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DÉCENTRALISER LA PRODUCTION: TROIS ESSAIS SUR LES POLITIQUES PUBLIQUES POUR LA TRANSITION ÉNERGETIQUE

Sous la direction de: Carine Staropoli

Jury

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DECENTRALIZED ENERGY SUPPLY: THREE ESSAYS ON PUBLIC POLICIES FOR THE ENERGY TRANSITION

Under supervision of: Carine Staropoli

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Résumé de la thèse

Les trois chapitres de cette thèse visent à mieux comprendre l'efficacité des instruments de politiques publiques liés au déploiement d'infrastructures énergétiques décentralisées.

Le premier chapitre étudie comment un choc sur les prix de l'énergie modifie la planification des actions locales pour atténuer les émissions de gaz à effet de serre (GES). Après l'invasion de l'Ukraine par la Russie en février 2022, les ménages ont connu une augmentation drastique de leurs factures. Cette hausse des prix pourrait réduire le coût social des Plans Climat établis par les autorités locales car ils permettent à la fois de protéger les consommateurs contre la hausse des prix de l'énergie et de réduire les émissions GES. Ces documents définissent un ensemble de mesures à mettre en œuvre sur le territoire d'une autorité locale pour atteindre des objectifs de réduction des émissions de GES. Compte tenu de la modification des coûts d'atténuation due à la hausse des prix de l'énergie et de leurs budgets limités, les autorités locales doivent mettre à jour leurs plans pour donner la priorité aux actions les plus coût-efficaces. En utilisant la ville de Bristol comme étude de cas (Royaume-Uni), j'évalue deux mesures envisagées par la ville pour décarboner la production de chaleur résidentielle: l'extension du réseau de chaleur urbain et la rénovation énergétique des bâtiments. Je construis un modèle pour réaliser une analyse coût-bénéfice *ex-ante* en utilisant des mécanismes précis pour estimer l'impact des rénovations – tirés de la littérature sur le "energy-efficiency gap" – et en tenant compte des incertitudes sur les tendances futures des prix de l'énergie. Je trouve que le réseau de chaleur urbain présente des coûts d'atténuation inférieurs à ceux des rénovations énergétiques lorsque les prix du gaz augmentent d'au moins 30% par rapport aux niveaux d'avant crise. Sous le choc des prix de l'énergie de 2022 – avec des augmentations annuelles presque doublées des prix de l'électricité et du gaz – les deux options de décarbonation génèrent plus de 1 livre sterling de bénéfices actualisés pour les consommateurs par unité de coût d'investissement. De plus, le réseau de chaleur urbain génère presque deux fois plus de bénéfices par unité de coût que les rénovations énergétiques. Cela souligne la valeur assurantielle intrinsèque des infrastructures énergétiques bas-carbone contre la hausse des prix des énergies fossiles.

Le deuxième chapitre évalue la mauvaise allocation dynamique des investissements observés dans les installations solaires photovoltaïques (PV) en France. Les installations solaires PV présentent des coûts actualisés de production d'électricité hétérogènes en raison de leur taille, leur emplacement, de leurs structures et de l'année de leur mise en service. Ainsi, le coût actualisé pour atteindre une trajectoire définie de production annuelle d'énergie solaire dépend fortement des choix de mise en service effectués entre différentes installations à une année donnée et la séquence des décisions d'investissement peut ne pas être coût-efficace. Typiquement en France, un choix délibéré a été de mettre initialement en service des installations résidentielles PV de petite taille qui sont plus coûteuses par unité d'énergie produite que des grandes centrales solaires au sol. Nous construisons un jeu de données sur l'ensemble des installations solaires en France métropolitaine qui détaille les dates de mise en service, la production d'énergie et les coûts actualisés pour chaque installation. Nous quantifions la mauvaise allocation dynamique des investissements qui a eu lieu en France sur la période 2005–2021. Nous faisons cela en comparant le coût actualisé des investissements observés pour développer le parc solaire français à une séquence d'investissements contrefactuelle, qui reproduit la production solaire observée chaque année en minimisant les coûts. Nous constatons que la même trajectoire aurait pu être réalisée pour seulement 70% des coûts totaux actualisés. Le déploiement précoce des installations solaire PV résidentielles semble être associé à une grande partie de cette mauvaise allocation. Cette observation est cohérente avec le niveau élevé des tarifs d'achat pour ces dernières. L'introduction plus tardive des mécanismes d'enchères est en revanche associée à une diminution significative de la mauvaise allocation. D'autres objectifs, au-delà de l'efficience, pourraient justifier la priorité donnée aux installations solaires PV résidentielles par rapport aux grandes installations, tels que la réduction des conflits d'utilisation des terres ou l'augmentation de l'emploi local. Le coût de la mauvaise allocation que nous avons trouvé peut donc être considéré comme une estimation du coût d'opportunité pour tout autre objectif que ces politiques tenteraient d'atteindre.

Le troisième chapitre étudie l'impact des réglementations sur l'utilisation des sols sur le déploiement des installations solaires photovoltaïques (PV) en France. Cette réglementation est une activité conjointe entre les autorités nationales et locales. Des critères d'éligibilité sont définis par le régulateur de l'énergie pour permettre l'implantation d'installations PV au sol et sont basés sur les zonages des documents d'urbanisme. Étant donné la variété des types de documents d'urbanisme utilisés par les communes, ces critères d'éligibilité peuvent être mal transposés au niveau local. Les différents types de documents d'urbanisme utilisés par les communes se différencient par au moins trois dimensions: le niveau de détail fourni pour identifier l'utilisation des terres, la date d'approbation du document et son intégration au niveau inter-communal. J'étudie comment l'articulation des critères d'éligibilité définis au niveau national avec les documents d'urbanisme au niveau local impacte la quantité de terres allouées aux installations solaires. Je construis un ensemble de données regroupant l'historique de la mise en service des installations PV au sol et les changements des documents d'urbanisme au niveau des communes. En utilisant une approche quasi-expérimentale, je trouve que la mise en place de documents d'urbanisme plus détaillés (PLU et PLU-i) augmente la quantité de terres allouées aux installations solaires par rapport à d'autres types de documents (RNU et CC). En revanche, avoir adopté un document d'urbanisme plus récemment ou bien, avoir intégré son plan au niveau inter-communal diminue la quantité de terres allouées aux installations solaires. J'explique ces effets par deux mécanismes. Premièrement un effet réglementaire: les critères d'éligibilité simplifient l'autorisation des projets solaires sur les terrains éligibles pour la construction. Ils sont donc mieux alignés avec des documents d'urbanisme plus détaillés (PLU et PLU-i) qui peuvent discriminer entre plusieurs catégories de développements. Deuxièmement, il existe un conflit sur l'usage des sols. Les développeurs de projets solaires sont mis en concurrence avec d'autres développements fonciers pour obtenir leurs permis de construire. Ils ciblent donc stratégiquement les communes qui présentent le moins de restrictions sur les nouvelles constructions. Typiquement, les communes avec des documents d'urbanisme anciens qui n'ont pas encore intégré l'évolution de la législation en terme d'artificialisation des sols (par exemple, la loi "Climat et Résilience" de 2021).

Thesis Summary

The three chapters of this thesis aim at better understanding the efficiency of public policy instruments associated with the deployment of decentralized energy infrastructures.

The first chapter examines how a shock on energy prices modifies local climate action planning. Following Russia's invasion of Ukraine in February 2022, European households experienced a dramatic increase in energy bills. This rise in energy prices could reduce the social cost of Climate Action Plans, as they can both protect consumers from rising energy prices and reduce greenhouse gases (GHG) emissions. Climate Action Plans are policy documents that identify series of measures to be implemented within a local authority's jurisdiction to achieve GHG reduction targets. Given modified mitigation costs due to increases in energy prices and limited budgets, local authorities must update their strategic planning to prioritize the most cost-effective actions. Using the city of Bristol (UK) as a case study, I evaluate two policy options considered by the city to decarbonize residential heating: either extending the local district heating network or energy efficiency retrofitting in buildings. I build a model to conduct an *ex-ante* Cost-Benefit Analysis, using precise mechanisms to estimate the impact of retrofits – taken from the "energy efficiency gap" literature – and accounting for uncertainties on future energy prices trends. I find that the district heating network has lower mitigation costs than energy efficiency retrofits when gas prices rise by at least 30% relative to pre-crisis levels. Under the 2022 energy prices shock – with almost twofold annual increases in electricity and gas prices – both decarbonation options generate more than £ 1 benefits in present value to consumers per unit investment cost and the district heating network generates nearly twice the benefits per unit of cost compared to energy retrofits. This highlights the intrinsic insurance value of low-carbon energy infrastructures against rising fossil fuel prices.

The second chapter quantifies the dynamic misallocation of observed investments in solar photovoltaic (PV) installations in France. Solar PV installations have heterogeneous levelized costs of electricity, due to differences in size, location, structural characteristics and year of commissioning. Therefore, the present value cost of achieving a defined trajectory of

annual solar energy production depends on which projects are commissioned when and the observed sequence of investment decisions need not be cost-efficient. Typically in France, a deliberate policy choice was to prioritize the development of small-scale residential PV installations, which are more costly per unit of energy produced than larger ground-mounted installations. We construct a dataset on the universe of solar installations in metropolitan France, with details on commissioning dates, energy output and present value costs for each installation. We estimate the dynamic misallocation of investments that occurred in France over the period 2005–2021. We do so by comparing the present value cost of realized investments to a counterfactual sequence of investments that reproduces the same trajectory of annual solar energy production at minimum costs. We find that we could have obtained the same trajectory for only 70% of the total present value costs. The early deployment of small-scale residential PV installations seems to be associated with a large part of the misallocation. This observation is consistent with the high level of early feed-in-tariffs for the latter. The introduction of public auctions is in contrast associated to a decrease in the magnitude of misallocation. Other objectives, beyond efficiency, could justify the prioritization of small-scale residential solar installations over large-scale ones, such as reducing land-use conflicts or increasing local employment. The cost of misallocation we estimated can thus be considered as an estimation of the opportunity cost for whichever other goals these policies are trying to address.

The third chapter studies the impact of land-use regulation on the deployment of ground-mounted solar photovoltaic (PV) installations in France. Land-use regulation for solar in France is a joint activity between top and local jurisdictions. Eligibility criteria defined by the french energy regulator to allow or ban the siting of ground-mounted solar installations are based on land-use planning at the municipality level. However, given the variety of land-use planning frameworks used by municipalities, eligibility criteria can be imperfectly transposed at the local level. Municipalities use different types of land-use planning frameworks which vary by at least three dimensions: the level of detail provided for identifying land use, the time of approval and whether it is integrated at the inter-municipality level. I investigate how the articulation of top-level eligibility criteria and local land-use planning affects the amount of land allocated to ground-mounted solar installations. I construct a dataset combining the history of commissioning of ground-mounted installations with changes in land-use planning frameworks at the municipality level. Using a quasi-experimental approach, I find that municipalities with more detailed land-use planning frameworks increase the amount of land allocated to solar installations. Conversely, recently updated land-use planning and integrated land-use planning at the inter-municipality level allocate less land to solar installations. I explain these effects in light of two mechanisms. First, there is a regulatory effect. Eligibility criteria simplify permitting in land plots that are identified for land developments. Thus, they are better aligned with more detailed land-use planning frameworks, that can discriminate between various categories of land developments. Second, there is a land conflict effect. As solar PV developers compete with other land developments to obtain building permits, they strategically target municipalities that present less restrictions for new land developments. Typically, municipalities with old land-use planning frameworks that have yet adopted evolving legislation on land conservation (e.g. "Climate and Resilience" law, 2021).

Contents

Introduction Générale

Réduire l'intensité carbone de l'approvisionnement énergétique est un levier essentiel pour atténuer les émissions de gaz à effet de serre (GES), à l'origine du changement climatique (IPCC, 2023). Cependant, une transformation profonde des systèmes énergétiques est nécessaire pour atteindre des objectifs ambitieux de réduction, transformation que l'on désigne par le terme de "*transition énergétique*". La *transition énergétique* implique l'électrification des usages – puisque l'électricité peut être produite à partir de sources bas carbone – et le passage d'une production fondée sur les énergies fossiles à une production bas carbone. Cette dernière repose sur des technologies convertissant des énergies renouvelables en électricité, telles que l'éolien, le solaire ou l'hydroélectricité, ou bien sur des technologies s'appuyant sur la circularité d'une ressource, comme la production de gaz renouvelable.

Le développement de la production d'énergie bas carbone suppose une *décentralisation* des infrastructures énergétiques. En effet, la majorité de ces technologies sont des installations de petite taille. Elles sont dispersées sur les territoires afin d'être situées au plus près de leur ressource énergétique primaire ou des usages finaux. Elles sont raccordées aux réseaux de distribution locaux (basse tension) plutôt qu'aux réseaux de transport nationaux (haute tension). De plus, leur mise en place est encadrée par des décisions locales, prises par des individus ou des collectivités, qui peuvent choisir d'investir ou d'autoriser le développement d'une unité de production.

Cette transition vers une production d'énergie décentralisée soulève de nouveaux arbitrages. D'abord, en raison des coûts supplémentaires qu'elle peut engendrer. Remplacer une centrale conventionnelle par plusieurs installations de petite taille peut entraîner un coût plus élevé de l'énergie produite, en raison des économies d'échelle, lorsque les coûts augmentent moins que proportionnellement avec la taille des installations. Des investissements supplémentaires peuvent également être nécessaires pour assurer le bon fonctionnement du réseau électrique accueillant un grand nombre d'installations renouvelables (Astier et al., 2023). Ensuite, les bénéfices nets d'une unité de production d'énergie varient fortement selon sa localisation. Les installations renouvelables ont des profils de production dépendant des conditions météorologiques locales (Pfenninger and Staffell, 2016), ce qui implique des variations significatives de la valeur de marché de l'électricité produite (Joskow, 2011) ainsi que de la quantité de GES et de polluants atmosphériques évités (Abrell et al., 2019a; Sexton et al., 2021). Elles peuvent aussi engendrer des externalités négatives lorsqu'elles sont implantées à proximité des habitations, notamment du bruit et des nuisances visuelles, entraînant des pertes d'utilité importantes (Gibbons, 2015; Dröes and Koster, 2021). Par conséquent, des controverses publiques et oppositions locales peuvent freiner la mise en service de nouvelles unités de production, dans ce qu'on appelle les phénomènes "NIMBY" ("Not In My Backyard") (Carley et al., 2020). Enfin, le déploiement d'infrastructures décentralisées suppose la création de nouveaux champs d'action pour les autorités locales qui participent à leur régulation (Poupeau, 2014; Bulkeley and Castán Broto, 2013). Cette décentralisation de la prise de décision ajoute de nouvelles articulations dans les processus administratifs. Augmenter le nombre de niveaux administratifs peut à son tour engendrer des coûts de transaction plus élevés pour la mise en œuvre d'une réglementation, et mener à des décisions incohérentes à l'échelle locale (Poupeau, 2014).

Compte tenu de la présence de multiples externalités et de la transformation profonde en jeu, des interventions publiques sont nécessaires pour mener à bien les changements requis par la transition énergétique, notamment pour répondre aux nouveaux arbitrages soulevés par cette transition et garantir son efficacité économique. En prenant les objectifs politiques comme donnés, une intervention efficiente est celle qui permet de les atteindre au moindre coût parmi les alternatives disponibles (Schmalensee, 2012). La Commission européenne vise à réduire les émissions de GES d'au moins 55 % d'ici 2030 et à accélérer le développement des énergies renouvelables (Plan RePowerEU, 2022), avec des augmentations significatives prévues en capacité installée. Par exemple, en France, environ 4 GW de capacité solaire et 2 GW d'éolien supplémentaires sont anticipés chaque année (Programmation Pluriannuelle de l'Énergie 2019–2028). Dans ce contexte, garantir l'efficience de la transition suppose de maximiser à la fois la valeur environnementale des nouvelles unités de production d'énergie – c'est-à-dire leur capacité à réduire les dommages environnementaux – et leur valeur marchande – leur capacité à réduire les coûts de production de l'énergie – pour un investissement donné (Borenstein, 2012). Par ailleurs, les politiques publiques doivent aussi veiller à ce que les changements induits par la transition énergétique soient socialement et politiquement acceptables, en agissant pour une répartition équitable des coûts et des bénéfices.

Cette thèse s'intéresse à trois instruments de politique publique pour développer la production d'énergie bas carbone:[1] (1) les dispositifs de soutien au prix, tels que les tarifs de rachat et les enchères publiques, mis en œuvre pour subventionner le développement de nouvelles unités de production ; (2) les investissements publics directs, utilisées par les gouvernements pour développer ou étendre leurs infrastructures ; (3) les instruments dits "de contrôle", qui reposent sur une réglementation imposant le respect de certaines normes fixées par les pouvoirs publics. Cette thèse examine les conditions d'efficacité de ces trois instruments dans le contexte de la décentralisation de l'approvisionnement énergétique. D'une part, la décentralisation implique des coûts et bénéfices hétérogènes difficiles à observer, étant donné la diversité des contextes, des localisations et des caractéristiques techniques des projets. Par conséquent, ces instruments peuvent ne pas conduire à un déploiement économiquement efficace des énergies renouvelables, en d'autres termes, ils ne permettent pas d'investir dans les projets qui génèrent la plus grande valeur sociale. D'autre part, la décentralisation de l'énergie s'accompagne d'une décentralisation de la prise de décision. Celle-ci peut introduire de nouvelles sources d'inefficacité qu'il faut analyser, telles que des décisions incohérentes ou des interactions délétères entre les juridictions locales.

[1]Notons que l'attention est portée sur des politiques dites de second rang. Bien qu'un consensus existe parmi les économistes selon lequel une tarification du carbone permettrait d'atteindre les objectifs de réduction au moindre coût – en égalisant les coûts marginaux d'atténuation à la valeur marginale des dommages évités – les instruments analysés ici sont mis en œuvre en l'absence ou en complément d'un prix du carbone incomplet.

La suite de cette introduction présente la contribution de la thèse pour chacun de ces trois types d'instruments.

Systèmes de soutien par les prix

Les systèmes de soutien par les prix garantissent un tarif payé aux producteurs d'énergie bas-carbone pour l'électricité produite tout au long de la durée de vie de leurs installations. Le tarif est attribué soit par des appels d'offres publics, soit par des tarifs d'achat garantis. Ils sont mis en place pour inciter à l'investissement et combler l'écart entre des technologies qui ne sont pas rentables pour les acteurs privés et les bénéfices non rémunérés qu'elles procurent du point de vue de la société. Des investissements publics importants sont nécessaires pour financer ces mécanismes. Par exemple, la France prévoit de dépenser plus de €4 milliards en subventions pour l'énergie éolienne et solaire en 2025 selon le régulateur de l'énergie (CRE).

Ces mécanismes peuvent être inefficients dans la mesure où les niveaux de soutien ne sont pas toujours alignés avec la valeur sociale des installations d'énergies renouvelables (Borenstein, 2012; Schmalensee, 2012). Ce mauvais alignement, entre les tarifs et la valeur sociale, provient de deux sources d'inefficience : les dispositifs de soutien disposent d'une information imparfaite sur les coûts privés des technologies, ou bien ils mesurent mal les bénéfices qu'elles génèrent.

Premièrement, les dispositifs publics de soutien doivent prendre en compte le coût actualisé de l'énergie (LCOE)[2] des technologies qu'ils subventionnent afin de les financer sur la base de leurs coûts de revient et éviter un fardeau excessif pour les finances publiques. Alors que les tarifs attribués via des appels d'offres peuvent refléter correctement le LCOE des installations, les tarifs d'achat peuvent rencontrer plus de difficultés à cet égard. Ceux-ci offrent généralement des niveaux de soutien différenciés selon la taille et le type d'installation, afin de correspondre avec les variations du LCOE au sein d'une même technologie. Toutefois, les niveaux de tarifs peuvent mal refléter la distribution réelle des coûts entre les installations. Typiquement, pour l'énergie solaire, le coût actualisé de l'électricité produite diminue

[2] Le coût actualisé de l'énergie (LCOE) désigne le ratio entre la somme des coûts totaux actualisés d'une installation et la somme de sa production énergétique actualisée.

de manière non linéaire avec la taille de l'installation et varie fortement selon son architecture – par exemple en comparant une installation en toiture à une installation au sol. La distribution des niveaux de soutien peut ainsi ne pas correspondre à la distribution réelle des coûts, avec des baisses de tarifs mal positionnées en fonction des tailles. Cela crée des effets de seuils, c'est à dire des concentrations anormales d'installations autour des seuils tarifaires définis entre certaines tailles. Les développeurs réduisent la taille de leur installation en deçà du niveau efficient ou renoncent à candidater au dispositif en raison d'une baisse trop abrupte du tarif (Pollinger, 2024). Ces écarts entre les niveaux de subvention et les coûts réels peuvent devenir encore plus problématiques lorsque les coûts d'investissement diminuent dans le temps du fait du progrès technologique. Cela complique davantage la tâche des régulateurs pour calibrer avec précision les mécanismes de soutien. Par exemple, en France à la fin des années 2010, la baisse des tarifs d'achat a pris beaucoup de retard par rapport à la forte diminution des coûts des modules photovoltaïques. Par conséquent, le rythme d'installations a fortement augmenté, entraînant une hausse significative du volume de subventions publiques. Le gouvernement a instauré un moratoire temporaire en 2010-2011 pour réviser les niveaux de soutien. Un phénomène similaire a été observé en Espagne durant la même période.

Deuxièmement, les dispositifs publics de soutien doivent refléter le niveau réel des bénéfices générés par les installations subventionnées. Alors que les prix de soutien sont fixés pour une technologie donnée, les bénéfices des énergies renouvelables subventionnées peuvent fortement varier entre installations. Ces bénéfices correspondent aux coûts évités et aux émissions évitées (GES et polluants atmosphériques) par la réduction de la production des centrales conventionnelles remplacées par l'unité renouvelable. Selon l'emplacement de l'installation et sa période de production, l'unité renouvelable ne déplace pas la même centrale sur le réseau et son énergie produite n'a donc pas la même valeur.[3]

Des travaux récents ont étudié les variations des bénéfices nets des énergies renouvelables selon leur localisation et les implications pour l'efficience des dispositifs de soutien. Par

[3] Des dispositifs de soutien plus sophistiqués ont été introduits pour inciter les installations renouvelables à produire pendant les périodes où l'énergie produite à le plus de valeur avec des niveaux de tarif qui dépendent des prix de marché, comme les contrats pour différence.

exemple, en Allemagne, où les tarifs sont uniformes, Lamp and Samano (2023) montrent que déplacer de manière optimale les installations solaires résidentielles à petite échelle des zones à faibles bénéfices marginaux vers des zones à bénéfices plus élevés augmenterait la valeur totale du parc photovoltaïque de 6 %. Des études similaires ont été menées aux États-Unis (Sexton et al., 2021; Callaway et al., 2018). Callaway et al. (2018) montrent que la quantité d'émissions évitées par les énergies renouvelables varie significativement selon les grands réseaux de transport américains. Ils quantifient l'écart entre le niveau de soutien et le niveau de bénéfices externes issus de la réduction des émissions carbone et trouvent de fortes disparités entre régions et technologies. Par exemple, ils estiment un écart positif de $ 450 par MWh pour le solaire dans certaines régions, ce qui suggère que le niveau de soutien y est bien supérieur aux bénéfices environnementaux générés.

D'autres bénéfices, au-delà de la correction des externalités environnementales, peuvent justifier des niveaux de soutien aussi élevés pour les énergies renouvelables. L'argument souvent avancé est la génération d'externalités positives d'apprentissage par la pratique ("learning-by-doing"), qui permettent de stimuler plus efficacement l'émergence d'une filière nationale d'énergie renouvelable. Bien que avérés, les preuves empiriques restent limitées quant à l'ampleur de ces effets d'apprentissage et à leur appropriabilité par l'ensemble des entreprises du secteur (Bollinger and Gillingham, 2019). Par ailleurs, plus de travaux de recherche sont nécessaires pour évaluer leur efficience comparativement à d'autres instruments tels que les subventions à l'innovation et les investissements publics dans la R&D.

Contribution de cette thèse. Cette thèse contribue à la littérature en explorant une autre source potentielle d'inefficience, à savoir que les mécanismes de soutien n'incitent pas nécessairement au développement des installations avec les plus faibles coûts actualisés pour produire une quantité donnée d'énergie. Comme mentionné précédemment, la technologie photovoltaïque solaire présente une variation significative des coûts actualisés selon les types d'installations et au fil du temps. Par exemple, le photovoltaïque résidentiel à petite échelle a un coût actualisé de production de l'électricité deux à trois fois plus élevé que les grandes installations, et a connu une plus forte baisse des coûts au cours des dernières décennies (CRE, 2019, 2014). Ainsi, une trajectoire donnée de production annuelle d'énergie solaire peut être atteinte avec des niveaux de coûts actualisés très différents selon les types d'installations déployées en priorité et le calendrier d'investissement retenu. La séquence d'investissement réalisée peut donc ne pas être efficiente.

Dans le Chapitre 2, nous illustrons ce point en quantifiant la mauvaise allocation dynamique des investissements solaires qui a eu lieu en France. Le cas français est particulièrement intéressant car les pouvoirs publics y ont historiquement privilégié les installations solaires résidentielles de petite taille au détriment des grandes installations, bien que ces dernières aient un LCOE significativement plus bas. La France est un pays où le réseau de transport d'électricité est rarement congestionné. Les bénéfices de l'énergie solaire ne varient donc pas beaucoup selon l'emplacement de l'unité solaire, contrairement à l'Allemagne ou aux États-Unis.[4] Il est donc probable que, dans ce cas, les inefficiences liées à la localisation des installations, largement étudiées dans la littérature (Callaway et al., 2018; Lamp and Samano, 2023), soient moins importantes que celles liées au type d'installation choisie et à l'année de mise en service.

Après avoir constitué une base de données détaillant l'ensemble des installations photovoltaïques en France métropolitaine, nous utilisons un programme d'optimisation linéaire pour calculer une séquence d'investissements contrefactuelle minimisant les coûts actualisés, tout en reproduisant la trajectoire de production solaire observée sur la période 2005–2021. Nous trouvons qu'une trajectoire similaire aurait pu être atteinte avec seulement 70 % des coûts actualisés totaux. La majeure partie de cette mauvaise allocation provient du développement des installations résidentielles à petite échelle, qui ont été mises en service en priorité avec des niveaux de tarifs d'achat élevés. L'introduction des appels d'offres après 2011 semble avoir réduit de manière significative cette mauvaise allocation. Ce coût doit cependant être mis en comparaison avec la valeur des bénéfices potentiels générés par les installations solaires résidentielles à petite échelle, tels que la création d'emplois locaux ou la réduction des conflits d'usage sur le foncier. L'ampleur de ces co-bénéfices pourrait justifier

[4] Installer une centrale solaire dans le sud ou dans le nord de la France déplace en moyenne la même centrale marginale sur le réseau électrique.

le choix délibéré des autorités publiques de privilégier ces installations. Cette question est laissée pour de futures recherches.

Investissements publics directs

Les actifs détenus par les pouvoirs publics, tels que les infrastructures de réseaux ou les bâtiments publics, sont développés et exploités au moyen d'investissements publics directs. Une part significative de ces actifs relève de la compétence des autorités locales, comme les réseaux de distribution d'électricité, les bornes de recharge pour véhicules électriques ou les réseaux de chaleur urbains. Les collectivités locales sont ainsi responsables de la décarbonation des infrastructures énergétiques dont elles sont propriétaires. Un nombre croissant de collectivités ont pris des engagements pour réduire les émissions de carbone sur leur territoire et ont établi des plans stratégiques pour atteindre ces objectifs, appelés Plans Climat. Par exemple, en Europe, plus de 800 villes ont publié un Plan Climat et se sont engagées dans des réseaux transnationaux d'action climatique tels que C40 ou le Global Covenant of Mayors (Hsu et al., 2020; Reckien et al., 2018).

Les Plans Climat requièrent des investissements considérables (Sudmant et al., 2016). Étant donné leurs contraintes budgétaires, les collectivités doivent identifier les investissements avec le plus de bénéfices — par exemple ceux qui génèrent la plus grande atténuation de GES et augmentation de bien-être pour les citoyens — par unité de coût. Toute politique n'atteignant pas cet objectif d'efficience est une occasion manquée pour la collectivité de pouvoir conserver une plus grande part de son budget pour la réalisation d'autres actions sur son territoire. Cependant, évaluer la rentabilité des investissements publics dans des mesures d'atténuation des émissions GES soulève de nombreux défis. Premièrement, il est difficile d'établir une séquence temporelle optimale pour implémenter les actions du Plan Climat. Les priorités données aux différentes mesures peuvent modifier significativement leur efficacité. Par exemple, mettre en place en priorité des politiques induisant des changements comportementaux — en favorisant des usages plus sobres de l'énergie par exemple — peut considérablement réduire les coûts futurs des autres mesures prévues (Swart et al., 2003). Deuxièmement, les évaluations *ex ante* peuvent être difficiles à conduire en raison des incertitudes à intégrer, comme les risques environnementaux liés au changement climatique. Par exemple, Caparros-Midwood et al. (2017) montrent qu'il peut exister des arbitrages importants dans la planification urbaine entre les objectifs de densification — visant à réduire les usages de la voiture — et la réduction des risques d'inondation ou de canicule. Troisièmement, les bénéfices bruts de ces politiques, principalement les émissions évitées, les co-bénéfices qu'elles génèrent et la volonté à payer des citoyens pour ces dernières sont difficiles à établir empiriquement (Karlsson et al., 2020).

Des études récentes soulignent qu'une large part des collectivités n'arrivent pas à mettre en œuvre leur Plan Climat (Tingey and Webb, 2020). Ce déficit de mise en œuvre s'explique notamment par les contraintes pesant sur la prise de décision locale. Bien qu'il existe des méthodologies bien établies pour accompagner la décision publique — fondées sur l'Analyse Coût-Bénéfice[5] — les collectivités élaborent leurs Plans Climat sans nécessairement justifier les fondements économiques sur lesquels elles priorisent certaines actions ou options d'investissement (Neves et al., 2015; Bulkeley and Castán Broto, 2013). Les méthodologies utilisées pour évaluer les Plans Climat locaux reposent principalement sur des Analyses Multi-critères, et sur des coûts marginaux d'abattement standardisés, popularisées par McKinsey & Company (Enkvist et al., 2007). La première méthode ne permet pas de valoriser les bénéfices agrégés d'une politique et offre une base de comparaison limitée entre différentes interventions publiques.[6] La seconde est fondée sur une analyse générique de l'efficacité des actions et n'intègre pas les mécanismes techniques et économiques susceptibles d'entrer en jeu lors de leur implémentation au niveau local, menant à des estimations imprécises des bénéfices économiques. La littérature sur les bénéfices économiques des Plans Climat locaux reste donc limitée. Plus particulièrement, il manque des preuves empiriques sur l'efficacité des politiques climatiques locales, la manière dont elles répartissent les bénéfices parmi les habitants, et la façon dont leur performance se compare aux instruments de politique publique au niveau national.

[5] Voir par exemple le *Green Book* au Royaume-Uni (Treasury, 2022), ou le *Guide de l'évaluation socio-économique des investissements publics* en France (France Stratégie, 2023).

[6] Les Analyses Multi-critères reposent sur une somme pondérée d'indicateurs selon des critères définis par les préférences locales des décideurs.

Contribution de cette thèse Dans le Chapitre 1, j'estime *ex ante* la valeur économique de politiques locales d'atténuation d'un Plan Climat, à partir du cas de la ville de Bristol (Royaume-Uni). La ville dispose de deux options pour décarboner le chauffage résidentiel: étendre son réseau de chaleur urbain ou rénover les bâtiments pour améliorer leur efficacité énergétique. Appliquer une analyse coût-bénéfice *ex ante* nécessite de prendre en compte des mécanismes économiques précis. En particulier, les effets des rénovations énergétiques sont estimés à partir de deux sources documentées des écarts observés d'efficacité énergétique ("energy efficiency gap") dans la littérature économique (Gillingham et al., 2009). Je considère à la fois les écarts entre les économies d'énergie effectivement réalisées dans les bâtiments et celles prévues par les modèles d'ingénierie et les effets rebond sur la consommation des logements après rénovation. Je prends également en compte les incertitudes futures sur les prix de l'énergie, afin d'intégrer le choc énergétique survenu en 2022 en Europe après l'invasion de l'Ukraine par la Russie. Cet événement a eu des conséquences majeures sur la planification climatique, en obligeant les autorités à mettre en œuvre des mesures qui renforcent à la fois la sécurité énergétique et réduisent les émissions de GES.[7] En intégrant des scénarios extrêmes de prix dans l'évaluation, le Chapitre 1 s'interroge donc sur la manière dont la planification climatique locale est modifiée par la crise énergétique.

Je construis un modèle d'analyse coût-bénéfice à l'échelle de la ville. Mon modèle est basé sur une base de données détaillant le parc immobilier de Bristol, constitué à partir des certificats de performance énergétique (DPE) observés au niveau de chaque logement. Le résultat principal de l'évaluation est le suivant. Bien que moins rentable avec les niveaux de prix de l'énergie d'avant-crise, investir dans le réseau de chaleur urbain devient plus efficient du point de vue de la société que dans les rénovations énergétiques dès lors que les prix du gaz augmentent d'au moins 30 %. J'estime aussi les bénéfices nets générés pour les habitants par unité de coût d'investissement public pour chaque option. Sous le choc énergétique observé en 2022 — avec un quasi-doublement des prix de l'énergie sur l'année — les deux options de décarbonation génèrent plus de £ 1 de bénéfices actualisés pour les consommateurs par unité de coût. En outre, les réseaux de chaleur produisent des bénéfices par euro investi presque

[7] Voir par exemple le paquet d'urgence du plan RePowerEU (2022) adopté durant la crise énergétique.

deux fois supérieurs à ceux des rénovations énergétiques.

Cela met en évidence la valeur assurantielle des infrastructures bas-carbone face à un choc sur les prix des énergies fossiles. Rendre ces résultats accessibles pourrait accroître le soutien local aux Plans Climat, et constituer un argument solide pour obtenir et faciliter les financements requis pour l'extension des réseaux de chaleur urbains. Cette étude montre aussi la forte sensibilité des Plan Climat aux incertitudes externes et souligne la nécessité de mettre en oeuvre des évaluations économiques rigoureuses et approfondies afin de garantir une bonne dépense des deniers publics.

Réglementation "de contrôle"

Les politiques de type "command and control" sont généralement privilégiées pour réguler les externalités environnementales locales, notamment dans les situations où certaines mesures procurent des bénéfices visibles et élevés pour les citoyens. Par exemple, les politiques visant à réduire la pollution de l'air peuvent imposer des obligations technologiques de traitement en bout de chaîne dans les industries (Goulder and Parry, 2008). Elles ont également été appliquées dans des secteurs où les coûts de surveillance et de contrôle d'une source de pollution sont très élevés, comme dans le secteur automobile pour réguler les niveaux d'émissions des véhicules.

La littérature souligne que ces politiques peuvent ne pas avoir été efficientes (Goulder and Parry, 2008). En raison de la variété des bénéficiaires, certains peuvent supporter des coûts de mise en conformité trop importants par rapport aux bénéfices générés. De même, la norme imposée peut ne pas correspondre à l'action qui permet de réduire le plus efficacement la pollution pour certains agents.

Des régulations "de contrôle" peuvent également être mises en œuvre par les autorités locales. Une littérature conséquente a étudié les conditions d'efficacité de la mise en place d'instruments réglementaires environnementaux au niveau local (Oates, 2002). La décentralisation de ces instruments peut s'avérer inefficace en raison de fuites, ou d'étalements, entre les juridictions causées par des niveaux de régulation hétérogènes. Par exemple, des études empiriques ont analysé la décentralisation partielle des normes de qualité de l'air aux États-

Unis et ont constaté que les États pouvaient choisir stratégiquement le niveau de régulation afin d'attirer davantage d'entreprises et d'industries (Bošković, 2015; Sjöberg, 2016), ce que l'on appelle un phénomène de course vers le bas ("race to the bottom"). En outre, les externalités entre juridictions, notamment en matière de pollution de l'air, peuvent entraîner des effets rebond dans la mesure où une réglementation plus stricte dans un État réduit les niveaux de pollution dans les États voisins sans coûts pour ces derniers.

Le déploiement d'infrastructures énergétiques bas carbone peut également être encadré par des réglementations de ce type, un exemple étant les instruments de planification spatiale. Ceux-ci consistent à fixer des normes pour autoriser ou interdire l'implantation de nouvelles installations renouvelables sur un territoire. Ils sont généralement conçus en cohérence avec la planification sur les usages des sols, une réglementation mise en œuvre au niveau local pour autoriser différents types de développement foncier. En effet, dans le contexte de la transition énergétique, la planification sur les usages des sols se voit confier de nouvelles responsabilités et peut être aussi utilisée pour identifier les terrains propices au développement d'infrastructures énergétiques bas carbone.

Cependant les coûts associés aux restrictions des usages des sols peuvent ne pas refléter parfaitement les bénéfices externes liés à la préservation des terres. Par exemple, les zones d'exclusion définies par les politiques de planification spatiale interdisent systématiquement l'implantation d'énergies renouvelables, alors que des terrains pourraient offrir des emplacements socialement rentables sous certaines conditions. Étant un champ d'intervention relativement nouveau, peu d'études sont disponibles sur l'efficience des politiques de planification spatiale pour allotir la production d'énergie renouvelable.[8] Des études récentes ont évalué l'efficacité de ces politiques pour le développement de l'éolien. Lehmann and Tafarte (2024) montrent que l'application de distances minimales entre les installations énergétiques et les habitations en Allemagne peuvent augmenter les coûts totaux d'investissement pour une trajectoire donnée de production. De plus, ces coûts additionnels pourraient dépasser les

[8]Des évaluations économiques complètes nécessitent une vision exhaustive des coûts et bénéfices de la conversion des terres pour les installations renouvelables, incluant des impacts difficiles à quantifier sur les écosystèmes et la biodiversité.

bénéfices attendus en termes de pertes d'utilité évitées.[9] Delafield et al. (2024) trouvent un résultat similaire au Royaume-Uni. Les zones d'exclusion pourraient entraîner une augmentation allant jusqu'à 60 % des coûts totaux pour atteindre les objectifs de production éolienne, sans que cela compense nécessairement les bénéfices liés à la préservation des terres.

Au regard du phénomène documenté de "course vers le bas" – les localités arbitrant entre qualité environnementale et développement ou aménités économiques au niveau local (Oates, 2002) – l'articulation des politiques avec la planification sur les usages des sols au niveau local pourrait induire des effets d'interaction entre juridictions qui nécessitent une attention particulière. Étant donné que les installations d'énergie renouvelable génèrent des externalités négatives pour les habitants locaux, une régulation décentralisée pourrait engendrer des effets similaires, les collectivités locales renforçant leurs restrictions réglementaires à l'encontre des énergies renouvelables pour préserver leurs aménités locales, au détriment des objectifs nationaux de déploiement des énergies renouvelables.

Contribution de cette thèse. Le Chapitre 3 de cette thèse étudie comment l'articulation entre régulations nationales et locales pour l'implantation d'installations renouvelables affecte leur déploiement spatial. Je me concentre sur la régulation sur les usages des sols pour le développement des installations photovoltaïques au sol en France, qui est particulièrement instructive pour au moins trois raisons. Premièrement, les installations photovoltaïques peuvent être implantées presque partout en France, grâce à des dispositions architecturales flexibles et une ressource solaire largement disponible sur l'ensemble du territoire. Deuxièmement, la France dispose d'un dispositif de régulation spécifique. La régulation au niveau national est formalisée par la Commission de Régulation de l'Énergie (CRE), qui définit des critères d'éligibilité pour autoriser ou interdire l'implantation de photovoltaïque au sol, ces critères s'appuient sur les documents locaux de planification sur les usages des sols établis au niveau des communes.[10] Troisièmement, la France a également mis en place

[9] Ils trouvent par exemple qu'une augmentation de la capacité installée serait nécessaire pour compenser la baisse de production d'électricité induite par l'imposition de zones d'exclusion. Une telle augmentation du nombre d'éoliennes pourrait accroître les coûts liés à la baisse de l'utilité des habitants.

[10] Cette politique peut donc être perçue comme une activité conjointe entre niveaux national et local : l'État fixe les standards (en délivrant les autorisations d'implantation), leur mise en œuvre étant assurée par les collectivités (via les documents d'urbanisme locaux).

des objectifs stricts de préservation des terres afin de réduire l'artificialisation nette, avec une intégration progressive et hétérogène selon les communes (e.g. loi Climat et Résilience, 2021).

Le chapitre montre que la diversité des documents d'urbanisme au niveau communal (environ 34,000 unités administratives) peut entraîner une traduction imparfaite des critères nationaux d'implantation spatiale. Les documents d'urbanisme varient selon au moins trois dimensions : le niveau de détail fourni pour identifier les catégories d'usage des sols, l'année d'approbation (qui peut varier), et le fait qu'ils relèvent d'une intercommunalité ou d'une commune seule. En prenant en compte ces dimensions, j'étudie comment l'articulation entre régulation nationale et documents locaux d'urbanisme affecte le déploiement du photovoltaïque au sol. Je construis une base de données combinant l'historique de la mise en service des installations et l'évolution des documents d'urbanisme au niveau communal. En utilisant une approche de différences-en-différences échelonnées, je montre que des documents d'urbanisme plus détaillés augmentent significativement la quantité de foncier alloué aux installations solaires, du fait d'un meilleur alignement avec les critères nationaux. Inversement, des documents plus récents ou établis à l'échelle intercommunale réduisent cette quantité de foncier. Mes résultats suggèrent que les développeurs solaires tirent parti de l'hétérogénéité des cadres réglementaires pour cibler stratégiquement les communes dont les documents d'urbanisme facilitent l'octroi de permis. Par exemple, les communes dotées de documents plus anciens appliquent moins strictement les objectifs de préservation des terres, qui ont été progressivement formalisés par la législation.

Dans l'ensemble, cette thèse examine la dimension de la centralisation dans l'élaboration des politiques publiques pour la transition énergétique. Une gouvernance centralisée peut théoriquement atteindre des résultats optimaux, en internalisant tous les coûts et bénéfices des actions de réduction, en prévenant les fuites et en évitant les comportements de passager clandestin (Oates, 2002). Toutefois, dans un monde de second rang où la surveillance est coûteuse et l'information incomplète, ces résultats peuvent ne pas être atteints. C'est particulièrement vrai pour les infrastructures énergétiques décentralisées, dont la dispersion spatiale et la diversité technique induisent des variations des bénéfices nets, nécessitant une mesure précise et robuste. En ce sens, la décentralisation de la décision vers les autorités locales pourrait être justifiée car elles peuvent disposer d'une meilleure connaissance des coûts et bénéfices liés aux installations. Par exemple, les collectivités peuvent mieux identifier les opportunités de décarbonation localisées, comme les réseaux de chaleur urbains. La décentralisation comporte également des limites. Bien qu'investies de nouvelles missions pour atteindre les objectifs climatiques, les collectivités locales manquent de ressources et de capacités pour la prise de décision (Poupeau, 2014). La politique locale et les processus de gouvernance peuvent aussi engendrer des inefficacités supplémentaires, notamment lorsque les coûts externes des énergies renouvelables sont supportés localement, alors que les bénéfices sont globaux. Enfin, les articulations administratives entre différents niveaux de juridiction peuvent engendrer des coûts de transaction supplémentaires et des effets d'interaction indésirables. L'allocation des instruments de politique publique entre différents niveaux de juridiction dans le contexte de la transition énergétique est donc une question qui mérite une attention particulière et des analyses approfondies.

General Introduction

Reducing the carbon intensity of energy supply is one key lever for mitigating greenhouse gases (GHG) emissions, at the source of climate change (IPCC, 2023). However, an important transformation of energy systems is required to achieve ambitious mitigation objectives, which is depicted by the term "*energy transition*". The *energy transition* involves the electrification of final energy supply – since electricity can be produced with low-carbon energy sources – and shifting from fossil-based to low-carbon energy production. Low carbon energy production can use technologies that convert renewable energy to electricity, such as wind, solar or hydro power, or technologies that hinge on the circularity of a resource, such as renewable gas production.

Developing low-carbon energy production involves the *decentralisation* of energy infrastructures. Indeed, most of these technologies are small-scale installations. They are scattered over territories to sit close to their primary energy resource, or close to final energy uses. They are connected to local distribution grids (at low voltage) rather than national transmission networks (high voltage). Moreover, they are framed by local decision making, either individuals or localities, that can decide to invest or authorize the commissioning of a production unit.

This transition to decentralized energy production raises new arbitrages to be resolved. First due to additional costs that they might generate. Replacing one conventional production plant by several smaller installations can be more costly per unit of energy produced because of economies of scale, where costs increase less than proportionately with the size of installations. Additional investments may also be needed to ensure the functioning of the electricity grid when hosting a large number of renewable energy installations (Astier et al., 2023). Second, the net benefits of a given energy production unit can vary to a great extent with its location. Renewable energy installations have production profiles that depend on local weather conditions at a given location (Pfenninger and Staffell, 2016), which implies significant variations in the market value of the generated electricity (Joskow, 2011) and in the amount of alleviated GHG emissions and air pollution (Abrell et al., 2019a; Sexton et al., 2021). They also generate negative externalities when they sit close to residential housing, typically noise and visual pollution, with significant amenity losses (Gibbons, 2015; Dröes and Koster, 2021). Consequently, public controversies and local opposition may hinder the commissioning of new production units, in so-called "NIMBY" politics (Carley et al., 2020). Third, the deployment of decentralized infrastructures requires creating new fields of action for local authorities that take part in its regulation (Poupeau, 2014; Bulkeley and Castán Broto, 2013). This decentralization of decision-making adds new articulations to be made in administrative processes. Increasing the number of administrative layers, in turn, can raise transaction costs for enforcing a regulation and may lead to incoherent decisions taken at the local level (Poupeau, 2014).

Given the presence of multiple externalities and the significant transformation at play, strong public interventions are required to bring about the changes necessary for the energy transition. Public policies are particularly needed to address new arbitrages raised by the latter and ensure a cost-efficient transition. Taking policy goals as given, an efficient intervention is the one, among other alternatives, that achieves them at the lowest possible cost (Schmalensee, 2012). The EU commission aims to reduce GHG emissions by at least 55% in 2030 and to accelerate the pace of development of renewable energy supply (RePowerEU Plan, 2022), with significant planned increases in installed capacity. For example, in France, about 4 GW of additional capacity of solar and 2 GW of wind power are anticipated each year (Programmation Plurinannuelle de l'Energie 2019–2028). In this context, cost-efficiency requires ensuring that both the environmental value of new energy production units – in the extent to which they avoid environmental damages – and their market value – in how much they reduce the cost of producing energy – are maximized (Borenstein, 2012). Additionally, public policies must ensure that the changes brought about by the energy transition are socially and politically acceptable, by acting towards a fair distribution of costs and benefits.

This thesis focuses on three public policy instruments for developing low-carbon energy production:[11] (1) price support schemes, such as feed-in-tariffs and public auctions, which have been implemented to subsidize the development of new production units; (2) direct public spending, used by governments to develop or expend their infrastructure; (3) "command and control" instruments, which use legislation to enforce compliance with some standards or targets set by governments. This thesis examines the efficiency conditions of the three policy instruments in the context of the decentralization of energy supply. On one hand, decentralized energy supply implies heterogeneous costs and benefits that are difficult to observe, given the variety of settings, location and technical characteristics to develop them. As a result, policy instruments may not lead to a cost-efficient deployment of renewable energy, not allowing or investing in projects that deliver the highest social value. On the other hand, decentralizing energy supply comes with decentralizing decision-making. This can also introduce new inefficiencies that need to be addressed, such as inconsistent decision-making or adverse interactions between local jurisdictions. In what follows, the contribution of the thesis in each type of instruments is outlined.

Price support schemes

Price support schemes guarantee a tariff paid to low-carbon energy producers for the energy output over the lifetime of their installations. The tariff is either granted through public auctions, or by feed-in tariffs. They are implemented to incentivize investments and close the gap between privately non-profitable technologies and the uncompensated benefits they procure at society level. Significant amounts of public investment are required to finance these schemes. For example, France expects to spend more than €4 billion in subsidies for wind and solar energy in 2025, according to the french energy regulator (CRE). These support

[11] Note that the focus is on second-best policies. Despite a global consensus among economists that carbon pricing would enable the achievement of carbon reduction targets at the least costs, since equating marginal abatement costs with marginal value of avoided damages, policy instruments studied in this thesis are implemented in the absence of or in parallel of incomplete carbon pricing.

schemes can be inefficient to the extent that support levels may not be well aligned with the social value of renewable energy installations (Borenstein, 2012; Schmalensee, 2012). This misalignment between support tariffs and social value comes from two sources of inefficiency: either support schemes have imperfect information on the private costs of the technology, or they do not measure well the benefits of the latter.

First, public support schemes must account for the actual levelized costs of energy (LCOE)[12] of the technology they subsidize in order to avoid being to costly on public finances. While tariffs granted though auctioning schemes can correctly identify the LCOE of installations, feed-in-tariffs may have more difficulty doing so. They usually offer support levels that differ with the size and type of installation to match variations in levelized costs of energy within a technology. However, their tariffs levels may imperfectly reflect the actual distribution of costs across installations. Typically for solar power, the levelized cost of electricity produced by solar installations decreases non-linearly with their size and varies to great extent with their architecture – e.g. rooftop versus ground-mounted installations. The distribution of support levels in this case may not be well aligned with the actual distribution of levelized costs, with decreases in tariffs that are put at the wrong size threshold. This creates kinks and bunches in the distribution of installations, where solar PV developers reduce the size of their installation relative to the efficient level or do not apply to the support scheme because of a too sharp decrease in tariff rates (Pollinger, 2024). Discrepancies between subsidy levels and actual costs can become even the more critical when investment costs decrease over time due to technological progress. This complicates further the task for energy regulators to precisely calibrate support mechanisms.[13]

Second, public support schemes must reflect the actual level of benefits generated by the subsidized energy installation. While support prices are fixed for a given technology, the benefits of the subsidized renewable energy can vary to a great extent across installations.

[12] Levelized cost of energy refers to the ratio of the sum of the discounted costs of an installation and the sum of its discounted energy output

[13] For example in France during late 2010s, the decline in feed-in-tariffs has lagged significantly behind the sharp decrease in the costs of PV modules. As a result, installation rates boomed, increasing significantly the amount of public subsidies. The government enacted a temporary moratorium in 2010-2011 to revise price supports levels. A similar mechanism was observed in Spain at the same period.

Gross benefits are measured by the avoided costs and avoided emissions (GHG and air pollutants) from reduced energy output of conventional energy plants that are displaced in the presence of the renewable energy unit. According to where the facility is located and when it is producing, renewable energy does not displace the same power plant on the electricity grid, and thus does not have the same value.[14] Recent studies have investigated the variations of net benefits generated by renewables according to their location and its implications for the cost-efficiency of public support schemes. For example in Germany, where price support schemes are uniform across space, Lamp and Samano (2023) find that optimally moving small-scale residential solar installations from sub-regions with low marginal benefits into regions with higher benefits increases their overall value by around 6%. Similar studies have been conducted in the US (Sexton et al., 2021; Callaway et al., 2018). Callaway et al. (2018) find that the variation in quantity of emissions displaced by renewable energy is significant across major transmission networks in the country. They quantify the difference between the level of support and the level of external benefits from carbon emissions reduction and find large variations across regions and renewable technologies. For example, they obtain a large positive $ 450 per MWh difference for solar power in some regions, suggesting that the support level is way higher than the environmental benefits of the latter.

Other external benefits than correcting environmental externalities can justify higher support levels to renewable energy. A main argument for providing high levels of subsidies is to generate positive learning-by-doing externalities, that can contribute to kick-off a domestic renewable energy sector more efficiently. However, there is only small evidence on the extent to which such policies have contributed to generate learning-by-doing spillovers between firms (Bollinger and Gillingham, 2019). Besides, even though learning spillovers have occurred under public support schemes, more research is needed on their cost-efficiency relative to alternative policy instruments directly supporting innovation, R&D grants for example.

[14] More sophisticated price schemes have then been introduced to incentivize renewable energy installations to produce during more valuable periods, with tariffs levels that depends on market price levels, such as contracts-for-differences.

Contribution of this thesis. In this thesis, we add to the literature by looking at another potential source of inefficiency, where price support schemes do not necessarily incentivize the development of installations with the lowest present value costs for producing a given amount of energy. As mentioned above, the solar PV technology has shown significant variation in levelized cost of energy across different types of installations and across time. For example, small-scale residential PV have a levelized cost of producing energy that is two to three times higher than large-scale installations and experienced higher costs decreases over the last decades (CRE, 2019, 2014). Hence, a given trajectory of annual solar energy production can be achieved with very different levels of present value costs according to which types of facilities are commissioned when and the realized sequence of investments may not be cost-efficient.

In Chapter 2, we illustrate this point by quantifying the dynamic misallocation of investments in solar installations that occurred in France. The french case is particularly interesting since public authorities have consistently prioritized small-scale residential solar PV over large-scale installations. France is also a country that is geographically dense and whose electricity transmission grid is seldom congested. The gross benefits from solar energy are thus not varying to a large extent across the country, as opposed to Germany or the US.[15] It is thus likely that in this case inefficiencies regarding *where* installations are built, which were extensively studied in the literature (Callaway et al., 2018; Lamp and Samano, 2023), are less important than inefficiencies regarding *when* installations are commissioned.

Taking the the universe of solar installations in metropolitan France, we use a linear optimization program to compute a cost-minimizing counterfactual sequence of investments that reproduces the annual solar energy production trajectory observed over the period 2005–2021. We obtain that a similar solar trajectory could have been realized with only 70% of total present value costs. The bulk of misallocation is driven by small-scale residential solar, that have been commissioned first in France under high feed-in-tariffs levels. The introduction of public auctions after 2011 seem to have significantly reduced the misallocation.

[15]Locating a solar installation in the Southern or in the Northern part of France displaces on average the same marginal power plant on the grid

Direct public investments

Government-owned assets, such as networks infrastructures or public buildings, are developed and operated using direct public investments. A significant part of these assets are under jurisdiction of local authorities, such as electricity distribution grids, electric vehicles charging, or district heating networks. Localities are thus responsible for decarbonizing the energy infrastructures under their property. A growing number of localities have made their own pledges to reduce carbon emissions within their jurisdiction and have issued strategic plans to achieve these targets, in so-called Climate Action Plans. For example in Europe, over 800 cities have issued Climate Action Plans and engaged in transnational networks for climate action such as C40 of the Global Covenant of Mayors (Hsu et al., 2020; Reckien et al., 2018).

Climate Action Plans require tremendous investments (Sudmant et al., 2016). Given limited budgets, localities must identify investments that generate the highest level of benefits – e.g. avoided carbon emissions and increases in welfare of local inhabitants – per unit of public investment costs. Any policy not achieving this cost-efficiency objective is a missed opportunity for the local authority: where a higher budget share could have been spent on other actions. However, evaluating the cost-efficiency of public investments in climate mitigation measures present many challenges. First, due to time framing, where the temporal sequence of measures that are implemented can change their overall efficiency. For example, implementing first policies that generate important behavioral changes, promoting more sober energy uses for instance, could significantly reduce the future costs of other measures that are planned (Swart et al., 2003). Second, due to uncertainties that are difficult to internalize in *ex-ante* evaluations, typically environmental risks caused by climate change. For example, Caparros-Midwood et al. (2017) show that there may exist important trade-offs in urban spatial planning when having to achieve urban densification objectives – to decrease transportation use – and reducing flood and heat risks. Third, to elucidate the willingness-to-pay of consumers for climate actions and the co-benefits they generate has proven to be a difficult empirical challenge (Karlsson et al., 2020).

Recent studies outline that a large part of localities fall short of implementing their Climate Action Plans (Tingey and Webb, 2020). This "implementation gap" is notably due to constrained decision-making at the local level. Despite well established methodologies to support public decision-making – which are based on Cost-Benefit Analysis[16] – localities issue their Climate Action Plans without necessarily justifying the economic basis on which they prioritize actions or investment options over others (Neves et al., 2015; Bulkeley and Castán Broto, 2013). Methodologies used to evaluate local Climate Action Plans are either based on Multi-Criteria Analysis, or standardized Marginal Abatement Costs Curves, popularized by McKinsey & Company (Enkvist et al., 2007). The first provides no possibilities to value the aggregate benefits of a policy and provides a weak benchmark to compare different policy interventions.[17] The second is based on a generic cost-effectiveness analysis and does not integrate technical and economic processes at play, leading to imprecise estimates of economic benefits. As a result, literature on the economic benefits of local Climate Action Plans is limited. There is a lack of empirical evidence on the efficiency of local climate change policies, how they distribute benefits to local inhabitants, and how their performance compares to national policy instruments.

Contribution of this thesis In Chapter 1, I estimate *ex-ante* the economic value of local climate change mitigation policies, using the case of the city of Bristol (UK). The locality has two policy options to decarbonize residential heating: extending the local district heating network or retrofitting buildings to improve energy-efficiency. Applying an *ex-ante* CBA requires considering precise economic mechanisms. Specifically, the impacts of energy efficiency retrofits are estimated using two sources of the documented "energy efficiency gap" in economics literature (Gillingham et al., 2009). I consider shortfalls in energy savings realized at building levels relative to expected ones by engineering estimates, and rebound effects after energy efficiency retrofits. I also account for future uncertainty on energy prices, to account for the recent energy price shock that occurred in 2022 across European countries after Russia's invasion in Ukraine. This event has major consequences for climate action

[16]See for instance the Green Book in the UK (Treasury, 2022) or the "Guide de l'evaluation socio-économique des investissements publics" in France (France Stratégie, 2023).

[17]Multi-Criteria Analysis are based on a weighted sum of indicators following criteria set by the local preferences of decision-makers.

planning, with public authorities that require to implement measures that can both increase energy security and reduce GHG emissions.[18]. By incorporating extreme prices scenarios in the evaluation, Chapter 1 asks how and to what extent local climate action planning is modified by the energy crisis.

I construct a model for conducting a CBA at a city level based on Energy Performance Certificates data, which follow a standardized format across a number of European countries. The assessment shows that – despite being less cost-effective under pre-crisis energy price levels – the district heating network has a lower mitigation cost than energy efficiency retrofits when gas prices increase by at least 30%. I also estimate the net benefits that are generated to local inhabitants per unit of public investment cost for each policy option. Under the energy prices shock observed in 2022 – with almost twofold annual increases of energy prices – both decarbonation options generate more than £ 1 benefits in present value to consumers per unit cost. Moreover, district heating networks generate nearly twice higher benefits per unit cost than energy efficiency retrofits. This shows the intrinsic insurance value of low-carbon energy infrastructures against fossil prices' inflation. Making these results accessible could help increase local support for local Climate Action Plans and make a robust case for financial support from national government, enabling direct comparison with national climate change mitigation policies.

Command and control regulation

Command and control policies have been generally favored to regulate local environmental externalities, in situations where promoted actions provide visible and high levels of benefits for end-users. For example, policies that aim at reducing air pollution can impose technology mandates for "end-of-pipe" treatment in industries (Goulder and Parry, 2008). They have also been applied in sectors where the costs for monitoring and enforcing a source of pollution are very high. For example in the automotive sector to regulate the levels of emissions of vehicles. Literature outlines that these policies may have not been cost-efficient (Goulder and Parry, 2008). According to the large number and variety of beneficiaries, some may

[18]see for instance the emergency package of the RePowerEU plan (2022) issued during the energy crisis

incur too important costs for complying with the standard as compared to the benefits that are generated. In the same vein, the standard imposed might not be the action that reduce the most the source of pollution for some agents.

Command and control polices can also be enforced by local jurisdictions. Substantial literature has studied the efficiency conditions of setting environmental regulatory instruments at the local jurisdiction level (Oates, 2002). Decentralizing these instruments can prove to be inefficient due to regulatory leakages, or spillovers, that result from heterogeneous regulation levels across jurisdictions. For example, empirical studies have analyzed the partial decentralization of Clean Air Standards in the US and find that States may strategically choose the level of the standard to attract more firms and industries (Bošković, 2015; Sjöberg, 2016), in so-called "race to the bottom" phenomena. Moreover, spillovers between jurisdictions, typically occurring with air pollution, may entail adverse interactions and rebound effects, where more stringent regulation in one State decreases pollution levels in neighboring ones at no costs.

The deployment of low-carbon energy infrastructures can also be framed by command and control regulations, a typical example being spatial planning instruments. They consist in setting standards to allow or ban the siting of new renewable facilities over a territory. They are usually designed in accordance with land-use planning, a regulation that is enforced at the local level to authorize different land developments over their territory. Indeed, in the context of the energy transition, land-use planning is given new duties and can be used to identify suitable land plots for developing low-carbon energy infrastructures. However, as for technology mandates in industry, the costs associated to land-use restrictions may not perfectly reflect the external benefits of preserving the land. For example, exclusion areas in spatial planning policies systematically forbid the siting of renewables although some land plots could offer socially profitable locations. Since a relatively nascent field of intervention, little research is available on the cost-efficiency of spatial planning to allocate renewable energy supply.[19] Recent studies have assessed the efficiency of spatial planning

[19]Comprehensive economic evaluations require having a complete view of benefits and costs of land conversion from renewable installations, where impacts on ecosystems and biodiversity are difficult to assess.

policies for developing wind power. Lehmann and Tafarte (2024) find that enforcing setback distances rules between energy installations and dwellings in Germany may have increased total investment costs for a given wind energy trajectory. Moreover, additional costs may be higher than the level of benefits induced by the policies from avoided amenity losses.[20] Delafield et al. (2024) find a similar result in the UK. Exclusion zones would imply an increase of up to 60% of total costs for meeting wind power generation targets, that may not compensate the benefits from avoided land conversion.

In light of the well documented "race to the bottom" phenomena – localities trading off environmental quality with local economic development (Oates, 2002) – the articulation of spatial planning instruments with land-use planning at the local level may induce interaction effects between jurisdictions that require close investigation. Given that renewable energy installations imply negative externalities for local inhabitants, decentralized regulation could imply similar adverse effects where localities increase their regulatory restrictions to renewable installations and trade-off renewable energy targets with local amenities.

Contribution of this thesis. Chapter 3 of this thesis investigates how the articulation of top to local regulations for siting renewable installations affects their spatial deployment. I focus on land-use planning regulation for the deployment of ground-mounted solar PV installations in France, which is particularly informative for at least three reasons. First, solar PV installations can be installed almost anywhere in France, due to flexible architecture settings and the availability of the solar energy resource that make them suitable over the whole french territory. Second, France has this specific setting where top-level regulation is formalized by the energy regulatory commission (CRE), defining eligibility criteria to allow or ban the siting of ground-mounted solar, which rely on local land-use planning frameworks. [21] Third, France has also enforced stringent land conservation objectives to reduce the rate of new land takes at municipalities' level, with gradual and heterogeneous integration across

[20] For example, they find that an increase in installed capacity would be required to overcome the loss in energy generation form the enforcement of exclusion areas. Increasing the number of wind power installations, in turn, may increase disamenity costs.

[21] This policy can thus be seen as a joint activity between the top and local jurisdictions: central governments set the standards (issue permitting for the commissioning of solar installations), with the implementation of the standards left for local governments (standards integrated in land-use planning categories).

municipalities (e.g. "Climate and Resilience" law, 2021).

Chapter 3 shows that the variety of land-use planning frameworks done at the municipality level (comprising around 34,000 administrative units) may translate imperfectly top-level criteria for siting solar installations. Land-use planning vary in at least three dimensions: the level of detail provided for identifying land-use categories, the time of approval (which may differ by year), and whether it falls under the jurisdiction of inter-municipalities or individual municipalities. Considering these dimensions, I study how the articulation between top-level regulation for siting ground-mounted solar and local land-use planning affects the deployment of solar PV installations. I construct a dataset regrouping the history of commissioning of ground-mounted installations and changes in land-use planning frameworks at the municipality level. Using a staggered-difference-in-difference approach, I find that having more detailed land-use planning significantly increases the amount of land allocated to solar installations due to better alignment with top-level criteria. Conversely, more recent land-use planning and integrated land-use planning at the inter-municipality level decrease the amount of land allocated to solar. My results suggest that solar PV developers take advantage of the heterogeneity in regulatory frameworks to strategically target municipalities with land-use planning that induce easier permitting. For example, municipalities with older land-use planning frameworks have less stringent enforcement of land conservation objectives, that have been gradually formalized by evolving legislation.

All in all, this thesis questions the dimension of centralization in the elaboration of public policies for the energy transition. Centralized governance in theory can reach optimal outcomes, by internalizing all costs and benefits from mitigation actions, preventing leakages and avoiding free riding effects (Oates, 2002). However, in a second-best world where monitoring is costly and information incomplete, the optimal outcome might not be achieved. This is specially true for decentralized energy infrastructures, where the spatial scattering and variety of technical forms taken by the latter implies variations in their net benefits that require precise quantification. Decentralizing decision-making to local authorities could be justified in that sense, since they can have more precise monitoring of the costs and benefits of installations. For example, the spatial allocation of installations can be framed at the municipality level since they have better knowledge on the land distribution over their territory. Localities can also have better information on decarbonation opportunities that can be implemented over their jurisdiction, such as district heating networks. However, decentralizing governance also comes with downfalls. While being given additional duties to achieve climate change policy objectives, localities lack adequate resources and capacity for decision-making (Poupeau, 2014). The political economy and governance processes at play in local jurisdictions may also create additional inefficiencies. Specially given that external costs of renewable energy may only accrue to local voters, while external benefits are at a global scale. Finally, administrative articulations between jurisdiction levels may raise additional transaction costs and induce adverse interaction effects. The allocation of policy instruments and decision-making across jurisdictions in the context of the energy transition is thus a question that necessitates specific focus and comprehensive assessments.

In the remaining parts of the manuscript, the three chapters of the thesis are presented. Then a general conclusion outlines some policy recommendations and avenues for future research.

Chapter 1

How Climate Action Plans are modified by the energy crisis? A focus on residential heating in Bristol

Abstract: The recent shock in European energy prices could substantially reduce the social cost of Climate Action Plans. This paper conducts an *ex-ante* Cost-Benefit Analysis of mitigation policies in residential heating and studies the extent to which energy prices inflation modifies their cost-effectiveness. I use the city of Bristol (UK) as a case study and assess two options: (1) investing in district heating networks in central districts or (2) subsidizing energy efficiency retrofits for least efficient dwellings. Implementing either of the two policy options under the 2022 energy prices shock increase economic benefits to households by around £ 1 per pound invested in present value, relative to a scenario with baseline energy prices trends. District heating networks become more cost-effective at mitigating carbon emissions than energy efficiency retrofits.[1]

[1]published in Revue d'Economie Industrielle, N° 184.
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1.1 Introduction

Following Russia's invasion of Ukraine in February 2022, European households experienced a dramatic surge in energy bills. Despite public support at the national level, such as price caps or targeted subsidies[2], households experienced year-on-year increases of 15% in France, 40% in the UK and 64% in Germany from 2021 (Sgaravatti et al., 2023). This shock on energy prices might be a turning point for local Climate Action Plans as they could appear more cost-effective than national policies to protect households from rising energy prices. Climate Action Plans are series of measures that could be implemented over an authority's jurisdiction to mitigate and adapt to climate change (Grafakos et al., 2020; Reckien et al., 2018). They may also generate economic benefits that add to the avoided costs of climate change, such as improving health conditions or reducing energy expenditures. This paper investigates the extent to which rising energy prices increase the value of these so-called *"co-benefits"*.

I study the Climate Action Plan issued by the city of Bristol (UK) in the context of the recent energy prices shock. The city of Bristol plans to invest over £ 1 billion to decarbonize infrastructures (heating, transportation, renewables, building stock), with the ambitious goal of becoming carbon neutral by 2030. Most of the investments are aimed to decarbonize the residential heating sector, for which the city has identified two options: either to invest in low-carbon energy assets, by extending the local district heating network, or in energy efficiency retrofits (Foster et al., 2018; BCC, 2020). Climate actions in residential heating also entail a number of co-benefits such as the improvement of dwellings' comfort conditions or reducing energy bills. Thus, the city should prioritize the most cost-effective mitigation measure, in terms of social costs per ton of carbon alleviated. Assessing these carbon mitigation options is complex as they may not generate the same levels of benefits across households. District heating networks may increase energy expenditures in some dwellings, while energy efficiency retrofits may provide lower energy efficiency gains than expected. It is thus crucial to appraise these policies *ex-ante* before making an investment decision.

[2]United Kingdom (UK) has allocated more than £ 100 Billion to shield consumers from rising prices between 2021 and 2023 (Sgaravatti et al., 2023)

I assess how the cost-effectiveness of the Climate Action Plan is modified by rising energy prices. I simulate impacts in terms of carbon emissions avoided, savings on energy expenditures, and increase in comfort for the period 2020–2050 under scenarios taking into account energy price trends after the recent energy crisis in Europe and forecasts done before the energy crisis. I find that a minimum 30% increase of retail energy price trends relative to forecasts done before the crisis imply that both policy options deliver positive net benefits. Moreover, district heating networks start having a lower mitigation cost compared to energy efficiency retrofits. By acting as a price cap, district heating networks shield households from higher energy bills and may deliver up to £ 1.9 to households for each pound invested in present value. Energy efficiency retrofits generate lower benefits to households and provide up to £ 1.1 for every pound invested.

Through this case study, I present an assessment model that can be replicated to other cities. Available methods used to appraise *ex-ante* local Climate Action Plans are limited for assessing economic benefits. Evaluation tools that are on the shelf for local decision-makers such as the ones provided by transnational municipal networks, e.g. *Covenant of Mayors*, *C40* or the *International Council for Local Environmental Initiatives (ICLEI)*, are mainly using generic carbon emissions inventories (GCoM, 2023) or standardized Marginal Abatement Cost Curves, popularized by McKinsey & Company (Enkvist et al., 2007). They do not integrate technical and economic processes at play, leading to imprecise estimates of economic benefits. Other methodologies that are available are based on Multi-Criteria Analysis (Azevedo and Leal, 2017; Neves et al., 2015). The methodology consists in selecting projects with the highest weighted sum of indicators, which follow criteria set by decision-makers. They are well adapted to address project inclusion and stakeholder engagement aspects but are limited for economic evaluation, with no possibilities to value aggregate benefits, and provide weak benchmark for comparing different policy interventions.

I use a Cost-Benefit Analysis (CBA) methodology aligned on the UK's Green Book framework (Treasury, 2022). This approach provides a strong benchmark to local decision-makers. In my case study, local policies could generate higher social value than some national measures recently implemented to shield the energy prices inflation. Outlining this could attract more resources from top-level governments to local authorities and help reduce the implementation gap currently observed in local climate action (Tingey and Webb, 2020; Gudde et al., 2021). Moreover, by explicitly integrating different prices scenarios and using specific data, my assessment produces different results than the usual ranking given by on-the-shelf evaluation tools. Under the 2022 energy price shock, my assessment prioritizes district heating networks over energy efficiency retrofits, despite being less cost-effective under lower prices trends.

I adopt a similar CBA framework as in Rosenow et al. (2018) that estimate the potential of different actions to meet UK's national carbon reduction targets. I conduct a more disaggregated assessment, modelling a detailed process for individuals' heating demand as in Giraudet et al. (2021) and Charlier and Risch (2012). I use Energy Performance Certificates (EPCs) data to run my assessment. EPCs are a good proxy to picture the building stock since they provide detailed information on energy characteristics at the dwelling level and are a mandatory rating scheme in the UK (BEIS, 2012). I simulate heating demands at the dwelling level and their response to each policy option relative to a status-quo scenario, where no changes are implemented relative to current measures already being implemented by the city. Heating demands in my model are calibrated using the building-physics modeling assumptions of EPCs and Heating Degree-Days trends (BEIS, 2012). I consider two sources of the *"energy-efficiency gap"* studied in the literature (Gillingham et al., 2009; Giraudet et al., 2018). First, I introduce a shortfall between realized energy savings and the ones reported *ex-ante* by EPCs using the history of past buildings' retrofits in Bristol. Then, I calibrate heating demands with recent empirical studies on the price elasticity for the heating service (e.g. Labandeira et al. (2017) or Sorrell et al. (2009)) and the rebound effect (e.g. Aydin et al. (2017) or McCoy and Kotsch (2021)). I do not include collective decision-making, such as landlord-tenant dilemmas, and heterogeneous credit constraints. I can omit these barriers since I consider the view point of a city to implement mitigation policies. The city, is the owner of the district heating networks, and has already identified the feasible connections of dwellings among the building stock. The city also considers a vast subsidy program for energy efficiency and bears all investments to implement them.

Overall, there is small evidence on the social value of local Climate Action Plans (Karlsson et al., 2020). This paper contributes to filling this gap by focusing on district heating networks, a policy option that is typically under jurisdiction of local authorities. While economic evaluations of energy efficiency retrofits are well covered by the literature (Giraudet et al., 2021; Charlier and Risch, 2012), only few papers assess the impacts of district heating networks, which are limited to specific technological aspects (Leurent et al., 2018; Groth and Scholtens, 2016; Spirito et al., 2021). The economic evaluation conducted in this paper underlines the intrinsic insurance value of district heating networks (Deletombe et al., 2024). Among low-carbon heating technologies, district heating networks can offer great price stability, with tariffs that are only partially dependent on variable costs, the other part being fixed to recover infrastructure costs. The case study used in this work has also allowed me to analyze jointly two policy options that are usually pertaining to separate assessments. I notably find that the two policies are more complements than substitutes, being more effective when targeted at different parts of the housing stock: central and collective dwellings for district heating networks versus owner-occupied ones for energy efficiency retrofits.

The rest of the paper is structured as follows. Section 1.2 presents the institutional background and the case study of Bristol. Section 3.5 describes the model constructed to conduct the assessment, the scenarios that are evaluated, and the datasets used for calibration. Section 1.4 presents the main results and several sensitivity analyses. Finally Section 3.7 and 1.6 derive the policy implications and conclusions of this work.

1.2 Institutional Background

Cities in the UK have statutory powers in several sectors, such as transportation, public buildings or district heating, and have different levers at hand to take climate actions. Typically, they can invest in infrastructures, promote private investments through performance-based contracts, or use regulatory instruments. Over 75% of local authorities in the UK have declared climate emergency and made their own local commitments to fight climate change (Gudde et al., 2021). This stems from increasing public awareness as well as the growing devolution of responsibilities to local authorities from the national government[3]. However, despite strongly committing for climate many local authorities remain to implement their Climate Action Plans. Local climate action is hindered by multiple barriers such as limited policy support, the lack of financial resources or complex local governance. Having adapted tools to prioritize best investment decisions may overcome some of the barriers at the source of this *"implementation gap"* (Tingey and Webb, 2020; Gudde et al., 2021).

The City of Bristol takes actively part in climate action. The City Council has an enhanced energy management capacity that can facilitate complex and integrated energy planning. In 2022, the Bristol City Council delegated a 20 years public-private partnership to a private consortium, called the Bristol City Leap energy partnership (BCL), to deliver low-carbon energy investments at city scale. The estimated cost of the investments to be made under the contract amounts to £ 1 billion (BCC, 2020). The BCL contract is scalable in the sense that parties progressively set short-term business plans defining the scope of investments to be realized in order to achieve broad objectives. For the first five years, the BCL aims at cutting 140,000 equivalent tons of carbon and generating £ 61 million of social value within five years (BCLEP, 2022). Social value is defined as the additional economic benefits generated by a project, either through direct funding to stakeholders or by monetizing projects' impacts.

I use the BCL contract's initial business plan to frame the options assessed in the paper. The BCL contract aims to extend the existing district heating network. The district heating network currently in place connects around 1,000 buildings using a mix of geothermal, gas and waste-to-energy plants. The BCL also aims to launch a program to implement energy efficiency retrofits. This program is in line with the City Council's objective of banning all dwellings in the city with energy efficiency labels lower than D by 2050 (Foster et al., 2018).

To conduct the assessment, I require the technical and financial characteristics for each project. I am relying on the resources provided by a candidate participating in the Bristol

[3]For instance, "City Region Deals" were put in place in 2010 to provide more power to large urban areas (Localism Act, 2011). Local authorities combined together to be conferred additional functions (Local Government Devolution Act, 2016). Policies to direct financial resources to local projects such as the Local Growth Fund (2017) or the Heat Networks Investment Project (2018).

City Leap tender. This candidate was involved in the ultimate rounds of the tendering process and thus has developed a detailed proposal for the district heating network extension project and the energy efficiency retrofitting program. The candidate is however not the final winner of the contract. Accessing this data was critical for setting up the project scenarios[4].

1.3 Materials and methods

1.3.1 Model overview

I construct a model to conduct a Cost-benefit Analysis (CBA) at the city scale. CBA is a counterfactual economic evaluation method that aims to select the best investment option among a set of project scenarios. The social costs and benefits of each project are estimated using microeconomic theory and are summed up in a *Socio-economic Net Present Value* (NPV). Each project scenario is evaluated against a counterfactual that implies a scenario of what the situation might be in the absence of the projects (Treasury, 2022). The model developed in this paper can be summarized by four steps.

First, Bristol's policy options are translated in project scenarios. Each scenario is defined by a schedule of works, i.e. number of buildings improvements per year, and the changes they imply for dwellings. Project scenarios are compared to a counterfactual represented by the status-quo scenario. Second, the model uses data to estimate heating consumption and heating characteristics at the dwelling level. Categories of tenures are taken into account to study the distribution of impacts across owner-occupied, rental private and rental social households. As policies only apply to residential buildings, data on commercial and public buildings are not included the model.

Third, the model applies a microeconomic framework to estimate the costs and benefits implied by changes in dwellings' heating characteristics. Benefits to households are estimated through changes in heating consumption at the dwelling level. Heating consumption is calibrated with the useful energy requirement of a dwelling per Heating Degree-Days (HDDs).

[4] I have access to a schedule of works for district heating networks with operation and investments costs for each year. I also have access to a provisional schedule of upgrades for the energy efficiency retrofitting program.

HDDs correspond to the amount of degrees Celsius and duration in days where the outdoor air temperature is below a threshold directly linked to the indoor temperature level desired by the household. Changes in heating consumption are estimated using a linear heating demand calibrated with price elasticity and rebound effect parameters (see 1.3.2). Households are impacted through expenditures savings and comfort gains. Carbon emissions reductions are monetized with the shadow price of carbon given by Treasury (2021).

The forth step computes the NPV for each policy option. A Monte Carlo experiment is implemented to obtain an expectation of the NPV by iterating the simulation on random samples of households conditional on eligibility conditions. The assessment then computes to measures of the cost-effectiveness of policy options: mitigation costs are computed by taking the ratio between net benefits over carbon emissions, benefit-to-cost ratios are benefits to Bristol's households over net costs (Treasury, 2022).

1.3.2 Theoretical Model

I assume that households have quasi-linear utilities for consuming a heating service, that can be expressed as the amount of Heating Degree-Days (HDD) linked to a target temperature level in a base year. The heating demand can thus be reduced to a linear form. The heating demand is defined on a yearly basis, denoted by h_t, and is expressed incrementally. Let Δp the price difference for the heating service, a first order approximation at year $t+1$ gives:

$$h_{t+1}(p + \Delta p) = h_t(p) + \frac{\delta h(p)}{\delta p} \Delta p \tag{1.1}$$

The effective price for the heating service is expressed relative to annual HDDs. It can be decomposed between a term giving the useful energy needed to heat a unit space by one degree difference, and the retail price of the energy vector used to heat the dwelling ($[\frac{£}{degree.days}] = [\frac{£}{kWh}] \times [\frac{kWh}{degree.days}]$). The useful energy requirement depends on the thermal characteristics of the dwelling, while the price per useful energy depends on the heating appliances' efficiency and the cost of the energy vector. Hence, implementing an energy efficiency retrofit in a dwelling is equivalent to a change in the first component (useful energy requirement), and connecting the latter to a district heating network changes the second component (retail price per useful energy unit).

Let $p = \alpha \times \hat{p}$, where α is the useful energy required per HDD ($[\frac{kWh}{degree.days}]$) and $\hat{p}$ is the retail price per unit of useful energy consumed ($[\frac{£}{kWh}]$). A first order approximation gives the change in heating demand after an energy efficiency retrofit (Eq. 2) or connecting to district heating networks (Eq. 3). Subscript A stems for the situation after the policy, and B for the situation before the policy.

$$h_t(\alpha^A, \hat{p}) = h_t(\alpha^B, \hat{p}) + \frac{\delta h(\alpha)}{\delta \alpha}\Delta\alpha \tag{1.2}$$

$$h_t(\alpha, \hat{p}^A) = h_t(\alpha, \hat{p}^B) + \frac{\delta h(\hat{p})}{\delta \hat{p}}\Delta\hat{p} \tag{1.3}$$

Building on Eq.1 to 3, the model simulates future heating demands at the household level recursively, considering changes of thermal characteristics (acting on α) or heating appliances (acting on $\hat{p}$) between periods t and period $t + 1$. The model assumes no other shocks on heating demand than policies' incidence and prices trends. Heating consumption is observed at t_0, allowing me to retrieve the useful energy requirement α at the household level. Partial derivatives of heating demands with respect to price components are approximated using demand price elasticity and rebound effect estimates.

Heating demands are then used to estimate the change in surplus experienced at the households level. Changes in households' surplus for each year, denoted ΔW_t is given by the following equation, assuming small changes of p, $p^A > p^B$ and quasi-linear utilities.

$$\Delta W_t = -(p_t^A - p_t^B)h(p_t^A) + \frac{(p_t^A - p_t^B)^2}{2}h'(p_t^A) \tag{1.4}$$

The first term in the formula depicts the difference in energy bills in the absence of changes in internal temperature. The second term is valuing the change in internal temperature induced by the price variation. I separate them in my assessment considering that the first stems for expenditures savings and the second for changes in comfort. As the demand for heating is rather inelastic, expenditures savings drive the major part of the changes in consumers' surplus.

Annual final energy consumption H_t can be retrieved from the heating demand (Eq. 5). Final energy consumption is then used to compute annual changes in carbon emissions (Eq. 6). τ is the carbon factor (in ton CO2-eq per kWh) and η the efficiency of households' heating appliances.

$$H_t = h_t \ \alpha \ \eta^{-1} \tag{1.5}$$

$$\Delta G = H_t^A \tau_t^A - H_t^B \tau_t^B \tag{1.6}$$

Benefits are aggregated across all households and discounted with costs in a Net Present Value (NPV) formula. Net costs are denoted by ΔC_t, ρ the discount factor, and $p_{co2,t}$ the social cost of GHG emissions.

$$NPV = \sum_t (\sum_i \Delta W_{i,t} + p_{co2,t} \sum_i \Delta G_{i,t} + \Delta C_t)(1+\rho)^{-t} \tag{1.7}$$

1.3.3 Scenarios

This section details the policy options and the status-quo scenario that are assessed. The status-quo scenario provides a counterfactual common to the two policy options. It represents a second-best alternative than can be chosen by the city instead of the project options. Exogenous trends such as new buildings or heating appliances' upgrades are ignored. As CBA relies on a counterfactual analysis, trends that are similar across all scenarios are cancelled out in the computation. Policy options are named *Project 1*, for the district heating networks extension, *Project 2*, for the energy efficiency retrofitting program, and the *Status-quo* scenario. The Bristol City Council is the entity taking the investment decision and thus bearing all investment costs.

Project 1 comprises the connection of 5,511 dwellings to district heating networks. The extensions take place in central districts [5]. The number of residential dwellings and the connection rates are taken from the bidder's proposal, which provided a schedule of dwellings connected each year. The district networks connect collective buildings only[6]. As I do not observe the specific buildings that will be connected to the district heating networks, I select random batches of collective dwellings within the selected districts in multiple iterations to obtain an expectation of the impacts in a Monte Carlo experiment.

Using the bidder's proposal to the BCL contract, I define an overall energy mix for the new district networks as displayed in Table 1.1. I select the most conservative scenario from the bidder's provisional plan to obtain a lower bound for the benefits of district heating. Other options for the energy mix include geothermal plants or larger heat pumps, entailing higher overall efficiency and lower emission factors.[7] District heating networks tariffs are composed of a fixed part to recover for capital investments. I convert this value in an equivalent price per energy[8]. District heating networks also charge a variable part to account for energy costs and operations. This results in a total tariff at 0.092 £ per kWh in 2020, with a 50% part varying with energy costs.

Table 1.1: District heating networks' energy mix. Energy efficiency and emissions factors (kg CO2-eq per kWh) from BEIS (2012); Treasury (2021)

Thermal plant	Energy mix	Efficiency	Emission factor
Gas boiler	70%	80%	0.22
Heat pump	20%	300	0.23
Biomass	10%	65%	0.04
Total	100%	122%	0.20

[5]Districts in the scope of the district heating networks extension are Old Market, Redcliffe, Temple, Bedminster, Spike Island, Frome Gateway, University of Bristol, Bristol Royal Infirmary, City Centre, Ashton Gate in the following postcodes: BS1, BS2, BS3, BS4, BS5 and BS8

[6]District heating networks have to leverage the most dense areas, in terms of heating demand per unit of connection length, to be economically viable

[7]Biomass plants can also generate additional revenues by combining heat and power, which are not taken into account in this study to apply the same lower bound logic.

[8]This fixed tariff is set at 115 £ per kW per year based on households' estimated consumption. I assume a heating demand of 2,500 hours per year with baseline HDDs levels. Doing so is equivalent to estimating the capacity required by a household based on useful energy requirements and standardized HDDs. The variable tariff is set at 0.046 £ per kWh.

Project 2 implements energy efficiency retrofits for residential dwellings through the program called "Bright Green Homes". This program provides upfront financing for a range of insulation measures including: external walls, cavity walls, lofts, underfloors and double glazing. The program is available for all households with a valid Energy Performance Certificate rated lower than D (i.e. E,F or G labels). The bidder's proposal has identified a number of dwellings that would be involved in the program under high certainty. This corresponds to 1,126 social housing and 3,747 private households retrofitted at a constant rate through 2050.

Energy efficiency retrofits are implemented in accordance with potential improvements reported in Energy Performance Certificates (see 1.3.5). I estimate retrofitting costs from estimated efficiency labels achieved after retrofitting, using Table A.7 reported in A.8. The table provides investment costs per square meters for retrofitting a dwelling from one label to the other (e.g. from E to C) and is adapted from Giraudet et al. (2021).

The *Status-quo* scenario is defined using past policies of the Bristol City Council in the heating sector. More than 10,000 private and public housing have undertaken retrofits in Bristol between 2008 and 2018 over which 32% where social housing buildings and 9% for private housing (Foster et al., 2018; Roberts et al., 2019). Past retrofits were supported either by national policies such as the Energy Company Obligation or the Green Deal, or by the local "Warm Up Bristol" scheme, a subsidy program from the City Council for least efficient dwellings. For the status-quo scenario, I assume that local ambition is strong even in the absence of the BCL. The city would continue to subsidize energy efficiency retrofits for residential dwellings to match the same retrofitting trends achieved in the past decade by national and local policies. By extrapolating linearly past retrofitting trends in Bristol, the status-quo scenario thus involves the upgrade of 976 social dwellings and 1,676 private dwellings by 2050. I assume no future deployment of the district heating network. The Bristol City Council remains with the existing networks located in Bedminster and Castle Park districts that almost operate at capacity [9].

[9]District heating networks expansions planned before the launch of the BCL contract only included ad-

1.3.4 Bristol's housing stock

This section presents the data used in the model, namely Energy Performance Certificates (EPC), which are used to estimate heating consumption and retrieve heating characteristics at the dwelling level.

EPCs are the UK's national energy labelling standard for residential buildings since 2007[10]. They are mandatory for any real estate transaction (rental, purchase, construction) and for implementing energy insulation measures (Summerfield et al., 2019). EPCs compute energy efficiency grades by using a building-physics model called the Standard Assessment Procedure (BEIS, 2012). Energy efficiency grades are displayed on a scale from 0 to 100 and linked to efficiency labels from A to G. Energy consumption are also estimated and expressed in annual expenditures. The SAP model requires detailed information collected at the dwelling level to estimate energy characteristics, typically on the thermal envelope of the building, the type of dwelling, and heating appliances. EPCs also provide a list of retrofitting measures for the dwelling with potential grades and energy consumption that could be achieved after implementing them.

I construct the most recent picture of Bristol's housing stock by selecting the latest EPC for each dwelling in the dataset. Since EPCs are mandatory in the UK, most buildings have at least one EPC recorded in the dataset. After regrouping EPCs by postal addresses, we observe 127,782 dwellings with EPCs which accounts for 63% of the Bristol housing stock. The housing stock suffers from negligible selection bias in terms of energy efficiency levels. 90% of the observations are EPCs issued for renting or selling which are independent of the energy efficiency of the dwelling. Dwellings can be categorized by tenure types, namely owner-occupied, rental (social), rental (private), as reported in Table 1.2. The "Unknown" category refers to the 13% of the dwellings which are not matched with a specific tenure type.

Although providing detailed information at the dwelling level, EPCs present caveats that I attempt to address in my model. First, EPCs are completed by energy efficiency

ministrative and commercial buildings, which are outside the scope of our assessment (Foster et al. (2018)).

[10] They are regrouped in an open source dataset by the UK Ministry of Housing and Local Communities. The dataset is accessible through the following website: epc.opendatacommunities.org

Table 1.2: Descriptive statistics of the Bristol housing stock decomposed by tenure types

Tenure	N	EPC rating (0–100)	Gas Appliances	Heating bills (in £)	Floor (in m^2)	Flats	Central districts
Rental (social)	16,665	67 (11)	76%	530 (243)	62 (22)	58%	14%
Rental (private)	34,508	63 (12)	75%	694 (360)	73 (39)	59%	41%
Owner-occupied	60,495	61 (12)	88%	823 (413)	94 (46)	23%	23%
Unknown	16,114	76 (12)	62%	487 (296)	72 (35)	60%	22%

Note: Standard deviations are given in (parenthesis)

assessors, prone to idiosyncratic errors (Gillingham and Palmer, 2020). Observations where data is assumed to be incorrect are washed out from the dataset, mainly EPCs comprising empty variables, zero heating consumption, inconsistent information were discarded from the dataset (less than 5% of observations). Second, EPCs provide an estimate for energy consumption which aims to be comparable across dwellings. The assessment sets a standard heating demand for all households assuming an indoor target temperature at 21 degree Celsius. However, households are more likely to heat their homes at a target temperature around 19 degree Celsius or less (Summerfield et al., 2019). This is corrected in the assessment by adjusting HDDs' base temperature as detailed in Section 1.3.5[11]. Finally, the estimated potential energy consumption indicated by EPCs represents an upper bound of the savings that could be achieved by a dwelling after implementing recommended retrofitting measures (Brøgger et al., 2019). Dwellings are likely to implement only a part of the retrofitting measures and thus would achieve less energy savings than expected (Fowlie et al., 2018; Gillingham and Palmer, 2020). This bias is corrected in the model using an econometric specification as detailed in next section.

[11] Theoretical energy consumption also diverge from observed consumption patterns due to other factors, for instance poorly estimating energy requirements for older buildings (Brøgger et al., 2019; Cuerda et al., 2020; Cozza et al., 2021). These factors are however not corrected in my model.

Heating appliances' characteristics.

From the analysis of EPCs, I obtain types of heating appliances that are used by Bristol's households, among which individual gas boilers and electricity heaters are the most common (used by 97% of the households). Table 1.3 below depicts heating appliances types available in the dataset. All characteristics are retrieved from the SAP and the Green Book documentation (BEIS, 2012; Treasury, 2021) [12]. Emission factors vary over the period following the Green Book documentation (Treasury, 2021). Consistently, similar decarbonation trends are applied to the energy mix of the district heating network.

Table 1.3: Heating appliances decomposed by fuel types in the Bristol housing stock

Heating Appliance	**N**	Efficiency	Emission factor	Emission factor (trend)
Gas	102,352	75%	0.22	-0.1%
Electricity	22,654	100%	0.23	-3%
Gas (community)	1,795	80%	0.22	-0.1%
Heat pump (air source)	654	170%	0.23	-3%
Liquefied petroleum gas	157	70%	0.24	-0.1%
Oil	108	70%	0.3	-0.1%
Biomass	62	65%	0.04	0%

Note: Carbon emissions factors expressed in kg CO2-eq per kWh (Treasury, 2022)

1.3.5 Calibration

My model takes different input parameters that are calibrated using either information from EPC data or values from the literature. Initial useful energy requirements for heating are retrieved at the household level from Energy Performance Certificates data. Elasticity parameters, namely the rebound effect and price elasticity, are calibrated with estimates obtained in recent empirical studies. I also use reports to make scenarios on retail energy prices trends, and HDDs trends. A summary of calibration parameters is provided in Appendix A.6.

[12] Individual gas boilers are taken as an average between different technologies reported in the SAP documentation (mainly differing by construction dates). Community schemes are considered to be equipped with gas boilers only. All households equipped with individual heat pumps are considered to be air-source. Biomass comprises wood logs, pellets and dual fuels (mineral and wood). Emission factors and retail prices are retrieved according to the technology from the SAP documentation, with the exception of the electricity grid's emission factor where I take emission factors reported in the Green Book supplementary material

Households' energy requirement.

The SAP methodology relies on estimating the total heat transfer coefficient of a dwelling (W/K), being the heat flow required for having the dwelling warmer than outside temperature by one Kelvin degree[13]. I aim to retrieve this data to estimate the useful energy requirement per degree-day at the dwelling level. The back computation is done as follows. Starting from annual energy expenditures, I obtain final energy consumption with standard energy prices used in the SAP documentation. Then, I use heating appliances' efficiency to convert final energy to useful energy consumption. The useful energy value per degree-day is obtained from retrieving the monthly temperature differences imputed by the model. Mounthly HDDs are given in the SAP for Southwestern England, computed by setting a threshold temperature at 18 degree Celsius[14]. Dividing the annual useful energy value by annual HDDs gives me the energy requirement in kWh per degree-day.

I use same steps as above to estimate the useful energy requirement per degree-day after an energy efficiency retrofit. Potential energy expenditures are computed in EPCs after estimating a new heat transfer coefficient achievable after the implementation of all potential retrofitting measures in the dwelling. However, this potential useful energy requirement only depicts a maximum boundary for heating savings assuming that the dwelling implements all the recommended retrofitting measures. Since, households likely implement only a subset of the measures (e.g. the most cost-effective ones), the actual heating saving experienced after a retrofit will inevitably be lower than expected. I correct for this upper-bias by estimating the average heating savings shortfall at the dwelling level, defined as the percent difference between the *ex-ante* estimated heating savings and the *ex-post* realized ones. I implement an econometric analysis applied to a dataset taking all EPCs in the Southwestern England region. The econometric strategy and the results are detailed in Appendix A.4. I find that households on average achieve only 32% of the expected heating savings and that this

[13]This coefficient is obtained by adding up all dwelling's elements U-value, parameter giving the heat flow that passes through a unit surface of a given material due to a unit temperature difference (in $W/K.m^2$)

[14]SAP adjusts the internal temperature in living areas at 21 degree Celsius. SAP then sets an average difference of 3 degree Celsius between outside and inside temperature assuming an heating period of 9 hours per day on week days and 16 hours on weekends and also accounting for heat gains from solar radiation and home appliances.

shortfall is heterogeneous across tenure types.

Heating Degree-Days.

Heating demand are also calibrated using annual HDDs forecasted through 2050. I extrapolate annual HDD observed in the Bristol region, from 2000 to 2021, recorded at three weather stations [15]. The SAP methodology computes HDDs with a threshold temperature at 18 degree Celsius. In contrast, I compute HDDs using a threshold temperature at 15.5 degree Celsius[16] to correct for the over-estimation of temperature in EPCs. I follow the base temperature thresholds provided by the UK's national meteorological service (UK Met Office), which is aligned with empirical studies (e.g. Hamilton et al. (2011) or Summerfield et al. (2019)). I estimate future annual HDDs by extrapolating past time-series with a constant linear trend through 2050[17]. I apply a simple OLS regression detailed in A.4. I observe a decreasing trend of -8 HDD per year which is significant at the 5% level and in line with statistics fund at the EU level ranging between -5 HDD per year for the UK and -13 HDD at the EU level (Spinoni et al., 2018; Eurostat, 2023).

Price elasticity and rebound effects.

Based on the literature[18], I calibrate estimates of the rebound effect and price elasticity parameters used to approximate partial derivatives of the heating demand (see Section 3).

Rebound effects depict the unexpected increase in the consumption of an energy service after an improvement of the service's energy efficiency, also known as the "Jevons' paradox". In this paper, the rebound effect corresponds to the part of incremental energy demand attributed to an increase in the internal temperature after the retrofit of the dwelling (Sorrell et al., 2009). This effect is documented as the *"temperature take-back factor"* and is measured

[15] monthly HDDs collected through the `degreedays.net` website's API with a base temperature at 15.5 degree Celsius

[16] Inside target temperature ranging between 18-19 degree Celsius with a 3 degree shortfall to account for internal gains and occupants' heating patterns

[17] I do not include uncertainty or variations in HDDs' standard deviations (e.g. climate change impacts). The assessment being a counterfactual analysis, variations that are common to all the scenarios would be cancelled out in the computation.

[18] Table A.6 in Appendix E is providing a recap of the literature review

as the elasticity of the energy consumption relative to the actual energy gains from a retrofit. This effect is lower and should not be confounded with heating savings shortfalls, also studied in the literature (Fowlie et al., 2018) [19]. I aim to provide heterogeneous estimates accounting for differences in income levels across tenure types. Individuals pertaining to lower-income groups are more likely to be constrained by energy expenditures at a sub-optimal heating level and to display a higher willingness to consume more of the energy service as its cost decreases. Variations in the effect can also be driven by changes in the use of the heating service such as more energy intensive behaviors pertaining to higher-income groups.

Sorrell et al. (2009) conducted a large literature review on the rebound effect in various sectors and find temperature take-back factors ranging from 0.05 to 0.3 with a mean around 0.2. Hamilton et al. (2011) study temperature take-back factors through an experiment for the UK and find a mean estimate of 6% of potential energy savings that could reach 22% for least efficient households. Hediger et al. (2018) apply a stated preference approach on Swiss households to estimate the compulsory increase in service consumption implied by an energy efficiency retrofit and find values ranging from 0.10 to 0.14. Aydin et al. (2017) is the first paper investigating the heterogeneity of the rebound effect across income groups in a study applied to the Netherlands. The paper finds a rebound effect of 0.27 for homeowners and 0.41 for tenants and a range of 0.20 - 0.48 according to income quantiles, implying a variation across tenures of more than 100%. However, the paper do not isolate the temperature take-back factor.

The price elasticity corresponds to the percent increase in the demand after a percent decrease in the price. Although the rebound effect and price elasticity should equalize in absolute terms (under perfect rationality), many studies find different responses when studying variations driven either by retail prices increase or by energy efficiency gains (Sorrell et al., 2009). These asymmetrical reactions would stem from households self-selecting into energy efficiency programs to improve their level of service, differences in perception of the impacts on energy expenditures, or different reactions between decreases and increases

[19] Indeed, studies estimating the rebound effect, such as Aydin et al. (2017) and Coyne et al. (2018) are based on expected energy gains stated *ex-ante* by the EPC assessor. The resulting estimates capture both the temperature take-back factor and the shortfall between potential energy savings and actual energy savings.

in energy expenditures. Two papers are best reporting price elasticity estimates to my knowledge. Labandeira et al. (2017) study heating demand price elasticity from a meta-regression analysis of 428 papers produced between 1990 and 2016. Price elasticity estimates are different according to the fuel source being -0.18 for gas and -0.13 for electricity. Chitnis et al. (2014) separate the relative contribution of income and substitution effects and find lower estimates; -0.09 for gas and -0.07 for electricity.

Table 1.4 is displaying the final estimates taken to calibrate my model. Since there is no precise estimates that can directly be applied to Bristol, I use several approaches that will be compared in a sensitivity analysis. I obtain the estimates by taking the mean between Labandeira et al. (2017) and Sorrell et al. (2009) for price elasticity and I use estimates ranges provided by Sorrell et al. (2009) and Hamilton et al. (2011) for rebound effects. I apply a variation across tenures categories similar to the ranges fund in Aydin et al. (2017), considering that income levels in the UK are closed to the Dutch context. The *Baseline* specification takes similar values for the rebound effect and price elasticity in absolute terms and average values from the literature. The *Distributional* specification takes a larger heterogeneity of estimates across tenures categories, assuming lower elasticity for owner-occupied and higher elasticity for rental tenures. The *Asymmetric* specification assumes that the elasticity relative to the cost of the energy service is lower when facing a price increase than a cost decrease (Labandeira et al., 2017; Chitnis et al., 2014).

Table 1.4: Calibration of elasticity parameters

Estimate	Rental (social)	Rental (private)	Owner-occupied
Baseline	0.17	0.12	0.07
Distributional	0.3	0.15	0.05
Asymmetric (rebound)	0.2	0.15	0.1
Asymmetric (elasticity)	-0.15	-0.1	-0.05

Prices scenarios.

Following Russia's invasion of Ukraine in February 2022, Europe experienced a dramatic surge in energy costs (Sgaravatti et al., 2023). I define two scenarios, the "BAU" and the “HIGH“ scenario, to forecast retail prices from 2021 to 2050. All price variations are expressed in real terms and applied to retail prices in 2020 retrieved from the SAP documentation. District heating networks’ price trends are computed using the share of its energy mix components and applied to the variable part of the tariff.

The *BAU* prices scenario takes retail price forecasts done before the energy crisis by the Green Book (Treasury, 2021). I select the scenario with the highest retail prices levels in the Green Book assuming that, without the recent energy crisis, the UK would still have experienced a short-term energy prices inflation due to the Covid-19 recovery. Indeed, domestic energy bills started to surge after September 2021, experiencing a 6% year-on-year increase in 2021 (BEIS, 2021b)). The BAU scenario forecasts a surge between 2020 and 2023 of respectively 25% and 39% for electricity and gas in real terms, followed by a plateau after 2024 putting electricity and gas prices at 14% and 45% higher in 2050 than 2020 levels.

The *HIGH* prices scenario aims to estimate retail price trends following the recent energy crisis in Europe. I use latest Quarterly Energy Price reports from the BEIS to define first years’ price trends (BEIS, 2022a,b, 2021b). Energy prices increased between September 2021 and 2022 by 16% for electricity and 20% for gas and are expected to continue increasing between 2022 and 2023 by 60% for electricity and 100% for gas. The scenario then assumes that the rate of price increase will slow down after 2024 and follow similar trends to the BAU scenario[20]. Tables 1.5 and 1.6 display the average trends of the two energy prices scenarios for two time intervals. Prices trajectories in each scenario are displayed in Figure A.2.3 in appendix A.2.

Table 1.5: Heating appliances’ price trends for the period 2020-2023 (real terms) (BEIS, 2022a, 2021b,a, 2012)

Scenario	electricity	gas	community	oil	LPG	biomass	HNs
BAU	25%	39%	10%	42%	42%	10%	17%
HIGH	128%	223%	37%	186%	186%	37%	67%

[20]Recent reports, such as the World Energy Outlook (IEA, 2022), agree on the fact that Ukraine war and its consequences might last for several years and that diversification of supply will be progressive.

Table 1.6: Heating appliances' price trends for the period 2024-2050 (real terms) (BEIS, 2022a, 2021b,a, 2012)

Scenario	electricity	gas	community	oil	LPG	biomass	HNs
BAU	-10%	4%	1%	5%	5%	1%	-1%
HIGH	-10%	4%	1%	5%	5%	1%	-1%

1.4 Results

This section presents the main results of the assessment. All costs and benefits are computed in present value using a discount rate at 3.5% as per the Treasury (2022). Carbon emissions are valued using the shadow price of carbon provided by the Treasury (2022).

1.4.1 Net benefits of policies under different prices scenarios

Applying my model to the case of Bristol, I find that both policies benefit from important windfall effects under the HIGH prices scenario and generate net benefits per unit of avoided carbon emissions. Moreover, district heating networks become more cost-effective to mitigate carbon emissions than energy efficiency retrofits. Under the HIGH price scenario, the mitigation cost of district heating networks decreases from £ 310 per ton CO2-eq to £ -390 per ton CO2-eq while energy efficiency retrofits from £ 100 per ton CO2-eq to £ -50 per ton CO2-eq. District heating networks cut three times more carbon emissions than energy efficiency retrofits per dwelling, profiting from lower carbon factors and higher efficiency ratios.

Figure 1.1 shows the cumulative discounted costs and benefits for each policy option, whose benefits are decomposed into comfort improvement, energy bills savings and climate avoided costs. District heating networks are reported as *Project 1* in the graph, and energy efficiency retrofits as *Project 2.* The energy crisis also implies a shift in the policy options' ranking based on benefit-to-cost ratios. While energy efficiency retrofits is the most cost-effective option under the BAU prices scenario, district heating networks achieve 85% higher benefits to households per unit cost in the HIGH scenario. This is driven by energy bills savings[21]. District heating networks display higher leverage to shield households from high

[21] In the context of rising energy prices, the benefit attributed to comfort gains is negligible relative to

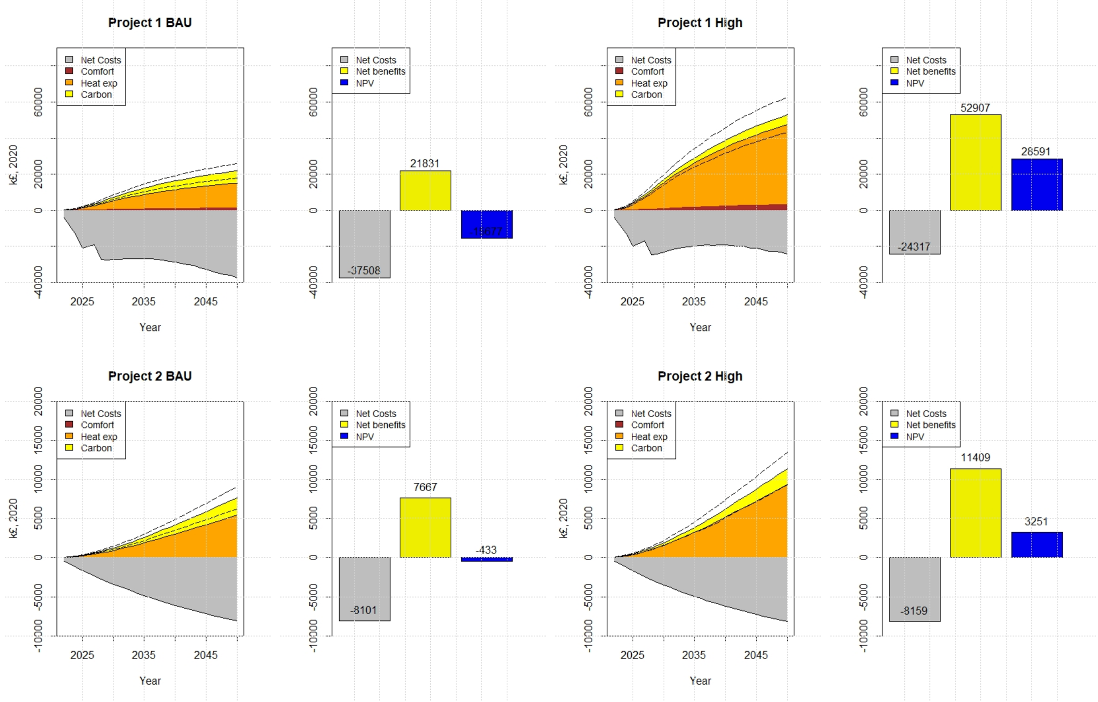

Figure 1.1: Expected cumulative net economic benefits generated in each scenario and net present values after a Monte Carlo experiment (10 iterations). Confidence intervals at the 95% level.

energy prices relative to energy efficiency retrofits. Each pound invested in district heating networks delivers £ 1.9 benefits to consumers in present value over a 30 years period, while each pound invested in energy efficiency retrofits delivers £ 1.1 benefits. Conversely, energy efficiency retrofits have higher leverage under the BAU scenario delivering £ 0.7 benefits per pound invested versus £ 0.4 for district heating networks.

Figure 1.2 reports the distribution of impacts to households in present value conditional on tenure types. Looking at aggregate values, district heating networks have distributional impacts that could be complementary to energy efficiency programs. First, district heating networks overcome the barriers usually faced by energy efficiency programs to reach rental housing (Giraudet et al., 2018). Taking place in dense and central districts, they involve collective dwellings that are more likely to be rental tenures. District heating networks con-

avoided carbon emissions and energy expenditures savings. The variation in surplus due to falling prices is much greater than the variation in energy demand.

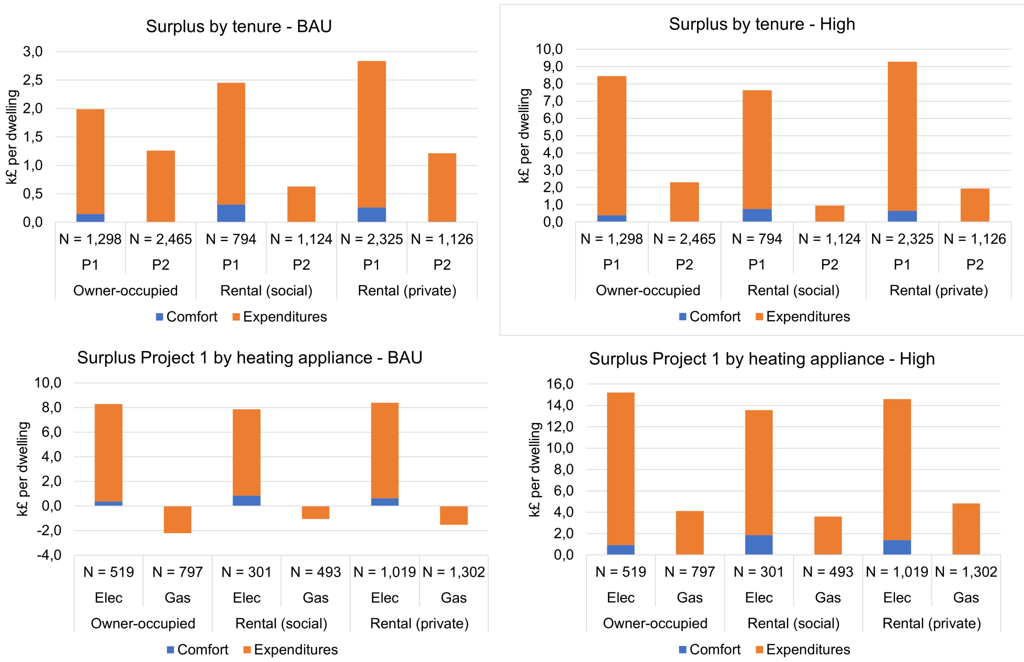

Figure 1.2: Consumer' surplus generated per tenure category

nect over 3,000 rental (private or social) dwellings, (57% of the dwellings), as compared to 2,250 for energy efficiency retrofits (46% of the dwellings). Second, district heating networks generate higher benefits for rental (private) and rental (social) tenures, whereas energy efficiency retrofits deliver less benefits for rental (social) tenures, since they have higher initial efficiency levels.

However, more than 60% of dwellings, formerly equipped with gas appliances incur a cost upon the implementation of district heating networks in the BAU scenario. Bottom panels in Figure 1.2 show important scale effects when looking at the distribution of impacts conditional on households' former heating appliances. As electricity is 4 to 5 times more costly than gas in the BAU, district heating networks generate two-fold additional expenditures savings for households formerly equipped with electric heaters. Conversely, district heating networks tariffs are 10% higher than gas retail prices in the BAU, implying an increase in heating expenditures for households formerly on gas. This disappears under the HIGH price scenario. Gas prices trends increase twice as much as other energy vectors putting the tariffs at higher levels than the district heating networks' tariffs. District heating networks have only a 50% variable part which is composed of electricity, biomass and gas. They offer greater stability for retail prices and some insurance against gas prices' uncertainty. From a back-of-the-envelope calculation, I find that gas prices have to increase by at least 28% more than other energy vectors to make district heating networks progressive.

1.4.2 Sensitivity analysis

In this section, I test the sensitivity of my results relative to the discount rate, prices scenarios and elasticity parameters. I then investigate the drivers of the cost-effectiveness of each policy option by studying alternative project scopes to assess how differences of timing and targeting of households' groups influence the results of the assessment.

Sensitivity to discount rates

Figure A.1.1 in A.1 shows the sensitivity of the two policy options conditional on discount rates. Energy efficiency retrofits have an internal rate of return at 2%, being the discount rate above which both projects have negative net present values. Under the BAU scenario, Project 1 displays consistently negative NPVs with different discount rates due to important investments taking place both at the beginning and at the end of the period. The HIGH price scenario increases the profitability of both policy options with sufficient margin and ensure that the discount rate does not interfere in the results. Energy efficiency retrofits have an internal rate of return at 10%, and district heating networks at 15%.

Sensitivity to elasticity parameters

I run again the assessment taking different calibration strategies as presented in 1.4. The results of the sensitivity relative to different calibration are displayed in Fig A.1.2 of A.1 . Results suggest that the output of the assessment is robust to different values of the elasticity parameters. Average economic benefits per dwelling tenures are of the same order across different specifications. The distributional option generate the highest benefits to rental dwellings pertaining to social housing. This slightly improves the cost-effectiveness of district heating networks, reducing its mitigation costs by 6%. Conversely, distributional parameters decrease the cost-effectiveness of energy efficiency retrofits by 4%.

Sensitivity to price scenarios

I test the sensitivity of my results according to different price scenarios by implementing two strategies, which are detailed in Appendix A.2. First, I create alternative scenarios by increasing all price levels observed at the beginning of the time window by a fixed rate. I obtain 12 scenarios by applying percent increases from 10% to 120%. The HIGH price scenario pertains to an average increase ranging between 80% and 120% relative to the BAU scenario across technologies. Figure A.2.6 of Appendix A.2 reports the NPV of each policy option conditional on the different rates. While energy efficiency retrofits start being profitable with a 10% prices increase relative to the BAU scenario, district heating networks are profitable starting from a 30% increase. District heating networks have a higher NPV than energy efficiency retrofits for price increases higher than 30% relative to the BAU scenario.

In a second sensitivity analysis, I explore alternative price scenarios by adopting energy price trajectories from the HIGH scenario until a specific year. Beyond that year, I use energy prices from the BAU scenario. The objective is to identify the minimum year of recovery from the energy crisis, i.e. when prices move from the HIGH to the BAU scenario, at which policy options start having a positive NPV. I generate twenty-five alternative price scenarios, each corresponding to a different year of recovery spanning from 2025 to 2050. Figure A.2.6 of A.2 displays the results of the sensitivity. I find that district heating networks are more profitable than energy efficiency retrofits if energy crisis price trends are experienced beyond 2032 and that energy efficiency retrofits are profitable if the energy crisis price trends are experienced beyond 2029.

Sensitivity relative to projects' scope

In this sensitivity analysis, I test alternative project scenarios where (1) the timeline of energy efficiency retrofits is aligned with district heating networks, and (2) energy efficiency retrofits are bundled with district heating networks at the dwelling level. All these alternative scenarios are studied under prices that follow the BAU scenario. Details of the scenarios and results are reported in A.3.

First, I increase energy efficiency retrofits and modify the schedule of retrofits' uptakes to match the timeline of district heating networks. Energy efficiency retrofits implemented more early in the period generate six times higher benefits than in the baseline assessment and become socially profitable even with the BAU prices scenario, generating a million £1.6 NPV. This leads to a 30% decrease in the mitigation costs.

Second, I create a scenario where a dwelling is retrofitted first and then connected to the district heating network. Results suggest that bundling the two projects does not involve synergies: despite increasing the potential for cutting carbon emissions and generating higher benefit per dwelling relative to either policy option, bundling the two policies does not trigger higher benefits than when implemented in parallel. Energy efficiency retrofits reduce heat revenues for the district heating networks, while district heating networks constrain energy efficiency retrofits to be undertaken in more efficient dwellings. Indeed, good candidates for connecting to district heating networks do not necessarily have good potential for energy efficiency. As retrofitting is not feasible in all central areas' dwellings, the incremental net benefit from energy efficiency retrofits is 50% lower than in Project 2.

1.5 Discussion

In this section, I first outline key takeaways for policymakers drawn from this case study. I then evaluate how the two policy options can contribute to the city's carbon neutrality objectives. Finally, I discuss the external validity of my findings.

Policy implications

My results suggest that a minimum 30% price increase relative to the BAU scenario is sufficient to make the two policy options socially profitable and changes their cost-effectiveness. This has three implications. First, mitigation costs are very sensitive to retail prices and can fluctuate over a wider range of values than indicated in the literature. District heating networks are more sensitive to price trends than energy efficiency retrofits. For example, the UK's Climate Change Committee finds values between -100 and -50 £ per ton of CO2-eq for energy efficiency retrofits and between -100 and 300 £ per ton of CO2-eq for district heating networks (Foster et al., 2021). I find mitigation costs ranging between 100 and -50 for energy efficiency retrofits and between -400 and 300 £ per ton of CO2-eq and for district heating networks.

Second, co-benefits are critical when estimating the social costs of the two policy options. They may have higher cost-efficiency than some short-term national support schemes to shield households against the energy inflation. District heating networks can act as a price cap and lever £ 1.9 benefits to households per £ 1 invested, in present value. Energy efficiency retrofits can act as a direct transfer to households and lever £ 1.1 per £ 1 invested. Conversely, the Energy Price Guarantee has a leverage of £ 1.3 per £ 1, according to latest studies (Adam et al., 2022). My results suggest that district heating networks offer a higher insurance value than energy efficiency retrofits against prices uncertainty. They offer a tariff structure that is less correlated to natural gas' prices since also relying on a mix of renewable energy sources. However, district heating networks may entail adverse distributional impacts if they propose tariffs that are higher than the tariffs of the former heating appliances installed at the household level.

Third, district heating networks and energy efficiency retrofits are complementary policies, given that they do not have the same impacts at the dwelling level. A cost-effective roll-out of the Climate Action Plan should thus target different types of dwellings for different policies. On the one hand, district heating networks are for collective buildings in central and dense districts. They should target dwellings equipped with electric heating appliances to generate higher co-benefits. This part of the housing stock is on average more energy efficient and less eligible to the energy efficiency retrofitting program. On the other hand, energy efficiency retrofits are more easily implemented in large and detached homes that are mostly located at the fringes of the city. These dwellings are on average less energy efficient and are more likely to be owner-occupied, which involves higher retrofitting rates.

Optimal mix of policies for decarbonizing the heating sector

Building on my results, I study the extent to which the two policies contribute to carbon neutrality when implemented on a larger scale[22]. I gradually adjust each policy scenario to either include more buildings or improve their decarbonation potential. This allows me to explore which scope, targeting, and efficiency parameters enable the most carbon reductions and for what additional investments. Project scenarios are expanded according to a pathway as follows: (1) district heating networks are expanded to all buildings in central districts at a constant marginal cost in order to maximize the density of the network. I do not allow to replicate the project in a different location as it requires different technical details and investment costs. In (2), I overlook the constraints on enrolment in the energy efficiency program that were imposed in the project scenario. Each dwelling lower than the label D in the EPC is retrofitted. In (3), I further extend the scope of the energy efficiency program by including dwellings that have energy efficiency grades lower than the label C in EPCs. Finally, in (4) dwellings achieve the full potential for energy savings by implementing all retrofitting measures reported in the EPCs.

The left panel of Figure 1.3 displays additional carbon savings relative to the annual emissions of the residential heating sector in years 2030 and 2050. The right panel of Figure 1.3 provides the detail of each project expansion's incremental emission savings in 2030 with additional investments to implement them. Contributions of each project expansion are ranked by decreasing cost-effectiveness order. Annual emissions are computed in a situation where no action is implemented (called "Baseline" in the graphs), although decarbonation trends and HDD trends that were included in the model reduce annual emissions by 21% in 2050.

The current mix of policies save an additional 1% of the annual emissions in 2030 (2% in 2050). This value is small since projects scenarios in the assessment involve a marginal portion of the city's building stock[23]. When both types of policies are fully expanded at

[22]Bristol's Climate Action Plan has set the ambitious goal of becoming carbon neutral by 2030, yet it does not specify any carbon reduction targets at the sector level. Therefore, I assume that carbon emissions must be minimized in the medium-term with no constraints on investment levels.

[23]The scenarios are based on conservative work programs and consistent technical provisions, thus only

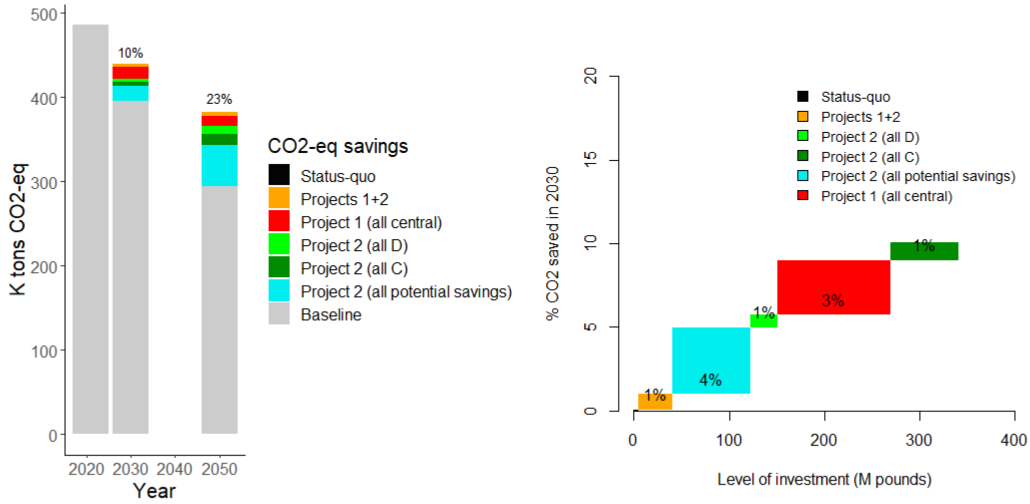

Figure 1.3: Decarbonation potential of the two policies when being gradually scaled-up. Left panel: incremental savings in annual CO2-eq emissions for the residential heating sector in 2030 and 2050. Right panel: Breakdown of the contribution of each project to 2030 annual emissions savings versus incremental investments.

the city level, annual emissions are further reduced by 10% and 23% in 2030 and 2050, respectively. This expansion requires an additional investment of about £ 340 million. I also approximate the co-benefits delivered by the two policies when fully expanded at the city level. I find that the net economic cost of the complete expansion would amount to £ 142 million[24].

Considering the optimal expansion pathway, I find that (1) expanding energy efficiency retrofits at the intensive margin, i.e. implementing all retrofitting measures reported in the EPCs, and (2) district heating networks in all central districts have the highest decarbonation potentials. Moreover, expanding energy efficiency retrofits at the intensive margin is the most cost-effective expansion option. Despite having a high potential to reduce emissions, district heating networks require 14% higher investment costs per unit carbon savings than when expanding the energy efficiency program to all dwellings lower than D. Finally, targeting dwellings in higher efficiency labels is the least cost-effective option.

include elements that would be implemented with high certainty.

[24]Computed using the leverage to consumers estimated for each policy option in the BAU prices scenario: 0.4 for district heating networks, 0.7 for energy efficiency retrofits, and 0.4 for retrofits with complete heating savings potential, in £per £invested

External validity of the assessment

The results of this assessment can be applied to other European cities. First, many cities in Europe have issued a Climate Action Plan (Reckien et al., 2018). Second, other European countries have also faced increases in energy prices due to the recent energy crisis, having to resolve a similar trade-off between achieving climate objectives and shielding the energy prices inflation. Third, European cities may have similar building stock characteristics than Bristol, typically: dense central districts with collective dwellings, majority of heating appliances using gas, and similar average energy efficiency levels. Regarding district heating networks, while technical details and investments are tailored to Bristol, the identified trade-off between having a high decarbonation potential and high investment costs applies more generally to other low-carbon heating systems, such as heat pumps.

Regarding the methodology, the model introduced in this paper is designed to be replicated to other cities. First, it relies on Energy Performance Certificates. They follow a transparent methodology (BEIS, 2012), and are publicly available in many European countries. Second, estimates for price elasticity and rebound effects used in the model's calibration are derived from the economic literature. While these parameters are primarily calibrated using studies focusing on the UK, the literature is sufficiently furnished to enable a focus on other countries (Sorrell et al., 2009).

1.6 Conclusion

This paper presents a model based on Cost-Benefit Analysis to evaluate *ex-ante*, and at a city scale, the economic benefits of climate policies in residential heating. This assessment aims to provide local authorities with a transparent and robust tool for policy evaluation, that offers an alternative to Multi-Criteria Analysis or standardized Marginal Abatement Cost Curves. More particularly, this model estimates the impacts of heating policies using detailed economic processes and calibrated at the dwelling level using Energy Performance Certificates data.

I apply this model to the city of Bristol and explore the effects of the recent energy prices shock on the economic benefits of two policy options: an energy efficiency retrofitting program and district heating networks. I find that a minimum 30% price increase compared to the energy price levels observed before the crisis is sufficient to make both policies socially profitable. Furthermore, higher energy prices shift the typical merit order for these options, favoring district heating networks over energy efficiency retrofits.

I see three directions for further research. First, my model could provide a more detailed assessment with additional data observed at the household level. Taking into account real energy consumption and observing income levels would improve the estimation of heating demands. This would also be required to improve the analysis of their distributional impacts. Second, this assessment can be extended to the appraisal of other policies, such as supports for the uptake of individual low-carbon heating appliances (e.g. heat pumps). A third extension would provide a more detailed comparison of local versus national mitigation policies.

Chapter 2

Dynamic (Mis)allocation of Investments in Solar Energy

Abstract: Because they differ in terms of technology, size and location, solar photovoltaic installations exhibit very heterogeneous levelized costs of producing electricity. Therefore, the present value cost of meeting a given trajectory of annual solar energy production depends on which projects are commissioned when: the observed sequence of investment decisions need not be cost-efficient. We propose a methodology to assess the magnitude of dynamic misallocation by comparing the present value cost of realized investments to a counterfactual optimal sequence of investments. Applying our methodology to France between 2005 and 2021, we find that the observed trajectory of annual solar output could have been produced at a present value cost about 30% lower than its realized value. Our optimized counterfactual suggests that investments in residential solar should have on average been postponed by 7 years, while investments in medium and large-scale installations should have occurred 3 to 4 years earlier. [1]

[1]This article is co-authored with Nicolas Astier and available as a preprint in the Journal of the Association of Environmental and Resource Economists.
Acknowledgments: We are grateful to seminar participants at the Paris School of Economics, the XI International Academic Symposium of the Institut d'Economia de Barcelona, the 1st PhD conference of the Paris Dauphine European Electricity Markets Chair, the 9th International Symposium on Environment & Energy Finance Issues, the 1st NEOMA workshop on the decentralization of the energy system, the 28th EAERE Annual Conference, the 18th IAEE European Conference, the FSR Loyola Autumn Research School and the 9th Joint Research Workshop Public Policies and Sustainable Development (Paris) for their feedback and suggestions.

2.1 Introduction

Increasing the share of solar photovoltaic (PV) energy in electricity supply is a cornerstone of both existing and envisioned climate policies.[2] Therefore, investments in solar energy, which have exceeded $100 billion/year globally over the past decade (IRENA and CPI, 2020), are expected to remain high or even to accelerate in the near future.

Meeting the objectives of the Paris agreement, however, requires an energy transition of an unprecedented speed. In this context, improving the cost-efficiency of investments in solar energy, that is, how much renewable electricity is produced per dollar invested, is of critical importance. Indeed, any significant inefficiency regarding when and where solar facilities are deployed means that more solar energy could have been generated with the same amount of private investments and public subsidies.

Following Callaway et al. (2018), the literature on the misallocation of solar investments has mainly focused on inefficiencies regarding *where* solar facilities are built. This body of work typically highlights that a social planner would have located solar facilities differently than what is observed in practice. In contrast, this paper studies inefficiencies regarding *when* investments in different types of solar installations took place. Indeed, solar PV installations differ significantly in terms of location (available resource, proximity to the existing power grid), size (e.g. residential vs. large-scale installations) and technology. As a result, the levelized cost of electricity (LCOE), that is, the ratio of the sum of the discounted costs of an installation and the sum of its discounted energy output, is highly heterogeneous across solar facilities. Therefore, an exogenously given trajectory of annual solar energy generation can be met at very different present value costs. In particular, the observed timing of investment decisions need not be cost-efficient.

Building on this observation, we propose a methodology to quantify the magnitude of dynamic misallocation in solar investments, which we apply to France for the period 2005-2021. We find that the relative cost of dynamic misallocation may have been as high as 30%,

[2]For example, reports from the Intergovernmental Panel on Climate Change (e.g. Pörtner et al. (2022)) consider solar energy to be one of the main potential contributor to net emission reductions (see for instance Figure SPM.7).

meaning that the exact same amount of solar electricity could have been produced each year for only 70% of the realized present value cost.

The magnitude of this dynamic misallocation is larger than most estimates of (static) misallocation found in the literature (Sexton et al., 2021; Lamp and Samano, 2023). For example, Colas and Saulnier (2023) estimate a misallocation of 6-11% for residential PV in the United States. Similarly, Lamp and Samano (2023) assess that reallocating residential solar facilities across space in Germany could have increased their social value by about 5% relative to their realized social value. In contrast to these estimates, however, we study all categories of solar PV installations rather than focusing only on residential PV. Consistently, when we freeze reallocation across categories,[3] we assess misallocation to be about 6%. In addition, when considering both large-scale and residential installations, Lamp and Samano (2023) find that misallocation could range between 15 and 30%. Therefore, our estimates are overall consistent with available evidence from the existing literature.

Misallocation in solar investments necessarily arises from some source of heterogeneity in photovoltaic installations. Existing studies usually focus on the heterogeneity in the gross social *marginal value* of electricity. For example, Callaway et al. (2018) note that different solar facilities displace generation from power plants with different fuel costs and environmental externalities. Lamp and Samano (2023) study the same source of heterogeneity, along with differences in solar irradiation. Focusing attention on differences regarding which power plant is displaced at the margin makes indeed perfect sense for countries that span across a large geographical area, such as the United States (Callaway et al., 2018; Sexton et al., 2021), and/or that experience high levels of congestion in their transmission grid, such as Germany (Lamp and Samano, 2023).

In contrast, we consider a situation where the marginal social value of 1 kWh of solar electricity is on average roughly uniform across space and types of solar installations.[4] This simplifying assumption is indeed realistic for a country with a relatively small surface and

[3] We do so by constraining each category of PV installations to meet the trajectory of annual output that they have actually produced.

[4] Appendix E discusses how our theoretical framework can be generalized to relax this assumption.

whose transmission grid experiences little congestion, such as France.[5] In addition, in the case of France, small-scale installations connected to the distribution grid have been found to deliver negligible grid savings relative to larger scale facilities connected to the transmission grid (Astier et al., 2022). However, solar facilities are very heterogeneous in terms of their levelized costs of electricity, notably due to economies of scale and differences in solar irradiation. For example, typical estimates suggest that the LCOE of a residential rooftop installation is two to three times higher than the LCOE of a large-scale ground-mounted solar farm. Even within a given type of installations, for example 90kW rooftop facilities, LCOEs remain very heterogeneous because they depend on average irradiation, roof orientation, how difficult it is to install the solar panels, etc.

Building on Asker et al. (2019), we consider the dynamic optimization problem faced by a social planner who must choose, over a period of several years, the commissioning dates of a given set of solar facilities. The optimization is made under the constraint to meet an exogenously given trajectory of total annual production, corresponding to the total solar output actually generated each year.[6] Because we assume the marginal social value of electricity to be on average uniform across installations, any combination of commissioning dates that meets these annual production targets generates the same gross social surplus. The social planner's objective is therefore to minimize the present value of investment and operating costs under a set of annual aggregate output constraints. Misallocation may then arise in a dynamic sense: the present value cost of realized investments can be significantly larger than the present value cost of the optimal sequence of investments.

In a number of ways, our methodology provides a lower bound of the magnitude of dynamic misallocation. We indeed shut down three important channels of potential inefficiencies. First, as discussed above, we assume the social value of solar energy to be uniform across space. Second, we restrict attention to the set of solar facilities that actually exist today. In other words, we do not allow for changes in the location or the size of solar in-

[5] Consistently, Callaway et al. (2018) note "*We find that variation in the quantity of emissions displaced by wind, solar, and efficiency resources is significant across regions but limited across resources within a region*".

[6] We thus assume that learning-by-doing is either exogenous or related to the total amount of electricity generated to date. This assumption is further discussed throughout the paper.

stallations. Therefore, our methodology does not suffer from possible measurement errors regarding the feasibility of installing a solar facility at a given location, which would otherwise be confounded with misallocation. In addition, we take the installed capacity of a given unit as exogenous, and hence do not allow for inefficiencies in the size chosen for each unit. Third, our optimized trajectory for annual aggregate production matches the realized trajectory. We thus do not allow for the possibility that it may have been welfare improving to produce more (or less) solar electricity in any given year.

Despite these conservative assumptions, we find dynamic misallocation to be very large when applying our methodology to the case of France. Specifically, we estimate that the exact same amount of solar electricity could have been generated each year from (a subset of) the exact same fleet of solar installations for about 70% of the realized present value cost. The comparison between the realized and optimized sequences of investments suggests that investments in residential solar should have on average been postponed by 7 years, while investments in medium and large-scale installations should have occurred 3 to 4 years earlier. These results are consistent with the observation that, over our period of interest, residential solar has benefited from significantly higher subsidies per unit of output than utility-scale installations. Arguably, this stronger policy support for residential solar may have pursued other policy objectives besides efficiency. If so, the dynamic misallocation we assess reflects the social opportunity cost of such objectives.

This work contributes to a vast literature on the design and efficiency of renewable electricity policies (e.g. Borenstein (2012); Fell and Linn (2013); Abrell et al. (2019a,b); Ambec and Crampes (2019); Abrell and Kosch (2022), among many others), as well as their distributional impacts (e.g. Reguant (2019); Liski and Vehviläinen (2020)). Within this literature, the cross-sectional heterogeneity in the marginal social value of renewable facilities plays a very prominent role (Cullen, 2013; Novan, 2015; Wolak, 2016; Callaway et al., 2018; Gillingham and Ovaere, 2020; Sexton et al., 2021; Lamp and Samano, 2023). In contrast, little to no attention has been dedicated to the significant heterogeneity in the investment costs of solar units, and its potential implications in terms of dynamic misallocation. This article aims to fill this gap.

The rest of the paper is organized as follows. Section 2.2 provides background information on the different sources of heterogeneity in solar installations, which create scope for misallocation. Section 2.3 formalizes the problem we study and defines our concept of dynamic misallocation. Section 2.4 discusses how solar energy has been deployed in France over the past two decades and describes the data we use in our empirical application. Section 2.5 presents our main results. Section 2.6 discusses robustness checks and policy implications. Finally Section 2.7 concludes.

2.2 Solar Energy and Misallocation

2.2.1 Heterogeneity in Solar Installations

Solar photovoltaic (PV) facilities are composed of arrays of solar cells, called modules. PV modules are characterized by their efficiency at converting solar irradiation into electricity,[7] which determines their peak power capacity, expressed in kW. In other words, the total capacity (in kW) of a given solar installation reflects how much electricity the facility will produce under specific (most favorable) conditions. When realized conditions differ from this benchmark, the amount of electricity produced by the installation over a given hour, expressed in kWh, will be smaller than its installed capacity.

Given these characteristics, the net social value of a solar installation with a given installed capacity can differ significantly depending on when and where it is built. For example, the prevailing prices of PV modules have decreased dramatically over the past couple of decades, notably due to economies of scale and technological progress in manufacturing. In addition, even conditional on a given cost of PV modules, a large heterogeneity in the net social value of solar installations can arise through three main channels.

First, total installation costs net of module costs can differ significantly across projects and over time. For example, fixed costs represent a much lower share of total costs for a

[7] In France, according to CRE (2019), most PV modules are composed of Crystalline Si solar cells (60% of ground PV and 90% of rooftop PV projects) and a minority are CdTe (27% of ground projects and 4% of shelters). Crystalline Si solar cells have a maximum efficiency of 26% whereas CdTe have a maximum efficiency of about 22% (Allouhi et al., 2022). Within a vintage, differences induced by heterogeneous technologies across solar PV projects can thus only reach a few percentage points.

300,000 kW ground-mounted project than for a 3 kW rooftop unit. Moreover, the installation of the latter is much harder to standardize or automate. Finally, in contrast to rooftop installations, ground-mounted installations require dedicated power lines to connect to the electricity grid, whose cost scale approximately proportionally to their distance to the closest grid substation.

Second, PV modules generate electricity under "real-life" conditions, which differ from the "optimal" conditions that define their peak capacity. The closer the former are on average from the latter, the higher the average electricity output produced by a given PV module. In particular, the solar resource available at a given location depends on average solar irradiation, which increases as one moves closer to the equator. France has relatively similar solar irradiation across its territory in comparison to many other countries. Yet, significant differences exist between the Northern and the Southern parts of the country. Figure B.9 in Appendix B illustrates this heterogeneity. In particular, it shows that the expected output per unit of installed capacity can be twice higher in the best locations than in the worst locations. This difference can be exacerbated by technological differences, such as whether or not tracking systems are installed.[8]

Table 2.1: Categories and size buckets used to refer to groups of solar installations

Category	Scale
Rooftop < 36 kW	Residential
Rooftop $0.036 - 0.1$ MW	Medium
Rooftop $0.1 - 0.5$ MW	Medium
Rooftop $0.5 - 2.5$ MW	Medium
Ground $0.5 - 2.5$ MW	Medium
Rooftop > 2.5 MW	Large
Ground $2.5 - 10$ MW	Large
Ground > 10 MW	Large

In order to capture these two sources of heterogeneity, namely non-module costs per kW and average operating conditions, we use in our empirical application 8 distinct categories of solar facilities.[9] These categories are defined along two dimensions. On the one hand,

[8]Tracking systems change the orientation of solar panels to follow the trajectory of the sun in order to maintain an optimum angle to maximize the amount of solar irradiation received.

[9]As discussed in Section 2.4, this taxonomy is largely driven by the granularity of the public data sources

we distinguish between rooftop and ground-mounted installations. Indeed, the former face much lower grid connection costs while the latter can be developed in the best locations and use tracking technologies. On the other hand, we consider different size buckets to reflect economies of scale. Table 2.1 lists our 8 categories of installations. For exposition purposes, we further group these 8 categories into 3 size buckets: residential (rooftop <36kW),[10] medium scale (36 kW to 2.5 MW) and large-scale (>2.5 MW).

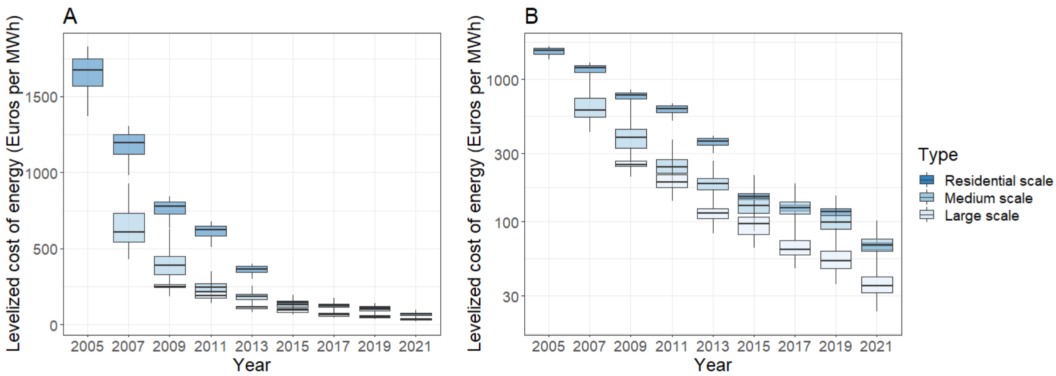

Figure 2.1: Distributions of LCOEs (€/MWh) over time for residential, medium and large-scale solar facilities in our dataset. The y-axis is displayed using both a linear (panel A) and a logarithmic (panel B) scale (see Appendix B for details).

In the electricity industry, total costs per kW (including module costs) and average operating conditions are generally collapsed under the concept of levelized cost of electricity (LCOE). Specifically, the LCOE of an installation is defined as the ratio of the sum of the discounted costs of an installation and the sum of its discounted expected energy output. Consistently with the above discussion, LCOEs are highly heterogeneous across solar facilities. In particular, as illustrated in Figure 2.1, the LCOE of residential solar projects has typically been two to three times larger than the LCOE of medium and large-scale projects. Figure 2.1 also shows that LCOEs have decreased substantially over time across all types

we use to assess installation costs.

[10]The threshold of 36 kW corresponds to the maximum grid connection capacity that residential households can request to the distribution grid operator. In practice, the vast majority of installations with a capacity lower than 36kW actually have a capacity lower than 9kW: as of 31 December 2023, 96.5% (in number of installations) / 80.3% (in MW) of the facilities with an installed capacity lower than 36kW actually have an installed capacity lower than 9kW (see `https://data.enedis.fr/pages/parc-raccorde/`, last accessed on 27 March 2024).

of solar installations. Importantly, this decrease has been significantly higher (in absolute value) for residential than for medium and large-scale installations. Specifically, between the mid-2000s and 2021, residential installations have experienced a decrease in LCOE of about 1000€/MWh, while medium and large-scale PV have seen a decrease of less than 500€/MWh.

Finally, the social value of a solar facility critically depends on the average social value of the electricity it is generating. This important observation generally argues against the use of the LCOE as a metric to compare the cost-efficiency of different electricity generation technologies (Joskow, 2011). However, as we explain in the next paragraph, we believe it is sensible, as a first approximation, to neglect this channel in the context of our empirical application. Appendix E discusses how our theoretical framework can be generalized to account for this third source of heterogeneity in the social value of solar installations.

2.2.2 Scope for Misallocation

Broadly speaking, the (levelized) net social value of the electricity produced by a given solar installation can be expressed as:

$$\text{Net social value [€/MWh]} = \text{Opportunity cost of electricity - } \frac{\text{Total levelized costs}}{\text{Total levelized production}} \tag{2.1}$$

In most existing studies about the misallocation of investments in renewables, misallocation stems from the heterogeneity in the opportunity cost of electricity and/or in total levelized production. In other words, total levelized costs are implicitly assumed to be roughly uniform across installations (per unit of capacity). In contrast, we assume in what follows that the opportunity cost of electricity is roughly uniform across installations, but we account for the heterogeneity in both total levelized production and total levelized costs.

Formally, consider a given solar installation i commissioned in year $t_c(i)$. We denote with $c_{it_c(i)}$ the present value cost (investment and operating costs) of the installation. Note that this cost depends on the commissioning date since installation costs have changed significantly over time. Let us further denote with $e_{it_c(i)t}$ the yearly electricity output of this installation in year $t \geq t_c(i)$.

Let $h \in H_t$ be a given hour in year t, where H_t denotes the set of hours for that year. During this hour, installation i produces an amount of electricity $f_{ih}e_{it_c(i)t}$, where $\{f_{ih}\}_{h=1,\ldots,H_t}$ is the generation profile of the installation during year t. This profile is normalized by energy output so that $\sum_{h \in H_t} f_{ih} = 1$.

The social opportunity cost of electricity produced by installation i during hour h corresponds to the social cost of the power plant displaced at the margin, which includes private costs (e.g. fuel), externalities (carbon emissions and local pollutants such as particulate matter), as well as possible other non-priced costs or benefits (e.g. savings in future grid investments). We denote with p^*_{ih} this social opportunity cost of electricity in hour h, which can be installation-specific.

Using these notations, the social net present value of installation i as of year $t_c(i)$ is:

$$NPV(i) = \sum_{t \geq t_c(i)} \rho^{t-t_c(i)} \left(\sum_{h \in H_t} p^*_{ih} f_{ih} e_{it_c(i)t} \right) - c_{it_c(i)} \tag{2.2}$$

where ρ denotes the social discount factor.

In what follows, we make a couple of simplifying assumptions, which are motivated by the fact that we use France as a case study for our empirical application.[11] First, we assume that p^*_{ih} does not depend on i. Indeed, under the prevailing market design over our period of interest, the French transmission grid was seldom congested. Therefore, the power plant displaced by a solar facility in a given hour only very rarely depended on the location of the solar facility. In addition, Astier et al. (2022) find that distributed solar installations in France are unlikely to deliver substantial savings in future grid investments, implying that small-scale installations connecting to the distribution grid provide negligible external benefits relative to larger transmission-connected facilities. Second, we assume that the normalized generation profile $\{f_{ih}\}_{h=1,\ldots,H_t}$ does not depend on i or, more precisely, that the heterogeneity it induces across installations (i.e., differences in the covariance between p^*_h and f_{ih}) can be neglected relative to the variations in $e_{it_c(i)t}$ and $c_{it_c(i)}$. Indeed, France has a relatively small surface and, as a result, solar generation at any given point in time is

[11] These assumptions are relaxed in Appendix E.

strongly correlated across locations.

Under the additional assumption that, from an *ex ante* perspective, the distributions of p_h^* and f_h are stationary (i.e., do not depend on t),[12] we can rewrite Equation 2.2 as:

$$NPV(i) = \left(\sum_{t \geq t_c(i)} \rho^{t-t_c(i)} e_{it_c(i)t} \right) \left(\sum_{h \in H} p_h^* f_h \right) - c_{it_c(i)} \tag{2.3}$$

that is:

$$\underbrace{\frac{NPV(i)}{\sum_{t \geq t_c(i)} \rho^{t-t_c(i)} e_{it_c(i)t}}}_{\text{Net social value [€/MWh]}} = \underbrace{\sum_{h \in H} p_h^* f_h}_{\text{Opportunity cost}} - \underbrace{\frac{c_{it_c(i)}}{\sum_{t \geq t_c(i)} \rho^{t-t_c(i)} e_{it_c(i)t}}}_{LCOE(i,t_c(i))} \tag{2.4}$$

In this expression, the average social opportunity of electricity (in €/MWh) is uniform across installations. This assumption, motivated by our empirical application, differs from most of the existing literature where significant cross-sectional variations in the output-weighted expected value of p_{ih}^* are a key driver of misallocation. In contrast, we take a dynamic perspective and note that, given the large heterogeneity in installation costs and average output (as captured by $LCOE(i, t_c(i))$ in equation 2.4), both across installations and over time, suboptimal choices of commissioning dates $t_c(i)$ can be another important channel of misallocation.

2.3 Dynamic Misallocation

2.3.1 General Framework

Assumptions and Notations

Our framework builds on Asker et al. (2019), where the authors assess the magnitude of dynamic misallocation in the context of oil extraction. We adapt their approach to account for the characteristics of solar facilities that differ from those of oil fields.

Misallocation is defined relative to an "optimal" counterfactual. The choice of this coun-

[12]Strictly speaking, our optimization program below does not require this assumption.

terfactual is of course critical. In particular, if the optimal counterfactual allows for outcomes that are infeasible in practice, misallocation will be partially confounded with measurement errors and, therefore, over-estimated. In order to avoid this pitfall to the largest extent possible, we make a number of conservative assumptions.

First, we keep constant the trajectory of total annual electricity generation from solar facilities $\{E_t\}_{t=1...T}$. In other words, the optimized sequence of solar investments has to produce in each year t the same number of kWh as the observed aggregate output E_t from the investments that were made in practice. We thus do not allow for the realized trajectory of solar generation being inefficient in terms of the aggregate gross social value that was created. Instead, given our assumption that the social opportunity cost of electricity is uniform across solar units, the total gross social value from solar energy is the same under both the realized and optimized scenarios.

Second, we assume that solar facilities (i) can only be installed at the location where they actually exist today; and (ii) cannot be sized differently than their actual size. We therefore do not face the risk of being mistakenly optimistic about how much solar capacity can be realistically installed in a given region, or about how large a given installation could have been. This feature is particularly important because local acceptability constraints, as well as technical and administrative constraints, are imperfectly observed and can prove very hard to capture accurately at a disaggregated level. In particular, restricting attention to existing solar installations alleviates the concern that land use conflicts could limit the number of large-scale installations that can actually be built.

We index solar facilities by i and denote with $x_{it} \in [0, 1]$ the fraction of unit i that is commissioned in year t.[13] We further denote with c_{it} the total present value cost (investment, connection to the grid, O&M discounted at commissioning date) of unit i when it is commissioned in year t (in euros). Note that this definition allows for (exogenous) learning-by-doing, that is, situations where c_{it} decreases with t.[14] Finally, the output in year t of a plant i that was commissioned in year t' is denoted with $e_{it't}$ (in kWh). This formulation

[13]Note that we do not constrain x_{it} to be an integer. This assumption is not restrictive for our problem (see below).

[14]We further discuss learning-by-doing in Section 2.6.

allows to account for both technological progress in conversion efficiency and the fact that the efficiency of solar panels decreases over time due to wear and tear.

Social Planner Problem

A social planner discounts future cash flows at a rate $\rho \in [0,1]$ and can build solar units from an exogenously given set of installations. He seeks to optimize the sequence of investments in solar facilities under the constraint to meet an exogenously given trajectory of aggregate production $\{E_t\}_{t=1...T}$. He therefore faces the following problem:[15]

$$\min_{x_{it}} \sum_{t=1}^{T} \rho^t \left(\sum_{i=1}^{N} x_{it} c_{it} \right)$$

$$\text{s.t.}$$

$$\forall t \in \{1,...,T\}, \quad \sum_{i=1}^{N} \left(\sum_{t'=1}^{t} x_{it'} e_{it't} \right) \geq E_t \quad (\rho^t \lambda_t)$$

$$\forall i \in \{1,...,N\}, \quad \sum_{t=1}^{T} x_{it} \leq 1 \quad (\bar{\mu}_i)$$

$$\forall i \in \{1,...,N\}, \forall t \in \{1,...,T\}, \quad x_{it} \geq 0 \quad (\rho^t \underline{\mu}_{it})$$

The objective function is the present value total cost of solar units (capital costs, grid connection and O&M). The first set of constraints corresponds to the target trajectory of annual solar generation $\{E_t\}_{t=1...T}$. For a given unit i in a given year t, the sum $\sum_{t'=1}^{t} x_{it'} e_{it't}$ is positive if, and only if, the plant has been commissioned by year t (otherwise, $x_{it'} = 0$ for all $t' \leq t$). If the unit has indeed been commissioned by year t, we then have $\sum_{t'=1}^{t} x_{it'} e_{it't} = e_{it_c(i)t}$ where $t_c(i)$ is the commissioning year of unit i ($x_{it'} = 0$ for $t' \neq t_c(i)$). Therefore, $\sum_{t'=1}^{t} x_{it'} e_{it't}$ corresponds to the output of unit i in year t. The sum of output in year t from all commissioned units must be greater or equal to the target amount of solar generation E_t for that year. The second set of constraints ensures that a facility can be commissioned only once. Note that installed capacities (in kW) are not explicitly modeled as variables,

[15]Note that the formulation of the problem implicitly assumes that the termination value does not depend on the chosen sequence of investments. This assumption does not hold exactly in our numerical application due to differential technological progress with impacts beyond year T (conversion efficiency and O&M costs). However, differences in termination values are small relative to total costs, so that neglecting differences in termination values represents a sensible simplification.

but are instead indirectly captured by the variables c_{it} and $e_{it't}$. Indeed, both total cost c_{it} (in euros) and yearly output $e_{it't}$ (in kWh) will be larger for bigger units. Finally, the last set of constraints reflects the fact that solar units are physical assets. As a result, it is not possible to "short sale" generation from inefficient units to trade it off against generation from more efficient units.

A key observation is that the social planner is facing a linear optimization problem, which can be solved with a wide range of readily available software.[16]

Measuring Misallocation

If we denote with $\{x^*_{it}\}_{i=1...N,t=1...T}$ the optimized investment decisions, we can compute the cost-efficient present value cost PV^* of meeting the trajectory of annual solar generation targets as:

$$PV^* \equiv \sum_{t=1}^{T} \rho^t \left(\sum_{i=1}^{N} x^*_{it} c_{it} \right)$$

However, the realized investments are instead $\{x^0_{it}\}_{i=1...N,t=1...T}$, with a corresponding present value cost PV^0:

$$PV^0 \equiv \sum_{t=1}^{T} \rho^t \left(\sum_{i=1}^{N} x^0_{it} c_{it} \right)$$

We define (relative) dynamic misallocation m as:

$$m \equiv \frac{PV^0 - PV^*}{PV^0} \in [0, 1]$$

This metric captures the fraction of the total present value cost of realized investments that may be considered as inefficient.[17]

2.3.2 Special Case of Static LCOEs

In order to build intuition, consider the simplest case where the cost and expected output of each installation do not change over time:

[16] We use the solver Gurobi in what follows.

[17] Note that since, by definition, $PV^* \leq PV^0$, choosing to express misallocation as a fraction of realized costs rather than of optimized costs mechanically yields lower values for relative misallocation. For example, a misallocation of 50% with our metric means the realized trajectory of investments is twice as expensive as the optimal trajectory.

$$\forall i, t,\ c_{it} = c_i \text{ and } \forall i, t, t',\ e_{itt'} = e_i$$

Up to a common scaling factor, we can define the LCOE L_i of solar facility i as:[18]

$$L_i \equiv \frac{c_i}{e_i}$$

Without loss of generality, we assume that solar units are indexed such that:

$$L_1 \leq L_2 \leq ... \leq L_{N-1} \leq L_N$$

Then, denoting $i_0 \equiv 0$ and $i_T \equiv N$, one can show (see Appendix D) that there exist thresholds:

$$i_0 \leq i_1 \leq ... \leq i_{T-1} \leq i_T$$

such that it is optimal to commission in year t the units whose index i lies in the interval between the thresholds i_{t-1} and i_t:

$$i_{t-1} < i \leq i_t$$

In other words, the cost-efficient investment decisions boil down to installing solar facilities in increasing order of LCOE. In the first year, the facilities with the lowest LCOE are built until total expected output reaches E_1. In the second year, the remaining facilities with the lowest LCOE are then commissioned until the total expected output of the whole generation fleet reaches E_2. And so on and so forth.

In the general case, however, the incentive to first install the facilities with the lowest LCOE has to be traded-off against the prospects of future improvements in LCOE. To see this, consider two facilities A and B with similar LCOEs today ($L_A^0 = L_B^0 - \epsilon$ with $0 < \epsilon << 1$) but different prospects in terms of future technological improvements. Specifically, assume that the social planner expects that, at a later date t, we will have $L_A^t << L_B^t$. In this situation, it is preferable to first install unit B in order to be able to benefit from the larger technological improvements that unit A will enjoy. Therefore, we cannot derive unambiguous analytical results in the general case. Instead, we turn to a realistic empirical application.

[18]Since we defined c_i as total present value costs (including O&M costs) and e_i as annual electricity generation of unit i, the proper definition of the LCOE of unit i is $LCOE_i \equiv \frac{c_i}{e_i \sum_{t=1}^{\tau} \rho^t}$ where τ is the lifetime (in years) of a solar unit. We thus have $L_i = \left(\sum_{t=1}^{\tau} \rho^t\right) LCOE_i$.

2.4 Application to France

2.4.1 Institutional Background

France ranks fifth among countries of the European Union in terms of installed solar PV capacity, with 12.5 GW installed as of January 1st, 2022 (France Territoire Solaire, 2022). France is committed to further increase its installed capacity in order to meet the renewable generation objectives set by the European Union. Consistently, the French government's multi-annual investment plan for electricity generation is targeting an increase in annual installation rates.

Over the past two decades, France has relied on a number of public support mechanisms to promote solar energy. For the most part, these mechanisms have consisted of feed-in-tariffs (FiTs). These tariffs were introduced in the 2000s and represent a commitment by the government to purchase electricity at a fixed price for a period of 20 years.

Until the early 2010s, FiTs were set to an exogenous value and targeted to small installations. Any installation below a certain size threshold (initially 100 kW) was eligible to receive the prevailing tariff. This tariff (in €/MWh), however, was decreasing with the size of the installation, and ranged between 300 and 550 €/MWh in 2006.

Although the level of FiTs has decreased over time, their decline has lagged significantly behind the sharp decrease in the costs of PV modules. As a result, installation rates boomed in the late 2000s, increasing significantly the committed amount of public subsidies. The government therefore enacted of temporary moratorium in 2010-2011 to revisit the mechanisms supporting solar installations.

After this moratorium, the system of FiTs was kept in place but with significantly lower tariffs. These rates were still differentiated according to the size of facilities and, as of 2021, were ranging between 90 and 180 €/MWh. Besides, the methodology to compute FiTs was adapted to prevent overshooting annual solar PV capacity targets through the inclusion of a parameter accounting for past installation rates.

For larger projects (above the automatic eligibility threshold for FiTs), the government introduced in 2011 technology-specific (e.g. ground-mounted versus rooftop) auctions. In these auctions, developers of solar projects bid the FiT at which they would be willing to build a given facility. Auctions are organized by the French Energy Regulation Commission (CRE), using a pay-as-bid format with technology-specific capacity targets set by the government. Table 2.2 reports the total volumes auctioned since 2011, broken down by year and (simplified) project categories. More detailed information on the various mechanisms that have been implemented in France to support solar PV can for example be found in Avril et al. (2012).[19]

Table 2.2: Annual PV capacity (MW) auctioned by the French Energy Regulation Commission, broken down by (simplified) categories.

	Auctions before 2016		Auctions after 2016	
Categories (MW)	Rooftop 0.1 - 0.25	All >0.25	Rooftop >0.1	Ground-mounted >0.5
Year	Annual volumes auctioned (MW)			
2012	240	450		
2013	300	400		
2014	120			
2015		400		
2016	240			
2017			450	1000
2018			425	1200
2019				1700
2020			450	1000
2021			450	1100

Source: adapted from `www.photovoltaique.info`.

Consistently with the nature of support mechanisms, the vast majority of solar units in France are distributed, that is, consist of relatively small-scale installations that connect to the distribution grid. More precisely, the French solar generation fleet may be roughly decomposed as follows (France Territoire Solaire, 2022). Almost half (46%) of the total installed capacity consists of rooftop power plants with a size smaller than 250 kW.[20] Most auctions for larger installations (ground-mounted and car park shelter) were only introduced

[19]See also `https://www.photovoltaique.info/fr/tarifs-dachat-et-autoconsommation/tarifs-dachat/anciens_arretes_tarrifaires/` for more recent years, last accessed on 23 April 2024.

[20]Indeed, a significant fraction of the auctions that took place before 2016 were restricted to rooftop PV projects between 100 and 250 kW (Table 2.2). This category also includes residential PV projects, which represent 13% of the total capacity.

after 2016, with a size cap at 17 MW. Therefore, only 6% of the total solar capacity consists of large installations connecting to the transmission grid.

2.4.2 Data Sources

We build a dataset that keeps track of (i) when and where solar projects were commissioned; (ii) the likely costs of solar projects as a function of both their characteristics and commissioning date; and (iii) the observed or simulated yearly output of each project in a given year, also as a function of both their characteristics and commissioning date.

Our main data source is a public registry listing the universe of power plants in France.[21] We observe 50,000+ installations commissioned between 2005 and 2021.[22] The dataset reports the location of solar units at the municipality ("commune") or sub-municipality ("IRIS") level, as well as their installed capacity and, for most of them, realized annual output and upstream substation.

We define categories of installations based on size bins and on whether they are rooftop or ground-mounted (see Table 2.1). We then use several public resources to estimate how the investment cost and the conversion efficiency of the different categories of solar facilities have evolved over time (IRENA, 2020; CRE, 2014, 2019). Appendix B details how we make use of these various data sources. For ground-mounted installations, grid connection costs are assessed based on the distance to the upstream (or, when unknown, closest) grid substation.[23] Specifically, we compute the as-the-crow-flies distance between the substation to which the installation connects and the centroid of the municipality where it sits. This distance is then multiplied by a connection cost of 100 €/meter when the unit connects to the medium voltage grid, and by a connection cost of 1,000 €/meter when it connects to the transmission grid (see Appendix B).[24]

[21] https://www.data.gouv.fr/fr/datasets/registre-national-des-installations-de-production-et-de-stockage-delectricite-au-31-12-2022-2/, last accessed on 30 August 2023.

[22] The smallest installations are listed as bundles rather than as individual units (see below), so that the actual number of individual units (when counting each small rooftop unit separately) is much higher.

[23] For the vast majority of units connecting to the medium or high voltage grids, we observe the substation to which they connect. Units connecting to the low-voltage grid are rooftop installations and thus do not require dedicated power lines to connect to the closest substation.

[24] All costs are expressed in real 2019 euros.

Finally, the public registry of power plants provides, for most medium and large-scale units, the total energy they produced in 2022. When no annual output was provided in the dataset, we retrieved expected annual capacity factors at different locations from the website renewable ninja (Pfenninger and Staffell, 2016; Staffell and Pfenninger, 2016).[25]

2.4.3 Description of the Main Variables

Categories of Installations and Observed Commissioning Dates (x^0_{it})

In what follows, we assign installations to categories that we use to assess cost functions (see below and Appendix B). These categories are defined according to (i) size bins; and (ii) whether a given installation is rooftop or ground-mounted (see Table 2.1).

While the public registry of power plants reports the installed capacity of each unit, it does not explicitly specify whether a given installation is a ground-mounted or a rooftop unit. Therefore, we assess whether each observation is a rooftop or a ground-mounted unit using different assignment strategies that are detailed in Appendix C.[26]

In addition, for any installation i, we further observe in the public registry its commissioning date. However, for residential installations,[27] the registry aggregates units at the municipality level. Because residential units in a given municipality are commissioned at different dates, detailed information on commissioning dates is lost with spatial aggregation. To address this issue, we proceed as in Astier et al. (2022) and use public information from the French Department of Energy to construct time series of aggregated residential PV capacity at the sub-regional ("departement") level (see Appendix C).

Table 2.3 shows the eight categories of solar installations we use in our analysis, along with corresponding summary statistics.

When re-optimizing commissioning dates, we allow for the partial commissioning of solar PV units in some years (that is, $x_{it} \in (0, 1)$). This assumption does not have any signifi-

[25] Given the high degree of spatial correlation in solar irradiation, we only sampled the locations of the substations, which represent over 2,000 locations in France.

[26] Whether a given unit is roof- or ground-mounted is assessed based on (i) its name (when available), (ii) the prevailing size limits in technology-specific auctions, and (iii) geolocalized data on photovoltaic facilities retrieved from OpenStreetMap. Around 1,000 observations could not be assigned and are allocated proportionally to the total installed capacity for each category at national level.

[27] Defined in the registry as privately-owned rooftop units with a capacity lower than 36 kW.

Table 2.3: Descriptive statistics by categories of photovoltaic facilities.

Category	Observations	Mean capacity (MW)	Total capacity (GW)	Commissioning date [Perc. 20 - Perc. 80]	Capacity factor	Connection length (km)
Rooftop aggregated $< 0.036\ MW$	1,501	1.5	2.3	2008 - 2018	0.14 (0.01)	0
Rooftop $0.036 - 0.1\ MW$	25,669	0.09	2.2	2013 - 2021	0.14 (0.02)	0
Rooftop $0.1 - 0.5\ MW$	8,603	0.19	1.6	2011 - 2019	0.14 (0.02)	0.3 (1.5)
Rooftop $0.5 - 2.5\ MW$	263	1.2	0.3	2011 - 2020	0.14 (0.03)	5.2 (3.6)
Rooftop $> 2.5\ MW$	58	4.5	0.3	2012 - 2020	0.15 (0.02)	5.0 (3.9)
Ground $0.5 - 2.5\ MW$	578	1.3	0.7	2011 - 2020	0.14 (0.03)	5.8 (5.1)
Ground $2.5 - 10\ MW$	669	5.6	3.8	2014 - 2021	0.16 (0.03)	6.0 (3.8)
Ground $> 10\ MW$	179	11.9	2.1	2013 - 2021	0.16 (0.03)	5.8 (4.2)

Note: Perc. 20 and Perc. 80 denote the lower and upper quintiles of the distributions of commissioning dates. For capacity factor and connection length, we report mean values as well as standard deviations (in brackets).

cant impact on our results. Indeed, given the linear nature of the optimization, less than 0.01% of the optimal x^*_{it} (32 out of 638, 214) are different from either 0 and 1. In addition, residential facilities are aggregated at the municipality level, so that, for these installations, commissioning a fraction of the total capacity is equivalent to installing many small units. Finally, many of the largest facilities actually appear in our data as a collection of smaller units.[28]

Cost Functions (c_{it})

For each solar unit i, we compute the variables c_{it} that represent the total present value cost of the unit, should it be commissioned in year t. The variables c_{it} are calibrated using category-specific cost functions (see Appendix B). These costs functions include the cost of PV modules (retrieved from public sources), other investment costs (that are assumed to decrease exponentially with category-specific growth rates), and grid connection costs (when relevant).[29]

[28]For example, the power plant of "*Cestas*", which has a total capacity of 300 MW, is listed in the public registry as 25 individual units of 12 MW.

[29]The decomposition of investment costs for the project categories larger than 100 kW are obtained from CRE (2014, 2019). Investment costs for the other categories are retrieved from IRENA (2020) and extrap-

Energy Output ($e_{it't}$)

For each solar unit i, we also compute energy output variables $e_{it't}$ which represent the energy produced by installation i in year t if it is commissioned in year t' (in particular, $e_{it't} = 0$ if $t < t'$). These installation-specific yearly outputs are built as follows. We first retrieve from the public registry of power plants the annual capacity factor of each installation for the year 2022.[30] In order to estimate capacity factors for other years and other possible commissioning dates, we need to account for two compounding effects. On the one hand, the earlier the commissioning date, the lower the conversion efficiency of PV modules. On the other hand, the conversion efficiency of a given unit decreases over time due to wear and tear. We estimate both effects directly from our data. Specifically, because the registry of power plants has been published every year since 2017, we use previous editions to build a panel of annual energy output over 2017-2022 for a set of 16,000+ installations. Using this dataset, we estimate a -1%/year rate for depletion and 1%/year rate for technological progress (see Appendix B).

The average capacity factors in 2022 are reported in Table 2.3, broken down by category. We notably observe that larger facilities have on average higher capacity factors. Indeed, larger installations (i) may locate in places with higher solar irradiation than average, (ii) may be equipped with tracking systems; and (iii) were installed towards the end of our study period and thus benefited from technological progress. Unit-level capacity factors are not directly observed for the smallest installations, which represent 35% of total installed capacity. Our method to assign capacity factors to these units relies on simulated values with a coarse spatial resolution, and therefore under-estimates the true heterogeneity in actual capacity factors. This method for inputting missing data represents another channel through which our assessment of misallocation can be considered as conservative (i.e., a lower bound).

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olated for years before 2010. The costs of modules are retrieved from IRENA (2020). See Appendix B for further details.

[30]This information is available for 92% of observations. The capacity factor for the remaining installations are estimated using the website “renewable ninja” (Pfenninger and Staffell, 2016; Staffell and Pfenninger, 2016). The corresponding installations are mostly residential PV systems, to which we assign capacity factors assumed to be uniform over the area supplied by a given substation (see Appendix B).

2.5 Main Results

2.5.1 Dynamic Misallocation

We use our dataset to assess the magnitude of dynamic misallocation in the case of France over the period 2005–2021. We find that the present value cost of the optimal sequence of solar investments would have been 32% cheaper than the realized present value cost (i.e., $m = 0.32$). Specifically, we estimate the optimal trajectory to have a present value cost of 18.1 billion euros, while the observed trajectory has a present value cost of 26.7 billion euros.[31] It corresponds to a decrease in the levelized cost of solar energy of about 59 euros per MWh.[32]

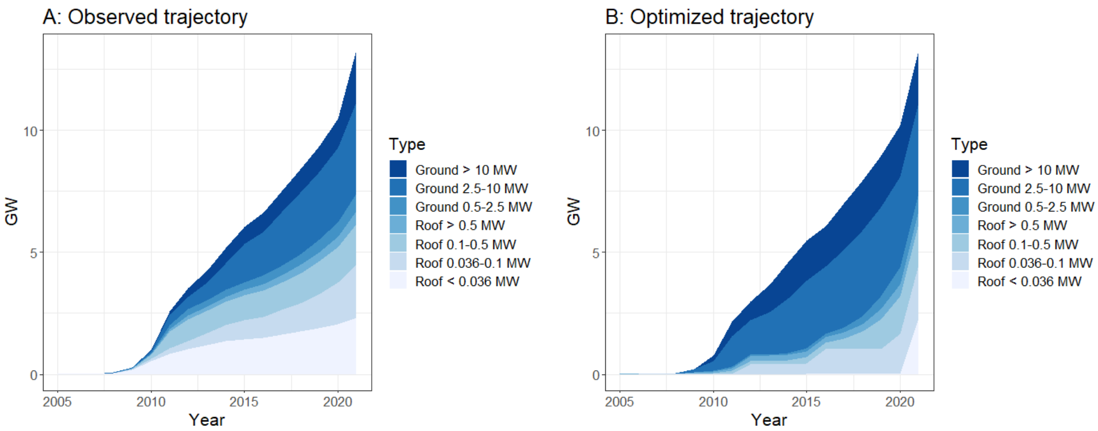

Figure 2.2: Realized (left panel) vs optimized (right panel) trajectories (cumulative installed capacity).
Note: Rooftop units larger than 0.5 MW are merged together for more clarity.

Figure 2.2 compares the realized and optimized trajectories of cumulative installed capacity, broken down by category. Our main result seems to be driven by two main effects. First, the optimization program leverages economies of scale by commissioning the larger solar projects much earlier than they actually were. Table 2.4 reports the average change in

[31]Present values are computed as of 2005 with a discount rate of 4.5% (real), following the French government's guidelines for public infrastructures.

[32]The difference in LCOE is computed by taking the ratio of the present value cost of misallocation and the total levelized energy produced by the solar fleet over a 20 year period after commissioning (assuming a depletion in energy output of 1% per year and a discount rate of 4.5%).

commissioning dates for each project category. The optimization program postpones on average residential PV by seven years, and installs ground-mounted and rooftop PV facilities bigger than 2.5 MW three to four years before their observed commissioning dates. Second, the optimization program anticipates differential trends in the decrease in investment costs. For example, in order to benefit from lower investment costs, it delays medium-size rooftop PV (between 0.1 and 0.5 MW) by two years compared to small-size rooftop (between 36 kW and 0.1 MW). Indeed, the assessed investment costs of small-size rooftop PV increase between 2016 and 2019. As a result, the optimization program allocates a substantial fraction of small-size rooftop PV installations before the cost increase, with no installations of small-size PV occurring between 2016 and 2019.

Table 2.4: Capacity weighted average change in commissioning dates (year observed - year optimal), broken down by category.

Project Type	Ground	Rooftop
Project Segment (MW)		
> 10	4	
2.5 - 10	3	4
0.5 - 2.5	-2	-2
0.1 - 0.5		-3
0.036 - 0.1		-1
< 0.036 (Residential)		-7

2.5.2 Sensitivity Analyses

Because they are expressed in present value terms, our results are sensitive to our choice of discount rate. Figure 2.3 shows, however, that the order of magnitude of misallocation remains similar for a wide range of discount rates. This counter-intuitive result stems from the fact that we account for (exogenous) technological progress.[33] Indeed, in absolute terms, the cost of smaller installations has decreased significantly more than the cost of larger installations. A large fraction of the misallocation is thus driven by the early commissioning of a large number of small installations (see below).

One of the main inputs of our optimization program are investment cost time series for

[33]Section 2.6 provides an in-depth discussion of the role of learning-by-doing.

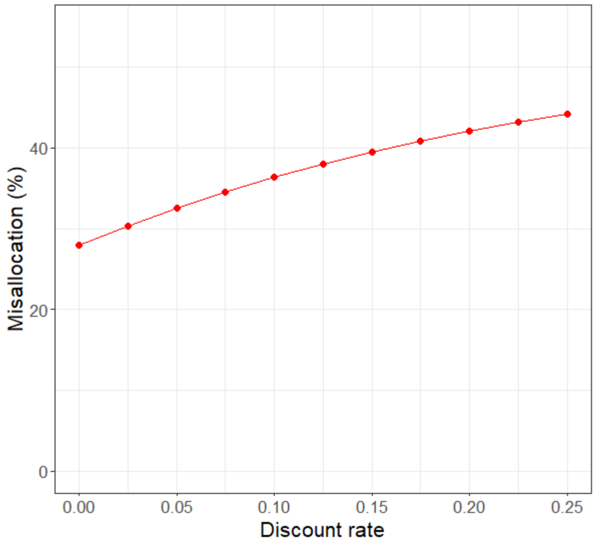

Figure 2.3: Assessed misallocation (%) as a function of the assumed discount rate.

each project category. These time series are imperfectly observed and therefore calibrated with different data sources (see Appendix B). In particular, because we do not have data before 2010, we extrapolate investment costs functions for the period 2005-2010 assuming category-specific exponential trends. We test the sensitivity of the estimated misallocation to this extrapolation by looking instead at an extreme scenario where we set investment costs for 2005-2010 to their 2010 level for each project category. Resulting cost functions thus represent a lower bound for actual investment costs. Under this assumption, we estimate that dynamic misallocation decreases to 31%, with present value costs for the realized and optimized trajectories of respectively 26.0 billion and 17.9 billion euros. Our results are therefore robust to different extrapolation strategies for investment costs occurring in the early years of our study period. Indeed, despite their early commissioning (and therefore higher weight in present value terms), the projects commissioned before 2010 only represent a small share of the total solar capacity, and therefore have a relatively small impact on the total present value cost of solar investments.

Finally, our optimized trajectory entails yearly installation rates (in MW/year) than can be significantly higher that rates that have been actually observed. Because such high installation rates might not have been feasible in practice, we run a sensitivity analysis where, for each category of solar facilities, yearly capacity additions are capped to the maximum yearly installation rate observed in practice for this category. Doing so only decreases the assessed amount of misallocation from 32% to 30%.

2.6 Discussion

In this section, we explore various reasons that may help rationalize the magnitude of the estimated misallocation. First, we decompose misallocation along various dimensions. We then discuss a number of alternative explanations which would imply that our assessment of misallocation is over-estimated. Finally, we conclude with a discussion of the limitations of our approach.

2.6.1 Decomposing Misallocation

In order to better understand where the large estimated misallocation may come from, we run three counterfactual simulations.

In the first two exercises, we decompose misallocation into various components by proceeding as follows. We first define a partition of the set of installations (e.g. small, medium and big). We then define the misallocation associated to each subset in the partition as the obtained misallocation when only optimizing the commissioning dates of all installations but the ones in the considered subset (which are frozen to their realized trajectory). In other words, we compute the misallocation associated to given subset of solar installations as the obtained misallocation when the social planner cannot change the commissioning dates of installations in this subset. We study two such partitions of the universe of solar installations. On the one hand, we distinguish the main categories of installations (ground-mounted, large rooftop, medium rooftop and residential). On the other hand, we partition installations according to their commissioning dates, distinguishing four distinct periods that roughly map into different phases of public support regimes.

Our last counterfactual seeks to isolate the role of within-category misallocation. To do so, we add in our optimization the constraints that the annual output trajectory of each of our eight categories of solar installations must be equal to its observed value. These constraints prevent large reshuffling of commissioning dates across categories of installations, meaning that misallocation mainly arises from cross-sectional heterogeneity within each category.

Misallocation Decomposed by PV Category

First, we consider four mutually exclusive categories of PV projects:

- Ground-mounted installations, which were mostly developed through auctions.
- Large rooftop (> 100 kW), which were under FiTs until 2011 and auctions after 2011.
- Small rooftop (between 36 kW and 100 kW), which were under FiTs for the whole period.
- Residential PV (< 36 kW), which were under FiTs for the whole period.

For each category of installations, we optimize the investment trajectory while freezing the commissioning dates of the corresponding installations. The obtained misallocation can be thought of, as a first approximation, as the contribution of the considered category to the total misallocation.[34]

Table 2.5: Decomposition of misallocation by project category.

Frozen category	Capacity share	Present Value (Billion Euros)	Difference with PV^* (Billion Euros)	Additional LCOE (Euros per MWh)
Ground-mounted	50%	20.1	2.0	26
Rooftop>100 kW	17%	18.6	0.5	21
Rooftop 36 to 100 kW	16%	18.7	0.6	27
Residential	17%	24.6	6.5	250

Note: Additional LCOEs are calculated as the ratio of (i) the difference between the present value of the category-constrained and unconstrained optimizations, and (ii) the total levelized energy output of the category (assuming a lifetime of 20 years and a depletion of energy efficiency of 1%/year).

Table 2.5 reports the obtained results. The present value costs of each constrained optimization are given, along with their difference with the unconstrained optimal present value cost. We observe that freezing the commissioning dates of residential PV installations induces the largest misallocation, despite the fact that these units only represent 17% of

[34]Such a "contribution" has to be understood in an "accounting" sense since we do not claim that our methodology causally identifies the underlying mechanisms responsible for the observed misallocation.

total installed capacity. Expressed as a ratio of absolute misallocation cost over the total levelized energy produced, the misallocation cost of the realized trajectory for residential PV is about 250€/MWh. In contrast, the misallocation that may be attributed to other categories is lower than 30€/MWh.

Misallocation Decomposed by Time Window

A second approach is to optimize the timing of investment decisions while taking as given the investments that took place during a given time window. Reshuffling the commissioning dates of PV installations is then only allowed for units that were commissioned outside of the considered time window. We consider four different periods, roughly corresponding to different phases in the policies supporting renewables:

- 2005-2008: early FiTs.
- 2009-2012: temporary moratorium and significant subsequent changes in support regimes.
- 2013-2016: first auctions.
- 2017-2021: new auction regimes with higher volumes of large-scale projects.

Again, the difference between the present value cost of the optimal trajectory and the present value cost of a constrained trajectory is interpreted, in an accounting sense, as the contribution of the considered time window to the misallocation.

Table 2.6: Decomposition of misallocation by time window.

Frozen period	Capacity share	Present Value (Billion Euros)	Difference with PV^* (Billion Euros)	Additional LCOE (Euros per MWh)
2005-2008	1%	18.7	0.6	601
2009-2012	26%	24.3	6.2	138
2013-2016	23%	19.3	1.2	32
2017-2021	50%	19.8	1.7	28

Note: Additional LCOEs are calculated as the ratio of (i) the difference between the present value of the category-constrained and unconstrained optimizations, and (ii) the total levelized energy output of the facilities commissioned during the considered time window (assuming a lifetime of 20 years and a depletion of energy efficiency of 1%/year).

Table 2.6 reports the obtained results. The first support mechanisms between 2005 and 2008 are association with the highest misallocation per unit of energy produced (about

600€/MWh). The misallocation then gradually decreased to reach less than 30€/MWh for auctions run after 2016. In absolute value terms, however, the period associated with the largest misallocation is 2009-2012.

Within-category Misallocation

Our main result suggests that large reallocations over time across categories of facilities, especially residential vs other installations, would have increased significantly cost-efficiency. In this paragraph, we focus instead on within-category misallocation, that is, the scope for improvements in cost-efficiency when we add the constraints that the annual aggregate output of each category of installations must remain equal to its realized value.

This exercise is interesting for at least two reasons. First, it is more comparable to the existing literature on (static) misallocation: because investment costs are roughly similar within a given category, misallocation will be mostly driven by cross-sectional differences in solar irradiation and/or distance to the electricity grid. Second, it provides a lower bound estimate of dynamic misallocation under an extreme scenario where learning-by-doing is fully endogenous and category-specific. Indeed, under such a scenario, constraining the annual aggregate output of each category of installations to remain equal its realized value ensures that the amount of learning-by-doing is identical under the realized and counterfactual trajectories. However, the optimal investment trajectory under fully endogenous and category-specific learning-by-doing may still find it cost-efficient to reallocate investments across categories over time. Therefore, the actual magnitude of dynamic misallocation is weakly higher than the magnitude we estimate in this paragraph.

With these additional constraints, we find that the observed sequence of investments entails a misallocation of 6%. This value can also be interpreted as the part of the misallocation that comes exclusively from cross-sectional inefficiencies. In that regard, its order of magnitude is similar to comparable estimates that exist in the literature (Lamp and Samano, 2023; Colas and Saulnier, 2023).

The maps in Figures A.1 to A.4 in Appendix A show the (capacity-weighted) average difference in commissioning dates broken down by categories of installations. Ground-mounted facilities exhibit the largest variation in the changes of commissioning dates. The optimization indeed leverages the high cross-sectional heterogeneity in LCOEs for this category. Besides arbitraging differences in solar irradiation conditions (e.g. postponing the commissioning of facilities in the Northern and Eastern parts of France), changes are also driven by idiosyncratic inefficiencies, possibly tied to the relative quality of the sites on which facilities are developed. For instance, the Southwestern part of France has good solar irradiation conditions, but sees its installed capacity being postponed by 2 years on average relative to the observed commissioning dates. This might stem from a significant number of sites that have less sun exposure or are more distant from the electricity grid. In contrast, the changes in the sequence of investments in smaller units seem to be mostly driven by local solar irradiation conditions.

2.6.2 Alternative Explanations to Misallocation

Learning-by-doing

Our framework assumes that the present value total cost c_{it} of installation i in year t is exogenously given. This strong assumption deserves some discussion since learning-by-doing is perceived as one of the main market failures that policies supporting PV generation have been trying to address. Credible amounts of learning-by-doing may indeed rationalize relatively high initial subsidies (Van Benthem et al., 2008), assuming this learning-by-doing is not appropriable, which is itself a debatable statement (Bollinger and Gillingham, 2019). Therefore, an important caveat of our framework is that it does not explicitly account for learning-by-doing. This concern may however be less critical than one may expect for several reasons.

First, PV modules represent a large fraction of the investment cost of a solar unit. These modules are traded on a global market, in which France represents a negligible share of total demand. Therefore, a significant portion of the observed decrease in investment costs is truly exogenous.

Second, it seems reasonable to assume that a sizable fraction of endogenous learning, such as decreasing O&M costs or improving conversion efficiency, can be related to the total amount of electricity generated to date. Because our optimization keeps constant the trajectory of annual aggregate generation of solar units, learning along these dimensions will be identical under both the realized and optimized investment trajectories, at least to the extent that learning spills over different installations in a similar way. The extreme polar assumption would be to assume that learning is category-specific and does not spill across categories of solar installations. This scenario was discussed in the previous section and was found to still yield a significant amount of misallocation.

Finally, a residual share of learning is likely to relate to construction costs, and therefore to scale with the total installed capacity of solar units rather than their aggregated output to date. Because we do not treat installed capacity as an explicit variable, our framework cannot account for such learning in a satisfactory manner. However, installed capacity and total generation are highly correlated, so that the discussion of the previous paragraph also applies, at least to some extent, to this type of learning-by-doing.

Imperfect Information

Our framework assumes that the social planner can perfectly forecast all relevant information, including future costs of solar units. This is of course a strong assumption since most forecasts back in 2005 did not correctly anticipate the significant decrease in the costs of PV installations. One may therefore wonder whether small mistakes when forecasting future costs could rationalize the observed trajectory of investments.

We focus attention on residential PV, which we found to be associated with the bulk of the assessed misallocation. Specifically, although smaller installations were in 2005 significantly more expensive than larger ones (on a per-MWh basis), a social planner might still have preferred to install residential PV facilities first under some beliefs about the future evolution of costs. Indeed, if larger installations were expected to benefit from much larger technological improvements relative to residential PV, it could have been rational to first install residential PV in order to wait for these improvements to materialize.

To explore this possibility, we assume that the social planner had correct beliefs about the future costs of all installation categories but residential PV. This assumption is conservative in the sense that these other categories have experienced a very strong decline in costs (about −14%/year on average), significantly larger than many forecasts from the mid-2000s. We then ask: what should have been the beliefs of the social planner regarding the future costs of residential PV in order to choose to commission these installations at the beginning of our study period?

Concretely, starting from assumed costs for 2005, we hypothesize different rates for the decrease in residential PV costs and look at when residential PV is installed in the optimized trajectory. We find that the social planner needs to believe that the cost of residential PV will *increase* by at least 3%/year in order to install it at the beginning of our study period. In other words, imperfect forecasts cannot rationalize the observed magnitude of dynamic misallocation. Even if the social planner was anticipating no technological progress in residential PV (and very significant technological progress for other categories), he would have installed residential PV towards the end of our study period.

Unobserved Social Preference for Residential PV

The previous counterfactual suggests that policy-makers likely had a strong preference for residential PV over medium and large-scale installations. This final exercise seeks to recover an order of magnitude of this willingness to pay.[35]

Specifically, we assume that the social planner has a "perceived" installation cost (or, equivalently, LCOE) of residential PV equal to a fraction $x\%$ of its actual value. In other words, for unobserved reasons, the social planner has an additional willingness to pay for residential PV equal to $(1 - x)$ times installation costs. We then re-run our optimization assuming the installation cost of residential solar is only x times its actual value, and back out the value of x for which the average commissioning date of residential installations is the closest to its observed value. We obtain a value of x equal to 33% which, in LCOE terms, amounts to about 290€/MWh. This number can be thought as a rough estimate of the additional willingness-to-pay of policy-makers for a residential over other technologies. Interestingly, this estimate is comparable to the share of misallocation that we found to be

[35] We are grateful to an anonymous referee for suggesting this counterfactual.

associated with residential PV (Table 2.5).

2.6.3 Limitations

Our results suggest that most of the estimated misallocation stems from having invested early on in large amounts of residential PV. These installations have indeed been deployed at a time when small-scale rooftop PV was much more expensive than medium and large-scale units. In addition, their costs have dramatically decreased in the following years, even more so than the costs of other categories of installations (in absolute terms). Consistently, early years with high installation rates of residential PV (2005-2012) are associated to the bulk of the assessed misallocation. Although France is not the only country to have massively deployed residential PV early on,[36] our results can of course lack external validity in other countries. In addition, a number of other caveats apply.

First, a fraction of inefficient investments may correspond to a somewhat necessary "trial and error" process when betting on a non-mature technology. In particular, our optimization assumes a perfect foresight of future cost reductions, which is of course unrealistic. Back in 2005, the forecasts for PV investment costs did not anticipate their incoming steep decrease. Although it cannot completely rationalize our results (see above), the significant gap between initial forecasts and realized costs may rationalize some amount of misallocation.

Second, we assumed learning-by-doing to be either exogenous or driven by cumulative output. Some learning-by-doing is however likely to depend on the cumulative stock of installations (e.g. decrease in balance-of-system costs). It is then an open question whether such learning is specific to each category (e.g. ground-mounted vs residential), or whether some learning spills over categories. In the latter case, the costly early residential PV installations may have actually contributed to trigger learning-by-doing effects benefiting all technologies.[37] Further research is however needed to investigate whether subsidies directed to small projects have generated significant learning effects for the overall sector. It is indeed unclear

[36] For example, De Groote and Verboven (2019) and De Groote et al. (2024) describe a similar adoption pattern in Belgium.

[37] For example, the first PV developers on the French market might not have been able to implement large-scale solar power plants if they did not have prior knowledge of how to commission smaller PV installations.

why small residential projects would generate learning that may not be obtained through pilot projects of medium or large-scale installations.

Third, the obtained misallocation may arise because the social planner was pursuing additional policy objectives beyond mere efficiency. If so, the estimated misallocation should be interpreted as the realized opportunity cost to fulfill these other policy goals. For example, small installations may generate economic benefits that are more spread out over space (jobs, taxes, etc.) and reduce land use conflicts. Investigating the nature of these other policy goals and whether they were indeed achieved is left for further research.

2.7 Conclusion

This paper proposes a methodology to quantify dynamic misallocation in the deployment of solar energy. We study a dynamic optimization problem where a social planner seeks to minimize the present value cost of investing in solar power plants, under the constraint to produce a given amount of solar electricity each year. In order to derive an arguably conservative estimate, our approach purposely freezes a number of possible channels of misallocation which are particularly prone to measurement errors.

We apply our methodology to the case of France for the period 2005-2021. Our results suggest that the present value cost of investments in solar energy could have been about 30% lower than the realized present value cost without any change in the aggregate annual production of solar energy. We then explore the mechanisms that may explain this misallocation. The early large-scale deployment of residential PV seems to be associated with the bulk of misallocation costs. This observation is consistent with the high level of the early feed-in-tariffs for small installations. The later introduction of auctions is in contrast associated to a significant decrease in the magnitude of misallocation.

Overall, this work shows that mechanisms supporting renewable electricity generation can be very far away from their cost-efficiency frontier. In a context where an energy transition of unprecedented speed is called for in order to meet climate objectives, improving the cost-efficiency of public spending can therefore represent a low-hanging fruit to speed up the deployment of renewables. In particular, our results show that significant amounts of misallocation can occur even in the early stages of the deployment of a new technology, which calls for running policy evaluations to determine the best approaches to support green technologies, even for promising but immature ones. Because the energy transition may end up relying heavily on several such technologies (e.g. large-scale battery production, hydrogen, etc.), our conclusions represent a cautionary tale for not losing sight of cost-efficiency when designing policies that support them.

Chapter 3

Ground-mounted solar and the impact of land-use planning: evidence from France

Abstract: Land will be a critical resource for meeting the European Union's renewable energy targets, which calls for spatial planning policies. However, policy makers may face an environmental tradeoff between allocating land to renewable energy infrastructure or land conservation. This paper investigates how France tackles this tradeoff for ground-mounted solar installations. I show that the translation of centralized regulation in decentralized land-use planning may have significant impacts on the deployment of ground-mounted solar. Using *Staggered Difference-in-Differences*, I find that: (1) more detailed land-use planning at the municipality level increase the amount of land allocated to ground-mounted solar. This is due to better alignment with centralized administrative rules for permitting solar. I also find that (2) more recently approved land-use planning, and (3) integrated land-use planning at the inter-municipality level *decrease* the amount of land to ground-mounted solar by an average 100 m^2 per km^2. This stems from the lagged adoption of new legislation by some municipalities, notably on land conservation objectives. [1]

[1] Acknowledgments: I am grateful to feedback and comments received from participants at the DES2024 conference of the Université Rouen-Normandie, at the EENR conference 2024 of the Laboratoire d'Economie d'Orléans, at the PPEES seminar in CIRED, and at the internal seminars of the Florence School of Regulation and University of Florence.

3.1 Introduction

The European Union (EU) has committed to massively roll-out renewable energy in power generation, notably by scaling-up solar photovoltaic (PV) capacity.[2] Land will be a key resource for achieving this roll-out since solar PV installations, like wind power, have relatively low spatial densities in terms of energy generation.[3] In this context, the cost-efficient allocation of land to renewable installations is a critical policy question to address, given that installations generate local negative externalities and may imply high opportunity costs from land-use conversion (Gibbons, 2015; Dröes and Koster, 2021; Maddison et al., 2023; Hernandez et al., 2014).

Spatial planning policies are regulatory instruments to identify areas deemed suitable for the installation of renewable energy infrastructures. For example, they consist in enforcing set-back distances between wind turbines and dwellings or identifying exclusion areas for preserving natural land. The implementation of these policies faces at least two challenges. First, the deployment of renewable energy may conflict with other policy objectives. Typically, spatial planning instruments for wind power may imply significant tradeoffs between additional investment costs for achieving a given wind energy target, increased conversion of natural land, and disamenity costs from increased proximity of wind turbines and households (Lehmann and Tafarte, 2024; Lehmann et al., 2023; Delafield et al., 2024). These arbitrages are also reflected in the policy arena at the EU level. On one hand, the RePowerEU plan (2022) requires to identify priority areas that are suitable for renewable projects and to accelerate their permitting. On the other hand, the EU 2030 Biodiversity Strategy (2021) sets more stringent objectives on land conservation.

The second challenge for spatial planning policies is that their implementation have to be articulated between top and local authorities. In most EU countries, municipalities have the jurisdiction for land-use planning (OCDE, 2017). Spatial planning policies are thus the

[2]The EU targets a fourfold increase in solar photovoltaic (PV) capacity by 2030 (additional 600 GW) Ground-mounted installations will make up a large part of this target (RePowerEU Plan, 2022).

[3]1 GW of additional ground-mounted solar PV requires at least 10 square kilometers of suitable land, which is more than ten times the land required for developing gas or nuclear power plants (Nøland et al., 2022)

result of a joint regulation, where top-level legislation is transposed at the local level. This decentralization can create inefficiencies due to additional costs resulting from the articulation between different administrative layers. Moreover, regulatory leakages or free-riding effects between jurisdictions may occur. As in the well documented "race to the bottom" phenomena studied in environmental regulations (Oates, 2002), municipalities could adopt more stringent regulation to avoid the siting of renewable installations in their jurisdiction and trade-off clean energy targets with local amenity losses. Hence, understanding the conditions under which spatial planning policies can be efficiently decentralized at the local level is crucial.

This paper is the first, to my knowledge, to investigate how joint regulation for spatial planning affects the deployment of renewable energy. I focus on solar power in France, and provide empirical evidence on the effects of the regulation in steering ground-mounted installations. The spatial deployment of ground-mounted solar follows a different logic than wind power, that has received strong attention in the literature (e.g. Meier et al. (2023); Lundin (2022)), and need not to be framed by the same policy instruments. Solar PV can be implemented almost anywhere: they entail less noise and visual pollution than wind power, they can be put in more versatile spatial configurations, and solar irradiation levels in EU countries makes them economically feasible in most locations.

In France, there are administrative rules to identify suitable land for new solar projects, referred as land-use regulations, which have to articulate with the land-use planning defined at the municipality level. However, not all municipalities have the same land-use planning framework, i.e. the set of rules used to restrict or allow new land developments. In 2023, about 40% of French municipalities[4] use land-use planning frameworks that only allows them, at most, to differentiate between land that can be developed or land that must be kept in its natural state (named RNU or CC). The other 60% use land-use planning frameworks with more than ten categories to discriminate between different types of land-uses (named PLU or PLU-i). Land-use planning also change with the administrative scale at which they are implemented, either integrating grouped municipalities (i.e. inter-municipality) or a

[4] about 34,000 municipalities in metropolitan France as of 2024

single municipality. Moreover, land-use planning vary by their time of approval, resulting in discrepancies with the current legislative context since it was different at the time they were drafted.

I show that the articulation of land-use planning with administrative rules for siting ground-mounted solar installations significantly impacts the amount of land allocated to the latter. This can be explained by two mechanisms. First, there is a regulatory effect. Administrative rules simplify permitting in land plots that are eligible for land developments. Thus, they are better aligned with more detailed land-use planning frameworks, since the latter can discriminate between more categories of land developments. Second, there is a land conflict effect. Having to compete with other land developments, PV developers target municipalities that present less restrictions for new land takes. Typically, municipalities that have yet adopted latest legislation in their land-use planning.

I uncover a causal evidence of the impact of land-use regulations by exploiting the heterogeneous transitions in land-use planning frameworks that took place during the last decade.[5] I construct a data-set on staggered changes of land-use planning at the municipality level matched to the history of commissioning of solar PV installations. I use several *staggered difference-in-difference* specifications to assess the impact of a type of land-use planning on the amount of land allocated to ground-mounted solar PV several years after its approval. More specifically, leveraging on the lengthy and uncertain time of approval of land-use planning, I compare municipalities that updated their entire land-use planning (treated) to their counterparts that are in the process of updating their land-use planning to a similar framework (controlled).

I find that land-use planning frameworks impacts the commissioning of solar PV along three key dimensions: (1) frameworks with more detailed land-use categories increase the amount of land for ground-mounted PV by an average 100 m^2 per km^2, (2) more up-to-date frameworks reduce the amount of land by -50 m^2 per km^2, (3) integrating land-use planning at the inter-municipality level reduce the amount of land by -100 m^2 per km^2. Estimates

[5] New legislation entailed important changes in land-use planning, notably the gradual integration of land-use planing at the inter-municipality level (”ALUR” law, 2014)

are significant starting from 5 years after the approval of a new land-use planning framework and are not conclusive for rooftop PV installations.

These findings are robust to different threats to the identification of a causal impact. First, both land-use planning and the permitting of ground-mounted PV involve different levels of governance, which reduces the risk of reversed causality. Land-use planning is first elaborated by the municipal council. Once approved, the PV developer asks for a building permit to the central government's representative (*préfet*). The decision of devolved authorities is independent of the municipality and is taken on the basis of a centralised administrative process. Besides, my treatment only comprises complete remodelling of land-use planning rather than partial modifications. This requires an administrative process involving the approval of several public entities other than the municipality.

Second, my treatment variable is arguably independent of potential confounders. I use propensity score matching based on land-use patterns to ensure that treated and controlled municipalities follow similar conditional parallel trends. I further ensure that my groups of municipalities do not follow divergent trends in socio-economic characteristics – namely income levels, value of land and tax revenues. Finally, I check whether the spatial diffusion of ground-mounted PV installations is explained by other channels not covered in the initial empirical strategy. First, I run alternative specifications to investigate if my treatments have spillovers on neighboring municipalities. Second, I study the spatial auto-correlation of ground-mounted solar, which could be explained by push-back attitudes (NIMBYism) or peer-effects. Preliminary results show that these other channels are not threats in my setting.

This paper highlights an environmental trade-off between allocating land to renewable energy infrastructure and land conservation. Land-use regulations induce ground-mounted solar PV installations to compete with other land developments. Hence, PV developers avoid more costly permitting by locating in municipalities with looser restrictions for new land takes. Typically, municipalities with older land-use planning, i.e. that are not aligned with latest legislation on land conservation, or municipalities with land-use planning that is not integrated at the inter-municipality level. This may imply distributional impacts that need to be assessed.[6] I show that land-use regulations direct more ground-mounted solar in municipalities with relatively higher property values and income levels. Thus, although not impacting lowest income groups, future projects might entail higher disamenity costs and higher renting fees if developed in these municipalities. Further research is required to evaluate how this affects the cost-efficiency of the solar PV deployment and whether upcoming spatial interventions increase or reduce these distortions.

This paper contributes to the vast literature studying the spatial determinants of the deployment of renewable energy and shows that land-use regulation is an important factor to consider. Literature shows that peer-effects and "NIMBY" politics play a key role in steering the spatial deployment of renewables (Jarvis, 2021; Carlisle et al., 2016; Bollinger and Gillingham, 2011), as well as their integration to electricity distribution grids (Gonzales et al., 2022; de Lagarde, 2018). The effect of land-use planning has received scant attention. Research has focused to a great extent on specific policy instruments, such as designated areas, protected areas or set-back distances, for the deployment of wind power (Lehmann and Tafarte, 2024; Lehmann et al., 2023; Meier et al., 2023; Delafield et al., 2024). Other articles study the effects of building regulation and simplified permitting processes on the development of rooftop solar PV installations (Carattini et al., 2024; Daniele et al., 2023). This article fills this gap and provides novel evidence of the effects of land-use planning on ground-mounted solar.

The rest of the paper is organized as follows. Section 2 provides the institutional background for commissioning ground-mounted solar PV and derives a conceptual framework from it. Section 3 presents the construction of the data-sets used for the analysis. Section 3.4 conducts a descriptive analysis of the spatial distribution of ground-mounted solar installations. Section 3.5 details the empirical setting. Section 3.6 presents main results and robustness checks. Finally, Section 3.7 provides a discussion on the policy implications of this work.

[6] I do not conduct an economic evaluation in this paper. This would require having a valid counterfactual of current land-use regulations and a comprehensive view of the local costs and benefits of ground-mounted solar.

3.2 Institutional background

France is the fifth European country in terms of solar PV capacity with 15.9 GW installed in 2023 (France Territoire Solaire, 2023). Consistently with EU targets, France plans a fourfold increase of solar photovoltaic (PV) capacity between 2020 and 2030 (*Programmation Pluriannuelle de l'Energie*, 2019), involving the deployment of 2 GW of additional capacity in ground-mounted solar installations per year.

Despite the lack of precise data we can deduct from cumulative installed capacity figures that around 90% of ground-mounted solar in France were developed under public support schemes (France Territoire Solaire, 2023). Since 2011, France relies on specific auctions to develop ground-mounted solar PV. They are organized by the French Energy Regulation Commission (CRE), using a pay-as-bid format. The past four iterations of public auctions already allocated a volume of 7.5 GW to ground-mounted solar installations. The 5th iteration (called *"CRE 5"*) is aiming at an additional 9 GW capacity by 2026 (France Territoire Solaire, 2023).

3.2.1 Where to develop ground-mounted solar?

Project developers have to follow key steps to secure suitable land for the installation of ground-mounted solar.

First, they must find a land plot that is eligible on a number of technical aspects. The land plot must be located in a close perimeter to electricity grids' substations.[7] In France, a rule of thumb states that the grid connection length must be less than 1 kilometer per MW of installed capacity to ensure reasonable connection costs. Then, the land plot must be of sufficient size to host a ground-mounted solar installation. Auctions specific to ground-mounted solar specify a minimum size of 0.5 MW and a maximum size of 17 MW, which correspond to areas ranging between 1 and 30 hectares. The land plot must also require low civil works and have a good solar orientation. In metropolitan France, all regions have

[7] in France, ground-mounted solar facilities connect either to the medium voltage level of the distribution grid (HTA) or to the higher voltage level (HTB). Most units connecting to either the HTA or HTB level incur grid connection costs. These costs consist of building/reinforcing power lines connecting the unit to the upstream substation.

suitable solar irradiation conditions to host solar PV: capacity factors only vary by a factor two between the northern and the southern parts of the country. Finally, PV developers must agree on a long-term lease for the land with the owner.

Second, the land plot must be eligible on a number of regulatory aspects in order to obtain a building permit. Permitting is issued by the central state representative (*préfet*) after a systematic appraisal by state devolved authorities on the basis of environmental impact assessments, realized beforehand by project developers.

Conditional on the siting conditions of the project, the application may require the feedback of additional public authorities. A key criterion for undertaking additional evaluations is the type of land where the project is located, which is determined by land-use planning. For example, if the project is in an area identified as natural land, the project will go under further evaluations. In this case, under appraisal of the *Commission for the Preservation of Natural, Agricultural and Forest areas (CDPENAF)*, to evaluate clear cutting conditions, endangered fauna and flora species, or the loss in wetland associated with its development. According to the context, the CDPENAF can impose drastic technical changes to the project or even cancel its permitting. Finally, the project has to pass a consultative process with local population. A state inspector is in charge of the process and gives the final approval to the *préfet*. Figure C.1.1 in appendix provides a sketch of the main steps in the permitting process.

After obtaining a building permit, PV developers still have to get an authorization to connect to the electricity grid and to secure a power purchasing contract, most often through public auctions. The overall time frame between the building permit application and the commissioning of the project is thus very variable and on average takes between 3 and 5 years.

3.2.2 Land-use planning frameworks

Municipalities are the lower of the three main administrative levels in France (*Régions, Départements, Communes*) and divide the french territory in more than 34,000 units. Each municipality is governed by a municipal council, directly elected from the local population. They have authority over a series of local public services, raise local taxes and are in charge of land-use planning. Municipalities are also part of inter-municipality entities, regrouping neighboring municipalities. Local public services can be transferred to this administrative level to leverage economies of scale, such as waste management or public transportation.[8] Since 2014, land-use planning is also being transferred to the inter-municipality level.[9]

Land-use planning comprises all rules to restrict or allow new land developments. Land-use planning are summarised in zonal maps that identify the type of activities (or land-use) over the different land plots in a territory. There are three main regulatory frameworks for elaborating land-use planning. First, municipalities can elaborate a *Carte Communale (CC)*. *CC* is a framework that only discriminate between land authorized to be developed and land that must be kept in its current state. Municipalities can also elaborate a *Plan Local d'Urbanisme (PLU)*. *PLU* provide more detailed categories of land-uses and allow for more specific orientations.[10] For example, within land authorized for new developments, they can differentiate between more than ten categories (e.g. housing, commercial, public facilities). When used by inter-municipalities, the framework is named *PLU-i*. Municipalities can also choose not to have specific land-use planning rules. In this case, municipalities follow the *Reglement National d'Urbanisme (RNU)*, which sets more restrictive rules for land development. Typically, the *RNU* states that new buildings constructions can only be developed nearby urbanized areas.

Among the 34,000 municipalities in metropolitan France, 58% of municipalities are equipped with a *PLU* or *PLU-i*, 15% of municipalities have a *CC* and 27% are under the *RNU*, as of 2023. In principle, there is no criteria that obliges the use of a specific frame-

[8]Integrating in inter-municipalities was not compulsory until 2010. All municipalities are now part of an inter-municipality containing at least 5,000 inhabitants. Inter-municipalities are governed by a board of municipal council members and vote on which public services and policies will be transferred to the upper-tier jurisdiction.

[9]Following last municipal elections in 2020, land-use planning is by law under the jurisdiction of inter-municipalities. However, municipalities can still keep their power if at least 25% of municipalities representing 20% of the population put their veto. In addition, municipalities are still in charge of delivering building permits and can keep their own existing land-use planning framework

[10]*PLU* was introduced in 2000 to replace *Plan d'Occupation des Sols (POS)*, a former land-use planning framework still gradually replaced in the next decade.

work over another. Figure 3.4 in Section 3.4 displays the distribution of land-use planning frameworks in Metropolitan France.

Land-use planning regulation has gradually evolved since last decades pushed by subsequent reforms. New legislation mainly aimed at upgrading the old land-use planning framework, called *POS*, to the *PLU*; and gradually transferring land-use planning under the jurisdiction of inter-municipalities.[11] This has been translated heterogeneously across the territory. For instance between 2012 and 2023 we observe:

- About 2,000 municipalities under a *CC* and 3,000 municipalities under the *RNU* that have upgraded to a *PLU* or *PLU-i*,
- About 6,000 municipalities either in *CC* or *RNU* frameworks that are still in the process of upgrading to a *PLU* or *PLU-i*,
- About 4,000 municipalities under the older framework, named *POS*, that have yet updated to a *PLU* or *PLU-i*,
- About 3,000 municipalities under a *PLU* that integrated to a *PLU-i* framework, while 4,000 municipalities that are still in the process of approving one.

Figure 3.1 displays the shifts of land-use planning frameworks that occurred during this period. This transitional situation is explained by important costs and delays for elaborating and approving a new land-use planning framework. Moreover, the "Climate and Resilience" law in 2021 formalized the objective of net zero land developments by 2030.[12] Municipalities have to halve their rate of new land takes by two after the approval of their new land-use planning.

Process for elaborating land-use planning. The creation or upgrade of land-use planning is a task initiated and approved by the (inter-)municipal council. Its elaboration results

[11]Notable milestone legislation as follows: the"SRU" law (2000) introduced the *PLU* to replace *POS*. The law of the 16th of December 2010 imposed the integration of municipalities in inter-municipal communities. The "ALUR" law (2014) imposed the transfer of the jurisdiction for land-use planning to the inter-municipal level. "ALUR" law has also set an expiry date for land-use planning frameworks under *POS*, compelling the latter to switch to *PLU*.

[12]This objective has been gradually introduced in legislation starting from "Grenelle II" Law in 2011.

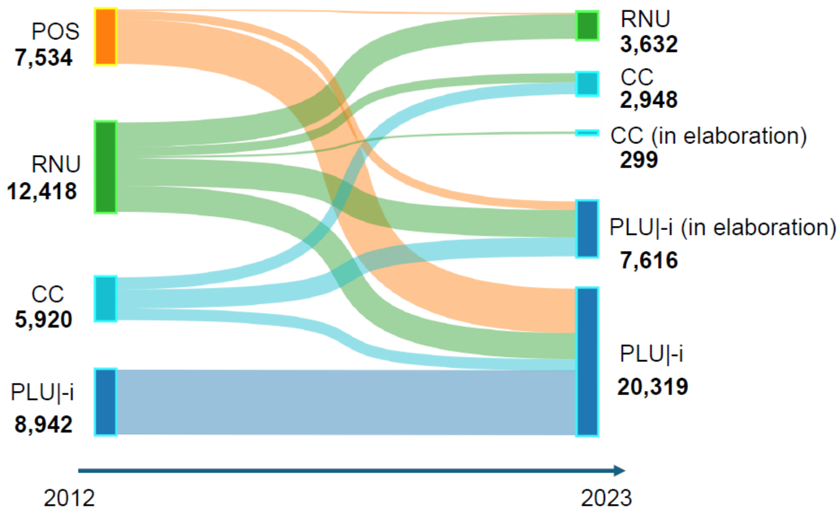

Figure 3.1: Shifts of land-use planning frameworks between 2012 and 2023 across French municipalities. *PLU* and *PLU-i* have been merged for more readability.

from a multi-levelled governance process as follows. (1) The municipal council initiates a need for its territory and prioritizes development objectives. (2) Then, the municipal council elaborates its local development plan, which serves as the basis for land-use planning, and has to comply with upper-tiers' strategic orientations.[13] During its elaboration phase, a panel of public entities give their feedback to the document. Typically, neighboring municipalities, upper-tier administrations, and the *préfet*. (3) The regional environmental authority appraises the impacts of the new land-use planning. (4) The project undergoes a public consultation process with local inhabitants. (5) The council approves the finalized land-use planning and is made available to the public. Figure C.1.2 in appendix C.1 depicts the main steps in the elaboration process of land-use planning.

The complexity of the elaboration process makes the time for approval highly uncertain. On average there are 3-5 years between the prescription of a new framework and its approval. *PLU-i* makes the process even longer, resulting from a bargaining process between member

[13]Regional authority's strategic orientations are formalized in documents called *SRADDET* which are renewed every 5 years. Sub-regional authority (*Département*) integrates these regional orientations in strategic documents called *SCOTs*. *SCOTs* can also be sub-departmental and regroup several inter-municipalities. Third, the inter-municipality can issue reference guidelines in relation to specific themes such as Climate, Air and Energy Plans (*PCAET*) or Local Housing Plans (*PLH*).

municipalities, and having to integrate more elements such as *Local Housing Plans (PLH)* and *Climate Air Energy Plans (PCAET)* in the land-use planning. Finally, the gradual integration of land conservation objectives ("Climate and Resilience" Law, 2021), increases the complexity of decision making for allocating land-uses.

3.2.3 How does ground-mounted solar interacts with land-use planning?

The permitting process of ground-mounted solar varies with the type of land on which it is located. The central administration follows an approach called "avoid-reduce-compensate", which prioritizes in first, already developed land with no potential other usages such as stranded or polluted sites. In second, the land deemed eligible for new developments. In last, the land identified as a natural area or hosting agricultural activities. The French Energy Regulation Commission (CRE), has formalized this approach by setting eligibility criteria for participating in the auctions for ground-mounted solar.[14] Applicants are eligible if and only if the land on which the project is located meets one of the following options:

- Case 1: project site located in a land plot that allows for new land developments, identified as labels U or AU in a *Plan Local d'Urbanisme (PLU)*.

- Case 2: project site located in a land plot that allows for new developments in a *Carte Communale (CC)*, identified by the label ZC. Otherwise, project site located in a land plot that does not allow for new land developments but that specifically authorize activities linked to renewables, identified by labels N-enr, N-pv or N-e in *PLU*. In this case, additional authorizations regarding clear cutting conditions, fauna and flora or wetlands are required.

- Case 3: project site located in an area deemed polluted or damaged that is listed in national inventories (e.g. old quarry and mines, stranded industrial sites, landfills, soil pollution)

[14] Certificate of Eligibility for the Land Settlement (CETI) introduced in 2016. First auctions for ground-mounted PV (between 2011 and 2015) only graded candidates offers according to the location of the project: good grades for already artificialized and damaged lands, bad grades for natural and agricultural spaces.

In addition, a part of the total grade (10-20%) for bidders is given conditional on the quality of the site, where best scores are awarded to damaged or polluted sites (Case 3) and the worst to natural and agricultural areas (Case 2).

Such translations of administrative rules in land-use planning frameworks may significantly impact the local potential of land for solar PV installations, and thus may steer the deployment of PV installations within the French territory. This will be tested empirically in next sections. For example, land plots authorized for new developments in *PLU* or *PLU-i* are suitable for ground-mounted solar, whereas land identified for new developments in *CC* involves more costly permitting processes and lower grades in auctions. Moreover, land plots under the *Reglement National d'urbanisme (RNU)* framework are not eligible to auctions, while this framework is still in place in 27% of municipalities as of 2023.

3.2.4 Conceptual framework

The objective of this paper is to estimate the impact of land-use regulations on the local amount of land allocated to ground-mounted solar facilities. Land-use regulations are the administrative rules to allow or ban the siting of solar projects defined conditional on land-use planning, as described above.

In an ideal setting, one wants to obtain the elasticity of land supplied to solar PV installations relative to the amount of land deemed eligible for solar by the regulation. However, three shortcomings arise when attempting such estimation. First, the amount of land eligible at the municipality level is not observed[15]. Second, this estimation might be biased by various confounders. For example, the demand for other land-uses or the level of local opposition to renewables can interfere with both land-use planning and the amount of land allocated to solar. Third, there are important time lags between changes in the amount of land eligible to solar and the commissioning of projects, stemming from long and complex

[15]The current data repository on land-use planning zonal maps, framed by the *Institut national de l'information géographique et forestière*, only provides a cross-sectional view of the distribution of categories of land types for 50% of the municipalities

administrative procedures.

I use an empirical setting that overcomes this shortcomings. I consider changes in land-use planning frameworks instead of the actual amount of land deemed eligible by the regulation. First, land-use planning frameworks are good proxies of the amount of land eligible to solar PV. Indeed, a municipality updating to another framework (e.g. from CC to PLU) will have to change the labels of its land plots using the categories of the new framework. This ultimately changes the amount of land eligible to solar PV due to the alignments with the central administrative rules. Moreover, land-use planning frameworks can be considered as good instruments in this setting. Adopting a new type of land-use planning is not meant to hinder or facilitate the development of solar PV *per-se*. This action is linked to a change in top-level legislation, for example integrating land-use planning at the inter-municipality level, rather than to meet specific preferences at the local level.[16] Moreover, when updated to a new framework, land-use planning is processed by multiple stakeholders, which averages out the idiosyncratic preferences of the locality towards solar (e.g. NIMBYism).

Updating to a new land-use planning framework can still be driven by underlying trends that could affect as well the potential for solar PV, e.g. higher local economic growth could increase land consumption and accelerate the upgrade of land-use planning to a more detailed framework. I aim to control for these underlying trends with an event study. I leverage on the long and uncertain administrative process for updating land-use planning. I use a *Staggered Difference-in-Differences* to estimate the differences in the amount of land allocated to solar between municipalities that have updated to a new land-use planning framework and municipalities that have not yet updated to a similar framework. I thus recover an average impact on treated municipalities, several years after the approval of a new land-use planning framework. This identification strategy holds as long as the land potential for solar follows similar trends in controlled and treated municipalities provided that the change in land-use planning doesn't occur. Hence, that differences are only explained by time-fixed characteristics at the municipality level. The validity of this assumption as

[16]The latter are met with partial modifications of land-use planning that follow a timely administrative process and involves less stakeholders

well as other identification threats are addressed in Section 3.5.2[17].

Table 3.1: Dimensions of Land-use planning frameworks

	RNU	CC	POS	PLU	PLU-i
Detail	L	M	H	H	H
Scale	L	L	L	L	H
Time	M	M	L	M	M

Note: Letters are used to indicate the intensity of each dimension in each framework: L for low; M for medium; H for high.

Direction of the impacts. Building on the institutional background, I identify three dimensions of land-use planning that might change the amount of land available to ground-mounted PV installations. The intensities of each dimension are detailed in Table 3.1:

1. Level of detail of land-use planning. This is given by land-use categories that can be identified in the land-use planning framework. *PLU(-i)* frameworks provide the most details, *CC* frameworks and *RNU* framework provide the least details.

2. Administrative scale of land-use planning. PLU-i are elaborated at the inter-municipality level, while other frameworks are done at the municipal level

3. Time of approval of land-use planning. There is no clear deadline to update land-use planning in a frequent manner. Hence, we observe a significant variability regarding the time of approval of land-use planning over the last decade. For example, *POS* frameworks are following a stranded regulation and should have disappeared and be replaced by PLU since 2000. Nonetheless, a significant part of municipalities were still under *POS* after 2010.

I then draw three propositions on the directions of the impacts of a change of land-use planning along each dimension on the amount of land for ground-mounted PV.

[17] Other assumptions must hold to uncover the average impact on the treated. First, the treatment should have no effect on controlled units, this is the so-called Stable Unit Treatment Validity Assumption (SUTVA). Second, my specification use matching to ensure that treated and controlled units follow similar conditional parallel trends conditional on having similar covariates. I thus require that there exist controlled units having the same level of baseline characteristics as treated units (common support assumption).

First, I posit that more detailed land-use planning unlocks more land for ground-mounted PV. This is driven by administrative rules for siting ground-mounted solar which are better aligned with *PLU* frameworks. This leads to the following proposition:

Proposition 1: Municipalities upgrading their land-use planning to a PLU framework increase the amount of suitable land for ground-mounted solar, all else equal.

Second, I posit that newer land-use planning frameworks unlock less land for ground-mounted PV. New legislation on land conservation has been progressively formalized in recent years. Hence, municipalities that have land-use planning approved prior to the enactment of new legislation have not yet integrated the latter. Nonetheless, municipalities with older land-use planning may also be saturated in their land development, since the land identified for construction has not changed in recent years. This is likely to be the case for municipalities under *POS* frameworks. I will test the following proposition:

Proposition 2: Municipalities with newer PLUs decrease the amount of suitable land for ground-mounted solar, all else equal.

Third, I posit that elaborating land-use planning at the inter-municipality level unlocks more land for ground-mounted PV. Following the findings of Tricaud (2021), I expect that the integration in inter-municipalities has an overall positive effect on building permits. This effect is likely to be higher for municipalities that have less weight in the negotiation process or municipalities that are reluctant to integrate the inter-municipality. This leads to the following proposition:

Proposition 3: Inter-municipalities approving a PLU-i increase the amount of suitable land for ground-mounted solar, all else equal.

3.3 Data

I build a dataset that keeps track of when solar projects were commissioned at the municipality level and when a land-use planning framework was put in place in a municipality.

My first data source is a public registry listing the universe of power plants in France.[18] I observe 50,000+ solar PV installations commissioned between 2005 and 2023[19]. The dataset indicates where the solar units are located down to the municipality level, along with their installed capacity. The registry does not explicitly specify whether a given installation is a ground-mounted or a rooftop unit. Therefore, I assess whether each observation is a rooftop or a ground-mounted unit using different assignment strategies that are detailed in Appendix B.4 to Chapter 2.[20]

My second data source is the list of land-use planning frameworks in place at the municipality level (*communes*)[21]. I observe the land-use planning framework in effect for the year 2023 along with its date of approval. The dataset also indicates if municipalities are in the process of updating their land-use planning and to which type of framework. In order to have the history of former land-use planning frameworks, I retrieve the same data but recorded in 2012. This corresponds to the oldest recording available so far. The match between the two recording years at the municipality level is almost perfect[22]. The dataset also contains cross-sectional data on the population, area, density of housing and density of firms at the municipality level collected from the french office of statistics, INSEE (2023).

I constitute a third dataset depicting the proportions of land pertaining to different types of land-use. My main source is the Corine Land Cover (CLC) inventory.[23]. CLC assigns 44

[18] https://www.data.gouv.fr/fr/datasets/registre-national-des-installations-de-production-et-de-stockage-delectricite-au-31-12-2022-2/, last accessed on 31 December 2023.

[19] The smallest installations are listed as bundles rather than individual units so that the actual number of individual units is much higher.

[20] Whether a given unit is roof or ground-mounted is assessed based on (i) its name (when available), (ii) the prevailing size limits in technology-specific auctions, and (iii) geolocalized data on photovoltaic facilities retrieved from OpenStreetMap. Around 1,000 observations could not be assigned and are allocated to rooftop installations in order to take a conservative approach.

[21] https://www.data.gouv.fr/fr/datasets/planification-nationale-des-documents-durbanisme-plu-cc-plui-cc-rnu-donnees-sudocuh-dernier-etat-des-lieux-annuel-au-31-decembre-2022/, last accessed on 12 January 2023

[22] Some municipalities have been merged between 2012 and 2023 (around 1,500 units). I retrieve the older status of newly created municipalities using a pro-rata rule based on merged municipalities' status.

[23] https://www.statistiques.developpement-durable.gouv.fr/corine-land-cover-0, last accessed on 30 August

different types of land-uses at a 100 meters raster level by using satellite images recognition. I use the cross-section of 2012, which corresponds to the beginning of my period of study. I nest the CLC items to around 15 categories differentiating between urban settlements, agricultural lands, natural spaces, wetland and coastal land. Table C.7 in appendix recaps these nested categories. Land-use categories at the municipality level are completed with polluted and stranded industrial sites. This data is obtained by using the inventory of polluted sites (BASOL) and stranded industrial sites (BASIAS)[24].

Finally, I use panel data on socio-economic trends. This data is retrieved from open-source datasets associated to Piketty and Cagé (2023). I focus on three key socio-economic characteristics at the municipality level. First, I retrieve timeseries on the average income per capita (before taxes). Second, timeseries on average properties value per capita, being the averaged value of housing observed on the real estate market. Third, timeseries on the average tax revenues per capita, comprising all local taxes raised by the municipality. The three variables are expressed as a ratio to their population means throughout the rest of the paper.

3.4 Where are ground-mounted solar installations?

This section presents the descriptive analysis drawn from the interaction of the location of ground-mounted solar installations with municipality level characteristics.

3.4.1 Ground-mounted solar and socio-demographic groups

First, I categorize municipalities in four groups that indicates their socio-demographic state. In line with Piketty and Cagé (2023), I categorize municipalities between Cities, units of more than 100,000 inhabitants; Suburbs, units that pertain to the urban areas of Cities; Towns units of more than 2,000 inhabitants that are not in a vicinity of a City; and Villages, units having less than 2,000 inhabitants. Figure 3.2 displays the spatial distribution of ground-

2023

[24] https://www.data.gouv.fr/fr/datasets/inventaire-des-sites-pollues/; https://www.georisques.gouv.fr/donnees/bases-de-donnees/sites-et-sols-pollues-ou-potentiellement-pollues, , last accessed on 30 August 2023

mounted PV installations crossed with the socio-demographic group of each municipality. Most installations seem to locate in Towns, or in Villages that are close to urban areas. This is likely driven by more affordable rents when locating further away from city centers. Besides, most installations are in Southern parts of France. More particularly in the Rhône bassin, the Languedoc-Roussillon arc, and in Aquitaine. A substantial part of installations are also located in Northern France, despite lower solar irradiation levels.

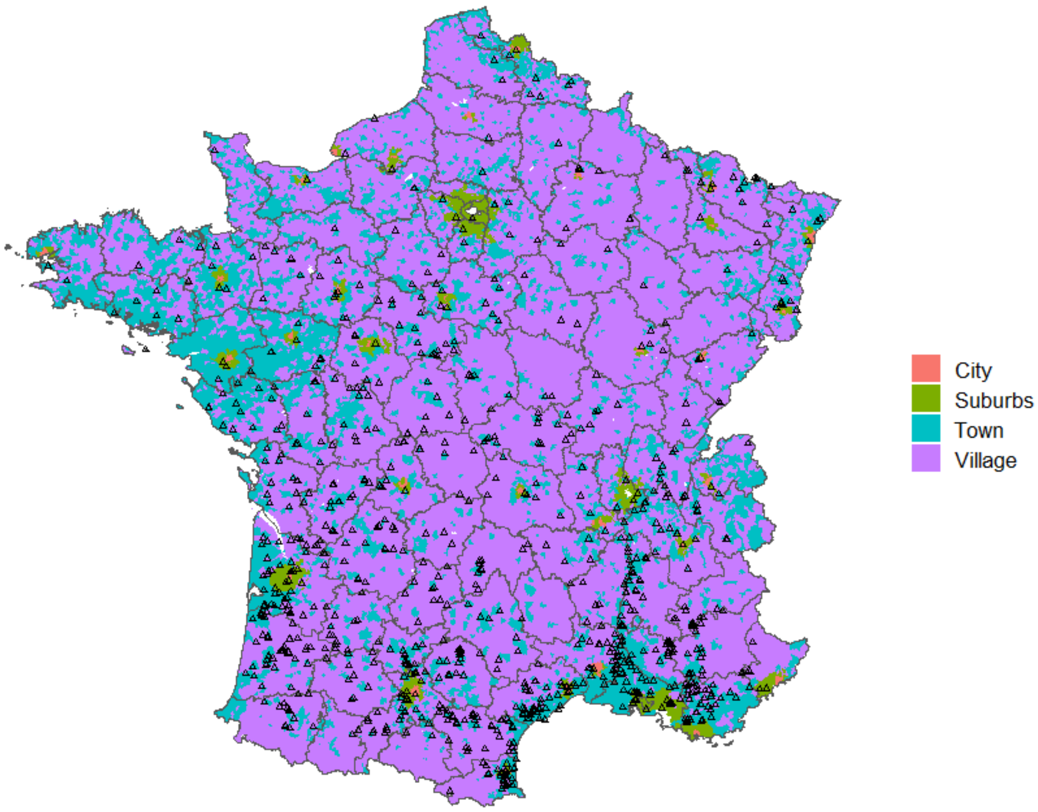

Figure 3.2: Map of ground-mounted solar facilities with socio-demographic groups of municipalities in 2023. Dark triangles are ground-mounted solar PV installations.

3.4.2 Ground-mounted solar and land-use planning

Figure 3.4 below displays the spatial distribution of ground-mounted PV installations crossed with the type of land-use planning framework in-use in 2023 at the municipality level. Most installations seem to locate in municipalities with a PLU or PLU-i. Graphs in Figure 3.3 provide further evidence of this steering. They display the distribution of projects (in number) observed in 2023 across groups of municipalities. While 80% of installations are located in either a Town or a Village, a similar share of 80% is also in municipalities with a PLU or PLU-i. As shown by the bottom panel of the Figure, ground-mounted solar seem to particularly locate in the 50% share of Villages equipped with a PLU or PLU-i. Moreover, when considering the land-use planning framework in place in 2012, a part of municipalities having solar installations in 2023 seem to have upgraded their land-use planning during the period.

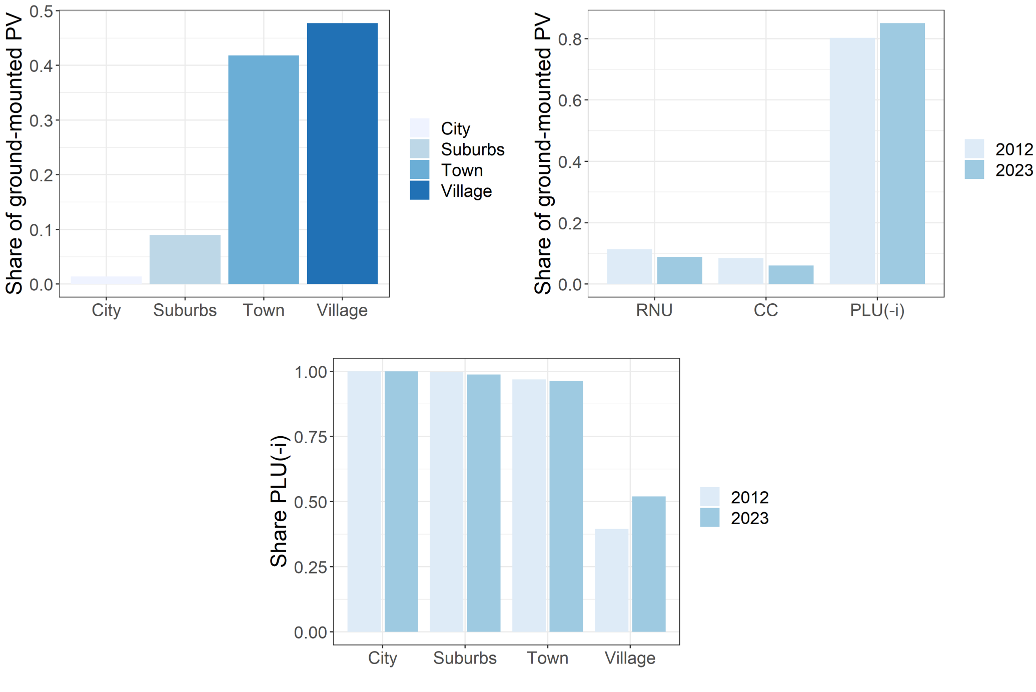

Figure 3.3: Distribution of ground-mounted PV installations observed in 2023 across municipalities (in number) by: socio-demographic group (top left panel); land-use planning in place in 2012 and in 2023 (top right panel); and land-use planning by group of municipalities in 2012 and in 2023 (bottom panel).

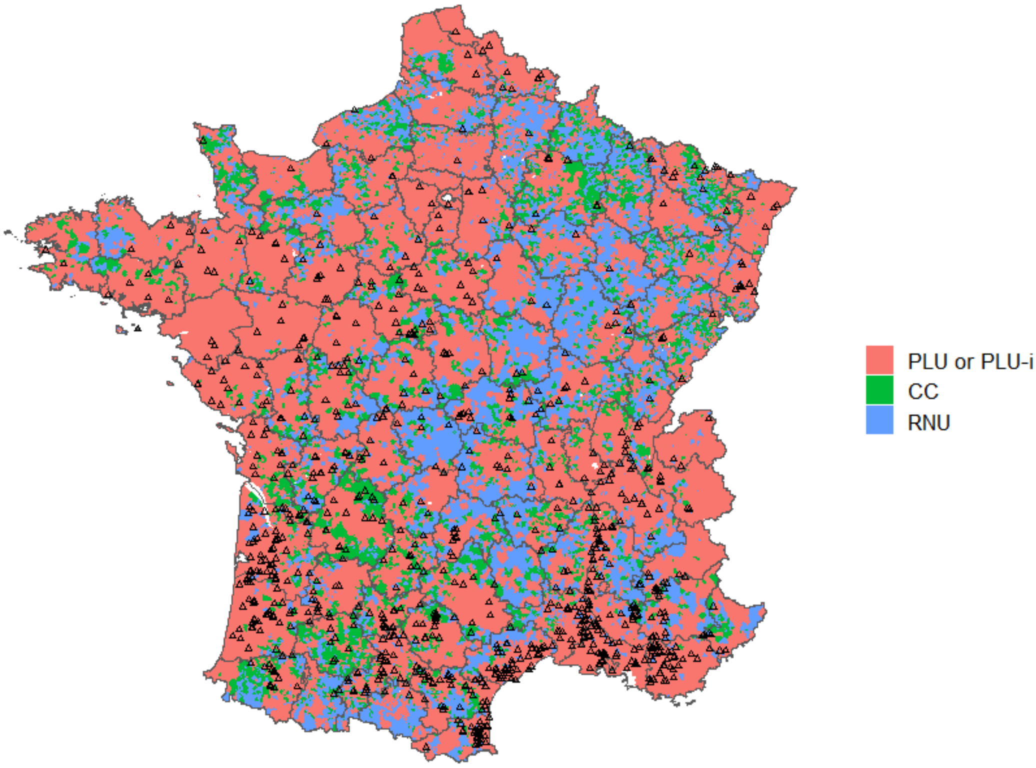

Figure 3.4: Map of ground-mounted solar facilities with types of land-use planning frameworks in 2023. Dark triangles are ground-mounted solar PV installations.

3.4.3 Ground-mounted solar and socio-economic variables

I further investigate whether the uptake of ground-mounted solar is associated with key socio-economic characteristics at the municipality level. Using Piketty and Cagé (2023) datasets on socio-economic trends at the municipality level, I study the location of ground-mounted PV installations in relation to average income, property value, and tax revenues levels observed in municipalities. Figure 3.5 displays the share of ground-mounted installations that locate in each decile of the distribution of municipalities in function of these three variables. The distribution of municipalities is computed by taking the average across the four last years observed in the datasets (2019-2022). Nevertheless, taking years at the beginning of the period (2008-2012) does not change the results, as shown in Figure C.3.8. If there is no apparent correlation between ground-mounted solar and the economic variable we expect to have a 10% share of installations located in each decile, as marked by the horizontal line on the graph.

There is, overall, a positive correlation of ground-mounted solar with property value and with tax income, as more installations are located in municipalities pertaining to the last deciles of these distributions. For example, more than 50% of installations locate in the 30% municipalities with the highest tax revenues. Considering income levels, ground-mounted solar is neither located in the poorest nor the richest municipalities, and seem evenly distributed across middle income levels of the distribution.

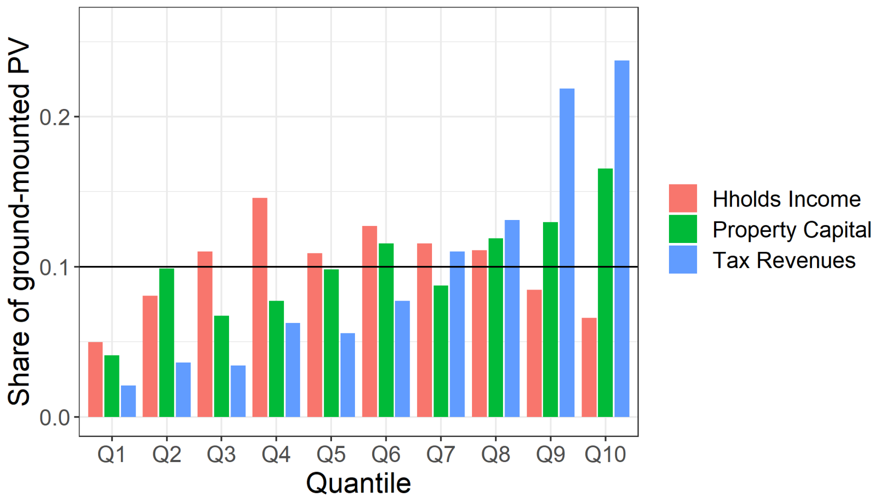

Figure 3.5: Share of ground-mounted PV installations in each deciles of municipalities distributed by key economic variables.
Description of the variables: (1) average income per capita; (2) value of dwellings per capita; (3) taxes raised by the municipality per capita.

Since most installations are located in Towns and Villages, I further look at the distribution of projects within these subgroups. First, Figures C.3.5 to C.3.7 in Appendix show that Villages and Towns are systematically distributed at lower levels for each economic variable than Cities and Suburbs. Figure 3.6 displays the share of ground-mounted installations that locate in each decile of the distribution of municipalities when focusing on each group. Despite still having a positive correlation between ground-mounted solar and tax revenues, the correlation with property capital is less stringent in Villages, and no longer observed in Towns. The higher shares of ground-mounted solar in higher deciles of the distribution of municipalities are thus mostly explained by units locating in Cities and Suburbs. In Towns, more ground-mounted solar locates in municipalities with lower income levels, while in Villages, projects are located in middle income levels of the distribution. Finally, taking levels at the beginning of the time window does not change the results, as displayed in Figures C.3.10 and C.3.9.

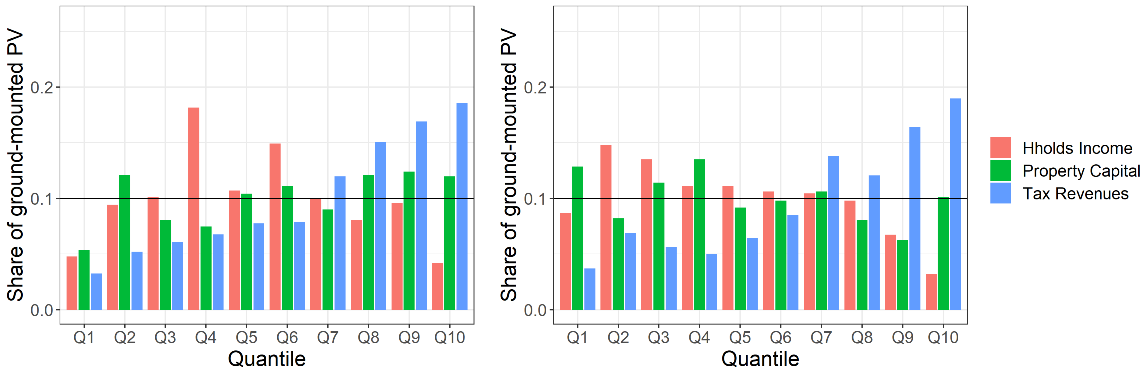

Figure 3.6: Share of ground-mounted PV installations in each deciles of Villages (Left) and Towns (Right) distributed by key economic variables.
Description of the variables: (1) average income per capita; (2) value of dwellings per capita; (3) taxes raised by the municipality per capita.

Hence, ground-mounted solar does not seem to be particularly driven by specific socio-economic aspects at the municipality level. I illustrate this further by implementing a logistic regression of the probability of having a ground-mounted installation at the municipality level relative to the three studied variables, a dummy for having a PLU or PLU-i, and fixed effects at the socio-demographic group level. Results are displayed in Table C.2 in appendix. Obtained coefficients are statistically significant and tell us that increasing the average property value level by one times its population mean increases the odds of having ground-mounted PV by 31%. A similar increase in average tax revenues increases the odds by 12%, and in average income levels decreases the odds by 70%. Conversely, having a PLU or PLU-i increase by 82% the odds of having ground-mounted solar.

I draw several observations from these descriptive statistics. First, ground-mounted solar are more likely to sit in localities with lower income levels, while not particularly directed towards the lowest income levels of the population. Second, solar is not necessarily locating in the land with the lowest value, nor in the poorest municipalities in terms of tax revenues.[25] This is quite striking as the economic theory would expect, if PV developers are profit seekers, to have a negative correlation between property values and ground-mounted solar. Such a selection of projects towards localities with higher fiscal resources could be explained by their land-use composition: solar would be more likely to locate near firms and industries, which generate higher revenues for the municipality. This selection could also be linked to the characteristics of municipalities having PLU or PLU-i, entailing more land developments and thus higher revenues.

3.4.4 Other spatial drivers

I finally explore whether the diffusion of ground-mounted solar could be steered by other spatial drivers that are not considered in this analysis. Indeed, the spatial deployment of ground-mounted solar could follow a spatial pattern where, on the one hand, they would likely concentrate in good locations (e.g. near electricity grids), and on the other hand, installations would likely push away other projects within a small area.

This is confirmed by measuring the spatial auto-correlation in the location of ground-mounted solar units. I compute the Moran's index to measure the spatial auto-correlation of solar installations using a weight matrix identifying all adjacent municipalities around each municipality. Figure C.7.15 in appendix plots the installed PV capacity in municipalities against the capacity in their adjacent neighborhood. I find a small but statistically significant spatial correlation in ground-mounted PV installations, with a Moran's Index equal to 0.1. This corroborates with the intuition that ground-mounted PV installations follow at the same time a spatial concentration effect, and a crowding-out effect.

[25] Note that there is no risks of reversed causality stemming from the siting of ground-mounted solar installations since these results are also true when considering levels at the beginning of the period.

I further investigate if ground-mounted solar installations are particularly located near electricity grids, which are supposedly an important enabler for their deployment (de Lagarde, 2018). I use data on the location of distribution grids' substations (interface between medium and higher voltage levels), to which most ground-mounted solar facilities are connected. Figures C.2.3 display regional maps with the spatial distribution of ground-mounted PV around the substations. Colored shades represent the type of land-use planning in place at the municipality level. The maps show that ground-mounted installations are mainly clustered around them, while also siting in localities covered by a PLU or PLU-i. A minority of projects are located further away from distribution grids' substations, notably in municipalities under the RNU. This might stem from solar installations implemented on damaged or polluted land plots, the "Case 3" land plots, that allowed them to have a higher grade in the auctions.

3.5 Empirical strategy

3.5.1 Econometric specification

I implement an event study to estimate the impact of changes in local land-use planning on the density of PV installations several years after its approval. I focus on a period spanning from 2010, which marks the beginning of the ground-mounted solar PV deployment in France, to 2023. I use a balanced panel of municipalities located in metropolitan France, excluding overseas territories and Corsica.

My treatment group is made of municipalities that have updated or upgraded their land-use planning between 2012 and 2023. I consider different treatment groups conditional on the mechanism that I investigate: (a) municipalities that upgraded a *RNU* or *CC* to a *PLU* or *PLU-i*; (b) municipalities that updated their *PLU(-i)* during the period; (c) municipalities that approved a *PLU-i*. My control groups are made of municipalities that are not yet treated. For example, in specification (a), municipalities in the control group are still in the process of upgrading their land-use planning to a *PLU(-i)*.

Three categories of PV installations are studied: small rooftop installations, ranging between 36 and 500 kW, large rooftop installations, bigger than 500 kW and ground-mounted installations[26]. I expect to find a significant effect only on ground-mounted installations, since they are directly affected by land-use regulations.

My baseline *Staggered Difference-in-Differences* specification estimates differences in additional capacity of solar PV several years after the treatment. I implement the method of Sun and Abraham (2021) to control for potential biases arising with differential timings. I estimate the following specification:

$$Y_{j,i,t} = \sum_{d=-9}^{9} \beta_d 1[t = t_0 + d] + \mu_i + \lambda_t + \rho_{r,t} + \epsilon_{i,t} \tag{3.1}$$

The dependent variable is the installed capacity density of photovoltaic installations of type j in municipality i at year t (in kW per km^2). Treatment dummies $1[t = t_0 + d]$ are equal to one several years before or after the year of approval t_0, indexed by a time-to-treatment variable d (negative before the approval year and positive after). β_d is the coefficient of interest. It captures the deviation from the parallel evolution of the dependent variable between the treatment and control groups due to the new land-use planning framework. Fixed effects are implemented at the municipality, time and region-time levels (indexed by subscript r) to control for any time invariant municipal characteristics, any changes over time that affect all municipalities, or specific to each region.

3.5.2 Threats to the identification

My empirical strategy involves several threats to the identification of a causal effect. There are three main sources of bias that may arise in the estimation. I use alternative specifications to address them.

Parallel trends. Although I compare treated with not-yet treated municipalities, it is possible that the two groups follow diverging trends in the dependant variable if not receiving the treatment. This would violates the main assumption on which the estimation is relying

[26] residential installations are in the process of being included in the analysis. At the moment, I consider that small rooftop installations follow same spatial diffusion processes as residential PV

on. To address this issue further, I use a nearest neighbor matching between treated and controlled units given land-use patterns observed in 2012 at the municipality level (with the Corine Land Cover data). The nearest neighbor methodology matches municipalities (one-on-one) based on the closeness of their propensity scores of being treated given the shares of land types. More details about the methodology are given in Appendix C.4.

Despite matching, parallel trends could still be not validated in my setting. First, divergent parallel trends could be explained by underlying changes in the economic characteristics of municipalities. In an alternative specification, I introduce socio-economic variables as time-varying covariates prior to the year of observation. Second, since less than 10% of municipalities host a ground-mounted solar PV installation in 2023 (see Figure 3.4), the outcome variable stays at zero during the whole period for the vast majority of observations. In this context, trends before the treatment could be parallel because there are zero installations at the beginning of the time window in both controlled and treated municipalities. However, it is possible that some controlled municipalities have zero potential for siting solar PV whatsoever. For example, specific topographic characteristics or the state of the local distribution grid could prevent the commissioning of solar in the locality. These characteristics are nonetheless independent of my treatment, since an update of land-use planning is not correlated with the local potential for solar in a municipality.[27]

Spatial auto-correlation. Updates of land-use planning frameworks should be independent of any concentration or crowding-out effects of solar installations stemming from unobserved spatial drivers. Despite small spatial auto-correlation (see Section 3.4.4), such underlying effects might still have an impact on my estimation. For example, the number of solar PV installations in a region might influence the content of land-use planning during its upgrade in unobserved ways and decrease at the same time the willingness of the local population for having solar PV installations. I check for that by adding the total installed

[27] This could however reduce the precision of my estimates. In a next iteration of this work, I intend to run an alternative specification as follows. I will further restrict my matching strategy to include only "ever treated" municipalities, being the units that have a non-zero probability to host ground-mounted solar PV. I will also exclude municipalities in mountainous and coastal areas, since they follow different land-use regulations than the rest of the observations.

capacity in all municipalities within a spatial buffer prior to the year of observation as a control variable in my specification.

Stable unit treatment validity assumption. In order to provide valid estimates, my treatment should have no spillovers, namely when the update of land-use planning in one municipality impacts also neighboring ones. My estimation could be affected by two types of spillovers. First a spillover of treated on controlled units. If a PV developer' scope is restricted to a given region, having longer permitting in one part of the region might move away all capacity in the other. This would entail a positive bias in the estimation. Second a spillover of treated on treated units. If a large part of a region changes to more restrictive regulations, given a limited regional scope, a project has still to be commissioned in the region and sits in more restrictive areas anyway, which negatively biases the estimation. I check for spillovers in my setting by implementing a more restrictive matching strategy. I exclude all adjacent municipalities to the treated units, thus introducing a spatial buffer between treated and controlled groups.

3.6 Impact on ground-mounted solar permitting

I test weather different upgrades or updates of a land-use planning framework have an impact on the amount of land allocated to ground-mounted PV over the period 2012-2023. I investigate the impact of land-use planning frameworks in light of the mechanisms described in Section 3.2.4. I then run alternative specifications to test the robustness of my results.

3.6.1 Main results

Figures 3.7 to 3.9 display the coefficients of the regression and Table C.8 in Appendix C.5 provides the estimates. The propensity score matching strategy used to balance treatment and control groups is detailed in Appendix C.4. Main results are displayed without accounting for a matching caliper, the minimum distance to match a unit pair between treatment and control groups. Estimations with a matching caliper are tested in Appendix C.4, which did not change the results.

The outcome is the density of ground-mounted PV commissioned at the municipality level in kW per km^2. Using a rule of thumb of 1 hectare per MW, I convert this value in m^2 of land per km^2 (Nøland et al., 2022). Vertical lines are the 95% level confidence intervals.

(a) Effect of land-use planning framework upgrades. Figure 3.7 displays the coefficients for the impact of upgrading RNU or CC frameworks to a PLU framework on the density of ground-mounted PV. First, no coefficients before the year of treatment is significantly different from zero with and without matching. After the treatment, we observe an average increase in ground-mounted PV density starting from 4 years after the approval of the new land-use planning. However, the obtained estimates have weak significance levels, being only statistically significant at the 90% level at the 4th year and 8th year.

Table C.8 in Appendix C.5 provides the estimates. On average, upgrading a less detailed land-use planning framework (CC or RNU) to a PLU framework increase the density of ground-mounted PV commissioned in the municipality by around 9 kW per km^2, as compared to controlled municipalities, which is equivalent to an additional 90 m^2 per km^2 of suitable land. The lag in the effect seems consistent with the average time for developing ground-mounted PV (see Section 3.2.1). Finally, plots of the estimates of the regression on rooftop PV categories are displayed in Appendix C.6. Updating to PLU have no significant effect on the density of large rooftop facilities (>0.5 MW) and a significant effect, yet small, on small rooftop facilities ($<$ 0.5 MW) of less than 0.5 kW per km^2.

PLU frameworks would unlock additional land for ground-mounted PV, confirming *proposition 1*. More detailed land-use planning frameworks identify larger amounts of land that is available to solar PV installations because they induce a simplification shock on the permitting process, due to a better alignment with auctions' criteria.

(b) Effect of more recent land-use planning. Figure 3.8 displays the coefficients for the impact of updating a land-use planning framework after 2012 compared to land-use planning frameworks approved before, that are still in the process of updating. In this case, matching was required in order to obtain significant estimates. While estimates are not different from zero before the treatment, we observe a significant effect on ground-mounted

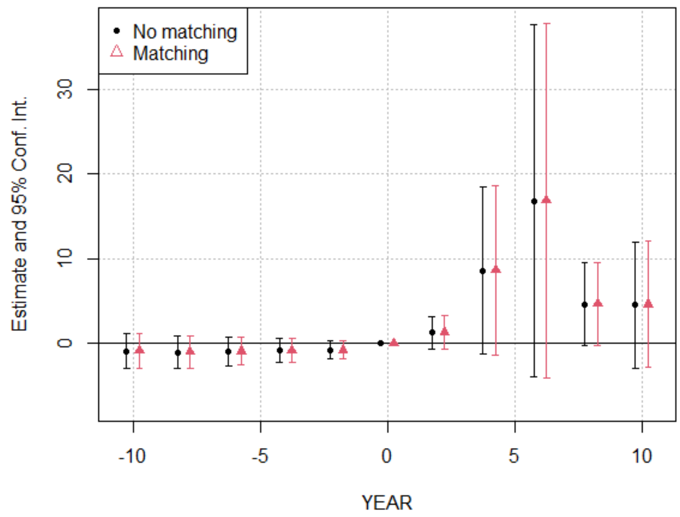

Figure 3.7: Estimates and 95% intervals from the staggered difference-in-differences regression. Treated municipalities are upgrading their land-use planning from a *RNU* or *CC* to a *PLU*

PV density starting from 4 years after the treatment.

Table C.8 in Appendix C.5 provides the estimates. On average, updating a *PLU* decrease the density of ground-mounted PV in the municipality by around -5 kW per km^2 and -10 kW per km^2 from 4 to 10 years after the approval date. We see no effect on the density of rooftop facilities.

Recent updates of land-use planning seem to reduce the potential for ground-mounted solar at the municipality level which validates *proposition 2*. Municipalities with older frameworks might be trapped by their land-use planning, that may have identified more land available for development than their counterparts with more recent land-use planning. Hence, recent legislation imposing more stringent land conservation objectives seem less compatible with targets for the deployment of renewables.

(c) Effect of inter-municipal mergers. Figure 3.9 displays the coefficients for the impact of integrating land-use planning frameworks at the inter-municipality level (*PLU-i*).

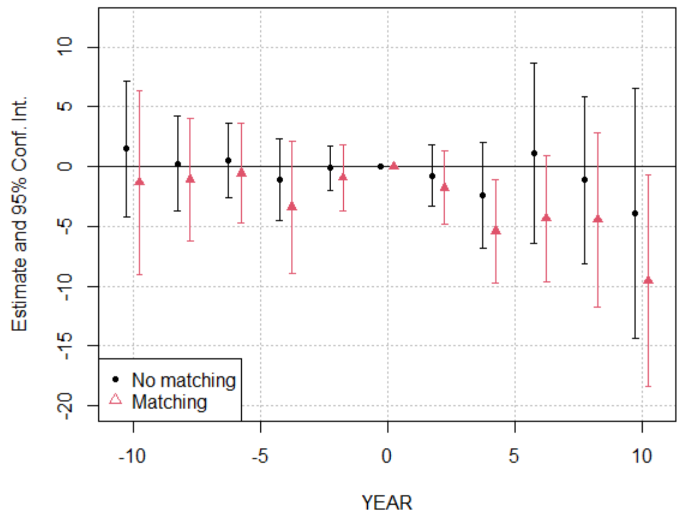

Figure 3.8: Estimates and 95% intervals from the regression. Treated municipalities have updated their *PLU* during the period.

Note that in this setting, treated municipalities originally have different land-use planning frameworks (*RNU*, *CC* or *PLU*). Elaborating a *PLU-i* consequently "re-shuffles" land-use planning at the inter-municipality level. Surprisingly, we observe a negative effect on ground-mounted PV density starting from 6 years after the treatment, which is statistically significant at the 99% level.

Table C.8 in Appendix C.5 provides the estimates. Integrating land-use planning in a *PLU-i* decrease the density of ground-mounted PV in the municipality by an average of -8 kW per km^2, corresponding to a missed potential of around -80 m^2 per km^2 compared to groups of municipalities that have not yet integrated their land-use planning. I also obtain a positive effect on the density of small rooftop facilities (PV <500 kW) two years after the *PLU-i* approval which may indicate a buidling development effect (increasing suitable space for rooftop PV).

Approving a *PLU-i* seems to reduce the potential for ground-mounted solar at the municipality level. This invalidates *proposition 3*. Potential drivers explaining this result are as follows. First, PLU-i might put more constrains on land development as a result of the

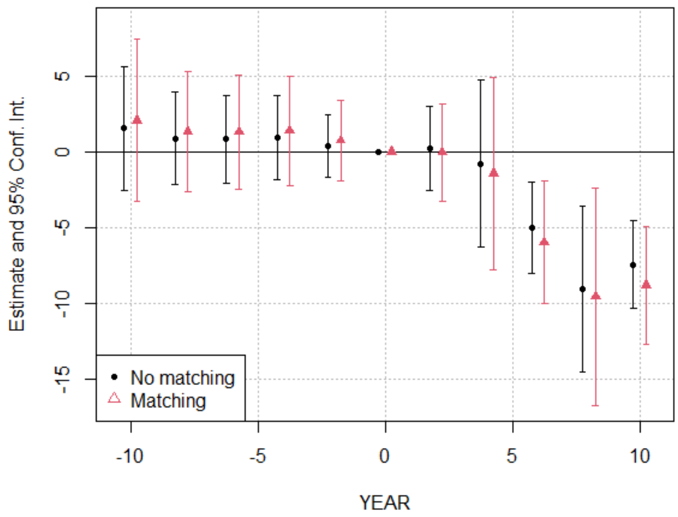

Figure 3.9: Estimates and 95% intervals from the regression. Treated municipalities are integrating their land-use planning in a *PLU-i*

bargaining between constituent municipalities. However, this interpretation is not confirmed for rooftop PV, where we see a positive trend, and is not in line with recent studies on the effects of inter-municipalities' mergers (Tricaud, 2021). A second potential driver might be that *PLU-i* comes with more regulation. More particularly, inter-municipalities of more than 20,000 inhabitants have to issue a local *Climate Air Energy Plan (PCAET)* in addition to their land-use planning. *PCAET* allows the inter-municipality to have a more specific planning approach towards the development of renewables. Conversely, it might be used to put more restrictions on the development of solar PV. This mechanism is further explored in the next section.

3.6.2 Parallel trends

In this section, I implement several additional econometric specifications to test the validity of the parallel trends assumption.

First, I implement placebo tests, to check if they are significant pre-treatment trends in my setting. I estimate the effect of having a treatment seven years before the actual time of approval for municipalities that are treated during the last five years of my time window. Last years of the dataset are deleted to only focus on the period before the treatment. Figures C.8.16 in Appendix displays resulting coefficients, that are all not significant across the three specifications.

Second, I include time-varying covariates in my specification to account for potential trends in economic characteristics that could confound the impact. I choose the same variables as in Section 4, taken from data-sets of Piketty and Cagé (2023). All variables are reported at the municipality level and for the whole time window. They are averaged per capita and expressed as a ratio to the mean. Tables C.3 to C.5 in Appendix C.3, display statistics for each treated and controlled groups across my specifications. We see that, despite fixed discrepancies, controlled and treated units seem to follow very similar trends (and small in magnitude) in function of these variables. Treated municipalities pertain to higher income and property levels across specifications a) to c). Conversely, treated municipalities pertain to lower tax revenues levels for specifications a) and c).

I introduce these socio-economic trends in my specifications as lagged variables before the year of observation. Figures C.8.17 shows the resulting coefficients. Estimates are not changed in either sign or magnitude.

However, these socio-economic trends risks being "bad controls" if updating land-use planning has also an effect on properties' value, income levels or tax revenues. I check for this by implementing a similar *Difference-in-Difference* strategy where I replace the dependant variable by my time-varying covariates. Results are displayed in Figure C.8.18. Across specifications a) to c) we see that updating or upgrading a land-use planning framework could impact socio-economic trends by magnitudes ranging between +0.06 and -0.02 deviations from their means. Given the small statistical significance of the estimates and the existence of pre-trends in some specifications, the three time-varying covariates can be considered as "good controls".

3.6.3 Spillovers

In this section, I run alternative specifications to verify if my results hold after controlling for spillover effects. For example, let's assume that a PV developer prospects land within a restricted area only.[28] Having stricter land-use regulations in some municipalities in the area would reduce the amount of land available to solar PV in the latter, but also increase the amount of land allocated to solar PV in the rest of municipalities that did not updated their land-use regulations. This would occur simply because PV developers would be driven to move to these municipalities with relatively simpler permitting processes. Conversely, if all municipalities change to stricter land-use regulations in the area, this would not reduce the amount of land, since PV developers still have to develop their projects within the area. Stricter land-use regulation would be, in this case, directly passed-through in projects costs.

To verify the existence of spillovers empirically, I introduce a spatial buffer between treated and controlled municipalities. I estimate the impact of land-use regulations by studying differences between treated and controlled units that are more distant from each other, which rules-out any bias that could stem from the direct proximity of a control and a treated unit. I construct a weight matrix indicating all the adjacent municipalities to each unit of observation. Then, for each treated unit, I delete all its adjacent municipalities when pertaining to the control group. Figure 3.10 below displays the obtained coefficients. The estimates seem unchanged when controlling for treated on controlled units spillovers. Surprisingly, estimates gain in significance in specification b). This may be driven by negative treated-on-controlled spillovers municipalities, which play against our intuition.

I use a similar approach to investigate the existence of treated on treated spillovers. Using the same weight matrix indicating adjacent municipalities, I delete all treated neighbors for each treated unit. However in this case, depending on the sequence, I do not end with

[28]This assumption is likely to be true at the scale of regions (12 regions in Metropolitan France), main firms developing ground-mounted solar PV are often separated in regional branches.

the same sample of treated municipalities. I thus iterate the exercise by randomly reshuffling my set of treated units. Figure C.8.19 in appendix displays the obtained coefficients in each specification after 5 iterations. Despite lowering the statistical significance of estimates, the sign and magnitude of the obtained coefficients seem not impacted by treated on treated spillovers for specifications a) and c). However, estimates loose in significance for specification b).

3.6.4 Spatial dependence

The update or upgrade of land-use planning frameworks is, arguably, independent of other unobserved drivers of the spatial diffusion of ground-mounted solar. However, the underlying deployment of ground-mounted solar could influence the local uptake of new projects in a municipality. For example, a municipality surrounded by ground-mounted PV facilities could both change its attitude towards ground-mounted solar and adapt its land-use planning to specifically hinder the deployment of solar.

In alternative specifications, I check whether the deployment of ground-mounted solar in the vicinity of municipalities is a threat for the identification. To do so, I include as a control the density of ground-mounted solar commissioned in all municipalities that are in a spatial buffer around each unit. First I consider only adjacent municipalities using the weight matrix defined above. Second, I include all municipalities within a 10 kilometers radius. Third, all municipalities that are located within a 50 kilometers radius. I introduce the control with different time lags as follows:

$$Y_{i,t} = \sum_{d=-10}^{10} \beta_d 1[t = t_0 + d] + \sum_{e=-5}^{-1} \gamma_e Y_{-i,e} + \mu_i + \lambda_t + \rho_{r,t} + \epsilon_{i,t}$$

Where $Y_{-i,e}$ is the installed capacity in all neighboring municipalities. I consider lags from minus one to five before the year of observation to account for the lengthy permitting process and elaboration of land-use planning. Figure 3.11 below displays the obtained coefficients. Overall, the significance and value of the estimates are not changed.

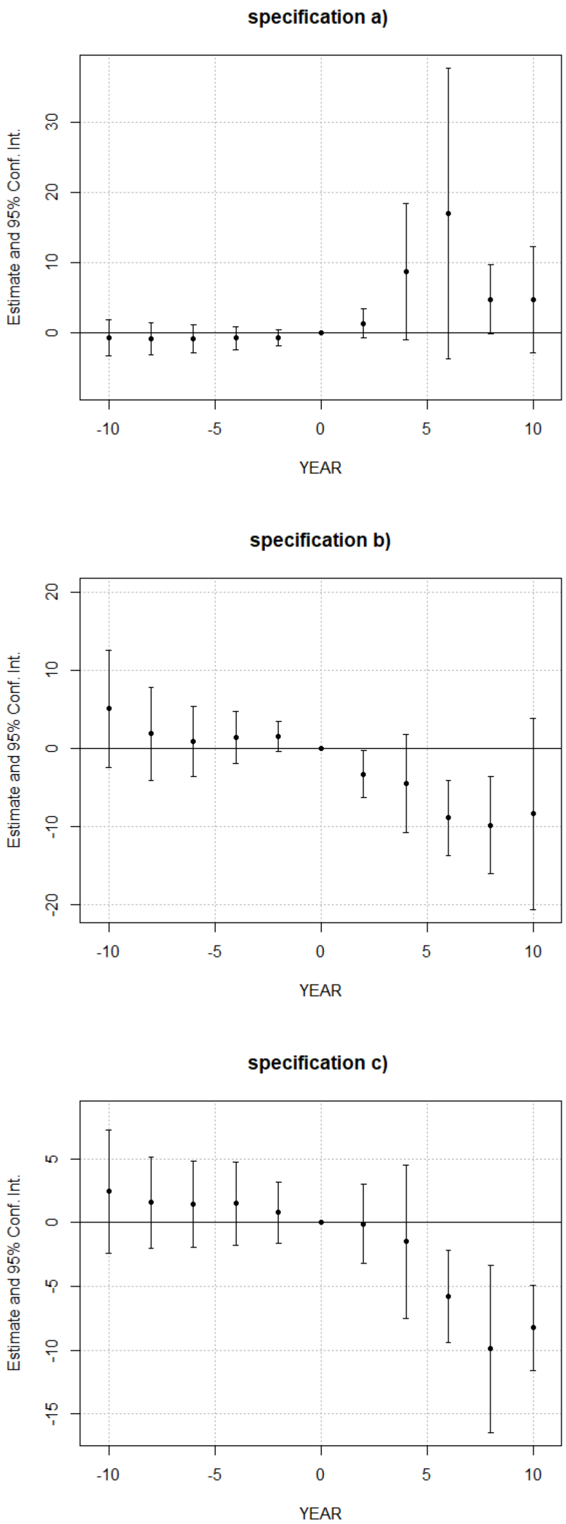

Figure 3.10: Estimates when removing municipalities adjacent to treated units in the control group.

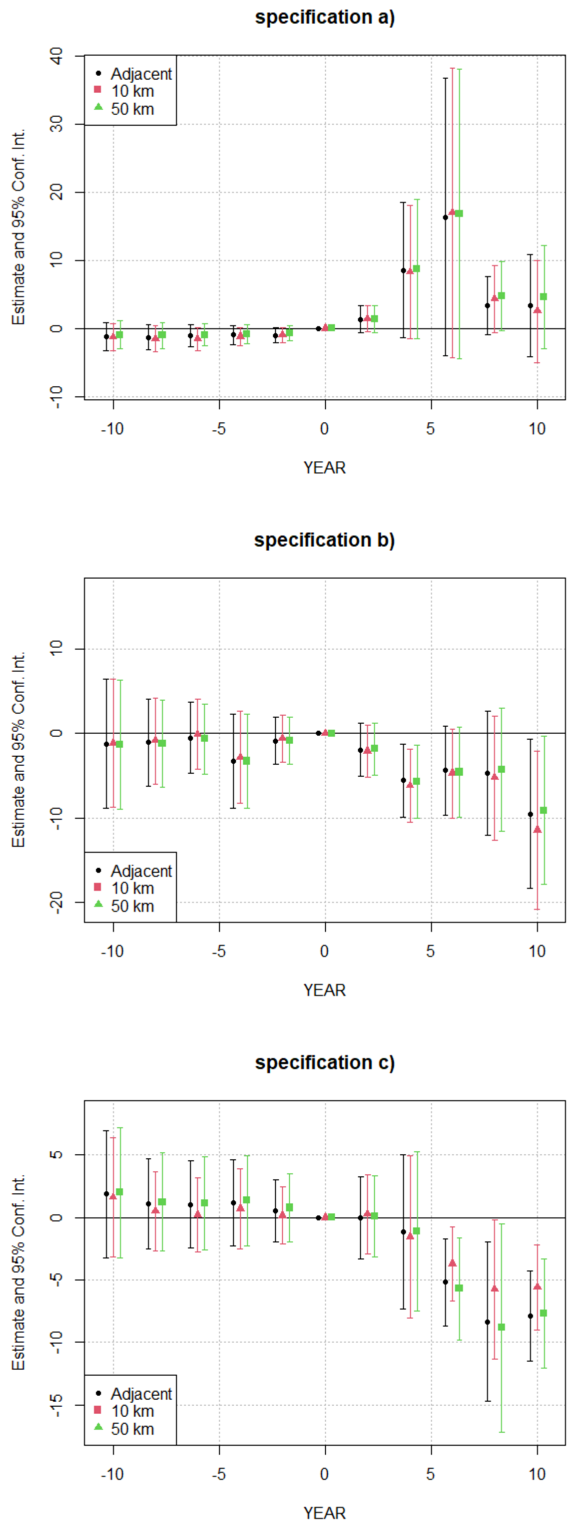

Figure 3.11: Estimates when adding lagged capacity installed within various spatial buffers.

3.7 Discussion

3.7.1 Policy implications

I find two key mechanisms explaining how land-use regulations steer the deployment of ground-mounted PV. First, land-use regulations, formalized in public auctions, induce easier permitting for installations when located in municipalities under a PLU. Indeed, the PLU framework has more categories of land-uses that fall under the different eligibility criteria set by the CRE (see Section 3.2.3). Moreover, a land plot eligible for new development in a CC framework would be disadvantaged compared to if it was identified in a PLU.

In a second step, PV developers are led to focus primarily on land plots identified for new developments in PLU when prospecting for new projects. Hence, they ultimately compete with alternative land-uses, such as housing supply. As a result, PV developers are steered towards locations that present less competition for new land developments. Typically, municipalities that, while framed by a PLU, present looser restrictions for new land developments. Empirical evidence suggests that municipalities with a PLU approved before 2012 (specification b), and municipalities that have not yet integrated their land-use planning at the inter-municipality level (specification c), offer less restrictions for new land developments and thus provide higher amounts of land for ground-mounted PV installations. Older $PLUs$ have not yet fully incorporated land conservation objectives, being formalized in laws that occurred later in the period. On the other hand, inter-municipalities have an additional tool for local energy planning ($PCAET$), that can be used to add more restrictions on the development of solar installations, this aspect is explored more in details in section 7.3. The two mechanisms described above highlight an environmental trade-off. Municipalities binding with land conservation objectives offer less suitable land for renewable installations, while municipalities not yet binding with the latest legislation would offer more land.

These results have three policy implications. First, such steering of solar installations could add irreversible costs on municipalities that are not yet aligned with latest legislation on land conservation. When having to bind with land conservation objectives, i.e. objectives set by the "Climate and Resilience" Law (2021), they could end with less margin available for other land developments.

Second, lagging municipalities will ultimately update their land-use planning and adopt more stringent land conservation objectives. When all municipalities will be on the same grounds, it will be harder for solar PV developers to find suitable land. More competition with alternative land developments would inevitably raise land renting fees and ultimately the cost of ground-mounted solar PV deployment. This phenomenon is already starting to materialize, latest rounds of public auctions saw a decrease in the number of candidates, which is partially explained by the scarcity of land (France Territoire Solaire, 2023). In reaction to this, CRE has started to include more eligibility criteria in ground-mounted solar auctions, notably hybrid settings conciliating agricultural and solar PV activities.

The third implication regards "renewables go-to areas", that are being implemented in France under the "APER" law (issued in 2023) following the RePowerEU Plan. French municipalities are asked to identify priority areas for new renewable projects and to report them at the central administration level. Given the heterogeneity in land-use planning frameworks, the identification of suitable land plots could be biased towards the localities with looser land-use regulations for solar, and thus reinforce the observed distortions. Hence, before adding new spatial planning policies, EU member states should ensure that localities are all on the same page regarding land-use planning to ensure an equitable and efficient deployment of solar installations.[29]

3.7.2 Distributional effects

Although not conducting an economic evaluation of the current spatial planning regulations,[30] this section discusses the potential effects of having such distortions. To do so, I attempt to characterize the municipalities that would happen to host more or less ground-mounted solar due to the current state of their land-use planning frameworks. I identify two groups of municipalities. The first group is composed of the ones that will likely have

[29] However, this policy implies that municipalities have the responsibility to report or not priority areas in their jurisdiction. Thus the reporting of "renewables go-to areas" could be biased by localities' preferences towards renewables. This is left for further research

[30] This would first require having a valid counterfactual of the current land-use regulations and a comprehensive analysis of the local costs and benefits of ground-mounted solar installations.

a relatively higher share of their land allocated to ground-mounted solar in next years. The group comprises treated municipalities in specification a), as well as controlled and never treated municipalities in specifications b) and c). The second group comprises the ones that will have a relatively lower share of their land allocated to ground-mounted solar. They are: controlled and never treated municipalities in specification a), treated municipalities in specifications b) and c).

I use again socio-economic characteristics at the municipality level. I plot the shares of municipalities that fall in each deciles of the population's distribution in function of average property value, income, and tax revenues levels. I only include municipalities pertaining to Villages and Towns as they have higher probabilities of hosting ground-mounted solar than Cities and Suburbs.

Figure 3.12 shows the distribution of the two groups compared to the population's distribution in function of each economic variable. Both groups follow relatively similar distributions in relation to each economic variable. Nonetheless, Group 2 has higher shares of municipalities than Group 1 in bottom deciles of the distribution in function of income levels and property values, and Group 1 pertains to slightly lower tax revenues levels than Group 2.

What can we say about distributional effects? First, having more solar installations in richer municipalities (in terms of income and property value) can raise both renting fees for the land plots and disamenity costs from the siting of the ground-mounted solar, which risks increasing the costs of their deployment. On the other hand, local costs would not fall on lower income groups. Second, results suggest that solar installations could imply higher increases in tax revenues for municipalities. Indeed, ground-mounted solar installations are subject to a specific local tax on energy infrastructures, called *IFER*, in addition to paying property taxes and a local tax linked to their commercial activity.

3.7.3 Effect of *Climate Air Energy Plans (PCAETs)*

As outlined above, a mechanism that might explain the sharp decrease of the amount of land allocated to ground-mounted solar in specification c), could be linked to the existence

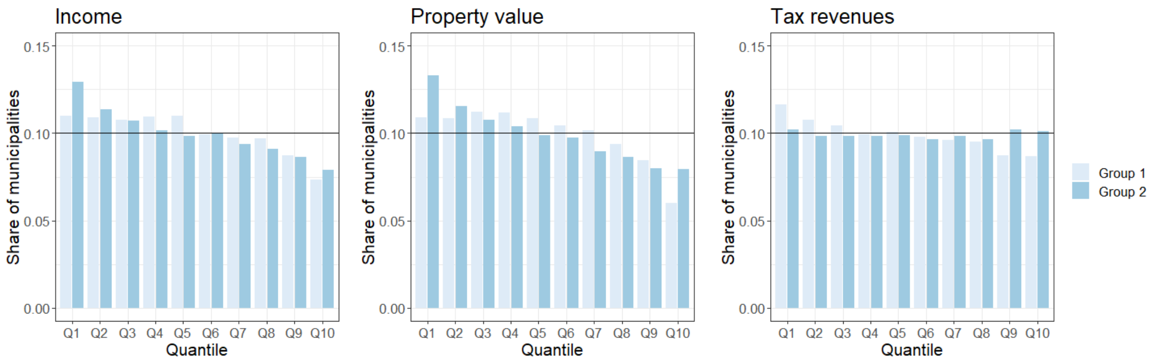

Figure 3.12: Share of municipalities in each deciles of the overall distribution by key economic variables.
Notes:
Group 1: municipalities with a relatively higher share of their land allocated to solar.
Group 2: municipalities with a lower share of their land allocated to solar.
Description of the variables: (1) average income per capita; (2) value of dwellings per capita; (3) taxes raised by the municipality per capita.

of an additional local planning tool. Indeed, since 2015,[31] inter-municipalities have to issue a local Climate Air Energy Plan (*PCAET*) in addition to their land-use planning. This became mandatory in 2019 for all municipalities larger than 20,000 inhabitants. *PCAETs* are meant to formalize climate objectives in local actions. Main aspects covered by the tool are: energy efficiency, renewable energy production, air pollution and biodiversity. For example, *PCAETs* can set precise targets for the development of renewables locally and identify a potential for each technology. Conversely, these tools could also be used to hinder the deployment of ground-mounted solar, by putting more emphasis on biodiversity objectives for instance.

Since, this planning tool became mandatory for inter-municipalities of more than 20,000 inhabitants, I can look at the impact of PLU-i conditionally of being above or below this population threshold. Results are displayed in Figure 3.13. We observe that the coefficients in the regression, conditional on being above the threshold, are lower than those below. Hence, *PACET* could be used by municipalities to "veto" the local commissioning of solar by municipalities, following a push-back attitude. However, we cannot directly associate this result with the use of *PCAETs* and further research would be required to investigate how

[31]See Law "TECV" in 2015.

the latter are used by local authorities.

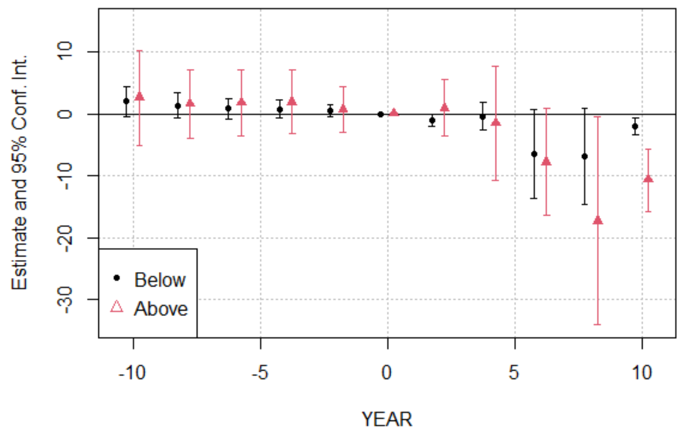

Figure 3.13: Estimates of specification c) conditional on having municipalities above or below the population threshold.

3.8 Conclusion

The EU aims to massively speed-up the roll-out of renewable energy. While financial incentives and simpler permitting are levers to accelerate investments, the availability of land for siting new renewable projects will be critical to achieve the EU's clean energy transition targets. However, the heterogeneity and evolving role of land-use planning across and within countries makes the implementation of new spatial planning policies more difficult.

This paper demonstrates that issue by showing that the heterogeneity of land-use planning in France could imply important spatial distortions of ground-mounted PV installations. More particularly, municipalities with more recent land-use planning can host less ground-mounted PV than municipalities lagging with the legislation. However, more research is needed on the distributional effects of such distortions and to properly evaluate the cost-efficiency of spatial planning interventions.

General Conclusion

Achieving ambitious climate change mitigation objectives will require a deep transformation of our energy systems. Given multiple market failures, a panel of public policy instruments – such as price support mechanisms, direct public investments, or regulatory schemes – are required to bring about the changes necessary for the energy transition.

A prominent feature of the energy transition is the shift from utility-scale, and centralized, energy production to small-scale, and scattered, energy infrastructures. This thesis explores how and to what extent this decentralization aspect changes the efficiency conditions of public policy instruments. First, decentralizing energy supply involves decentralizing public decision-making. Local authorities, such as municipalities or cities, are given more responsibilities to take part in the energy transition. However, inefficiencies may arise when transposing policy instruments to the local level. Chapter 3 shows that there can be leakages in regulation between jurisdictions, where one locality has stricter enforcement than the other. This stems from the variety of local administrations, that differ in size, capacity or political constraints. Localities may also lack adequate planning capacity and require more robust economic evaluations to support their decision-making, as studied in Chapter 1. Second, the energy transition involves making strategic decisions about which types of energy infrastructures to develop in priority. Given the various architectures, location settings, and dynamic progresses, both within and across technologies, the choice of commissioning low-carbon energy technologies is not trivial and can significantly impact the cost-efficiency of achieving the energy transition (Chapter 2). Below, main policy implications and potential research extensions are outline for each chapter.

Policy implications and paths for future research

Chapter 1 studies how and to what extent the cost-effectiveness of local climate change mitigation policies are modified by a shock on energy prices. The chapter underlines the importance of conducting ex-ante Cost-Benefit-Analysis (CBA) to ensure cost-efficient decision-making, which is a methodology that is not well formalized at local authorities' level (Gudde et al., 2021; Tingey and Webb, 2020; Bulkeley and Castán Broto, 2013). The two policies under study are direct investments in district heating networks and supports for energy efficiency retrofits in the city of Bristol (UK). In the context of the energy price shock observed in 2022, integrating energy prices inflation in *ex-ante* CBA drastically changes the efficient order of measures to achieve decarbonation targets. District heating networks become more cost-effective at mitigating emissions than energy efficiency retrofits, particularly due to their insurance effect against higher energy prices.

Quantifying precisely the economic value of their planned mitigation actions could help localities gaining support and overcome barriers that hinder the implementation of local Climate Action Plans (Gudde et al., 2021; Tingey and Webb, 2020). This is all the more important for district heating networks, since they are almost exclusively under jurisdiction of local authorities, and only small evidence exists on their social value (e.g. Leurent et al. (2018)). An immediate following of this work would extend the scope of the CBA to compare the cost-effectiveness of district heating networks with other mitigation measures that are considered for decarbonising the heating sector, namely individual heat pumps. I decided not to include heat pumps in the study since they imply similar impacts to district heating networks: high upfront investment costs, important decarbonation potential, higher price stability that gas boilers. Nonetheless, comparing the two technologies should be done in future works. For example, sensitivity analysis on the energy mix of district heating networks could be conducted to study the minimum penetration level of low-carbon heating sources in the network from which the latter is preferred to individual heat pumps. Another extension could also explore how planning spatially the uptake of each mitigation measure could increase their overall cost-effectiveness, given that energy efficiency retrofits are more efficient when targeting owner-occupied dwellings, while district heating networks are preferred in central collective ones.

Further research should aim at better understanding the social value of district heating networks in a context of uncertainty. This has become a critical policy question in the context of the 2022 energy prices shock in Europe, see for instance measures taken by the RePowerEU plan (2022) that aims at both increasing energy security and climate mitigation. This is specially relevant for localities owning district heating networks. District heating networks usually suffer from public opposition because they increase energy bills to consumers when energy prices are low, and thus fail to attract more users or invest in low-carbon heating sources. Social acceptability for the technology, however, could be greatly improved under energy prices uncertainty. For example, the city of Versailles (France) has decided to decarbonize and extend its district heating network – shifting from gas to geothermal energy supply – after experiencing public controversies due to energy prices increases last year (VersaillesGrandParc, 2023). More refined economic valuation techniques should be conducted to assess the efficiency of such public intervention. First, the economic insurance value of district heating networks can be quantified to provide precise estimation on the part of the economic value of a district heating network that is attributed to reducing risks. This requires to quantify by how much the technology reduces the willingness to pay of consumers to reduce uncertainties (i.e. the risk premium) as studied by Deletombe et al. (2024). Insurance valuation can allow a social planner to directly make arbitrages on the desirability of the technology in function of the degree of risk aversion of consumers. Second, the option value of district heating networks can be estimated, in how much they are a low-regret option given uncertain prospects about future market conditions. District heating networks have the possibility to install new heating sources at reasonable costs later on, with main investments in infrastructure networks that are already sunk. Hence, they have this benefit of switching to more valuable heating technologies and adapt to future economic shocks or technological progress. This was the case of Bristol's district heating network, that adopted large-scale heat pumps after its network was built. Scant research is available on the option and insurance values of district heating networks which opens pathways for new studies to fill this gap.

Chapter 2 and Chapter 3 study the effects and efficiency of policy instruments linked to the deployment of solar PV installations in France. Chapter 2 shows that the sequence of investments in solar facilities to achieve a given solar energy trajectory was not cost-efficient. We show that only 70% of total investments in solar PV installations could have been spent for producing the same amount of solar energy every year throughout the period of study (2005–2021). This stems from the early large-scale deployment of small-scale residential PV, that have received high levels of feed-in-tariffs.

Chapter 2 calls for caution when designing policies to support the development of new technologies. For solar PV, most countries have started to incentivize in priority the development small-scale installations over larger ones, see for instance Belgium (De Groote and Verboven, 2019), or Germany (Lamp and Samano, 2023). However, these decisions can be far from their cost-efficiency frontier. In our context, the actual answer depends on the level of co-benefits that are generated by small-scale residential installations. More empirical studies are thus needed to quantify the impacts of residential solar on local jobs creation compared to large-scale solar installations (Sovacool et al., 2023; Fabra et al., 2024), or to assess the increases in local tax revenues induced by large-scale facilities and the distribution of subsidies across population implied by small-scale ones (Fabra et al., 2024). An other argument for prioritizing small-scale installations is that learning-by-doing could spill more efficiently when developing smallest projects before largest ones. More research is needed to investigate the learning-by-doing processes at play in the solar industry and study the extent to which sequential learning could have occurred, in the sense that one started by developing small-scale units to learn how to construct large-scale installations later on. For example, solar developers could learn more rapidly latest construction techniques if installations are scattered over the territory and on different types of rooftop (Bollinger and Gillingham, 2019). Conversely, developing the technology in large-scale projects could standardize industrial processes more rapidly. Although this only involves the fraction of investments linked to architecture and installation settings, solar modules being standardized across installation types, the existence of sequential learning could significantly increase the cost-efficiency of prioritizing small-scale units. Investigating such learning-by-doing processes in detail could also provide important policy recommendations for quick-starting other promising green technologies, such as hydrogen or batteries.

Chapter 3 shows that the interaction of regulatory frameworks across jurisdictions for land-use regulation distorts the spatial deployment of ground-mounted solar installations. France has a joint regulation for spatially allocating ground-mounted solar PV, where top-level eligibility criteria defined by the energy regulator are based on local land-use planning done by municipalities. However, the various types of land-use planning frameworks issued at the municipality level articulate differently with top-level regulation, which steers the siting of ground-mounted solar installations in certain municipalities. I find that permitting is easier in municipalities with more detailed land-use planning frameworks and more difficult in recent and integrated land-use planning at the inter-municipality level.

Chapter 3 points at an issue when elaborating spatial planning polices for renewable energy. Given that measures to accelerate the roll-out of renewable energy are taken at the top-level (RePowerEU Plan, 2022), national governments must design policy instruments that can be efficiently articulated with local jurisdictions that are in charge of land-use planning. This opens several research pathways. First, there is a need to investigate the consequences of these administrative articulations on the cost-efficiency of the development of solar installations. On one hand, future work should study the extent to which heterogeneous changes of regulatory levels and in time can increase the costs of meeting a solar energy target. For example, the optimization program used in Chapter 2 could be extended to quantify the increase in total costs of meeting a solar energy trajectory when adding regulatory constraints – preventing the siting of installations before the observed upgrades of land-use planning – compared to a counterfactual without regulatory constraints. On the other hand, future work should study the cost-efficiency of the spatial allocation given geographical variations of net benefits induced by solar installations. Economic evaluations could quantify changes in private and external costs for deploying ground-mounted solar installations under the regulatory distortions documented in this thesis. Distributional impacts induced by the observed spatial distribution of projects across municipalities should also be explored, where some municipalities could be more exposed to the siting of renewable installations due to easier permitting rather than economic efficiency criteria. Second, there is a need to better understand how spatial planning policies can handle a mix of different environmental policy objectives. In France two recent laws will significantly impact land-use planning. The "Climate and Resilience" law (2021) has enforced stringent objectives to reduce the rate of new land takes in municipalities, so called net-zero artificialization objective. The "APER" law (2023) aims to accelerate the development of renewable energy supply by targeting suitable land and streamlining permitting processes. Further research should assess how the implementation of the two policies can be done given potential trade-offs to be made in spatial planning. For example, to study whether municipalities that are in line with the land conservation objective would reduce the amount of land available for the deployment of renewable installations. In the near future, empirical studies could also focus on the first iteration of the "APER" law in France, requiring municipalities to identify priority areas over their jurisdiction for installing new renewable capacity. The outcomes of these process should be investigated, to assess how efficient these scheme is to spatially allocating renewables relative to current regulatory mechanisms, and to better understand the motives and reasons behind localities' participation in this program. In this regard, governance and political economy aspects may play an important role in their decision processes. Third, this chapter opens a research avenue to study how, and at which governance level, a cost-efficient spatial allocation of renewable energy should be achieved. One could use the literature on environmental federalism (Millimet, 2013) and extend theoretical models on the optimal allocation of environmental authority (e.g. Oates and Schwab (1988)) to the specific aspects of the deployment of renewable energy installations.

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Appendix A

Appendix to Chapter 1

A.1 Sensitivity to discount rates and elasticity parameters

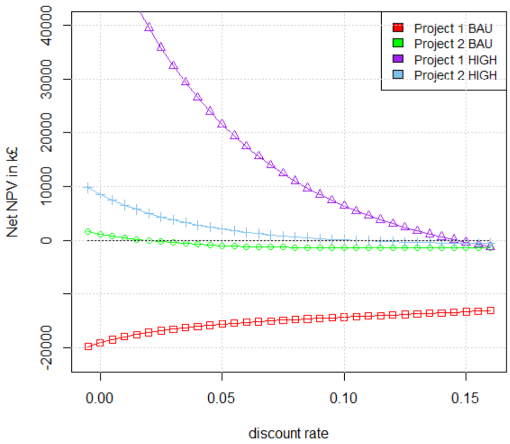


Figure A.1.1: NPVs with discount rates

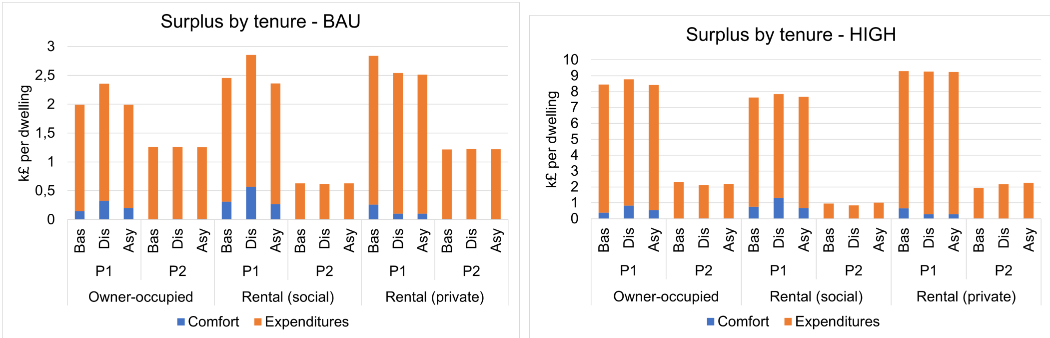


Figure A.1.2: Sensitivity of distributional impacts to elasticity parameters - (Dis = distributional parameters: Asy = asymmetric parameters; Bas = Baseline parameters)

A.2 Sensitivity to prices scenarios

This section outlines the methods used to examine the sensitivity of prices trajectories in my assessment. Figure A.2.3 displays the price trajectories per fuel type in each scenario. The Business As Usual (BAU) scenario aligns with the price trends in the Green Book supplementary material (Treasury, 2021). The High scenario relies on two assumptions: (1) an energy price shock lasting until 2024, following trends observed in the latest Quarterly Energy Prices reports from BEIS (BEIS, 2022a,b, 2021b), and (2) energy prices post-2024 following similar trends to the BAU scenario and that remain consistently high. I explore the impact of this second assumption on my results by conducting two sensitivity analyses, as explained in the following paragraphs.

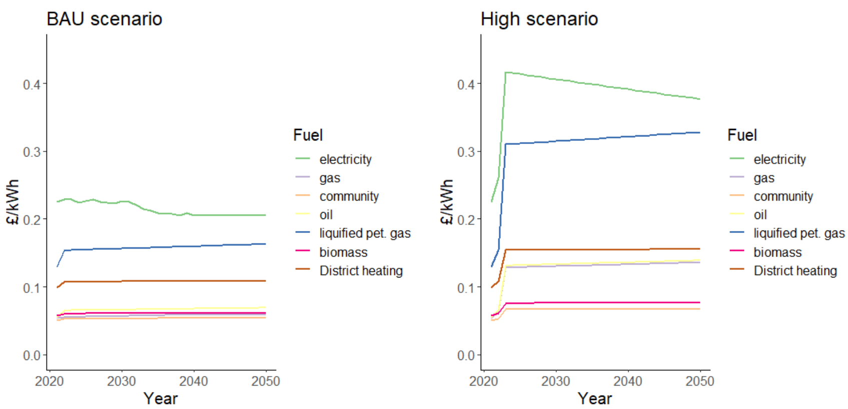


Figure A.2.3: Trajectories per fuel type in each prices scenario

A.2.1 Constant rates for prices increase.

In the first strategy, I apply different rates for the increase of the heating appliances' prices initially set in the BAU scenario. I apply a fixed percentage increase ranging from a 10% to 120% to the prices of the BAU scenario resulting in 12 alternative prices trajectories. Figure A.2.4 displays the price trajectories that are obtained alongside the BAU trajectory.

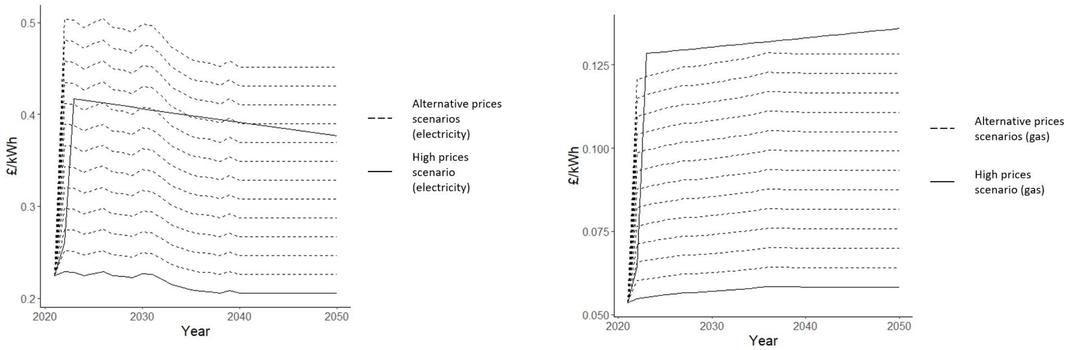


Figure A.2.4: Price trajectories following BAU scenario increased by a fixed rate from 0% to 120% versus High scenario. Left: trajectories for electricity retail prices. Right: trajectories for gas retail prices

A.2.2 Transition from HIGH to BAU scenarios.

In the second strategy, I implement alternative price scenarios following energy prices trajectories from the HIGH scenario until a certain year in the period and energy prices from the BAU scenario after that year. Twenty-five alternative prices trajectories are produced where the year at which prices fall back to the BAU scenario ("year of recovery") ranges from 2025 to 2050. Figure A.2.5 displays the price trajectories alongside the BAU and HIGH prices scenarios.

Figure A.2.6 below displays the net present value of the two policy options for each alternative price trajectory defined in the sensitivity analysis.

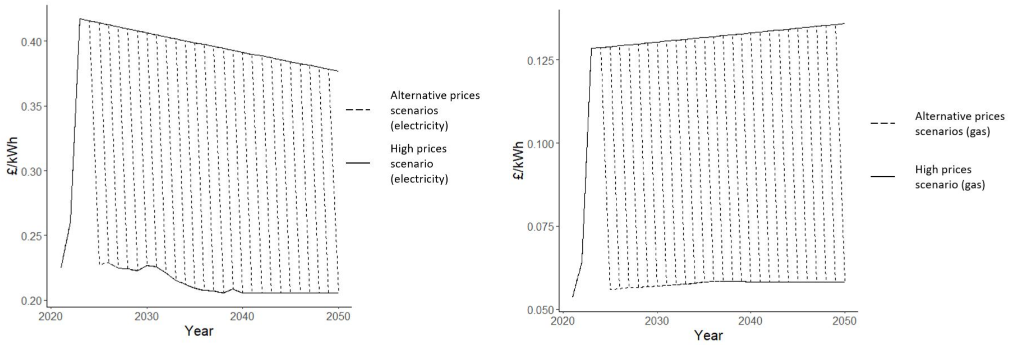


Figure A.2.5: Price trajectories following transitional trends between HIGH and BAU scenarios. Left: trajectories for electricity retail prices. Right: trajectories for gas retail prices

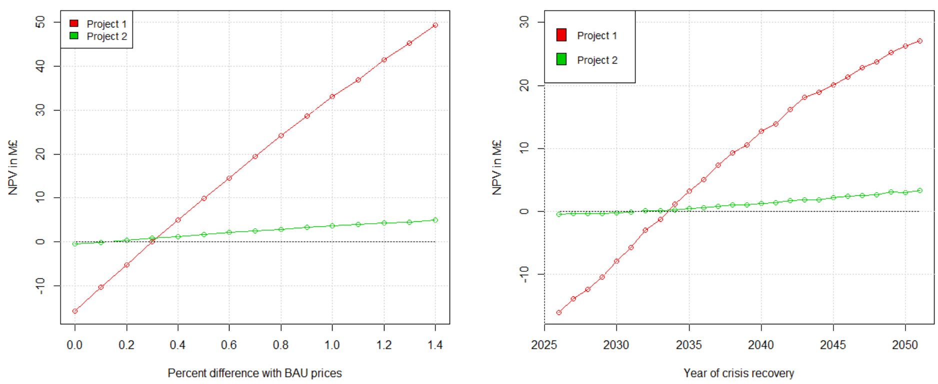


Figure A.2.6: Net Present Values obtained for each sensitivity analysis: Left: Net Present Values conditional on the fixed rate of price increase relative to the BAU scenario. Right: Net Present Values conditional on the year of recovery

A.3 Sensitivity relative to projects' scope

A.3.1 Aligning projects' timeline and volume.

The two policy options differ in their timing and the number of units involved. District heating networks connect groups of dwellings within a neighborhood, adding large increments of connected dwellings early in the time period, while energy efficiency retrofits renovate dwellings at a constant rate. Besides, energy efficiency retrofits involve 13% less dwellings. I test how differences of scope may drive the results of the assessment by aligning the energy efficiency retrofitting rates with the district heating networks' connection rates. First, I expand energy efficiency retrofits to involve the same number of units. Second, retrofitting uptakes are modified to match the incremental timeline of district heating networks. Note that doing the opposite is not technically relevant since district heating networks are tied to programs of works deploying district heating networks in specific areas. They are thus constrained to connect dwellings in the same area simultaneously.

Figure A.3.7 displays the cumulative NPV of Project 2 compared to the baseline results and Table A.1 the change in cost-effectiveness metrics.

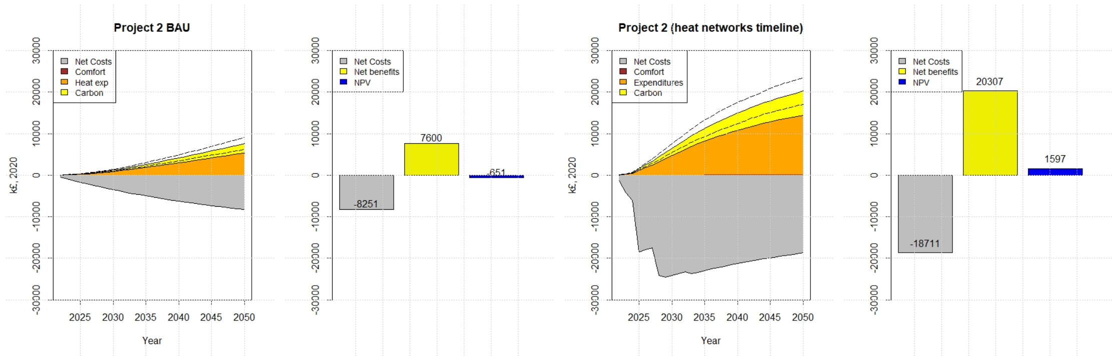


Figure A.3.7: Cumulative economic benefits for Project 2 when aligned with the district heating networks in the BAU prices scenario

A.3.2 Bundling energy retrofits and heat networks

This second counterfactual investigates potential interactions of the two policies by bundling them at the dwelling level. In this scenario, a dwelling is retrofitted first and then connected

Table A.1: Cost-effectiveness of Project 2 when aligned with the district heating networks.

Scenario	Mitigation Cost	Leverage
Project 2	0.10	0.67
Project timeline	0.07	0.77

Note: Mitigation cost is the ratio of the net economic cost (in present value) per unit of carbon reduction (k£ per tCO2-eq) for each policy. Leverage is the benefit-to-cost ratio: net benefits to households per unit cost. Both measures are computed in the BAU prices scenario.

to the district heating network. Fig A.3.8 and Table A.2 display the cumulative net benefits and cost-effectiveness metrics.

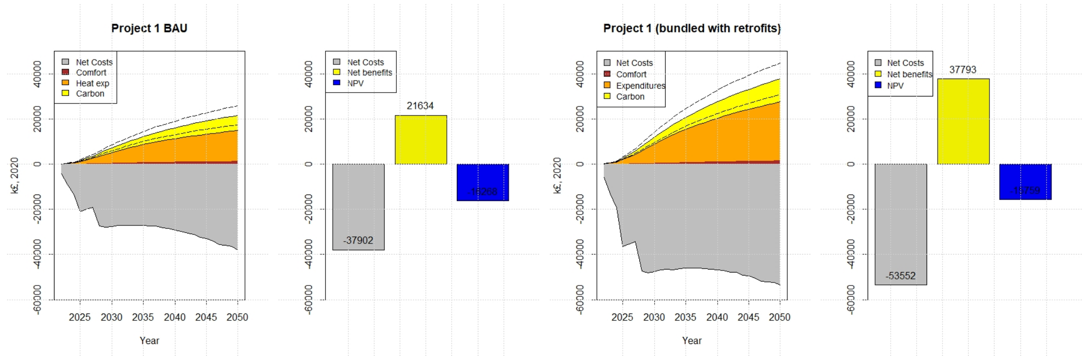


Figure A.3.8: Cumulative economic benefits for Project 1 when bundled with Project 2 at the dwelling level in the BAU prices scenario

Table A.2: Cost-effectiveness of Project 1 when bundled with Project 2.

Scenario	Mitigation Cost	Leverage
Project 1	0.31	0.40
Project 2	0.10	0.67
Project bundled	0.24	0.52

Note: Mitigation cost is the ratio of the net economic cost (in present value) per unit of carbon reduction (k£ per tCO2-eq) for each policy. Leverage is the benefit-to-cost ratio: net benefits to households per unit cost. Both measures are computed in the BAU prices scenario.

A.4 Correcting for potential heating savings

I explore the shortfall between potential heating savings, estimated *ex-ante*, and actual heating savings after a retrofit using an econometric analysis. I identify the shortfall in potential heating saving by using reported energy consumption variables in two consecutive EPCs before and after a retrofit. I extend the EPC dataset to the UK's Southwest region to retrieve more observations. The dataset is reduced to dwellings that had conducted multiple EPCs through time. The dataset is then split into two groups: a control group comprises dwellings with multiple certificates that did not retrofitted and a treatment group with dwellings that did retrofit. A retrofit is identified by an improved energy efficiency grade between two EPCs. I use the following equation to identify the effect of *ex-ante* heating savings on the actual decrease in heating consumption:

$$\log(Y_{i,k,t}) = \alpha + \beta X_{i,t} \times D_{i,t} + \theta Z_{i,t} + \lambda_t + \mu_k + \epsilon_{i,k,t} \tag{A.1}$$

where $log(Y_{i,k,t})$ measures the natural log of the actual heating consumption in dwelling i and location k at time t, while $X_{i,t}$ is the measure of potential heating savings estimated by the previous EPC for the dwelling. Potential heating savings are computed as the ratio between the potential decrease in consumption and the former consumption and are thus negative. $D_{i,t}$ is a dummy variable equal to 1 if the dwelling implemented a retrofit between the two EPCs. The parameter of interest is β, capturing the effect of an increase in potential heating savings on the *ex-post* consumption of a dwelling after an energy efficiency retrofit. A value of 1 for β means that +1 percentage point in potential heating savings generate +1 percentage point in actual heating savings. The equation also includes a vector of characteristics at the dwelling level, $Z_{i,t}$, year fixed effects λ_t, and location fixed effects set at the Lower Super Output Area level μ_k. [1].

Table A.3 displays the results of the regression. According to the estimation results,

[1] As the vast majority of dwellings have at most two consecutive EPCs in the data, I observe only one observation per dwelling displaying the shortfall between *ex-ante* and *ex-post* energy savings. In that setting, fixed effects at the dwelling level cannot be implemented

dwellings that undertake a retrofit achieve on average 32% of the *ex-ante* potential heating savings. Hence, actual energy savings after implementing a retrofit would be significantly lower than the values measured *ex-ante*.

In Table A.4, I repeat the exercise conditional on tenure types. Owner-occupied tenures achieve 20% more of their potential heating savings than rental (private), and 32% more than rental (social). This discrepancy can be explained by differences in income levels, insulation measures with high potential required higher investment costs. Moreover, deeper insulation measures are more difficult to be implemented in rental households' since they result of a collective bargaining between owners and tenants. Finally, the effect of the Bristol dummy variable on the outcome is small (0.06) and not significant. Energy efficiency retrofit activities in the Bristol area thus shares similar characteristics to other regions.

The regression results are sufficiently robust to calibrate my model. First, dwellings with multiple EPCs have low selection bias. Main reasons for having multiple EPCs are linked to real estate transactions that seems weakly correlated with a dwelling's thermal characteristics. Second, I observe EPCs around an energy efficiency retrofit with variable time intervals. This allows me to control for the persistence of the heating savings after a retrofit. Third, year fixed effects and time lapse variables control for potential trends in consumption. Fourth, location fixed effects partially control for idiosyncratic errors from EPC assessors. However, dwellings' self-selection for retrofits cannot be controlled in this model. This likely overestimates the share of heating savings actually realized, despite the already large energy efficiency shortfall that is obtained.

The econometric regression results allow the heating savings to be adjusted by applying a data generating process as follow:

$$Y_{i,soc} = 0.2 * X_i \tag{A.2}$$

$$Y_{i,ren} = 0.32 * X_i \tag{A.3}$$

$$Y_{i,own} = 0.5 * X_i \tag{A.4}$$

Where $Y_{i,soc}, Y_{i,ren}, Y_{i,own}$ are the estimated actual heating savings for resp. rental (social), rental (private), and owner-occupied dwellings, and X_i is the potential heating savings identified at the dwelling level.

Table A.3: Regression results

	Dependent variable:
	log(Cons_after)
Constant	6.023***
	(0.054)
Potential savings	−1.236***
	(0.023)
EE upgrade	−0.165***
	(0.009)
Potential savings x EE upgrade	0.323***
	(0.027)
Flat	−0.223***
	(0.008)
Semi-Detached	−0.051***
	(0.006)
Total floor (m2)	0.007***
	(0.0001)
Rental (private)	0.035***
	(0.006)
Rental (social)	−0.049***
	(0.006)
Time Lapse (years)	0.025***
	(0.001)
Single price	−0.157***
	(0.006)
Observations	18,077
R^2	0.647
Adjusted R^2	0.644
Residual Std. Error	0.308 (df = 17920)
F Statistic	210.999*** (df = 156; 17920)

*p<0.1; **p<0.05; ***p<0.01

Table A.4: Regression results conditional on tenure types

	Dependent variable:		
	log(Cons_after)		
	Rental (social)	Rental (private)	(Owner-occupied)
Constant	5.904***	5.946***	6.145***
	(0.083)	(0.114)	(0.088)
Potential savings	-0.827***	-1.286***	-1.346***
	(0.037)	(0.054)	(0.032)
EE upgrade	-0.190***	-0.139***	-0.098***
	(0.012)	(0.022)	(0.014)
Potential savings x EE upgrade	0.198***	0.324***	0.502***
	(0.045)	(0.062)	(0.039)
Observations	5,271	3,910	8,896
R^2	0.677	0.619	0.657
Adjusted R^2	0.669	0.605	0.651
Residual Std. Error	0.229 (df = 5144)	0.356 (df = 3769)	0.305 (df = 8744)
F Statistic	85.639*** (df = 126; 5144)	43.736*** (df = 140; 3769)	110.787*** (df = 151; 8744)

*p<0.1; **p<0.05; ***p<0.01

A.5 Forecasting Heating Degree Days

This section details how future trends for annual heating degree-days (HDD) are calibrated. I derive a linear time trend for the decline in HDDs by analyzing historical data from the Bristol area. I then apply a similar time trend to estimate the trajectory of future HDD in the period 2021 to 2050. HDD data are collected over the period 2000-2021 at three weather stations around Bristol. Lulsgate is the station located at Bristol's airport and has the identification code EGGD. Yeovilton is a station located in the Yeovil's Military base, 60 km away from Bristol, coded EGDY. Cardiff is a station at Cardiff airport, 60 km away from Bristol, coded EGFF. Figure A.5.9 reports monthly HDDs recorded at the three stations over the time period. The three stations agree very well across monthly's measurements[2].

The equation used to estimate HDD future trends is given below:

$$HDD_{t,k} = t\beta + \lambda_k + \epsilon_{t,k}$$

where $HDD_{t,k}$ are the annual heating degree-days in year t measured at each station k. The parameter of interest is β, which estimates an annual decrease in HDD per year.

[2]HDD time-series for the three weather stations are retrieved from the degreedays.net website's API with a base temperature taken at 15.5 degree Celsius.

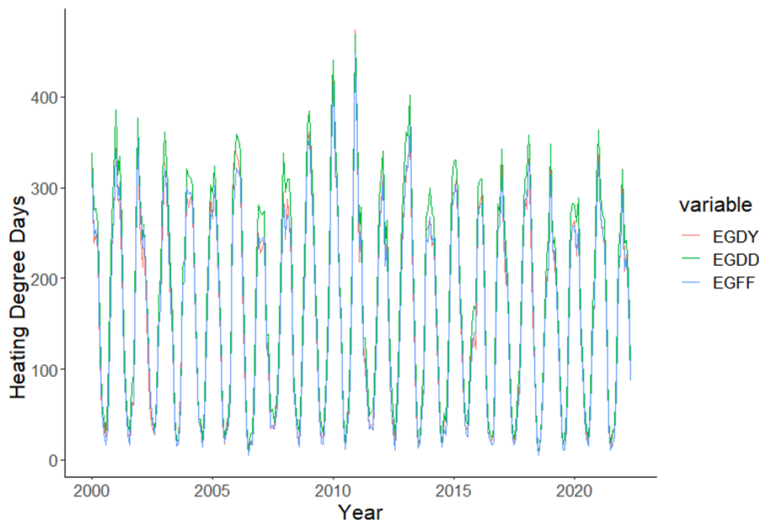


Figure A.5.9: HDDs for all three weather stations (EGDY = Yeovilton, EGGD = Lulsgate, EGFF = Cardiff) in degree-days.

The equation also includes fixed effects at the station level to account for localised weather events and measurements errors, denoted by λ_k. I find a linear trend of -8 HDD per year which is significant at the 5% percent.

This value is of the same order of magnitude as recent studies on heating demand forecasts. EU level statistics on heating degree-days statistics outline that they decreased by 19% between 1979 and 2022 (Eurostat). This decline is well approximated by a linear trend and corresponds to a constant annual decrease at -14 heating degree-days per year. Furthermore, Spinoni et al. (2018) is a recent paper studying how climate change impact HDD trends at the EU level taking different climate scenarios from IPCC. They find that British isles would experience an annual decrease ranging from -3 to -5 heating degree-days per year for highest carbon emissions scenarios until 2100.

A.6 Summary of the key calibration parameters.

Table A.5: Calibration parameters. Standard deviations are displayed in parenthesis

Parameter	Description	Unit	Mean value	Sources	Heterogeneity	Endogeneity
Energy requirement	Annual useful energy consumed per degree-day with initial prices levels	kWh/HDD	7 (5)	dataset (BEIS, 2012)	Dwelling level	Yes
Potential heating savings	Rate of decrease of annual energy consumption after retrofitting estimated in EPCs	%	22% (18)	dataset (BEIS, 2012)	Dwelling level	-
Heating savings shortfall	Fraction of the potential heating savings realised by dwellings	%	41% (11)	dataset (BEIS, 2012)	Tenure level	Yes
Heating Degree-Days	Amount of degree and days where the outside temperature is higher than a threshold	°C.days	1865 (163)	Local weather stations	-	-
Elasticity	Variation of heating demand relative to a variation in prices resp. heating savings	0.2 (0.03)	Economic literature	Tenure level	-	-
Prices	Average retail energy prices in different scenarios	Pounds/kWh	0.07 (0.08)	BEIS (2022b,a, 2021b,a)	Fuel type level	-

A.7 Summary of the literature review for elasticity parameters

Table A.6: Literature review on the elasticity of residential heating demand

Topic	Paper	Estimates	Methodology
Rebound effect	Aydin et al (2017)	0,199 – 0,485	Various econometric approaches. Sample of 563,000 households in the Netherlands
Rebound effect	Sorrell et al (2009)	0,32 – 0,5	Review of 20 papers studying rebound effect in residential heating
Rebound effect	McCoy et al (2021)		Various econometric approaches. Sample of 4 million households the UK
Rebound effect	Coyne et al (2018)	0.33 – 0.41	Quasi-experiment. Sample of 260 social housing tenures in Ireland
Rebound effect	Chitnis et al (2015)	0,41 (gas) – 0,48 (electricity)	Household demand model
Price elasticity	Chitnis et al (2015)	-0,09 (gas) – -0,07 (electricity)	Household demand model
Price elasticity	Lambarderia et al (2016)	-0,126 (electricity) – -0,180 (gas)	Meta-regression analysis on energy prices elasticity
Price elasticity	Sorrell et al (2009)	-0,1 – -0,58	Review of 20 papers studying rebound effect in residential heating
Temperature take-back	Sorrell et al (2009)	0,05 – 0,30	Review of 20 papers studying rebound effect in residential heating
Temperature take-back	Hamilton et al (2011)	0,06 – 0,2	Assessment of the Warm Front efficiency program on a sample of 1,600 dwellings
Temperature take-back	Hedinger et al (2018)	0,110 – 0,144	Stated preferences approach on 3,555 households in Switzerland
Temperature take-back	Greene et al (2015)	0,76°C (living room) – 2,82°C (bedrooms)	Assessment of the Warm Front efficiency program on 1,600 dwellings

A.8 Energy efficiency retrofitting costs

Table A.7: Retrofitting costs per energy efficiency label (in £ per m2) adapted from Giraudet et al. (2021)

Label	F	E	D	C	B	A
G	65,36	116,96	172,86	233,06	301,86	380,12
F		54,18	111,8	175,44	246,82	328,52
E			60,2	125,56	199,52	284,66
D				67,94	145,34	233,06
C					79,98	171,14
B						94,6

Appendix B

Appendix to Chapter 2

B.1 Appendix

B.2 Supplementary Figures

Figure B.2.1: Ground-mounted facilities. Panel A: density of installations per sub-region as of 2021 (kW/km^2). Panel B: capacity weighted average changes in commissioning dates obtained from the optimization (year observed - year optimized).

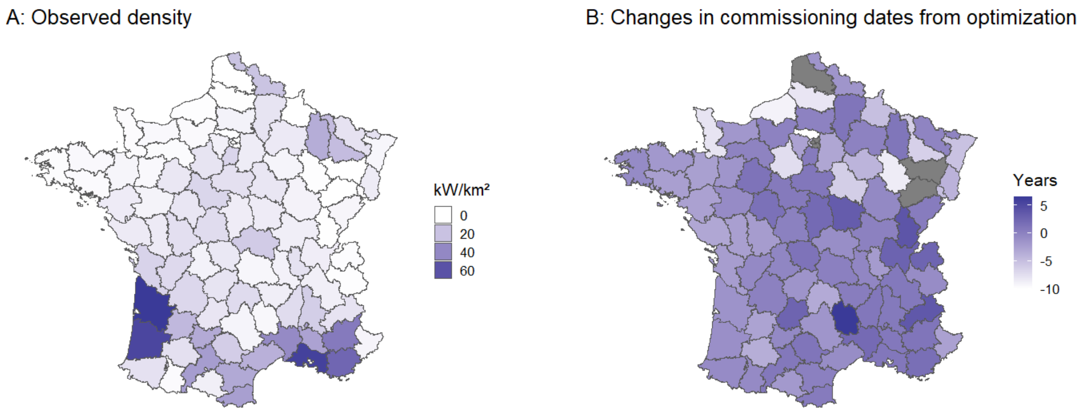


Figure B.2.2: Large rooftop facilities (greater than 100 kW). Panel A: density of installations per sub-region as of 2021 (kW/km^2). Panel B: capacity weighted average changes in commissioning dates obtained from the optimization (year observed - year optimized).

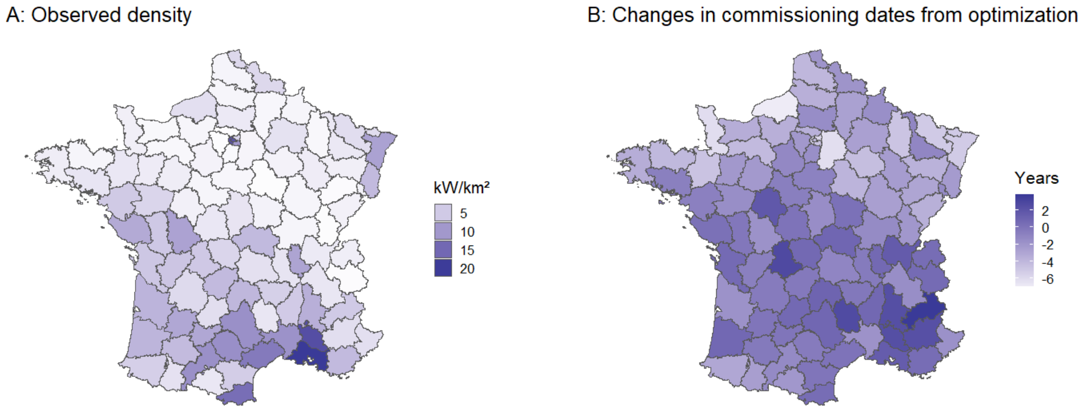


Figure B.2.3: Rooftop installations between 36 and 100 kW. Panel A: density of installations per sub-region as of 2021 (kW/km^2). Panel B: capacity weighted average changes in commissioning dates obtained from the optimization (year observed - year optimized).

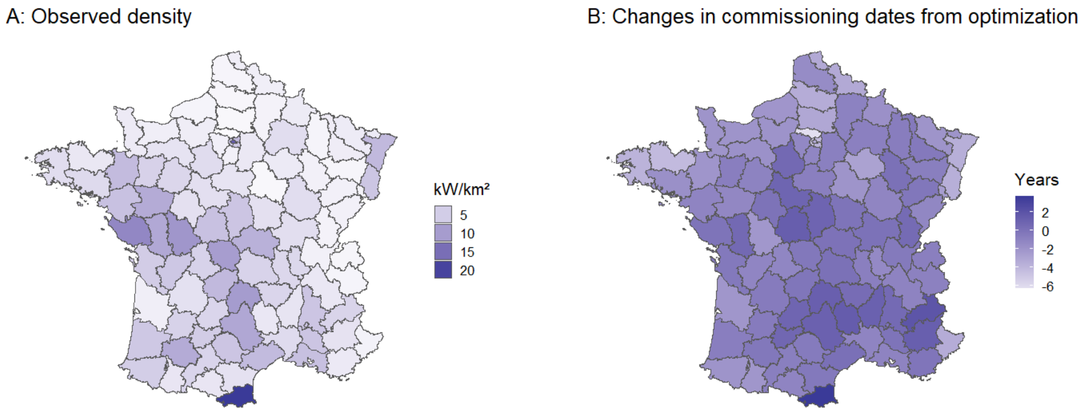
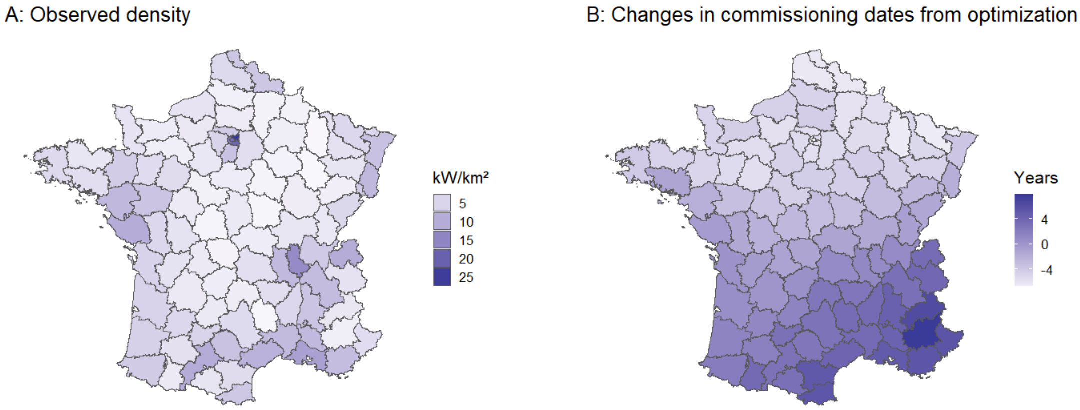


Figure B.2.4: Rooftop installations lower than 36 kW. Panel A: density of installations per sub-region as of 2021 (kW/km^2). Panel B: capacity weighted average changes in commissioning dates obtained from the optimization (year observed - year optimized).



B.3 Computing Solar Units' Costs and Energy Output

This Appendix details how we compute the cost and yearly energy output of each solar unit in the inventory, as a function of its commissioning date. Step 1 uses several data sources to calibrate investment cost functions for different categories of projects. Step 2 computes connection costs (for ground-mounted installations) based on the distance between solar facilities and the grid sub-stations to which they connect. Step 3 estimates the expected annual energy output as of 2022 for PV units that do not report their realized production in the inventory. Step 4 calibrates depletion and learning-by-doing factors.

B.3.1 Calibrating Investment Costs Functions

We use three main data sources to calibrate different cost functions for different types of projects. First, we rely on two reports by the French Energy Regulation Commission (CRE) that provide a detailed analysis of the costs of large PV projects (greater than 100 kW) in France. The first report covers the period 2010-2016 (CRE, 2014), and the second one the period 2017-2020 (CRE, 2019). Second, for small PV projects (lower than 100 kW), we rely on a report by IRENA (IRENA, 2020). This report provides time series of investment costs specific to France on the period 2010-2020. Third, for PV module costs, we use data from the *Our World in Data* website[1] in the publication by Ritchie et al. (2023).

We define different cost functions for 8 categories of projects. These categories are defined by the combination of a type of installation (ground-mounted or rooftop) and a size bucket (in MW):

- Ground-mounted >10 MW
- Ground-mounted 2.5-10 MW
- Ground-mounted 0.5-2.5 MW
- Rooftop >2.5 MW

[1] `https://ourworldindata.org/grapher/solar-pv-prices`. Data adapted from IRENA (2023), Nemet (2009) and Farmer and Lafond (2016).

- Rooftop 0.5-2.5 MW
- Rooftop 0.1-0.5 MW
- Rooftop 0.036 - 0.1 MW
- Rooftop <0.036 MW

We calibrate cost functions for project categories above 100 kW by extrapolating data from CRE, complemented with data on PV modules' costs. For project categories under 100 kW, we rely on IRENA's data. All costs are computed in real 2019 euros.

Cost Functions for Project Categories above 100 kW To compute cost functions for large projects (>100 kW), we mainly rely on CRE's reports. CRE makes a distinction between rooftop and ground-mounted projects, and uses three size buckets that correspond to our categories. We compute total costs by summing two components: (1) PV modules' costs, which are taken from Ritchie et al. (2023) and are common to all project categories; (2) other investment costs, which are extrapolated (separately for each project category) from CRE (2014) and CRE (2019). These latter costs include construction, inverters, wires, engineering and procurement as well as the present value of future O&M costs.[2] Figure B.3.5 shows investment costs other than PV modules and grid connection costs as a function of the commissioning date. Figure B.3.6 shows the assumed evolution for the cost of PV modules.

Because we only have a few data points for the costs other than modules' cost, we extrapolate cost functions over the whole period (2005-2021) for each project category. Specifically, if we denote with $f(i,t)$ is the cost per kW of commissioning a solar unit of category i in year t, we make the following parametric assumptions:

$$f(i,t) = w_t + m_{i,t} \tag{B.1}$$

$$log(m_{i,t}) = a_i + b_i t \tag{B.2}$$

[2] We account for maintenance and rental costs, which are given per project category. Taxes are not included in the variable costs. Present values are computed with a discount rate of 4.5% and a project lifetime of 20 years.

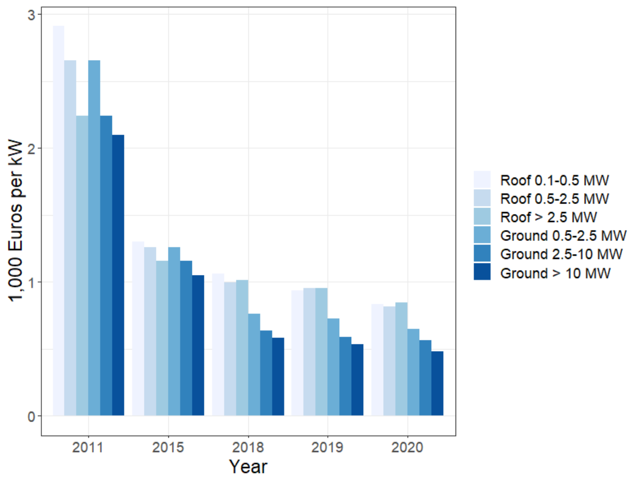


Figure B.3.5: Assumed investment costs (real euros 2019) other than PV modules and grid connection costs, by project category and commissioning date.

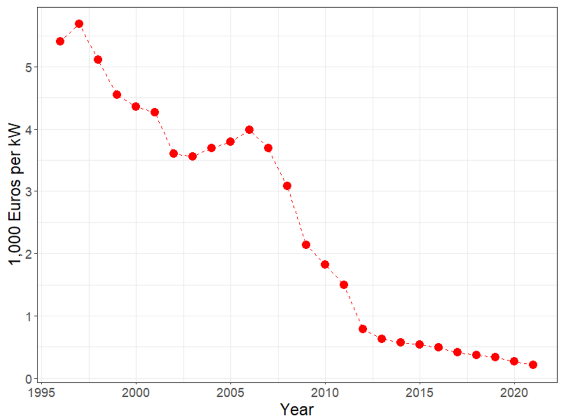


Figure B.3.6: Evolution of the cost of PV modules (real euros 2019)

where w_t is the cost (per kW) of PV modules cost in year t (common to all categories) and $m_{i,t}$ captures all other costs, which are category-specific. We use OLS regressions to calibrate $m_{i,t}$ from cost observations in 2011, 2015, 2018, 2019 and 2020. The obtained coefficients (a_i, b_i) are reported in Table B.1.

Cost Functions for Project Categories below 100 kW Cost functions for small projects ($<$ 100 kW) are calibrated using IRENA (2020), which reports time series of total installation costs for commercial and residential PV in France. Since these time series only

Table B.1: Calibrated parameters for project categories larger than 0.1 MW

Type	Size (MW)	Coeff. a	Coeff. b
Rooftop	0.1 - 0.5	276	-0.13
Rooftop	0.5 - 2.5	259	-0.12
Rooftop	>2.5	212	-0.1
Ground-mounted	0.5 - 2.5	327	-0.16
Ground-mounted	2.5 - 10	333	-0.16
Ground-mounted	>10	347	-0.17

span from 2010 to 2020, we apply the same extrapolation as above outside of this time window. Coefficients obtained from the regression are reported in Table B.2. IRENA (2020) only reports total installation cost, not O&M costs. We assume that the present value of O&M costs represents a fixed percentage of installation costs, equal to the average of the observed percentages for larger rooftop categories (about 20%). Finally, PV modules' costs are taken from Ritchie et al. (2023), as for larger project categories.

Table B.2: Calibrated parameters for project categories smaller than 0.1 MW

Type	Size (MW)	Coeff. a	Coeff. b
Rooftop	< 0.036	420	-0.2
Rooftop	0.036 - 0.1	256	-0.12

Obtained Cost Functions Figure B.3.7 shows the assumed cost function for each category, as well as the observed data points. Note that cost functions for the smallest categories (lower than 0.1 MW) are always higher than observed data points since the former include O&M costs while the latter do not. It is worth noting that only a negligible total capacity was installed before 2010, consisting mostly of small rooftop projects.

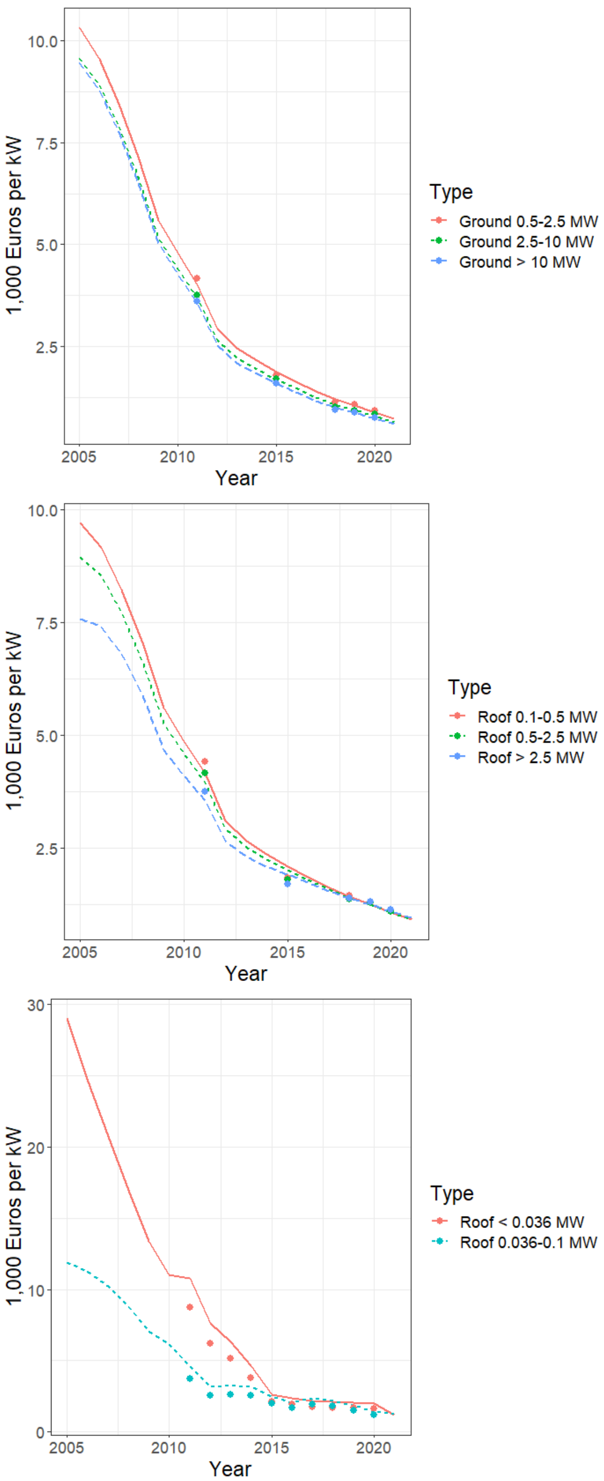


Figure B.3.7: Assumed cost functions vs observed data points.

B.3.2 Grid Connection Costs

Grid connection costs can represent a sizable fraction of total installation costs (up to 20% of investment costs). This paragraph describes how we estimate connection costs.

Solar installations can connect to the grid at different voltage levels. If they connect to the distribution grid, they may either connect to the low voltage level (BT) or to the medium voltage level (HTA). The size of PV installations connecting to the low voltage (resp. medium voltage) grid is capped to 250 kW (resp. 17 MW). Larger units have to connect to the grid at higher voltage levels (HTB).

Solar units connecting to the low voltage level (BT) are assumed to have zero connection costs. Indeed, these units are rooftop installations and rarely require any significant expansion or reinforcement of the power grid.

Most solar units connecting to either the HTA or HTB level are assumed to incur grid connection costs. These costs most often consist of building/reinforcing power lines connecting the unit to the upstream substation. PV installations lower than 250 kW that are connected to the HTA level[3] are assumed to bear zero connection costs. Indeed, these installations have the choice between connecting to the BT or HTA voltage level. Connecting to the latter reveals that this option was likely cheaper than a connection to the low voltage grid (which is assumed to entail negligible costs). Consistently, over 30,000 consumers in mainland France are directly connected to the HTA level, many of which can accommodate on-site solar PV installations.

We compute connection costs as the product of the as-the-crow-flies distance between the PV installation and the substation to which it connects and a fixed connection cost per meter: 100 €/m in HTA and 1000 €/m in HTB (Enedis, 2021). The location of solar facilities is only reported at the municipality level. We assume they sit at the centroid of their municipality. GPS coordinates of substations are obtained from the TSO and DSO open data portals. For all installations but 5%, the public inventory of power plants indicates to which upstream

[3]This represents only 3% of units in the range of [0.1-0.5 MW] and less than 1% of units in the range [0.036-0.1 MW].

substation each solar unit connects.[4] Finally, we correct outlier observations[5] by drawing a random distance from a log-normal distribution calibrated on the rest of the dataset.[6] Table B.3 reports summary statistics for the obtained distribution of connection distances, broken down by voltage level.

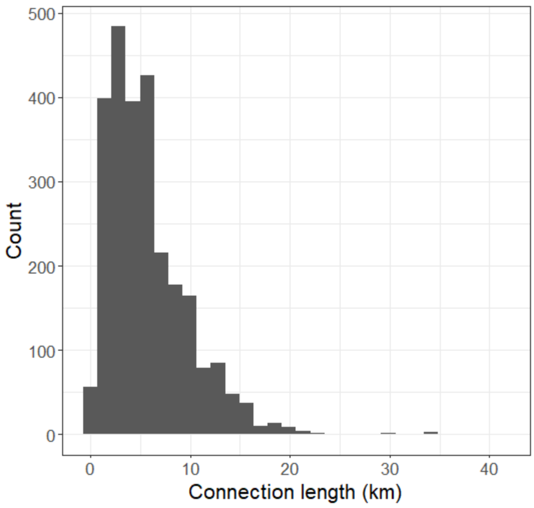


Figure B.3.8: Histogram of connection distances for units connecting to HTA and HTB voltage levels.

Table B.3: Distribution of obtained grid connection distances (in km).

Grid Voltage	N Obs.	Min	1st Q	Median	3rd Q	Max
HTA	2.525	0.05	2.8	4.9	7.9	41
HTB	90	0.6	1.5	2.2	6.4	6.4

B.3.3 Yearly Energy Output

For most observations (∼92%) in the registry of power plants, we observe the total output they produced during the previous 12 months. As such, we observe the energy produced by each unit between December 2021 and December 2022.

[4]Installations for which this information is missing are matched to the closest substation.

[5]Our procedure only yields 2% of outliers, defined as observations whose distance of connection is either zero or larger than 50 km. These outliers likely stem from missing substations or matching errors between sub-stations and solar units.

[6]Using a log-normal distribution is motivated by the fact that distances must be non-negative, as well as by the shape of the distribution of connection distances (Figure B.3.8).

For the remaining observations (8%), we first retrieve simulated capacity factors at different locations and in different years from the website renewable ninja (Pfenninger and Staffell, 2016; Staffell and Pfenninger, 2016). We sample 2,214 locations in mainland France (corresponding to the locations of grid substations) for 2010-2020 (i.e., 11 years corresponding to different weather conditions).[7] We average capacity factors over these years to obtain a single expected capacity factor per location. Figure B.3.9 maps these capacity factors (averaged over larger geographical units for more clarity). Finally, we match each solar installation for which no output is observed in the public registry to the closest location we sampled.

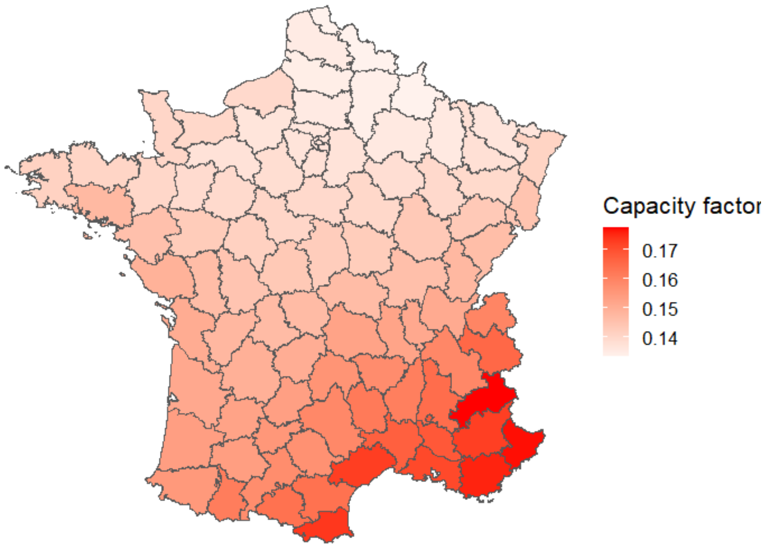


Figure B.3.9: Simulated capacity factors averaged over 2010-2020 at the sub-region level.

Simulated capacity factors retrieved from renewable ninja are theoretical benchmarks that do not account for outages and depletion. Table B.4 compares the distribution of simulated capacity factors to the distribution of capacity factors observed in the public registry of power plants. We observe that simulated capacity factors are on average higher than observed ones. However, installations commissioned after 2018 have comparable capacity

[7]The API requires to set a number of parameters about the characteristics of the considered solar installation. We set these parameters to the same value for all requests: a tilt angle of 28 degrees, an azimuth angle of 178 degrees, system losses at 10%, and no tracking technology.

factors to simulated values. This suggests that the conversion efficiency of solar units decreases over time, a phenomenon that we account for in the next paragraph.

Table B.4: Observed vs simulated capacity factors

Sample	N Obs.	Min	1st Q	Median	3rd Q	Max
Inventory	34,634	0	0.13	0.14	0.16	1.6
Inventory (after 2018)	13,407	0	0.13	0.15	0.16	1.6
Simulated	3,356	0.13	0.14	0.15	0.16	0.19

Table B.4 also reveals that output data reported in the public registry is prone to mistakes. In addition, observed capacity factors can mis-represent the average performance of the unit (e.g. due to long outages). We account for outliers by setting a minimum (resp. maximum) threshold over (resp. under) which the observed capacity factor is deemed to be inaccurate. We set the minimum threshold to 0.03 and the maximum threshold to 0.3.[8] All units reporting capacity factors above or under these thresholds are assigned energy outputs as of 2021 computed from simulated capacity factors. The obtained final distribution of capacity factors is reported in Figure B.3.10.

B.3.4 Learning-by-doing and Depletion Rates

The annual output in given year of a solar plant installed at a given location depends on its commissioning date for at least two reasons. First, conversion efficiency decreases over time due to wear and tear. Second, due to improvements in solar PV cell technologies, units commissioned later in the period tend to have higher conversion efficiencies. To account for these two effects, we assume that if a given solar unit i commissioned in year t_c would have instead been commissioned in year t, its annual output in year t' would change as follows:

$$e_{itt'} = e_{it_c}(1+\alpha)^{t-t_c}(1+\beta)^{t'-t} \tag{B.3}$$

Where α is the annual rate of technological improvement for solar modules and β is the annual rate of depletion. The variable e_{i,t_c} is the annual energy output following the initial

[8]This maximum threshold corresponds to the highest capacity factor achievable for a plant equipped with 2-axis tracking, suffering no system loss, and installed in the most irradiated location.

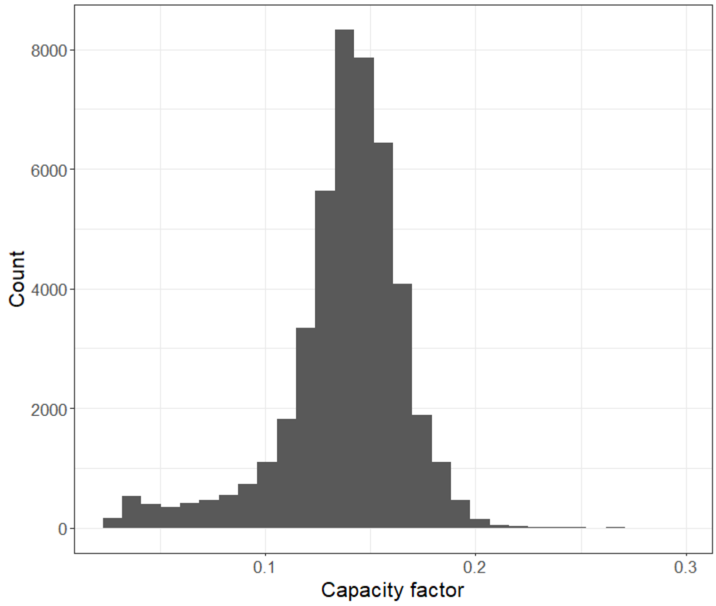


Figure B.3.10: Histogram of PV project capacity factors after correcting for outliers.

year of commissioning of the plant, denoted by t_c.

We estimate depletion and technological improvement rates directly from our data. Using all public inventories of solar plants published between 2017 and 2022, we build a panel dataset consisting of the annual energy output of 16,000+ solar units for these 6 consecutive years. After applying a log-transformation and a first order approximation to the above equation, we seek to estimate the following equation:

$$ln(Y_{itt'}) = ln(e_{it_c}) + (t - t_c)\alpha + (t' - t)\beta + \epsilon_{it'} \quad \text{(B.4)}$$

Where $ln(Y_{itt'})$ measures the natural logarithm of the capacity factors in year t' of unit i, which was commissioned in year t. The parameters of interest are α, which measures the annual rate of increase in the output due to technological learning, and β, which captures the annual depletion rate in output.

Because we do not observe e_{it_c}, we instead estimate:

$$ln(Y_{itt'}) = c + (t - t_c)\alpha + (t' - t)\beta + \gamma ln(\Gamma_i^{TH}) + \lambda_{t'} + \epsilon_{it'} \quad \text{(B.5)}$$

where Γ_i^{TH} is the simulated capacity factor of unit i (see above) and $\lambda_{t'}$ are year fixed effects. Table B.5 reports the obtained results. We estimate a depletion rate of -1% per year and a technological learning rate of 1% per year. Our estimates are in line with other values found in the literature. For example, De Groote and Verboven (2019) assume a yearly depletion rate of 1%, Borenstein (2017) a rate of 0.5% and Feger et al. (2022) set the depletion rate to 3% for the first year and to 0.7%/year for later years. Regarding technological learning, the literature review by Allouhi et al. (2022) suggests a rate of 0.5% per year.

Table B.5: Regression results

	Capacity factor (logarithm)		
	(1)	(2)	(3)
$t - 2005$	0.011***	0.011***	0.008***
	(0.001)	(0.001)	(0.001)
$t' - t$	-0.011***	-0.012***	-0.012***
	(0.0004)	(0.0005)	(0.0005)
$\ln(\Gamma^{TH})$			0.645***
			(0.009)
Constant	-1.986***	-1.988***	-0.753***
	(0.006)	(0.007)	(0.018)
Fixed effects (Year)	No	Yes	Yes
Observations	97,554	97,554	92,412
R^2	0.048	0.051	0.106

*p<0.1; **p<0.05; ***p<0.01

Note: This table displays the results of the regression of the logarithm of capacity factors on (i) the commissioning year and (ii) the number of years since commissioning. Three specifications are reported. Column (1) does not introduce additional controls; column (2) controls for year of production fixed effects, column (3) controls for year of production fixed effects and the logarithm of simulated capacity factors, denoted by Γ^{TH}.

B.4 Details on the Public Inventory of Installations

This Appendix details the two steps implemented to build our final inventory of PV installations. First, we retrieve the installed capacities of small installations (<36 kW) over time by combining the list of larger installations (>36 kW) and the annual time-series of PV installations aggregated at the department level. Second, large units (>500 kW) are labeled to be either ground-mounted or rooftop projects.

B.4.1 Building Residential PV Time-series at the Departement Level

For most small PV units (< 36 kW), that is, residential PV, the public inventory of power plants only reports a cross-sectional view of their installed capacity. We thus use other data sources to construct annual time series for the evolution of residential capacity between 2005 and 2021. More specifically, we compute annual time series of residential PV capacity aggregated at the "departement" level, which is sufficient for our analysis.[9]

We compute these departement level time series of residential PV capacity as follows. First, for 2005 to 2016, we use a dataset from the French Department of Energy (DOE) that provides yearly panel data of total installed capacities at the departement level.[10] Because we observe their commissioning dates in the public inventory, we first build departement-level time series of non-residential installations. We then subtract these time series to the time series of total installed capacity, which leaves us with residential PV installations. Second, from 2017 onwards, we use the total capacities of residential PV, as directly reported in the inventory of the corresponding year.[11] Figures B.4.11 and B.4.12 show the obtained results for each departement. Overall, the two sources agree very well as we do not observe significant discrepancies in values between the years 2016 and 2017. As shown in Figures B.4.11 and B.4.12, we constrain time series to be weakly increasing.

[9] Given our methodology, coarser levels of spatial aggregation actually works against finding large amounts of misallocation, which strengthen the conservative nature of our estimates.

[10] https://www.statistiques.developpement-durable.gouv.fr/tableau-de-bord-solaire-photovoltaique-quatrieme-trimestre-2021. Our data consist of the publications released in the last quarter of each year.

[11] The first public inventory of power plants was released in 2017. We collect public inventories from 2017 to 2021, selecting the versions updated in December 31st of each respective year.

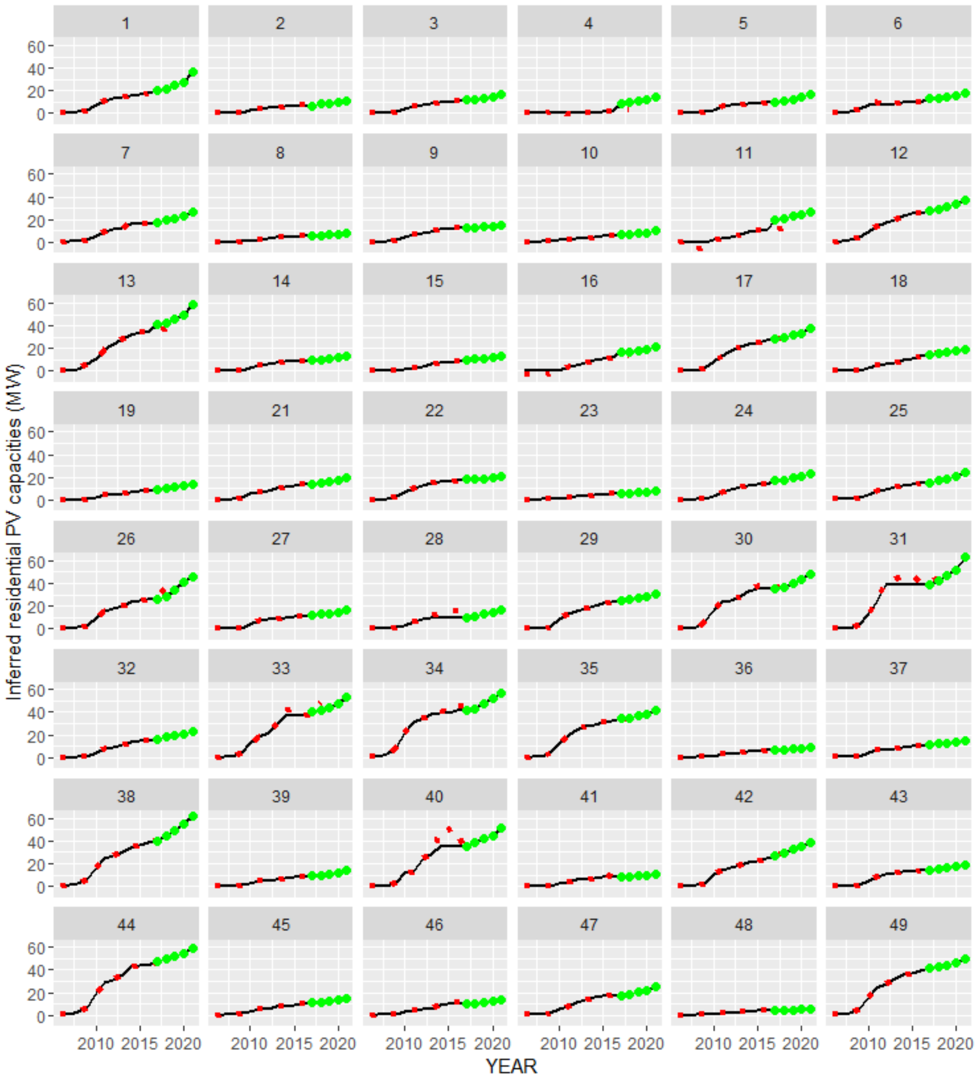


Figure B.4.11: Inferred departements level time series of PV capacity from aggregated units (first 49 departements). Green dots represent capacities as reported in solar plants inventories for 2017, 2018, 2019, 2020, 2021. Red dots are capacities obtained from the French Department of Energy (DOE) dataset.

Note: Green dots represent capacities as reported in solar plants inventories for 2017, 2018, 2019, 2020, 2021. Red dots are capacities deduced from the French Department of Energy (DOE) dataset.

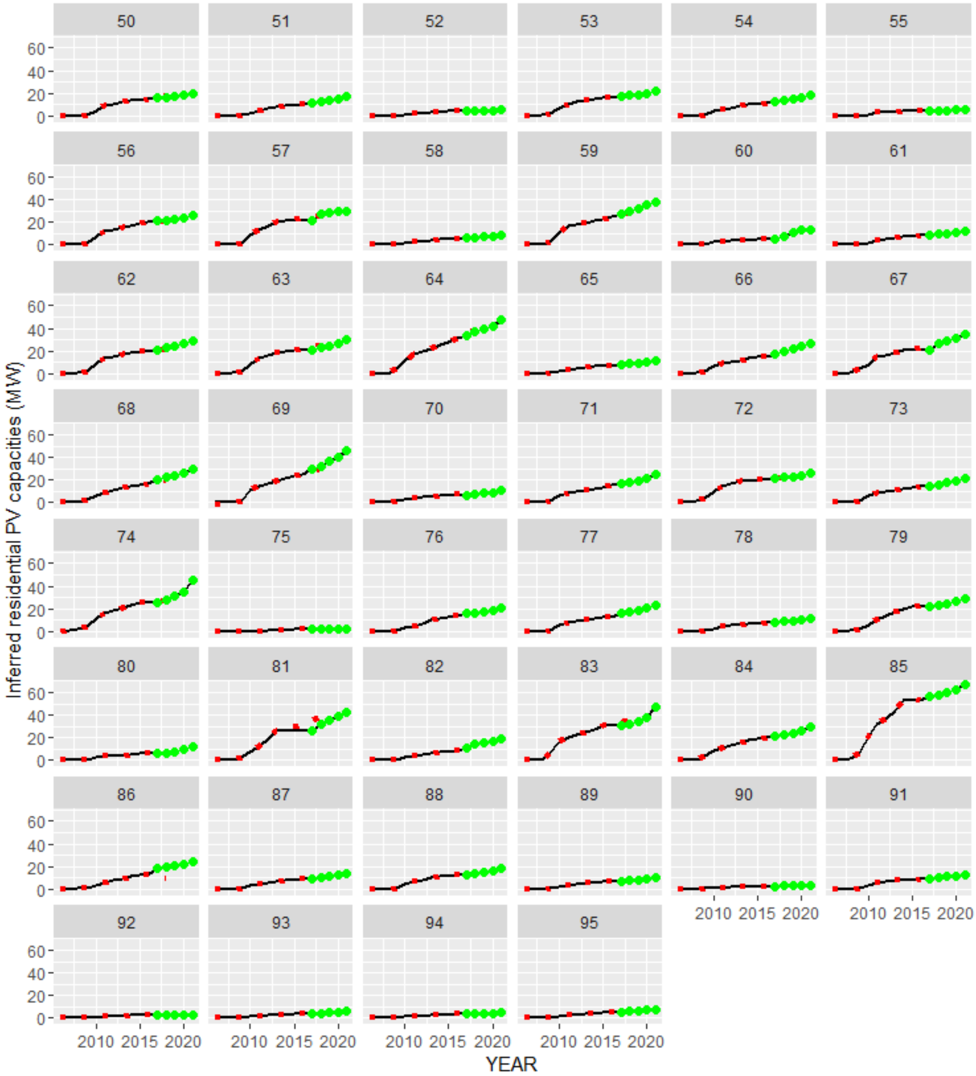


Figure B.4.12: Inferred departements level time series of PV capacity from aggregated units (last 45 departements).
Note: Green dots represent capacities as reported in solar plants inventories for 2017, 2018, 2019, 2020, 2021. Red dots are capacities deduced from the French Department of Energy (DOE) dataset.

B.4.2 Assigning Technologies to Large Individual Installations

The public inventory of power plants does not specify if a given unit is ground-mounted or rooftop. Four strategies are implemented to assign PV facilities to either rooftop or ground-mounted types, as detailed in the paragraphs below.

Dictionary of Keywords in Installations' Names

The first strategy we use to identify project types is to match installation names with a dictionary. We use the following key words:

- Words specific to rooftop installations: PARKING; PKG; OMBRIERE; TOITURE; SCI; TERREAL; DESORGUES

- Words specific to buildings: SERRE; LOGISTIQUE; TECHNOPOL; LA POSTE; CENTRE COMMERCIAL; CENTRE; SAINT CHARLES; UNIVERSITE; ENTREPOT; STATION; HIPPODROME ;STADE; RESERVOIR; ARENA; OMNISPORT ;LYCEE; ETABLISSEMENT; CASERNE; HANGAR; USINE ;ZAC; SIEGE SOCIAL; BATIMENT; BAT; AEROPORT; STADE; STADIUM; CINEMA; SUPERMARCHE

- Words specific to large retailers and firms: CASINO; AUCHAN; GEANT; SANOFI; GIFI; SISLEY; IKEA; UBISOFT; LEROY MERLIN; RENAULT; LECLERC; CARREFOUR; SUPER U; SYSTEME U; HYPER U

- Words specific to ground-mounted installations: FERME SOLAIRE; CENTRALE; PARC SOLAIRE; CHAMP; AU SOL

- Known project names for ground-mounted projects: GABOTS; LAVANSOL; SOLAIREISTRES; ENFINITY; KRONOSOL; PLAINES; QUINCIEUX; TSAOS4.7; SALAUNES; MEES

This strategy allows us to assign more than 800 units to rooftop types and about 50 units to ground-mounted types.

Size Thresholds

The second strategy is to define size thresholds for each type by using eligibility rules of support mechanisms and stylized facts. From support mechanisms' rules we are able to define three thresholds:

- There are no ground-mounted PV under 500 kW. Indeed, CRE auctions are only for projects larger than 500 kW.
- Solar energy auctions before 2016 set a maximum size for rooftop projects at 4.5 MW. We therefore assume that all units above 4.5 MW and installed between 2012 and 2017 (using one year construction lag) are ground-mounted.
- Auctions after 2016 have extended the size limit for rooftop PV to 8 MW. After 2017, only units larger than 8 MW are therefore automatically assigned to being ground-mounted.

This strategy allows us to assign about 40,000 additional units to rooftop types and about 400 units to ground-mounted types.

Auction Winners

In the third strategy, we retrieve the list of winners from ground-mounted specific auctions and match the candidates names to the installations names in the inventory. This method only identifies about 30 additional ground-mounted installations.

OpenStreetMap Facilities

In the fourth strategy, we combine the list of solar units in the inventory with the list of solar installations that are reported in OpenStreetMap (OSM). OSM is an open-source database that stores geographic objects worldwide, including PV installations. OSM reports more than 1,300 PV installations that are located in mainland France.[12] As OSM focuses on spatial objects with significant land footprints, the majority of PV installations identified in

[12] Obtained from OpenStreetMap's API: `https://overpass-turbo.eu/`, specifying objects with label "solar" in the "plant" category and within France geographic boundaries.

the database are ground-mounted facilities. Rooftop installations listed in OSM are explicitly associated with the specific buildings on which they are installed (e.g. factory, warehouse, stores). After being assigned to either rooftop or ground-mounted types, the OSM dataset is matched to the public inventory of solar plants using either (i) ERC codes, a unique identifier for PV installations, or (ii) projects' installed capacity and location. This allow us to match about 400 additional units to rooftop and ground-mounted types.

Finally, we proceed in two steps to attribute project types for the 1,300 remaining units with unknown types:

- Units lower than 1 MW are assigned to rooftop types until the total installed capacity of rooftop facilities within the range of 0.25 and 1 MW that is observed in mainland France is reached (France Territoire Solaire, 2023). Remaining observations lower than 1 MW are then assigned to ground-mounted PV.

- Units larger than 1 MW are randomly assigned based on the observed distribution of project types within specific size categories. For example, among units of sizes ranging between 2 and 3 MW, there are only 10% of rooftop facilities among the observations that are already assigned to a category. We thus randomly assign 10% of the unknowns within the range of 2 and 3 MW to the rooftop type and the remaining observations to ground-mounted.

At the end of our assignment procedure, we have 1,700+ ground-mounted and 44,000+ rooftop solar units.

B.5 Special Case of Static LCOEs

In this Appendix, we solve the simplified case where there is neither technological progress nor wear and tear of installations:

$$\forall i, t,\ c_{it} = c_i \text{ and } \forall i, t, t',\ e_{itt'} = e_i$$

The optimization program then simplifies to:

$$\min_{x_{it}} \sum_{i=1}^{N} c_i \left(\sum_{t=1}^{T} \rho^t x_{it} \right)$$

$$\text{s.t.}$$

$$\begin{array}{lccc}
\forall t \in \{1, ..., T\}, & \displaystyle\sum_{i=1}^{N} e_i \left(\sum_{t'=1}^{t} x_{it'} \right) \geq E_t & (\rho^t \lambda_t) \\
\forall i \in \{1, ..., N\}, & \displaystyle\sum_{t=1}^{T} x_{it} \leq 1 & (\bar{\mu}_i) \\
\forall i \in \{1, ..., N\}, \forall t \in \{1, ..., T\}, & x_{it} \geq 0 & (\rho^t \underline{\mu}_{it})
\end{array}$$

One can then write the Lagrangian as:

$$\begin{aligned}
\mathcal{L}(x_{it}, \lambda_t, \bar{\mu}_i, \underline{\mu}_{it}) = \quad & \sum_{i=1}^{N} c_i \left(\sum_{t=1}^{T} \rho^t x_{it} \right) \\
& + \sum_{t=1}^{T} \rho^t \lambda_t \left(E_t - \sum_{i=1}^{N} e_i \left(\sum_{t'=1}^{t} x_{it'} \right) \right) \\
& + \sum_{i=1}^{N} \bar{\mu}_i \left(\sum_{t=1}^{T} x_{it} - 1 \right) \\
& - \sum_{i=1}^{N} \sum_{t=1}^{T} \rho^t \underline{\mu}_{it} x_{it}
\end{aligned}$$

Besides the complementary slackness conditions, we get (taking derivative w.r.t. x_{it}) the following first-order conditions:

$$\text{For all } i,\ t: \qquad \rho^t c_i - e_i \sum_{t'=t}^{T} \rho^{t'} \lambda_{t'} + \bar{\mu}_i = \rho^t \underline{\mu}_{it}$$

On the right hand-side of the equation, the multiplier $\underline{\mu}_{it}$ is non-negative and equals 0 if, and only if, $x_{it} > 0$, that is if unit i is (at least partly) commissioned in year t. If we denote $t^*(i)$ the year at which plant i is optimally commissioned, we thus have:

$$\forall t, \qquad \rho^{t^*(i)} c_i - e_i \sum_{t'=t^*(i)}^{T} \rho^{t'} \lambda_{t'} \leq \rho^t c_i - e_i \sum_{t'=t}^{T} \rho^{t'} \lambda_{t'}$$

In other words:

$$t^*(i) = \underset{t}{\operatorname{argmin}} \left[\rho^t c_i - e_i \sum_{t'=t}^{T} \rho^{t'} \lambda_{t'} \right]$$

Which may be rewritten:

$$t^*(i) = \underset{t}{\operatorname{argmin}} \left[\rho^t L_i - \Lambda_t \right] \text{ where } L_i \equiv \frac{c_i}{e_i} \text{ and } \Lambda_t \equiv \sum_{t'=t}^{T} \rho^{t'} \lambda_{t'}$$

We then have the following Lemma:

Lemma 1 *For all* i, j, $L_i < L_j \Rightarrow t^*(i) \leq t^*(j)$

Proof.

By definition of $t^*(j)$, we have:

$$\forall t, \; \rho^{t^*(j)} L_j - \Lambda_{t^*(j)} \leq \rho^t L_j - \Lambda_t$$

Then:

$$\begin{aligned} \rho^{t^*(j)} L_i - \Lambda_{t^*(j)} &= \rho^{t^*(j)}(L_i - L_j) + \rho^{t^*(j)} L_j - \Lambda_{t^*(j)} \\ &\leq \rho^{t^*(j)}(L_i - L_j) + \rho^t L_j - \Lambda_t \\ &\leq (\rho^{t^*(j)} - \rho^t)(L_i - L_j) + \rho^t L_i - \Lambda_t \end{aligned}$$

For $t > t^*(j)$, we have $(\rho^{t^*(j)} - \rho^t) > 0$. In addition, $(L_i - L_j) < 0$. As a result:

$$\forall t > t^*(j), \; \rho^{t^*(j)} L_i - \Lambda_{t^*(j)} < \rho^t L_i - \Lambda_t$$

And thus:

$$t^*(i) = \operatorname{argmin}_t \left[\rho^t L_i - \Lambda_t \right] \leq t^*(j)$$

■

Assume, without loss of generality, that we have indexed units such that:

$$L_1 \leq L_2 \leq ... \leq L_{N-1} \leq L_N$$

From Lemma 1, and denoting $i_0 \equiv 0$ and $i_T \equiv N$, there exist indexes:

$$i_0 \leq i_1 \leq ... \leq i_{T-1} \leq i_T$$

such that units commissioning in year t have an index i such that:

$$i_{t-1} \leq i \leq i_t$$

Finally, we can pinpoint the thresholds i_1, i_2, ... , i_{T-1} using the target trajectory of annual solar generation. Specifically, the threshold index i_t in year t will be chosen so that unit i_t is the last one needed to meet the energy output target:

$$\sum_{i=1}^{i_t-1} e_i \leq E_t \leq \sum_{i=1}^{i_t} e_i$$

B.6 Extension to Heterogeneous Marginal Social Values of Solar Output

In this Appendix, we discuss how our framework could be generalized to account for heterogeneity in the social value of the electricity produced by different solar facilities.

In essence, our measure of dynamic misallocation follows a cost-efficiency approach. Indeed, given our simplifying assumption that the social value of solar electricity is uniform across space, the gross social surplus created at a given point in time is proportional to the amount of electricity produced. Therefore, the constraint that the trajectory of electricity output remains equal to the observed trajectory boils down to freezing the trajectory of gross social surplus to its observed value. Our optimization program then aims at finding the least-cost strategy to reach this target trajectory of gross social surplus.

This perspective suggests a natural way to generalize our framework to a more general setting. As in paragraph 2.2, we denote with p^*_{ih} the social value of the electricity generated by installation i in hour $h \in H_t$, which can be installation-specific. As a first-order approximation, we treat p^*_{ih} as being exogenous, an assumption that may need to be relaxed in applications where very large changes in the hourly solar output (which could in turn impact significantly equilibrium prices) occur.

We further denote with $\{f_{ih}\}_{h=1,...,H_t}$ the generation profile (normalized by energy output so that $\sum_{h \in H_t} f_{ih} = 1$) of installation i during year t. Note that we implicitly assume that this generation profile does not depend on the commissioning year of the installation (relaxing this assumption is straightforward but would require cumbersome notations).

Let the average social value $\bar{p}^*_{it}$ of the electricity produced by installation i in year t be defined as:

$$\bar{p}^*_{it} \equiv \sum_{h \in H_t} f_{ih} p^*_{ih}$$

Finally, we denote with $t_0(i)$ the observed commissioning date of installation i.

Using these notations, our optimization program can be generalized to a situation with cross-sectional heterogeneity in the value of solar electricity as follows:

$$\min_{x_{it}} \sum_{t=1}^{T} \rho^t \left(\sum_{i=1}^{N} x_{it} c_{it} \right)$$

s.t.

$$\forall t \in \{1,...,T\}, \quad \sum_{i=1}^{N} \left(\sum_{t'=1}^{t} \bar{p}^*_{it} x_{it'} e_{it't} \right) \geq \sum_{i=1}^{N} \mathbf{1}[t \geq t_0(i)] \bar{p}^*_{it} e_{it_0(i)t} \quad (\rho^t \lambda_t)$$

$$\forall i \in \{1,...,N\}, \quad \sum_{t=1}^{T} x_{it} \leq 1 \quad (\bar{\mu}_i)$$

$$\forall i \in \{1,...,N\}, \forall t \in \{1,...,T\}, \quad x_{it} \geq 0 \quad (\rho^t \underline{\mu}_{it})$$

where $\mathbf{1}[t \geq t_0(i)]$ is a dummy variable that takes the value 1 if the solar facility i has been commissioned by year t in the realized trajectory.

In words, this generalized optimization program requires that the trajectory of annual gross social surplus from solar installations is as least as large as the observed trajectory. Note in particular that, when $\bar{p}^*_{it}$ does not depend on i, it cancels out in the first set of constraints, which coincide with the constraints we use in the optimization program of the main text since:

$$E_t \equiv \sum_{i=1}^{N} \mathbf{1}[t \geq t_0(i)] e_{it_0(i)t}$$

Finally, it is worth noting that, contrary to the amount of electricity produced, gross social surplus is a metric that can be summed up (with proper discounting) in the objective function of a social planner. Therefore, the optimization program could be further generalized by collapsing the set of the first T constraint (second row of the program) into a single aggregate gross surplus target over the whole period. Because it relaxes the imposed constraints, such a program would mechanically yield larger assessments of misallocation. It could however suggest optimal trajectories of solar deployment (both in kW or kWh) that differ very significantly from the observed one, and would therefore provide more speculative conclusions is the observed trajectory embeds other relevant economic constraints (e.g. available public funds, feasible deployment rates, etc.) that are not captured in our simple framework.

Appendix C

Appendix to Chapter 3

C.1 Supplementary Figures

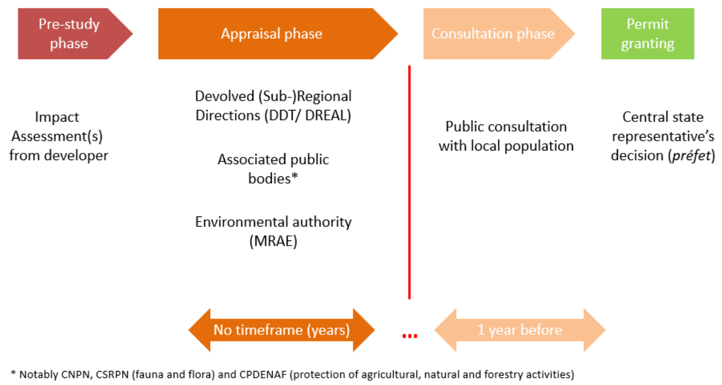


Figure C.1.1: Process for permitting ground-mounted solar PV, adapted from France Territoire Solaire (2021).

C.2 Regional maps

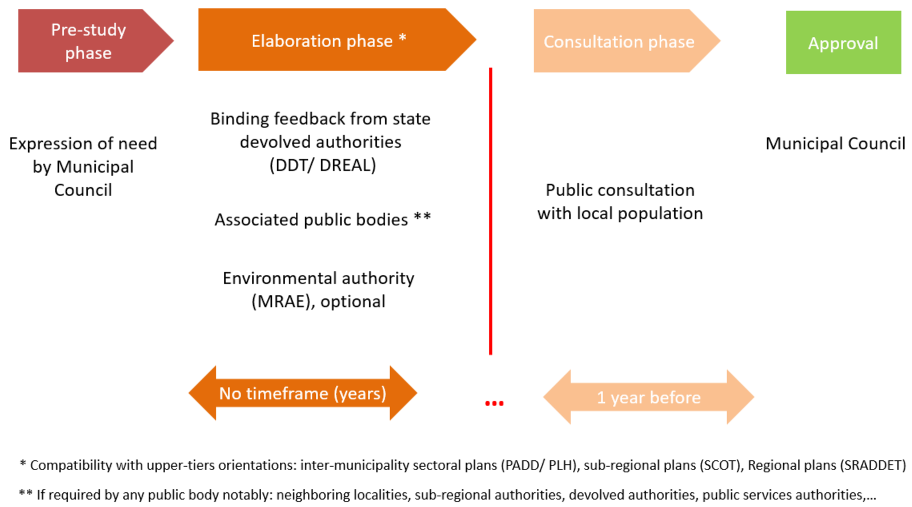


Figure C.1.2: Process for elaborating land-use planning, Code de l'Urbanisme, 2023.

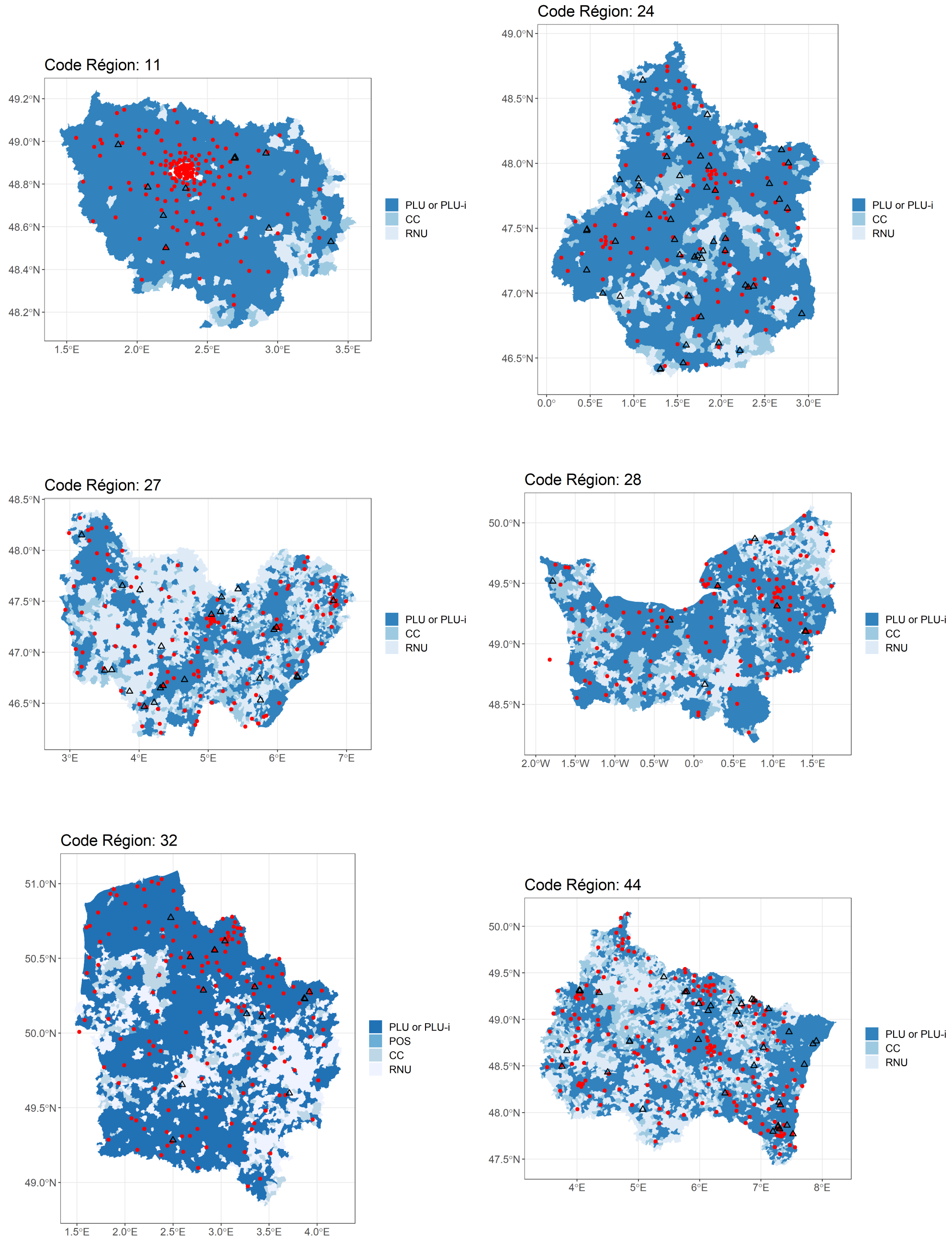


Figure C.2.3: Map of ground-mounted solar spatial distribution in the first 6 regions. Red dots are the electricity grid's substations, black triangles are ground-mounted solar installations.
Regional codes: "11" = *Ile-de-France*, "24" = *Centre-Val de Loire*, "27" = *Bourgogne-Franche-Comté*, "28" = *Normandie*, "32' = *Nord-Pas-de-Calais-Picardie*, "44" = *Grand Est.*

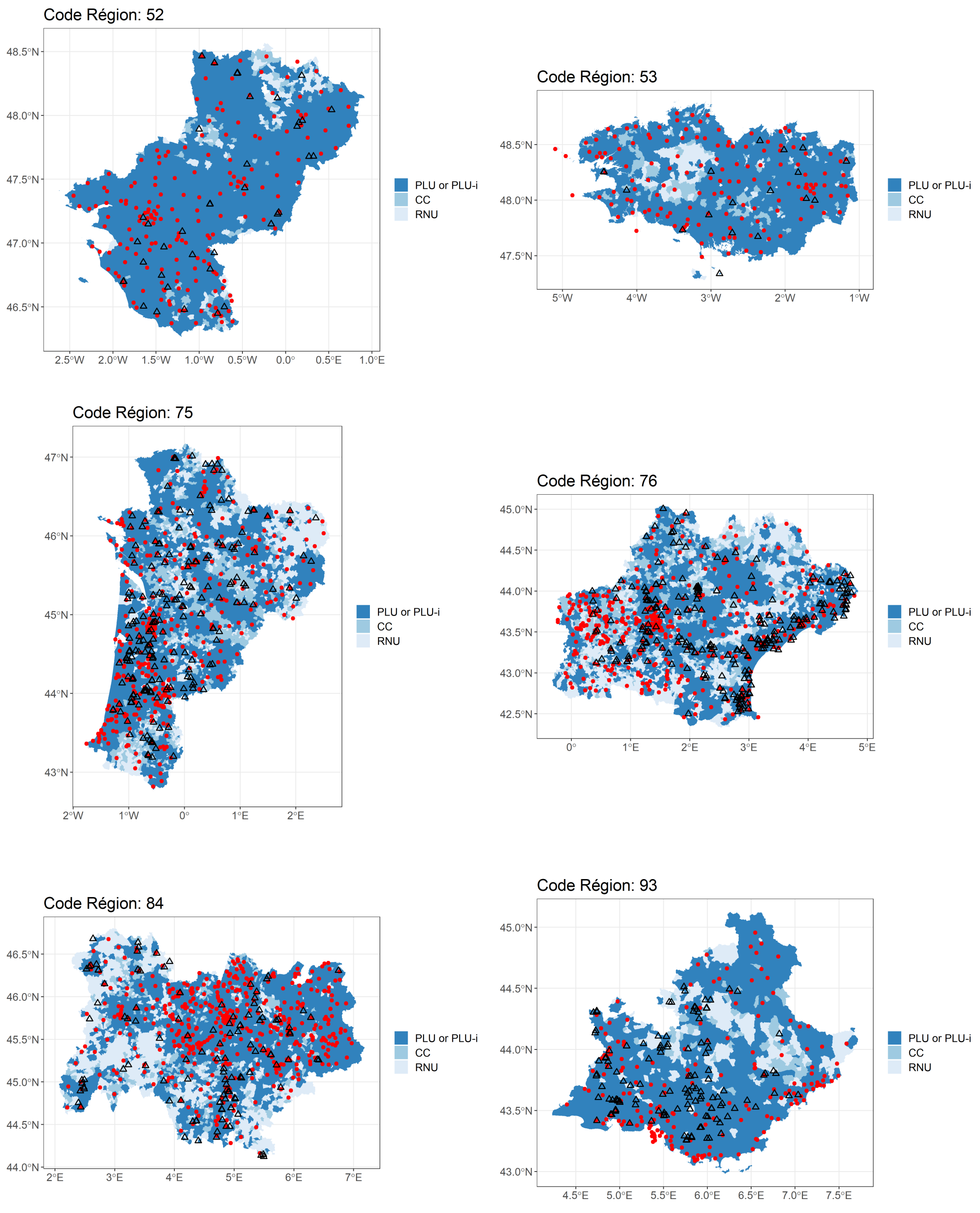


Figure C.2.4: Map of ground-mounted solar spatial distribution in the last 6 regions. Red dots are the electricity grid's substations, black triangles are ground-mounted solar installations.
Regional codes: "52" = *Pays de la Loire*, "76" = *Occitanie*, "53" = *Bretagne*, "75" = *Nouvelle Aquitaine*, "93' = *Provence-Alpes-Côte d'Azur*, "84" = *Auvergne-Rhone-Alpes*.

C.3 Descriptive statistics

Table C.1: Statistics at the regional level

Region code	Munici-palities	Ground-mounted PV (GW)	Share PLU(-i) in 2023	Share PLU(-i) in 2012	Year Approbation Q20	Year Approbation Q80
11	1,267	0.16	0.88	0.08	2012	2020
24	1,757	0.51	0.73	0.41	2010	2021
27	3,698	0.36	0.43	0.17	2008	2020
28	2,679	0.07	0.62	0.32	2010	2020
32	3,764	0.26	0.70	0.36	2011	2020
44	5,122	0.69	0.50	0.13	2007	2019
52	1,220	0.35	0.90	0.42	2011	2021
53	1,215	0.08	0.83	0.29	2009	2020
75	4,305	2.63	0.66	0.30	2009	2020
76	4,456	1.54	0.59	0.17	2008	2020
84	4,024	0.78	0.64	0.17	2009	2020
93	945	1.50	0.78	0.09	2011	2019

Notes: Shares are in terms of surface area. Year Approbation stems from the year of approval of land-use planning frameworks, where Quantiles 20 and 80 are reported.

Region codes: "11" = *Ile-de-France*, "24" = *Centre-Val de Loire*, "27" = *Bourgogne-Franche-Comté*, "28" = *Normandie*, "32' = *Nord-Pas-de-Calais-Picardie*, "44" = *Grand Est*, "52" = *Pays de la Loire*, "76" = *Occitanie*, "53" = *Bretagne*, "75" = *Nouvelle Aquitaine*, "93' = *Provence-Alpes-Côte d'Azur*, "84" = *Auvergne-Rhone-Alpes.*

C.3.1 More on socio-economic characteristics

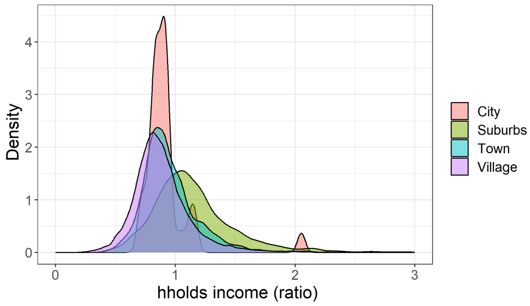


Figure C.3.5: Distribution of municipalities in function of average households income levels observed in 2019–2022.

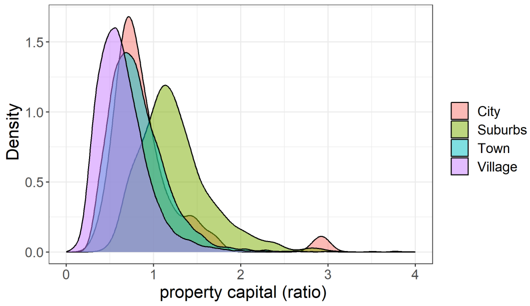


Figure C.3.6: Distribution of municipalities in function of average property value levels observed in 2019–2022.

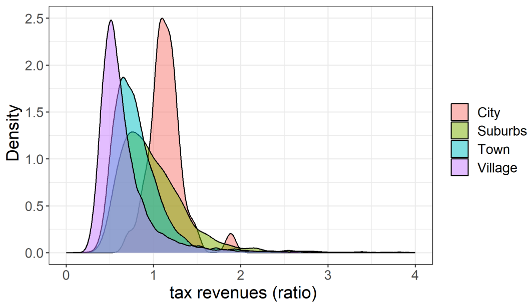


Figure C.3.7: Distribution of municipalities in function of tax revenues value levels observed in 2019–2022.

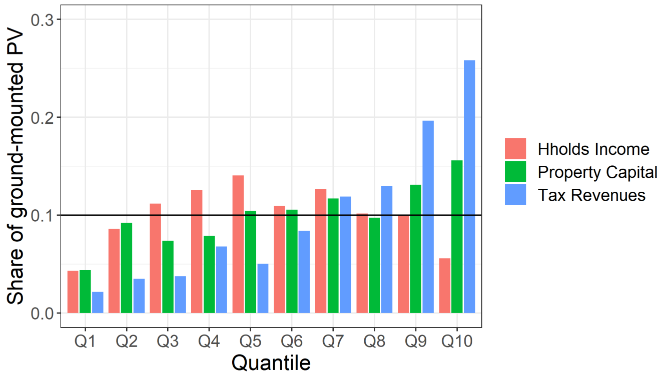


Figure C.3.8: Share of ground-mounted solar in each deciles of municipalities in function of economic variables, levels observed in 2008–2011.

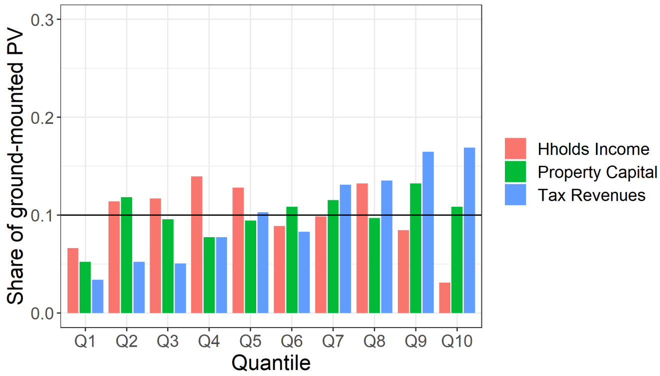


Figure C.3.9: Share of ground-mounted solar in each deciles of Villages in function of economic variables, levels observed in 2008–2011.

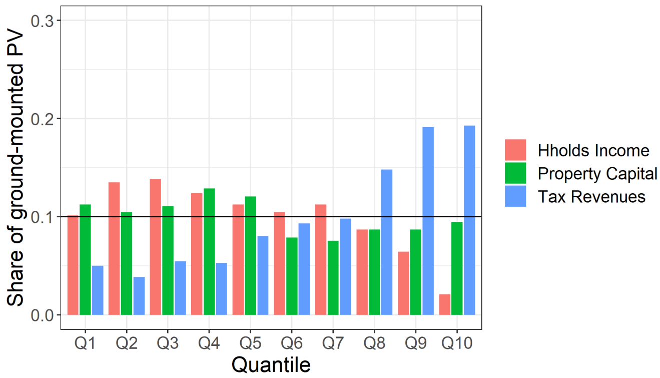


Figure C.3.10: Share of ground-mounted solar in each deciles of Towns in function of economic variables, levels observed in 2008–2011.

Table C.2: Probability of having a ground-mounted PV installation relative to socio-economic characteristics at the municipality level (logistic regression).

	Ground-mounted PV
PLU or PLU-i	0.67^{***}
	(0.133)
Income	-1.18^{***}
	(0.178)
Property	0.27^{**}
	(0.114)
Tax revenues	0.11^{***}
	(0.029)
Constant	-0.98^{**}
	(0.451)
Category Fixed Effects	Yes
Observations	33,932
Log Likelihood	−4,010.631
Akaike Inf. Crit.	8,039.262

*p<0.1; **p<0.05; ***p<0.01

Notes: Income, tax revenues and property value are expressed per capita and as a ratio to their population's mean.

C.3.2 Econometric specifications

Table C.3: Statistics for specification a), without matching

	Control	Treated
Municipalities	5,823	5,204
incl. Villages	5,800	5,105
Income		
	0.820	0.847
	(0.168)	(0.159)
	[-0.000]	[-0.000]
Tax		
	0.670	0.648
	(0.456)	(0.526)
	[0.001]	[0.001]
Property		
	0.608	0.673
	(0.266)	(0.267)
	[-0.005]	[-0.005]

Notes: Averaged levels for the period 2008–2012. Standard deviations are reported in (parenthesis) and [brackets] give annual trends, being the average change per year over the studied period (2010–2022). Income, tax revenues and property value are expressed per capita and as a ratio to their population's mean.

Table C.4: Statistics for specification b), without matching

	Control	Treated
Municipalities	2,722	4,952
incl. Villages	1,858	2,756
Income		
	0.934	0.979
	(0.229)	(0.223)
	[0.000]	[0.001]
Tax		
	0.761	0.772
	(0.658)	(0.541)
	[0.001]	[0.000]
Property		
	0.800	0.910
	(0.328)	(0.357)
	[-0.004]	[-0.004]

Notes: Averaged levels for the period 2008–2012. Standard deviations are reported in (parenthesis) and [brackets] give annual trends, being the average change per year over the studied period (2010–2022). Income, tax revenues and property value are expressed per capita and as a ratio to their population's mean.

Table C.5: Statistics for specification c), without matching

	Control	Treated
Municipalities	9,114	6,221
incl. Villages	7,992	5,190
Income		
	0.879	0.891
	(0.195)	(0.188)
	[-0.000]	[0.000]
Tax		
	0.700	0.688
	(0.511)	(0.390)
	[0.000]	[0.000]
Property		
	0.686	0.740
	(0.286)	(0.325)
	[-0.005]	[-0.005]

Notes: Averaged levels for the period 2008–2012. Standard deviations are reported in (parenthesis) and [brackets] give annual trends, being the average change per year over the studied period (2010–2022). Income, tax revenues and property value are expressed per capita and as a ratio to their population's mean.

C.4 Propensity Score Matching

Matching consists in selecting beforehand a subset of units in control and treated groups that are "most like" conditional on baseline covariates to reduce bias in the estimation. I use a *one-on-one nearest neighbor matching* approach to balance my treatment and control groups. [1] The approach estimates the propensity score of being treated conditional on baseline variables that are likely confounders in the estimation. I use the land-use distribution at the municipality level given by the Corine Land Cover dataset in the year of 2012 (see Section 1.3.4). Indeed, the type of land in a locality could influence both the upgrade of land-use planning frameworks and the suitability for ground-mounted solar installations. For example, a municipality with a majority of land identified as forestry and prairies would likely be under a less detailed framework (CC or RNU). This municipality would also have a lower potential for ground-mounted solar. Land-use categories are nested following Table C.7.

I add two additional variables depicting the share of land occupied by old, stranded and polluted sites.[2] Under current regulation, this type of land is prioritized for siting ground-mounted solar installations. Besides a municipality with such land types (e.g. old mines, landfills, stranded industrial sites) is likely to be under a detailed land-use planning framework (i.e. PLU or PLU-i). I also add the density of population, the proportion of detached houses versus apartments and the proportion of secondary residences observed at the municipality level in 2012. Finally, a dummy variable indicates if the unit is in one of the four Southern regions in metropolitan France.

I perform the matching using the *"Matchit"* package in R. A Logit is used as a link function to estimate propensity scores. Results of Logit regressions estimating the probability of being treated conditionally to the three main specifications are displayed in Table C.6 . The fifth column of Table C.6 shows a similar regression when studying the presence of ground-mounted solar installations instead.

[1] I match all units of the smallest group to their closest counterparts in the largest group.

[2] This data is taken from national registries BASOL and BASIAS, more details in Section 1.3.4

Table C.6: Logit regression for the three specifications and ground-mounted PV

	(a)	(c)	(b)	(PV)
Basias	152.223*	15.130	−3.009	22.844***
	(89.940)	(10.854)	(5.699)	(8.279)
Basol	−8.246	3.683	−2.853*	1.227
	(9.653)	(2.363)	(1.489)	(2.490)
CLC_111	242.010	3.871**	0.525	4.123*
	(654.693)	(1.637)	(1.189)	(2.496)
CLC_112	−2.295	1.986***	0.692	−2.483***
	(1.413)	(0.694)	(0.497)	(0.918)
CLC_121	13.505***	1.405	0.640	5.329***
	(4.355)	(0.888)	(0.647)	(1.084)
CLC_123	5.273*	1.208	−0.281	0.869
	(2.709)	(1.191)	(0.942)	(1.472)
CLC_13	6.595**	5.712***	0.710	9.816***
	(3.253)	(1.900)	(1.387)	(1.862)
CLC_14	4.979	0.543	−0.106	1.554
	(3.853)	(1.284)	(0.902)	(1.730)
CLC_21	1.658	1.256**	−0.613	−2.427***
	(1.104)	(0.632)	(0.459)	(0.765)
CLC_22	1.453	−0.133	0.805*	−1.366*
	(1.136)	(0.670)	(0.481)	(0.789)
CLC_24	0.640	0.502	−0.133	−2.410***
	(1.104)	(0.634)	(0.460)	(0.766)
CLC_31	1.027	1.023	−0.540	−2.476***
	(1.107)	(0.637)	(0.462)	(0.767)
CLC_32	1.389	1.188*	0.545	−0.170
	(1.120)	(0.659)	(0.485)	(0.785)
I(Region)	0.274***	0.039	0.025	1.613***
	(0.046)	(0.040)	(0.036)	(0.085)
Pop. density	0.695***	−0.163***	−0.002	−0.672***
	(0.066)	(0.033)	(0.026)	(0.120)
Houses	−0.065	−0.493***	−0.379***	−2.207***
	(0.350)	(0.183)	(0.134)	(0.267)
2ndary	0.035	−0.447***	−0.652***	−4.064***
	(0.187)	(0.145)	(0.138)	(0.334)
Observations	11,027	15,333	17,719	34,452
Log Likelihood	−7,398.281	−10,233.880	−11,836.460	−3,854.915

*p<0.1; **p<0.05; ***p<0.01

Notes: Only significant variables are displayed

Table C.7: Nested categories taken from Corine Land Cover (2012)

Nested category	Description	Corine Land Cover
CLC_111	Urban environment (continuous)	CLC_111
CLC_112	Urban environment (discontinuous)	CLC_112
CLC_121	Enterprises zone	CLC_121
CLC_122	Transportation infrastructures	CLC_122
CLC_123	Ports and airports	CLC_123
CLC_13	Landfills, mines, worksites	CLC_131 to 133
CLC_14	Green spaces (urban)	CLC_141 to 142
CLC_21	Agricultural fields	CLC_211 to 213
CLC_22	Vegetables farming	CLC_221 to 223
CLC_24	Agricultural others	CLC_231 to 244
CLC_31	Forests	CLC_311 to 313
CLC_32	Prairies	CLC_321 to 333
CLC_335	Glaciers	CLC_335
CLC_334	Fire zones	CLC_334
CLC_4	Humid land	CLC_411 to 423
CLC_5	Coastal land	CLC_511 to 523

Matching caliper. In the main estimation, my matching strategy is only used to balance control and treatment groups. I do not impose further restriction on the closeness of the matched pairs. I do so to ensure that my groups are large enough and increase the chances of observing ground-mounted PV installations in the final sample. However, some treated units might have been compared to more distant controlled units in terms of the baseline covariates. I thus face a tradeoff between sample sizes and the common support assumption.

I test the robustness of my results to having a matching caliper, being the maximum difference in propensity scores that is allowed to define a pair. Any pair with a score under that threshold is discarded from the final sample. I choose a caliper of 0.2, which is approximately the standard deviation of propensity scores across my specifications.

Figures C.4.11 below display the estimates obtained in each specification when using a caliper. Overall, results remain unchanged. Nonetheless, magnitudes of obtained estimates in specification a) are decreased to -5 kW per m^2.

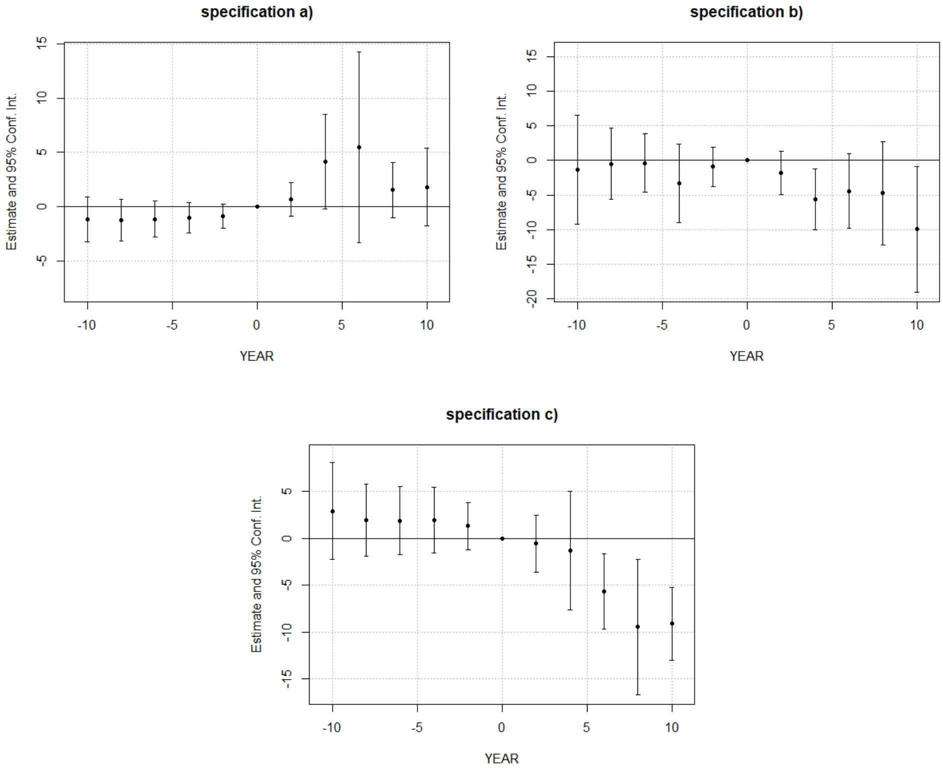


Figure C.4.11: Regression estimates with a matching caliper of 0.2.

C.5 Table of estimates

General notes on the table: The following table of estimates correspond to the specifications a) to c) in the empirical setting. By concern of readability, I have dropped some variables that were not significant.

Table C.8: Table of estimates for the main results' specifications

	Ground-mounted PV (density)		
Model:	(a)	(b)	(c)
YEAR = -8	-0.996	-1.08	0.812
	(1.03)	(2.62)	(1.78)
YEAR = -6	-0.927	-0.565	0.733
	(0.895)	(2.13)	(1.57)
YEAR = -4	-0.808	-3.41	0.961
	(0.793)	(2.84)	(1.44)
YEAR = -2	-0.802	-0.944	0.477
	(0.655)	(1.43)	(1.03)
YEAR = 2	1.70	-1.77	-0.085
	(1.26)	(1.57)	(1.39)
YEAR = 4	8.80*	-5.42**	-1.48
	(4.77)	(2.21)	(2.44)
YEAR = 6	20.0	-4.34	-5.29***
	(13.2)	(2.70)	(1.79)
YEAR = 8	4.65*	-4.46	-8.02***
	(2.51)	(3.72)	(2.93)
YEAR = 10	4.65	-9.58**	-8.80***
	(3.78)	(4.52)	(1.98)
Fixed Effects	Yes	Yes	Yes
Observations	145,292	76,188	169,862
R^2	0.32152	0.64907	0.35484
Within R^2	0.00238	0.00187	0.00011

Clustered (Municipality) standard-errors in parentheses
*Signif. Codes: ***: 0.01, **: 0.05, *: 0.1*

C.6 Plots of estimates for rooftop PV installations

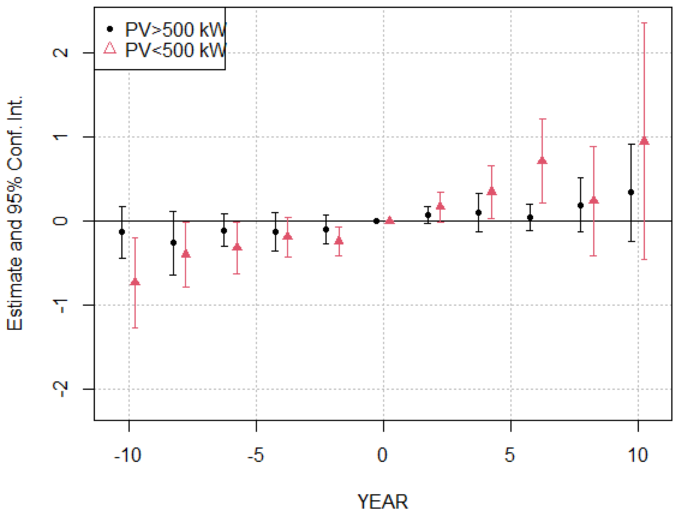


Figure C.6.12: Plot of the estimates for specification a), after matching

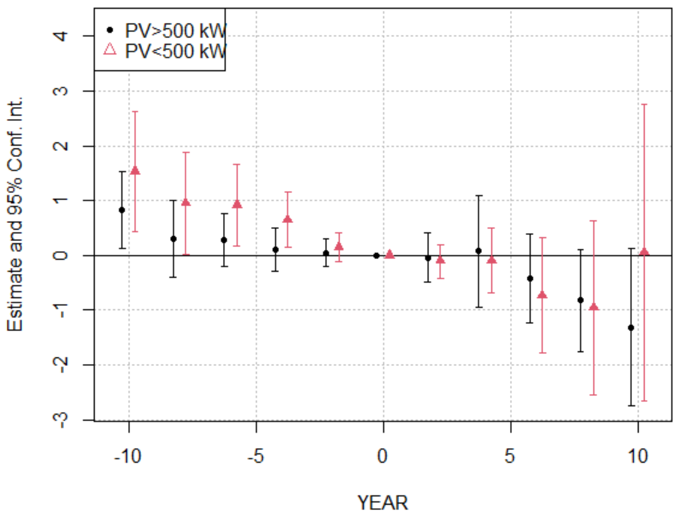


Figure C.6.13: Plot of the estimates for specification b), after matching

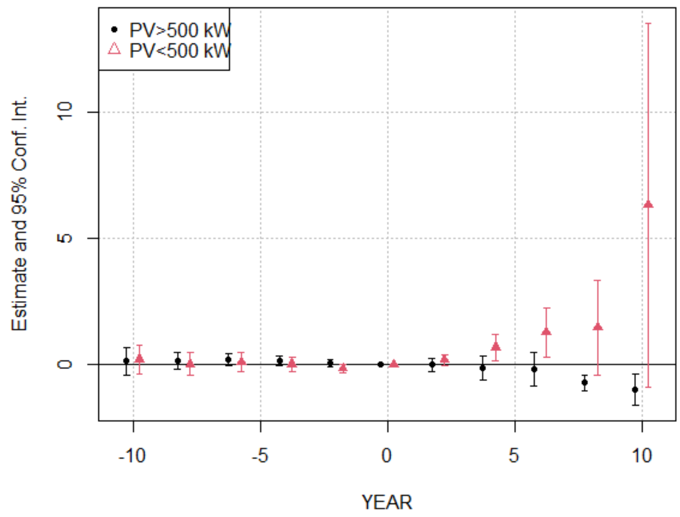


Figure C.6.14: Plot of the estimates for specification c), after matching

C.7 Spatial dependence: Moran's plot

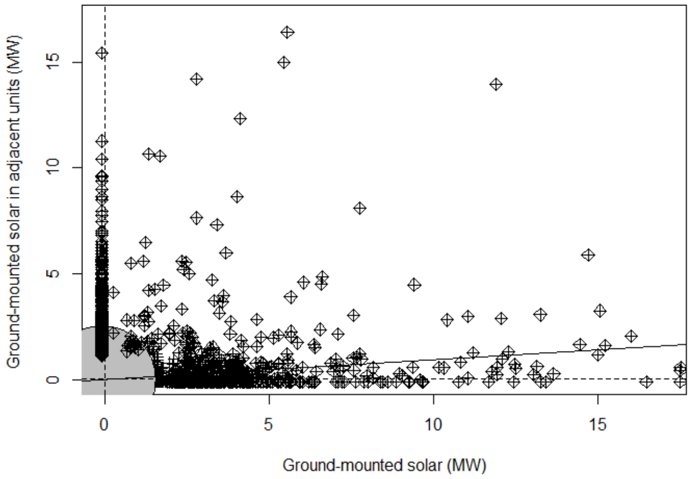


Figure C.7.15: Plot of ground-mounted solar capacity against ground-mounted solar capacity installed in the adjacent municipalities. Both variables are de-meaned. Statically significant Moran's Index of 0.1 (p-value $<2e^{-16}$)

C.8 Robustness checks

C.8.1 Placebo tests

These tests are realized on specifications a) to c). I estimate the effect of having a fake treatment seven years before the actual one after only selecting municipalities that are treated during the last five years of my time window. The last 5 years of the dataset are consistently deleted to only focus on the period before the treatment. Figure C.8.16 below displays the obtained coefficient for the three specifications. All estimates are not statistically different from zero, which rules-out the possibility of having pre-trends in my setting.

C.8.2 Time-varying covariates

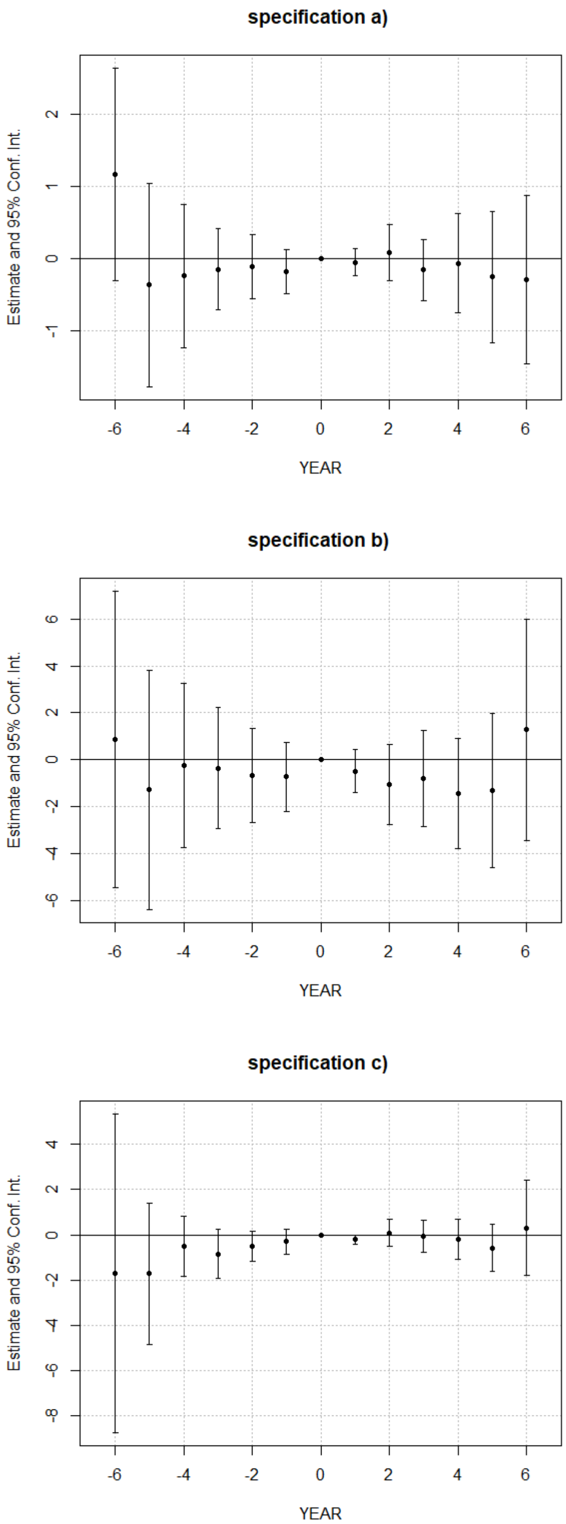


Figure C.8.16: Estimates and 95% intervals for placebo tests on specifications a) to c).

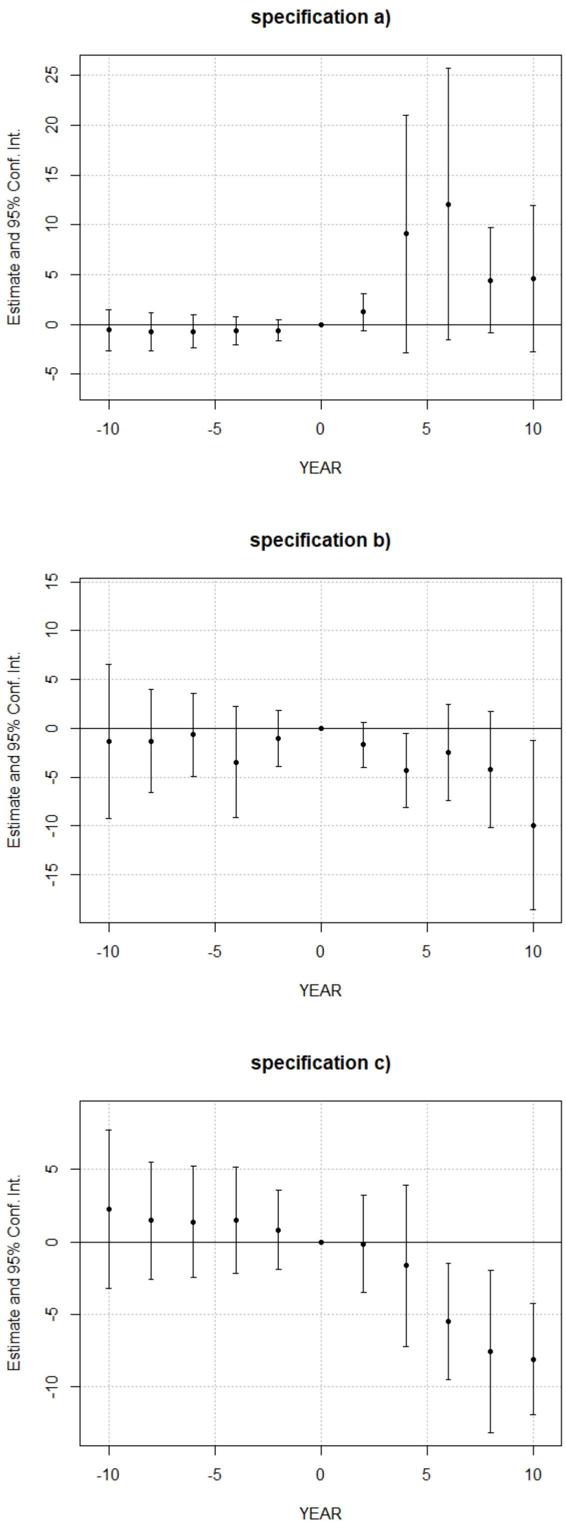


Figure C.8.17: Estimates and 95% intervals when adding lagged time-varying covariates for specifications: a) to c).

C.8.3 Effect on time-varying economic trends

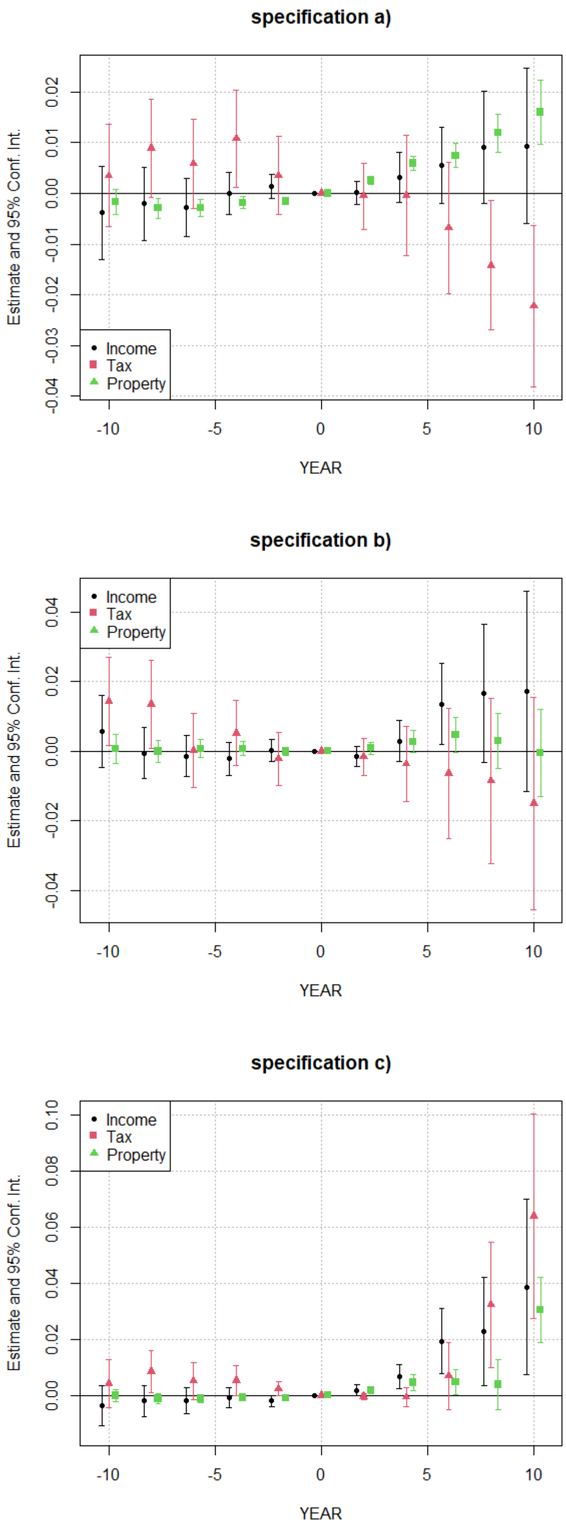


Figure C.8.18: Estimates and 95% intervals from staggered difference-in-differences for the impact of land-use planning upgrades on lagged time-varying covariates for specifications a) to c)

C.8.4 Treated-on-treated spillovers

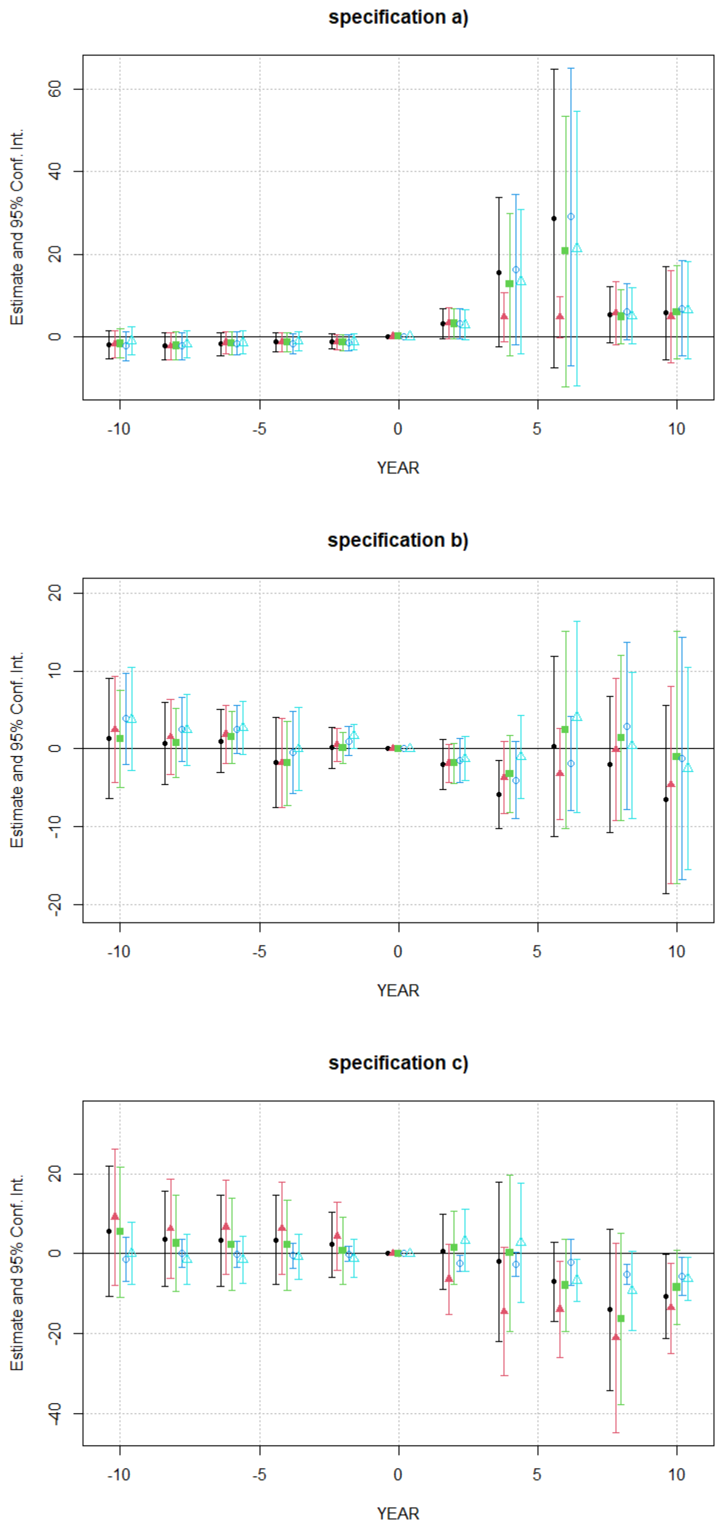


Figure C.8.19: Estimates when removing municipalities adjacent to treated units in the treatment group, Random shuffling of treated units in 5 iterations.