Heterogeneous environmental and grid benefits from rooftop solar and the costs of inefficient siting decisions. Technical report, National Bureau of Economic Research.
- Spiegel (2011). NIMBY protests threaten Germany’s energy revolution.
- Sunak, Y. and Madlener, R. (2016). The impact of wind farm visibility on property values: A spatial difference-in-differences analysis. *Energy Economics*, 55:79–91. ISBN: 0140-9883 Publisher: Elsevier.
- Sunak, Y. and Madlener, R. (2017). The impact of wind farms on property values: A locally weighted hedonic pricing model. *Papers in Regional Science*, 96(2):423–444. ISBN: 1056-8190 Publisher: Wiley Online Library.
- The Economist (2021). Solar power’s NIMBY problem.
- The New York Times (2022). The US will need thousands of winds farms. Will small towns go along?
- Traber, T. and Kemfert, C. (2011). Gone with the wind?—Electricity market prices and incentives to invest in thermal power plants under increasing wind energy supply. *Energy Economics*, 33(2):249–256. ISBN: 0140-9883 Publisher: Elsevier.

- UNDP (2021). Issue Brief - China's 14th 5-Year Plan: Spotlighting Climate & Environment. Technical report.
- Van Der Horst, D. (2007). NIMBY or not? Exploring the relevance of location and the politics of voiced opinions in renewable energy siting controversies. *Energy Policy*, 35(5):2705–2714.
- Vyn, R. J. and McCullough, R. M. (2014). The Effects of Wind Turbines on Property Values in Ontario: Does Public Perception Match Empirical Evidence? *Canadian Journal of Agricultural Economics/Revue canadienne d'agroeconomie*, 62(3):365–392.
- WEF (2024). The Global Risks Report, 19th Edition. Technical report, World Economic Forum.
- WHO (2021). Climate change and health.
- Wilson, I. A. G. and Staffell, I. (2018). Rapid fuel switching from coal to natural gas through effective carbon pricing. *Nature Energy*, 3(5):365–372.
- Wolak, F. A. (2015). Measuring the competitiveness benefits of a transmission investment policy: The case of the Alberta electricity market. *Energy Policy*, 85:426–444.
- Woo, C., Moore, J., Schneiderman, B., Ho, T., Olson, A., Alagappan, L., Chawla, K., Toyama, N., and Zarnikau, J. (2016). Merit-order effects of renewable energy and price divergence in California's day-ahead and real-time electricity markets. *Energy Policy*, 92:299–312.
- Woo, C.-K., Horowitz, I., Moore, J., and Pacheco, A. (2011). The impact of wind generation on the electricity spot-market price level and variance: The Texas experience. *Energy Policy*, 39(7):3939–3944. ISBN: 0301-4215 Publisher: Elsevier.
- WP (2020). Biden calls for 100 percent clean electricity by 2035. Here's how far we have to go. *The Washington Post*.
- Würzburg, K., Labandeira, X., and Linares, P. (2013). Renewable generation and electricity prices: Taking stock and new evidence for Germany and Austria. *Energy Economics*, 40:S159–S171. ISBN: 0140-9883 Publisher: Elsevier.
- Yang, Y. (2022). Electricity interconnection with intermittent renewables. *Journal of Environmental Economics and Management*, 113:102653.
- Zerrahn, A. (2017). Wind power and externalities. *Ecological Economics*, 141:245–260. ISBN: 0921-8009 Publisher: Elsevier.

Zhou, Y. and Huang, L. (2021). How regional policies reduce carbon emissions in electricity markets: Fuel switching or emission leakage. *Energy Economics*, 97:105209.





## RÉSUMÉ

---

Cette thèse est composée de trois chapitres indépendants portant sur les implications du déploiement des énergies renouvelables. Elle examine comment ces énergies contribuent à la réduction des émissions de gaz à effet de serre et comment elles peuvent affecter négativement les populations locales. Les deux premiers chapitres se concentrent sur la valeur environnementale des énergies renouvelables, c'est-à-dire la quantité d'émissions de CO<sub>2</sub> évitées par la génération d'un mégawatt-heure supplémentaire. Le **Chapitre 1** analyse comment cette valeur est modifiée par l'intégration des marchés de l'électricité. Il montre que cette intégration augmente les émissions évitées en France grâce à l'éolien espagnol, mais diminue celles évitées en Espagne, réduisant ainsi la valeur environnementale globale. Ce résultat est dû à une substitution moindre du charbon en Espagne et à une plus grande substitution du gaz en France. Il en résulte un coût de la réduction de la tonne de CO<sub>2</sub> supérieur. Le **Chapitre 2** quantifie les variations régionales de la valeur environnementale aux États-Unis en fonction des prix des combustibles et du CO<sub>2</sub>. Il révèle que sans prix du carbone, les renouvelables remplacent principalement du gaz, offrant des bénéfices modestes. Avec un prix du carbone croissant, le charbon devient marginal, augmentant la valeur environnementale des renouvelables jusqu'à un seuil. Au-delà de celui-ci, le charbon devient non rentable, et la valeur environnementale diminue à mesure que le gaz redevient marginal. Le **Chapitre 3** examine l'impact des éoliennes sur les prix immobiliers en Allemagne, documentant le phénomène NIMBY (opposition locale). Les résultats montrent une baisse des prix des maisons, du tourisme local et des permis de construire suite à l'installation de nouvelles turbines. Ces effets sont plus prononcés pour la première turbine. Sur le plan positif, chaque éolienne installée augmente la capacité fiscale locale d'une municipalité grâce à sa contribution aux revenus fiscaux commerciaux locaux.

## MOTS CLÉS

---

Énergies renouvelables, Intégration des marchés, Décarbonation, Révolution du gaz de schiste, Externalités locales, Économétrie appliquée

## ABSTRACT

---

This thesis consists of three independent chapters examining the implications of deploying renewable energies. It explores how these energies contribute to reducing greenhouse gas emissions and how they can negatively affect local populations. The first two chapters focus on the environmental value of renewable energies, specifically the amount of CO<sub>2</sub> emissions avoided by generating an additional megawatt-hour. **Chapter 1** analyzes how this value is altered by the integration of electricity markets. It shows that market integration increases emissions avoided in France due to Spanish wind energy but decreases more those avoided in Spain, thus reducing the overall environmental value. This result is attributed to a lesser substitution of coal in Spain and a greater substitution of gas in France, leading to a higher cost of CO<sub>2</sub> reduction. **Chapter 2** quantifies regional variations in the environmental value in the United States based on fuel and CO<sub>2</sub> prices. It reveals that without a carbon price, renewables primarily replace gas, offering modest benefits. As the carbon price increases, coal becomes the marginal technology, enhancing the environmental value of renewables up to a threshold. Beyond this point, coal becomes uneconomical, and the environmental value decreases as gas becomes the marginal source again. **Chapter 3** examines the impact of wind turbines on property prices in Germany, documenting the NIMBYism phenomenon. The results show a decrease in house prices, local tourism and building permits following the installation of new turbines. These effects are more pronounced for the first turbine. On the positive side, each installed wind turbine increases a municipality's local tax capacity through their contribution to local commercial tax income.

## KEYWORDS

---

Renewable energy, Market integration, Decarbonization, Shale gas boom, NIMBY, Local disamenities, Econometrics