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The Economic Cost of Carbon Abatement with Renewable Energy Policies

By Jan Abrell, Mirjam Kosch, and Sebastian Rausch*

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This paper exploits the randomness and exogeneity of weather conditions to identify the economic cost of decarbonization through renewable energy (RE) support policies. We find that both the aggregate cost and the distribution of cost between energy producers and consumers vary significantly depending on which type of RE technology is promoted—reflecting substantial heterogeneity in production cost, temporal availability of natural resources, and market conditions (i.e., time-varying demand, carbon intensity of installed production capacities, and opportunities for cross-border trade). We estimate that the cost for reducing one ton of CO_2 emissions through subsidies for solar are €500–1870. Subsidizing wind entails significantly lower cost, which can even be slightly negative, ranging from €-5–230. While the economic rents for energy producers always decrease, consumers incur three to five times larger costs when solar is promoted but gain under RE policies promoting wind. (JEL Q28, Q48, Q54, L94, C01)

Public policies aimed at promoting energy supply from renewable resources have become a major means towards mitigating climate change by lowering the reliance on fossil fuels and carbon dioxide (CO_2) emissions. Renewable energy support (RES) policies have overwhelmingly concentrated on incentivizing energy supply from wind and solar resources, having led to a recent surge in investments in the production capacities for harvesting these renewable natural resources.[1] Also, these policies are highly likely to continue to be a main pillar of climate policy in the future. To design RES policies in an efficient, environmentally effective,

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[1]As of 2016, about 110 jurisdictions worldwide—at the national or sub-national level—had enacted feed-in policies for wind and solar power, making this the most widely adopted regulatory mechanism to promote renewable power (REN, 2016). In the United States, the federal government provides sizable production and investment tax credits for renewables and more than half of the states have adopted renewable portfolio standards mandating minimum levels of renewable generation (U.S. Department of Energy, 2016). The Renewable Energy Directive by the European Commission (2010) established an overall policy for the production and promotion of energy from renewable sources in the EU requiring to fulfil at least 20 % of its total energy needs with renewables by 2020; a new regionally binding target seeks to increase this share to 27 % by 2030. In implementing these goals, many of the EU countries have heavily relied on feed-in tariffs and tendering mechanisms for electricity generated from wind and solar power.

and socially equitable manner, it is critical to understand the market impacts of policy-induced increases in renewable energy (RE) supply.

The increase of RE supply generally has two effects on electricity markets. First, it replaces conventional by RE generation, which we refer to as the *replacement effect*. If fossil fuel technologies are replaced, this leads to lower CO_2 emissions in power generation. Second, as generators with high marginal cost are pushed out of the market, the wholesale electricity price decreases, which we refer to as the *price effect*. This unambiguously lowers profits (i.e., capacity rents) for energy producers that use conventional energy technologies. Consumers, however, may gain or lose overall because they benefit from lower energy prices but also face higher costs to the extent that RE subsidies are re-financed through taxes on electricity demand.

While the theoretical mechanisms for the impacts of RES policies on electricity markets are well understood, an empirical analysis is needed to shed light on the following questions that are central to public policy-making in the domain of carbon mitigation and climate change: Which fossil fuels and how much are replaced if RE supply from wind and solar resources increases? What are the impacts on CO_2 emissions? What are the economic costs of reducing CO_2 emissions through promoting energy supply from RE sources? And how are these costs distributed among energy producers and consumers? Despite the fundamental importance of these questions for designing public interventions to reduce fossil fuel use, surprisingly little is known about the market impacts of RE support schemes in terms of an *ex-post* policy assessment.[2]

This paper develops an empirical quantitative framework to quantify the cost of carbon abatement through RES policies for wind and solar.[3] Besides estimating aggregate cost, we also focus on the incidence of cost between energy producers and consumers. To identify the impacts of RES policies, we exploit the randomness and exogeneity of weather conditions that drive the hourly variation in electricity generated from wind turbines and solar panels. Focusing on Germany and Spain—the two countries having adopted some of the worldwide most aggressive support schemes for wind and solar energy—enables us to exploit the quasi-experimental variation in RE supply for markets in which wind and solar energy make up sizeable shares of total energy supply.[4] We use a structural economic equilibrium model of (short-run) electricity supply to derive our econometric specifications and to define consistent welfare metrics which can be used to measure the economic costs of CO_2

[2]In comparison, ex-ante assessments of RES policies are relatively abundant in the economic literature. Methodologically, they typically rely on counterfactual analysis using numerical economic simulation models. These structural models, while being useful for examining future policies, are of limited value in terms of an ex-post assessment as they often rely on a rather parsimonious empirical foundation. See, for example, Weigt, Ellerman and Delarue (2012), Rausch and Mowers (2014), Goulder, Hafstead and Williams III (2016) as well as a number of related papers which emerged from multi-model comparison studies under the framework of the Stanford Energy Modeling Forum (EMF) for the US (Fawcett, Clarke and Weyant, 2014) and the European context (Weyant et al., 2013).

[3]We focus only on the carbon abatement effects of RES policies. Other common rationales for promoting RE, which focus more on medium- to long-term impacts, include fostering innovation, learning-by-doing, and local employment associated with using new RE technologies.

[4]In our sample, the average market share of electricity generation for wind and solar power in Germany over the 2011-2015 period was 10.5 and 5.3 % , respectively. For the Spanish market, the respective average values for the 2014-2015 period are 19.4 and 4.9 % , respectively.

abatement through RES policies.[5]

Our main findings are as follows. First, we find that there are substantial differences in the carbon abatement cost for RES policies depending on the type of targeted RE source. The implicit abatement cost for feed-in tariffs for solar range from 500–1300 and 960–1870 € per ton abated CO_2 for the German and Spanish market, respectively—depending on assumptions of the foreign carbon offset. We find considerably lower implicit cost for subsidizing wind energy. With 110–230 € per ton of CO_2, the abatement costs for wind subsidies in the German market are about five times smaller relative to those for solar. These estimates are, however, highly dependent on market conditions. In Spain, we find that subsidizing wind energy entails CO_2 abatement costs which are slightly below zero (-5 to -7 € per ton of CO_2). The reason is that in the Spanish market the average revenue per MWh of wind sold to the market exceeds the subsidies paid per MWh of energy generated from wind.

Second, we find that the RES policies, depending on which type of RE source is promoted, lead to quite different distributional effects for producers and consumers. Producer rents are always impacted negatively but the magnitude differs depending on whether solar or wind energy is pushed into the market. Losses for producers are larger for a policy which supports solar energy as an increased in-feed of solar reduces high peak prices during times when electricity demand is high. In contrast, subsidizing wind energy leads to smaller losses as the availability of wind exhibits a smaller correlation with demand. For consumers, the change in surplus varies in sign depending on the type of RE: it is positive for wind and negative for solar. The difference is mainly due to the refinancing tax for RE subsidies levied on electricity demand which is higher in the case of solar—reflecting the fact that, given higher production costs for solar, a more stringent policy support is needed to incentivize profitable production. Under a policy targeting the promotion of wind energy, consumers are better off and even experience an increase in consumer surplus. Consumers gain as the decrease in energy prices more than offsets the higher cost due to the refinancing tax. Comparing the relative impacts on economic rents across consumers and producers, we find that with policy support for solar, consumers bear three to five times larger costs than producers. With policy support for wind, producers incur losses whereas consumers gain.

Third, to truthfully portray the cost and incidence of carbon abatement through RES policies targeting wind or solar, we need to capture the heterogeneous market impacts of wind and solar. When assessing RES policies, our analysis reveals that the market impacts of an increased energy supply from wind and solar vary substantially depending on (i) the correlation between the (daily and seasonal) availability of the natural resource and time-varying energy demand, (ii) the composition of installed production capacities (and their CO_2 intensity), and (iii) the degree of international market integration governing opportunities for cross-border energy trade. Our analysis thus underscores the general point that a generic appraisal of

[5]We restrict our attention to CO_2 emissions abated in the electricity sector. An economy-wide analysis which would also consider the impacts on non-electricity sectors, including inter-sectoral leakage effects, is beyond the scope of this paper.

RES policies is problematic.

Our findings have important implications for policy implementation. First, cost-effective RES schemes, such as feed-in tariffs or market premiums, should be differentiated to reflect the heterogeneous environmental value (i. e., CO_2 emissions impacts) and market value (i. e., consumer and producer rents) of RE technologies. Our analysis suggests large efficiency cost for carbon abatement due to failing to appropriately differentiate feed-in tariffs between wind and solar. In particular, the differentiation of feed-in tariffs should not be based on production cost—as it is done under current policy design. For the German and Spanish markets, wind energy should have received a higher subsidy rate as compared to the observed feed-in tariff. In contrast, cost-effective carbon abatement would have required a lower subsidy rate for solar energy.[6] Second, given that the political acceptance and feasibility of RES policies depends crucially on their distributional consequences, our findings suggest that subsidies for wind energy are likely to receive more favorable support from consumers (while in both cases with subsidies for wind and solar, the problem of losses for energy producers arises). While this insight stems from analyzing the German and Spanish electricity markets, it is very likely to carry over to other markets, too, to the extent that subsidy payments for solar exceed those for wind.

This paper contributes in three important ways to the existing literature. First, to the best of our knowledge, this paper provides the first ex-post assessment of carbon abatement cost of RES policies for the European context. For the US context, Callaway, Fowlie and McCormick (2017) provide an ex-post analysis of marginal abatement costs of energy efficiency measures and RE sources using hourly emissions data and Johnson (2014) estimates the abatement costs of a renewable portfolio standard. Marcantonini and Ellerman (2014) and Marcantonini and Valero (2017) rely on counterfactual analysis using numerical simulation models to assess the cost of carbon abatement induced by RES mechanisms for Germany and Italy, respectively. Böhringer, Landis and Reanos (2017) assess distributional impacts of RE promotion in Germany using ex-ante policy analysis based on a numerical general equilibrium model. None of these studies, however, provides an ex-post assessment of the implicit abatement cost of RES policies using an econometric model.

Second, we are not aware of existing studies which provide estimates for both the price and quantity market impacts following an increase in RE supply. Kaffine, McBee and Lieskovsky (2013), Novan (2015*a*) and Cullen (2013) use hourly wind generation and emission data to calculate greenhouse gas abatement by wind penetration for several states in the US. Wheatley (2013) and Di Cosmo and Malaguzzi Valeri (2014) assess the carbon abatement induced by wind in Ireland. A growing literature analyzes the impact of RE in-feed on wholesale electricity market prices—also called merit-order effect (see, for example, Cludius et al., 2014;

[6] The point that the (temporal and spatial) heterogeneity in the market and environmental value of wind and solar power should be taken into account when designing RES policies in the electricity sector is not novel (see, for example, Fell and Linn, 2013; Wibulpolprasert, 2016; Callaway, Fowlie and McCormick, 2017).

Wuerzburg, Labandeira and Linares, 2013; Cludius et al., 2014). Importantly, estimating the price and quantity impacts of RE policies enables us to quantitatively assess both the implicit costs of carbon abatement through RES policies and how these cost are distributed between energy producers and consumers.

Third, this paper contributes to the empirical literature on assessing the heterogenous market impacts of RE supply. Intuitively, carbon abatement (and its economic cost) depend on the carbon intensity of generation that is replaced which, in turn, depends on a number of factors. First, it hinges on the composition of installed production capacities. Second, differences in daily and seasonal availability profiles of wind and solar energy means that RE supply from these sources cannot be viewed as a homogeneous good on environmental grounds.[7] This insight is not novel (see, for example, Novan, 2015*a*; Cullen, 2013; Callaway, Fowlie and McCormick, 2017; Zivin, Kotchen and Mansur, 2014). Yet, most of the existing empirical literature has focused on the US context (in particular, the case of Texas) where only wind, but not solar, represents a significant share of electricity production. In contrast, our focus on the European context enables us to study markets in which wind *and* solar have achieved significant market size. Third, while in a closed electricity market one MWh of RE should replace one MWh of conventional generation, this does not necessarily hold when energy can be traded across borders. Contrasting the case of Spain and Germany—with the latter being more tightly integrated in the European electricity market than the former—enables us to analyze the impacts of RE supply for two countries which differ in terms of their possibilities to engage in cross-border trade following the imposition of a RES policy.

The remainder of the paper proceeds as follows. Section I lays out the conceptual framework which helps guide the subsequent empirical analysis. Section II describes our estimation strategy. Section III describes the data and the policy context for our study. Section IV examines the impacts on prices, quantities and carbon emissions caused by a policy-induced increase in RE. Section V presents and discusses our main findings on the economic cost of carbon abatement through RES policies. Section VI concludes.

I. Conceptual Framework

This section lays out the conceptual framework which we use to empirically measure the cost of carbon abatement through RE policies. We first present an equilibrium model of short-run electricity supply and then describe the impacts of RE generation on electricity prices, the production of conventional electricity producers, and CO_2 abatement. Finally, we define metrics for the economic cost of carbon abatement through RES policies and for the incidence of cost between energy producers and consumers.

[7]Solar tends to correlate more strongly with peak demand during the day while wind tends to replace base demand during the night. As the carbon intensity of peak and base energy generation differs, the environmental value of an incremental increase in energy generation from wind and solar can differ greatly.

A. An Equilibrium Model of Short-Run Electricity Supply

Wholesale electricity firms are assumed to operate under perfect competition maximizing profits using production quantities as the decision variable.[8] Generation units of a firm are represented at the technology level where total production of technology $i \in I$ in hour $t \in T$ is denoted by X_{it}. The set I comprises thermal carbon-based generation plants (i.e., hard coal, lignite coal, natural gas) and other conventional plants (i.e., nuclear, hydro, pump storage, biomass). Generation from wind and solar is modeled exogenously. Production at any point in time cannot exceed given (and fixed) installed capacity $\overline{K}_i$:

$$\overline{K}_i \geq X_{it} \quad \perp \quad \mu_{it} \geq 0 \quad \forall\, i,t \tag{1}$$

where μ_{it} is the shadow price of capacity for technology i at time t. The value of capacity in a given hour is zero ($\mu_{it} = 0$) if production is below the capacity limit; it is positive ($\mu_{it} > 0$) if the capacity constraint is binding.[9]

Marginal cost $c_{it}(\theta_i, \vartheta_i)$ of a generation unit at time t depend (i) on the previous generation levels $\theta_i = \{X_{i(t-1)}, X_{i(t-2)}, \dots\}$, reflecting dynamic constraints and ramping costs, and (ii) on other contemporaneous exogenous factors such as fuel prices, variable operation and maintenance costs (i.e., capital and labor prices), and temperature affecting heat efficiency which are contained in ϑ_i. In equilibrium, the following profit condition, relating unit costs (comprising marginal costs and the opportunity costs for capacity) to unit profits determines supply of technology i, X_{it}:

$$c_{it}(\theta_i, \vartheta_i) + \mu_{it} \geq P_t \quad \perp \quad X_{it} \geq 0 \quad \forall\, i,t \tag{2}$$

where P_t measures unit profits or the wholesale electricity price at time t. If unit cost exceed unit profit, positive generation would lead to losses and thus $X_{it} = 0$. Given perfect competition and no barriers for market entry or exit, zero profits in equilibrium (i.e., unit cost equal to unit profit) determine a positive level of electricity supply $X_{it} > 0$.

Markets for electricity in a given hour balance if total supply is equal to hourly demand $\overline{D}_t$:

$$\sum_i X_{it} = \overline{D}_t \quad \perp \quad P_t \text{ “free”} \quad \forall\, t\,. \tag{3}$$

Equations (1)–(3) imply that given demand the equilibrium allocation of hourly electricity supplies is determined by the available capacity and the marginal cost

[8] We thus abstract from price regulation and imperfect competition in the electricity sector. We leave for future work the careful comparison of how alternative assumptions about market structure may influence our results.

[9] We use the “$\perp$” operator to indicate complementarity between equilibrium conditions and variables. A characteristic of economic equilibrium models is that they can be cast as a complementarity problem, i.e. given a function $F\colon \mathbb{R}^n \longrightarrow \mathbb{R}^n$, find $z \in \mathbb{R}^n$ such that $F(z) \geq 0$, $z \geq 0$, and $z^T F(z) = 0$, or, in short-hand notation, $F(z) \geq 0 \perp z \geq 0$ (Mathiesen, 1985; Rutherford, 1995).

ordering of technologies. The equilibrium outcome of each technology thus depends on its own as well as on the marginal cost of all other technologies: $X_{it}^{*} = X_{it}^{*}\left(\overline{D}_t, c_{it}(\theta_i, \vartheta_i), K_i, c_{-it}\left(\theta_{-i}, \vartheta_{-i}\right), K_{-i}\right), \forall i, t.$[10] Equation (2) determines the price as the marginal cost of the marginal generator, i.e. the generation that earns zero capacity rent in the given hour ($\mu_{it} = 0$).

B. Impact of Renewable Generation on Prices, Quantities and Emissions

A temporary increase in generation from intermittent renewables leads to a change in this equilibrium allocation as shown in Figure 1. Let "0" and "R" denote the equilibrium situation before and after an increase in the supply of intermittent renewables. The increase in wind and solar has generally two effects. First, it effectively shifts the electricity supply curve outward or, equivalently, reduces residual demand, i. e. demand net of renewable generation, from $\overline{D}_t^0$ to $\overline{D}_t^R$. Given that demand in the short run is price-inelastic (see Assumption 1 below), an increase in renewable generation results in a decrease in equilibrium level of output of conventional technology i. This so called *replacement effect* is given by:

$$\Delta X_{it} = X_{it}^{R} - X_{it}^{0} \leq 0\,. \tag{4}$$

If any of the offset generation comes from plants burning fossil fuels, their replacement leads to a reduction in carbon emissions depending on their carbon intensity φ_i (measured in tons of CO_2 emissions per MWh of electricity generated). The aggregate level of CO_2 emissions, E, is reduced by the amount ΔE which is given by:

$$\Delta E = \sum_{i,t} \varphi_i \Delta X_{it}\,. \tag{5}$$

Second, as generators with high marginal cost are pushed out of the market, the wholesale electricity price decreases by ΔP_t—which we refer to as the *price effect* given by:

$$\Delta P_t = P_t^{R} - P_t^{0} < 0\,. \tag{6}$$

To quantify these effects, we need to impose the following two assumptions:

ASSUMPTION 1: *Hourly electricity demand does not respond to wholesale prices.*

ASSUMPTION 2: *The hourly supply of electricity generated from wind and solar is random and exogenous.*

Given the short-run nature of our analysis, we argue that both assumptions are innocuous. Assumption 1 is reasonable as consumers do not base their day-to-day

[10] The dependence of the equilibrium quantities on own and other generators' marginal cost and demand can also be understood in terms of bid functions in a perfect competitive market. Under perfect competition each generator bids the whole capacity at marginal cost into the market. The market operator then chooses the cheapest bids until demand is fulfilled. Thus, the acceptance of a bid depends on the ordering of marginal cost as well as available capacities and demand.

demand decisions on hourly wholesale market prices. Residential and commercial customers buy electricity at fixed prices which are constant for a period of time, ranging from one month to several years. Electricity demand variations are driven by exogenous forces such as temperature variation or diurnal patterns of economic activity and are not influenced by prices in the wholesale market.[11] Assumption 2 simply reflects the fact that in the short-run, the hourly variation from wind turbines and solar panels is determined almost entirely by exogenous changes in the available wind energy (e.g., wind speed, wind direction, air density) and solar radiation.

Assumptions 1 and 2 imply that renewable generation can be subtracted from total demand on the right-hand side of equation (3), so that it then effectively represents residual demand, i. e. total demand net of renewable generation. This way of representing electricity supply from wind and solar power is valid as long as the marginal costs of electricity generated from wind and solar are smaller than those of the lowest marginal-cost conventional generation technology. The (near) zero marginal costs of wind and solar generation imply that whenever electricity is available from these sources, it is supplied to the market. Figure 1 graphically represents this leftward shift of the vertical demand curve from $\overline{D}_t^0$ to $\overline{D}_t^R$.

HETEROGENEITY OF IMPACTS—The (short-run) price and replacement effects of one MWh of electricity produced by wind turbines or solar panels can vary considerably due to the demand and supply characteristics of the electricity market. The heterogeneity of impacts depends on the type, costs, and carbon intensity of the marginal generator that is being replaced—which in turn hinge on the following factors:

(i) *Plant portfolio.*—For any given system, the possibilities for replacing generation are determined by the existing plant portfolio and the carbon intensities of different generators.

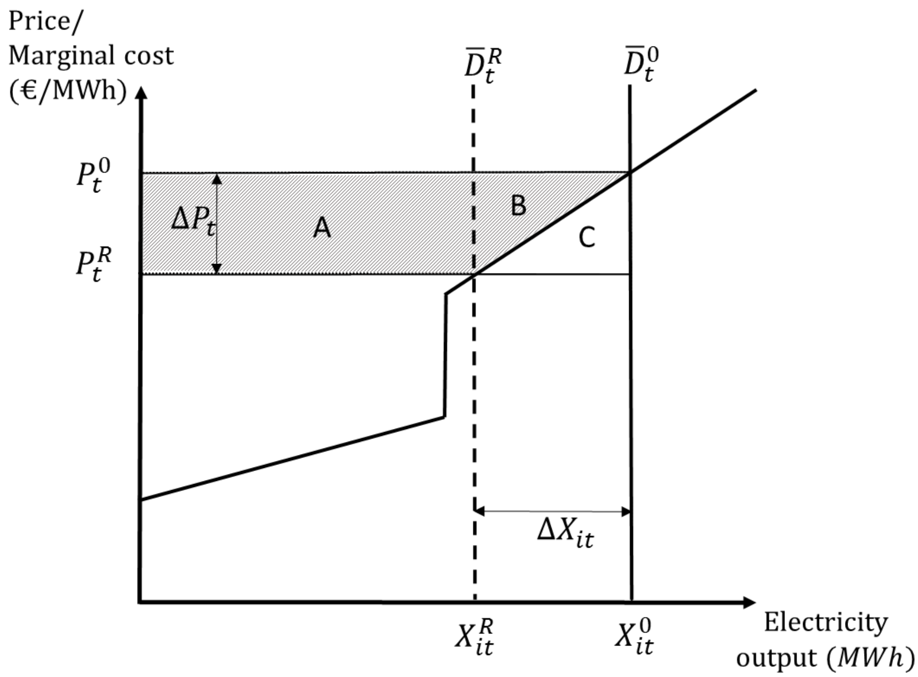
(ii) *Correlation between demand and intermittent renewable generation.*—As both electricity demand and generation from intermittent renewables exhibit a substantial diurnal and intra-annual (seasonal) variation, the impact of one MWh of electricity produced by renewables depends largely on when exactly the in-feed occurs and how demand and renewable supply are correlated over time.

(iii) *International market integration.*—The size of replacement and price effects also depend on the reaction of net imports which, in turn, depend on the possibilities for cross-border electricity trade, i. e., the existing cross-border transmission capacity and cross-country price differentials.

In summary, one additional MWh of intermittent renewable in-feed can have very different impacts on the generation level of conventional technologies, the level of aggregate CO_2 emissions, and wholesale market prices. Importantly, the marginal

[11]This is in line with previous literature (see, for example, Gelabert, Labandeira and Linares, 2011; Wuerzburg, Labandeira and Linares, 2013; Cullen, 2013; Cludius et al., 2014; Novan, 2015*b*).

Figure 1. Short-run electricity market impacts of exogenous variation in RE supply from wind and solar



Notes: P_t^0, X_{it}^0, $\overline{D}_t^R$, P_t^R, X_{it}^R and $\overline{D}_t^R$ denote the electricity price, the quantity of conventional generation and residual demand before and after the introduction of renewable energies, respectively. The area "A + B" corresponds to the decrease in capacity rents for producers due to renewable in-feed, "A + B + C" is the increase in consumer rents due to the price decrease.

impacts of intermittent renewables is likely to exhibit substantial heterogeneity both within a given market across time and type of renewable resource as well as across markets. Assessing the implicit cost of carbon abatement from RES policies and how these costs are shared between consumers and producers requires taking into account this heterogeneity. A descriptive analysis on how the different countries and technologies differ with respect to these factors is presented in Section III.

C. Measuring the Cost of Carbon Abatement

Given the short-run focus of our analysis and inelastic energy demand (Assumption 1), the change in economic rents due to a policy-induced increase in RE supply is equal to total subsidies paid to RE producers minus the revenues earned from selling the RE supply at market price.[12]

As, in practice, RE subsidies in most countries, including Germany and Spain, are funded through a tax on electricity consumption, the total subsidy payments are equal to total revenues collected from this refinancing tax, which we denote

[12]Note that given Assumption 1 there are no additional efficiency costs (deadweight loss) from introducing a subsidy.

here by ξ. We can thus measure the economic cost of the feed-in tariff policy, denoted by Ψ^S, by using data on the level of subsidies F_e, i.e. the feed-in tariff paid per MWh of RE type, indexed by $e = \{Wind, Solar\}$, and deduct the unit revenue earned by selling the RE output into the market at time t, P_t^R:[13]

$$\Psi^S = \sum_t \xi \overline{D}_t = \sum_{e,t} (F_e - P_t^R) Output_{et} \,, \tag{7}$$

where $Output_{et}$ denotes RE generation. The cost of carbon abatement through the RES policy per ton of CO_2 abated can then be calculated as:

$$\Psi = \frac{\Psi^S}{\Delta E} \,. \tag{8}$$

D. *Distribution of Costs between Consumers and Producers*

As the subsidies are refinanced through a tax on electricity demand, the costs of carbon abatement are primarily borne by the consumers. The replacement and price effects induced by the in-feed of renewables lead, however, to a redistribution of economic rents from producers to consumers: producers suffer from losses in their capacity rents due to lower output prices and reduced sales volumes while consumers profit from lower electricity prices.

Total cost for consumers are then defined as the quantity of electricity demanded $\overline{D}_t$ times the refinancing tax ξ on electricity demand minus the change in electricity price, $|\Delta P_t|$. This corresponds to the total costs of carbon abatement Ψ^S minus the change in consumer rents due to lower electricity prices:

$$\Psi^C = \sum_t (\xi - |\Delta P_t|) \overline{D}_t = \Psi^S - \sum_t \underbrace{\overline{D}_t \, |\Delta P_t|}_{\substack{=:A+B+C \\ \text{(Change in consumer rents)}}} \,. \tag{9}$$

The rents for conventional energy producers decrease due to lower prices and generation levels.[14] From the conditions in equation (2), we can express the equilibrium capacity rents for all generation technologies as: $\pi = \sum_{i,t} [P_t^* - c_{it}(\theta_i, \vartheta_i)] X_{it}^*$. The loss in producer rents Ψ^P, which represents the producer cost, is then given by the difference in capacity rents before and after the introduction of renewable energies:

$$\Psi^P := \pi^R - \pi^0 = \sum_{i,t} \underbrace{X_{it}^R \, |\Delta P_t|}_{\substack{=:A \\ \text{(Change in rents for units} \\ \text{whose output is not affected)}}} + \underbrace{P_t^0 \, |\Delta X_{it}| - c_{it}(\theta, \vartheta) \, |\Delta X_{it}|}_{\substack{=:B \\ \text{(Foregone rents for units} \\ \text{whose output is affected)}}} \,. \tag{10}$$

[13]It should be pointed out that our cost metric does not comprise (i) additional grid and balancing cost due to an increased supply of RE, (ii) benefits from environmental protection, and (iii) positive external effects due to, for example, learning spillovers associated with using RE technologies.

[14]We argue that—given the current policy design—the existing feed-in tariffs are set such that renewable producers exactly cover their investment costs. This implies that the change in rents for RE producers are zero.

The terms A and B in Figure 1 and equation (10) provide an intuitive decomposition of the change in capacity rents between generation units whose output is or is not affected by the renewable in-feed. For units whose output is not affected, the decrease in capacity rents is only induced by lower wholesale market prices. For units whose output is affected, the decrease also depends on marginal cost.

Figure 1 provides a graphical illustration of the components A, B and C describing changes in economic rents on both sides of the market. A and B depict the losses in producer rents. These are redistributed to consumers. In addition, consumer rents are increased by C. Area C, however, corresponds to previously incurred fuel costs which can now be saved due to the replacement of fossil technologies with RE generation, i. e. it does not change the producer rent.

EMPIRICAL CHALLENGES.—The challenge of empirically measuring A, B, and C is that one needs to know marginal generation cost at the plant level. In our empirical context such data are, however, not available. First, our data (see Section III) resolve electricity generation at the technology level. Second, we do not observe marginal costs. As a result, we cannot disentangle areas B and C. We do know, however, that the forgone capacity rents must equal at least area A and at most the total area given by $A+B+C$. Thus, without observing marginal cost of plants, it is possible to provide lower and upper bound estimates of Ψ^P:

$$\Psi^P = \begin{cases} \text{Lower bound}\,(\Psi^{P_L}): & A = \sum_{i,t} X_{it}^R \Delta P_t \\ \text{Upper bound}\,(\Psi^{P_U}): & A + B + C = \sum_{i,t} (X_{it}^R + \Delta X_{it}) \Delta P_t\,. \end{cases} \tag{11}$$

The characterization of lower and upper bound estimates of Ψ^P relies on the following two assumptions:

ASSUMPTION 3: *Marginal cost of firms producing electricity from conventional sources are not affected by the supply of wind and solar energy.*

ASSUMPTION 4: *Marginal cost are non-decreasing in output.*

Assumption 3 simply expresses that shifts in residual demand do not affect the supply curve, i. e. the marginal cost schedule.[15] Assumption 4 expresses the fact that generators are dispatched according to their marginal cost (from low to high) which is the fundamental premise underlying the structural equilibrium model given by conditions (1)–(3).

II. Identification and Econometric Specifications

In the following we describe our strategy for empirically estimating the effects of RE supply on equilibrium output (*replacement effect*) and wholesale market prices (*price effect*).

[15]Given the randomness and exogeneity in the availability of wind and solar supply this assumption seems innocuous. To the extent that firms can forecast RE supply, an increase in wind and solar generation may affect the intertemporal optimization of a firm's plant portfolio through dynamic cost considerations, i. e., start-up and ramping costs. As ramping costs, however, typically account only for a very small share of fuel costs, the impact on marginal costs is negligible.

A. Replacement Effect

Given the structural model in Section I, the equilibrium output of technology class i at time t depends on demand, renewable output, the technology's marginal costs and capacity, and the marginal costs and available capacities of all other plants in the market, i.e.:

$$X_{it}^* = X_{it}^* \left(\overline{D}_t, Output_{et}, c_{it}(\theta_i, \vartheta_i), K_i, c_{-it}\left(\theta_{-i}, \vartheta_{-i}\right), K_{-i}\right) + \epsilon_{it} \quad \forall i, t \tag{12}$$

where $Output_{et}$ is the exogenous in-feed of RE produced from resource of type $e = \{Wind, Solar\}$ at time t.

The first main identifying assumption we exploit is that demand $\overline{D}_t$ does not respond to wholesale electricity prices in the short run (Assumption 1). The problem of estimating market equilibrium quantities X_{it}^* then essentially boils down to one of estimating a supply function given exogenous demand. As demand is exogenous, we do not have to deal with a simultaneity bias caused by the joint determination of supply and demand.

Second, we exploit the randomness and exogeneity of wind and solar generation patterns (Assumption 2) and the assumption that marginal cost do not depend on the level of RE supply (Assumption 3). This allows us to determine the impact of renewable in-feed on the equilibrium outputs. Wind and solar power production may not be completely random to the extent that generation from wind or solar are intentionally reduced (curtailed).[16] We argue, however, that curtailments are driven exogenously by transmission infrastructure restrictions.[17] Exploiting Assumption 2 to estimate the price and quantity impacts critically requires that there is sufficient variation in electricity output generated from wind and solar. Table 2 in the following section provides evidence that this is indeed the case. First, there is substantial variation in hourly wind and solar generation in both the German and Spanish market. Second, the share of domestic electricity generation from both intermittent sources is large in both markets. Third, Figure 3 in Section IV shows that the generation of RE additionally varies both by time and type of energy resource.

To estimate equation (12), we need to measure each of the variables. We observe realized hourly generation by technology X_{it}, demand $\overline{D_t}$, and wind and solar generation $Output_{et}$. We also observe installed capacity at the technology level on a yearly basis. We do not, however, observe unforeseen plant outages and maintenance shut-downs, i.e. available capacity at an hourly level. As the installed capacity of conventional technologies is virtually constant over the time period of our sample, we do not include installed capacity in our econometric specification.

Although we do not observe marginal costs, we know that they mainly depend

[16]In Germany the curtailment ratio recently increased from 0.8 % in 2011 to 3.5 % in the first three quarters of 2015. In Spain the most recent data are from 2013 when the ratio was 2.1 % (WindEurope, 2016).

[17]Instrumenting for the hourly level of wind generation using wind speed, Novan (2015*b*) provides evidence in the context of the Texas electricity market that ignoring the issue of wind curtailment does not result in biased estimates.

on heat rates of plants within a technology class, start-up and ramping cost, and fuel prices. Heat rates are unobserved, too, so we include temperature as a proxy for the change of heat rates over time as it is known to affect the efficiency and hence costs of power plants (if temperature rises, plants become more inefficient which in turn increases marginal cost). We also do not directly observe start-up and ramping cost. Hence, to control for start-up and ramping cost as well as dynamic constraints and expectations of conventional electricity producers over the whole planning cycle, we include lagged terms of generation levels of conventional technologies and of all contemporaneous controls over the previous 24 hours, $\boldsymbol{V}_t$.[18]

Primary fuel prices are, in principle, observable. Without plant-specific information, it is, however, not clear at all which fuel prices should be used for a given technology class. We thus omit fuel prices from our econometric model and instead include day-year fixed effects, $\boldsymbol{D}_t$, to control for additional daily factors that affect power plant behavior. The day by year dummies control for both observable and unobservable factors (such as, for example, unforeseen outages and forward contract positions) that vary by day. Table 1 provides a detailed list of the independent variables included in the statistical models in equations (13) and (15).

Based on the above considerations, we estimate realized generation by technology i in hour t for a given market $r = \{Germany, Spain\}$, X_{itr}, as a function of wind and solar output, past generation, and a set of controls:

$$
\begin{aligned}
(13) \qquad X^*_{itr} = \beta_{ir0} &+ \sum_e \beta^e_{ir1}\,Output_{etr} + \beta^e_{ir2}(Output_{etr})^2 + \beta^e_{ir3}\,Output_{etr}\overline{D}_{tr} \\
&+ \gamma_{ir1}\overline{D}_{tr} + \gamma_{ir2}(\overline{D}_{tr})^2 + \gamma_{ir3}\,Temp_{tr} + \gamma_{ir4}\,Temp^2_{tr} \\
&+ \boldsymbol{V}_{tr}\boldsymbol{\omega}_{ir} + \boldsymbol{D}_t\boldsymbol{\delta}_{ir} + \epsilon_{irt}\,.
\end{aligned}
$$

We include squared terms for renewable output, demand and temperature to account for possible non-linear relationships. To identify how a marginal increase in wind and solar affects conventional output during hours with different levels of demand, we interact renewable output with demand.

Given our identifying assumptions of exogenous demand and renewable generation, equation (13) is consistently estimated using ordinary least square (OLS).[19] The random variation of renewable in-feed identifies our main coefficients of interest, β^e_{ir1}, β^e_{ir2} and β^e_{ir3}, which determine the impact of wind and solar generation on the output of conventional power plants.

B. *Price Effect*

Given the equilibrium condition in equation (2), the equilibrium wholesale electricity price is defined by the marginal cost of the marginal generator i^*, i. e. the

[18]In the German and Spanish electricity market, trading takes mainly place in day-ahead markets. In these markets, operators bid prices and quantities for each hour of the following day given demand and RE forecasts. The planning period therefore compromises 24 hours.

[19]Note that as we include lagged own and other technology output, the regressors for each technology class i are identical. We can thus estimate equation (13) for each i separately using OLS without forgoing any efficiency gains as compared to a seemingly unrelated regression approach.

Table 1. Estimation variables

Independent variables	Description
Contemporaneous variables	
$Output_{et}$	RE production of technology e (MWh)
$Temp_{tr}$	Daily mean temperature (°C)
$\overline{D}_t$	System demand for current period (MWh)
Lagged variables $\boldsymbol{V}_t$ ($\tau = 1, \ldots, 24$ hours)	
$Output_{et-\tau}$	RE production lagged τ hours
$Output^2_{et-\tau}$	Square of RE production lagged τ hours
$Output_{et-\tau}\overline{D}_{t-\tau}$	Interaction term between RE and demand lagged τ hours
$Temp_{t-\tau}$	Daily mean temperature for country lagged τ hours
$Temp^2_{t-\tau}$	Square of daily mean temperature lagged τ hours
$\overline{D}_{t-\tau}$	System demand lagged τ hours
$(\overline{D}_{t-\tau})^2$	Square of system demand lagged τ hours
$X^i_{t-\tau}$	Generation of conventional technology i lagged τ hours
Dummies $\boldsymbol{D}_t$	
Day/Year	Dummy for each day in the sample

generator that earns a zero capacity rent. Hence, the equilibrium price for region r in period t is given by:

$$P^*_{tr} = P_{tr}\left(c_{i^*t}(\theta_{i^*}, \vartheta_{i^*})\right) + \epsilon_{tr}\,. \tag{14}$$

We do not observe plant-level output and hence the marginal generator is unknown which makes it impossible to directly estimate the equilibrium price as a function of marginal costs. We know, however, that—given constant available capacities and marginal costs—the marginal generator, and thus the equilibrium price, is determined by the level of residual demand. We can thus estimate P^*_t as a function of demand $\overline{D}_t$ and RE output $Output_{et}$. In addition, to control for daily, weekly, and seasonal variation in other factors (such as fuel price shocks or plant outages) which affect marginal cost, we include day-year fixed effects $\boldsymbol{D}_t$.

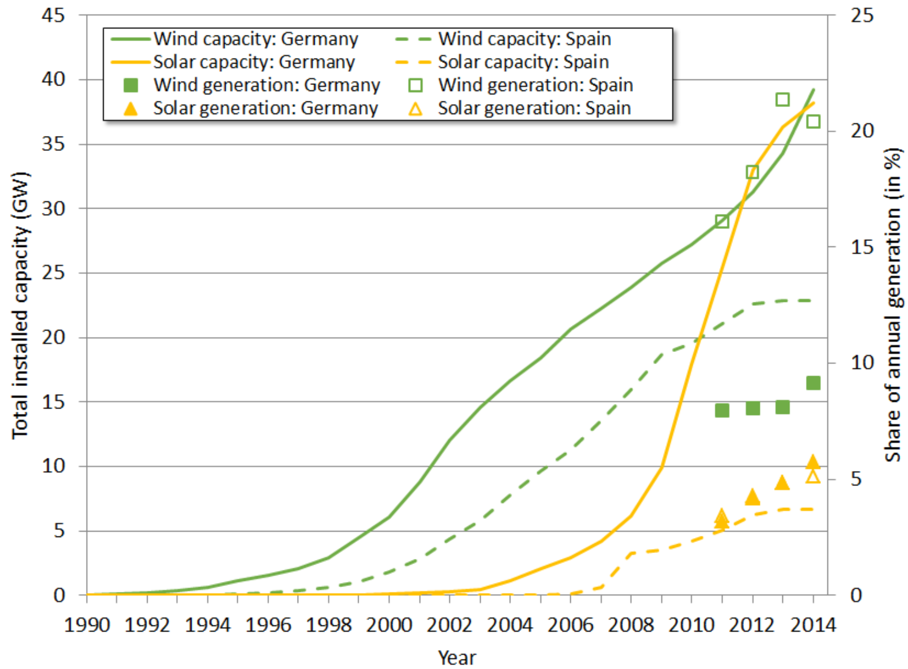
Given the above considerations, we estimate the following reduced-form model of equation (14):

$$\begin{aligned} P^*_{tr} = \alpha_{r0} + \sum_e \alpha^e_{r1}\, Output_{etr} + \alpha^e_{r2}(Output_{etr})^2 + \alpha^e_{r3}\, Output_{etr}\overline{D}_{tr} \\ + \alpha_{r3}\overline{D}_{tr} + \alpha_{r4}(\overline{D}_{tr})^2 + \boldsymbol{D}_t\boldsymbol{\gamma}_r + \epsilon_{tr}\,. \end{aligned} \tag{15}$$

Demand and squared demand are included to control for the variation in prices caused by the variation in demand. To identify how a marginal increase in wind and solar affects prices during hours with different levels of demand, we interact RE output with demand.

Given the assumptions of exogenous demand (Assumption 1) and exogeneity of wind and solar generation (Assumption 2), equation (15) can be consistently estimated using OLS. The assumption of random variation of RE in-feed then identifies the main coefficients of interest for estimating the price impacts: α^e_{r1}, α^e_{r2} and α^e_{r3}.

FIGURE 2. Total installed capacity 1990-2014 (primary axis) and share of wind & solar generation 2011-2014 (secondary axis) for Germany and Spain



Notes: Capacity and generation data for Germany and Spain is taken from BMWi (2015) and RED Electriciy de Espana (2016), respectively.

III. Context and Data

To identify and gauge the implicit costs of carbon abatement from RES policies on electricity production, prices, and CO_2 emissions, this paper focuses on the specific case of two countries: Germany and Spain. This section comprises three parts. First, we motivate our choice of countries and provide background information on the policy context, in particular with respect to RE policies in the electricity sector. Second, we present our data sources and describe the construction of our data set in detail. Third, we take a first look at the data by providing a descriptive analysis which focuses on characterizing the heterogeneity in terms of RE sources (wind and solar) and the country-specific market conditions.

A. Regional Focus of the Study

EMPIRICAL CONTEXT.—Three main considerations motivate our choice of Germany and Spain as empirical focus of this study. First, wind and solar generation in both countries represent a substantial share of total electricity generation. Second, both countries account for large proportions of European power sector CO_2 emissions and have adopted aggressive renewable support schemes, suggesting that the observed, policy-induced renewable in-feeds in both countries have majorly contributed to emissions reductions achieved by European RE policies. Third, exploiting the variation across the German and Spanish markets enables us to examine the role of international market integration and pre-existing plant portfolios for the effects of RE generation on prices and quantities in different electricity markets.

Both in Europe and globally, Germany and Spain are among the countries with the largest reliance on electricity generated from wind and solar energy. Over the past two decades, total installed capacities and generation of wind and solar electricity in both countries have sharply increased as shown in Figure 2: wind capacity in Germany (Spain) today is 6 (12) times larger than 15 years ago; solar capacity has skyrocketed increasing by a factor of 503 (3'900) in Germany (Spain) over the same period. In 2014, electricity from wind was 9.1 % and 20.4 % and electricity from solar was 5.7 % and 5.1 % of total generation in Germany and Spain, respectively.[20]

POLICY BACKGROUND.—The rapid deployment of wind and solar electricity in Germany and Spain has been majorly spurred by the adoption of RES policies. Both countries rely on a feed-in system which guarantees RE generators a fixed price at which produced electricity can be sold. These fixed prices are independent of the actual market price and are differentiated by the type of renewable generator, e.g., wind and solar power, according to their production costs.[21]

In Germany, RE support started with the *Electricity Feed-in Law* ("Stromeinspeisungsgesetz") of 1991 ensuring grid access for wind and solar power. In addition, the grid operators had to pay a guaranteed price to RE producers which was refinanced using a surcharge on the final consumer price (IEA/IRENA, 2016*a*). In 2000, the *Electricity Feed-in Law* was replaced by the *Renewable Energy Sources Act* ("Erneuerbare-Energien-Gesetz", EEG) which also granted feed-in tariffs for hydro power. The EEG was revised several times, mainly adjusting the amount of premiums paid. Based on the total payments made to RE generators (Netz-Transparenz, 2016) and the total amount of generation (BMWi, 2015), the average feed-in tariff between 2011 and 2014 was 0.08 €/kWh for wind and 0.33 €/kWh for solar power.

In Spain, the *General Electricity Law 54/1997* provided the ground for renewable promotion liberalizing the electricity market and granting grid access for RES (IEA/IRENA, 2016*b*). The *Royal Decrees 436/2004* and *661/2007* granted feed-in tariffs for "special regime" producers including besides wind and solar power also other RES types such as biomass. Further changes to the RES policy under the *Royal Decrees 1578/2008* and *661/2010* introduced limitations on the amount of subsidies for renewable power. In 2012, the *Decree-Law 1/2012* abolished the promotion of renewable power in Spain. Figure 2 shows that after the change of RES policy in Spain in 2012, no new wind and solar capacities were added. However,

[20]Both countries have put forward ambitious plans to further increase their reliance on renewable energies covering about 40 % of gross electricity consumption by 2020 from RE sources, including hydro power (European Commission, 2015).

[21]More recently, a market premium model has been introduced in Germany, and also in Spain producers are given the choice between a feed-in tariff and a market premium. While under a feed-in system the grid operator is responsible for bringing RE to the market, the market premium model allows generators to directly sell their electricity to the market. If the market price is below the premium, generators receive the difference between the premium and the actual market price.

as the abolishment of the RES support is not retroactive, generation facilities established before 2012 continue to receive financial support. The average feed-in tariff in Spain between 2004 and 2012 was 0.04 €/kWh for wind and 0.38 €/kWh for solar (del Rio and Mir-Artigues, 2014).

B. *Data Sources and Construction*

For both countries, we use hourly times series data on electricity generation, wholesale prices, demand, and net imports. Generation data are resolved on a technology level and differentiated by fuel type. The technology categories for generation are: wind, solar, hard coal, lignite, natural gas, nuclear, pump storage, run-of-river & reservoir hydro, other generation (mainly comprising thermal renewable production from biomass). Additonally, we use daily temperature data, average carbon coefficients for coal and gas plants, and data on subsidy payments for wind and solar production.

ELECTRICITY DEMAND AND TECHNOLOGY-SPECIFIC GENERATION.—Hourly electricity demand for Germany and Spain is based on ENTSO-E (2016) and RED Electriciy de Espana (2016), respectively. Generation data for Germany for the period 2010-2015 are compiled from for Solar Energy Systems ISE (2015) which collects and combines data from different sources including the EEX transparency platform (EEX, 2016) and transmission system operator information on solar and wind production. Unlike for Spain, German pump-storage data do not include demand but only generation of pump-storage plants. Additionally, for Solar Energy Systems ISE (2015) points out that hydro and pump-storage data obtained from EEX (2016) do not match with yearly total production of these plants.[22]

For Spain, generation data are provided by the Spanish system operator (RED Electrica de Espana) through the ESIOS system for the period from 2014 to 2015 (ESIOS, 2016).[23] ESIOS reports measured generation for all power plants at the Iberian peninsula aggregated by fuel type as well as hourly net imports. Generation and demand of pump storage facilities are provided separately. We aggregate them to represent generation net of pump storage. We further aggregate hydro generation from large and small hydro power plants which are reported separately by ESIOS.

WHOLESALE MARKET PRICES.—As most of the electricity is traded on the day-ahead market[24], we use data on hourly day-ahead market prices as wholesale market prices. The price data is based on the European Power Exchange (EPEX, 2015) for Germany and the Spanish electricity market place (OMIE, 2015).

TEMPERATURE DATA.—To control for heat efficiency changes due to temperature, we use data on daily mean temperature for weather stations in Germany and Spain from "The European Climate Assessment & Data Project" (ECA&D, 2016).

[22]Generation data in for Solar Energy Systems ISE (2015) is thus scaled to meet total yearly production by other sources; unfortunately, the correction factors are not reported. As these scaling factors distort the original data, our estimates for German hydro and storage facilities have to be carefully interpreted.

[23]The sample period for Spain is shorter than the one for Germany as prior to 2014 solar generation for Spain is not reported separately.

[24]In 2014, about 46 and 70 % of electricity demand in Germany and Spain has been traded on the day-ahead market, respectively.

CARBON COEFFICIENTS.—To calculate CO_2 emissions, we use average carbon emission coefficients by fuel. For Spain, these coefficients are provided for each year by IEA (2015). For Germany, IEA (2015) does only provide estimates for aggregated coal use ignoring differences between hard coal and lignite. We thus adopt the Tier-1 method recommended by IPCC (2006) to derive the carbon coefficients for Germany. We first use data on yearly generation and fuel use by the German Federal Ministry of Economic Affairs and Energy (BMWi, 2015) to derive the average heat efficiency for each technology class. We then multiply average heat efficiency by the fuel-specific emissions factor as provided by IPCC (2006).

RENEWABLE ENERGY SUBSIDIES.—Finally, we use data on paid subsidies for wind and solar generation to calculate the implied costs of carbon abatement. For Germany, these data are derived from the annual balance sheets of the renewable support scheme which comprehensively reports all payments (Netz-Transparenz, 2016). For Spain, we use the average of annual feed-in-tariffs for the years 2004 to 2012 as calculated by del Rio and Mir-Artigues (2014). For later years there are no data available. As the support for new power plants was abolished in 2012 but continued for existing capacities and as renewable capacity had not been increasing after 2012 (see Figure 2), we assume that average payments remain unchanged.[25]

C. A First Look at the Data: Heterogeneity across Technologies, Markets and Time

As already elaborated on in Section I, RE sources differ in their costs and effectiveness of abating CO_2 emissions due to their heterogeneity in terms of replacement and price effects. We identify three main factors which drive the heterogeneity of effects across countries and technologies. In the following we describe these mechanisms and provide a descriptive analysis using our data.

(i) Plant portfolio.—For any given system, the possibilities for replacing generation are determined by the existing plant portfolio and the implied carbon intensities of different generators. For systems in which coal (natural gas) accounts for a relatively large capacity share, one MWh of intermittent RE is *ceteris paribus* more likely to replace coal- (gas-) fired generation. For the same reason, the price decrease following an increased in-feed of renewables is likely to be smaller in the predominantly coal-based system—given that the marginal production costs are lower for coal than for natural gas.

Table 2 shows installed capacity and generation per technology and country. The plant portfolios of Spain and Germany differ with respect to several aspects. First, Germany has a significantly higher share of hard coal and lignite capacity relative to their gas capacity while in Spain the gas capacity exceeds the coal capacity by a factor of three. Hence, in Germany (Spain) it is, *ceteris paribus* more likely that renewable energies replace coal (gas). Second, in Germany more than half of the total capacity consists of combined heat and power (CHP) plants, while in Spain this share is relatively small. Therefore, in Germany gas generation is less

[25]In addition, we calculate a simple average over different years as we have no information on the vintage of installed renewable capacity which would allow differentiating the subsidies received in the years of our sample period for Spain (i. e., 2014 and 2015).

Table 2. Descriptive statistics: installed capacity, hourly generation, and domestic market share by technology by market (Germany=G and Spain=S)

Technology i	Installed capacity (GW)		Hourly generation (GWh)						Share domestic generation (%)	
			Mean		Std. dev.		Max			
	G	S	G	S	G	S	G	S	G	S
Coal	27.2	9.5	11.6	5.3	5.5	2.6	20.9	9.7	18.8	18.1
Lignite	20.1	1.9	16.0	–	2.2	–	20.9	–	26.1	–
Natural gas	25.7	31.2	4.6	2.7	2.7	1.4	21.4	10.3	7.6	9.3
CHP	14.6	4.8	-	-	-	-	-	-	-	-
Hydro	4.2	13.7	2.5	3.5	0.6	1.9	4.9	9.5	4.0	12.1
Reservoir	0.3	12.5	-	-	-	-	-	-	-	-
Pump storage	5.7	4.8	0.8	0.1	0.8	1.3	5.9	3.8	1.3	0.3
Nuclear	12.1	7.5	10.7	6.2	2.1	0.8	18.5	7.1	17.4	21.4
Wind	-	-	6.4	5.7	5.8	3.3	33.0	17.4	10.5	19.4
Solar	-	-	3.3	1.4	5.1	1.7	25.8	5.7	5.3	4.9
Other	17.3	6.9	5.5	4.3	0.7	1.7	9.0	7.6	9.0	14.6
Net import	15.0	2.2	-2.8	-0.4	4.0	1.0	18.7	3.6	–	–

Notes: (i) Capacity data comes from Eurelectric (2013), net transfer capacities from Abrell and Rausch (2016) and sources for generation data are described in Section III.B. *(ii)* Natural gas capacity consists of combined heat and power (CHP) plants and open or combined cycle gas turbines. The distinction between the two is only available for capacity whereas for generation only aggregate data is available. Similarly, data on installed capacity for hydro power are available separately for run-of-river and reservoir while the generation data is available as an aggregate. *(iii)* "Other" includes oil, derived gas, biogas, biomass and waste technologies. *(iv)* The share of total generation is calculated by dividing the aggregate generation by source over total domestic generation (over the entire sample period for each country).

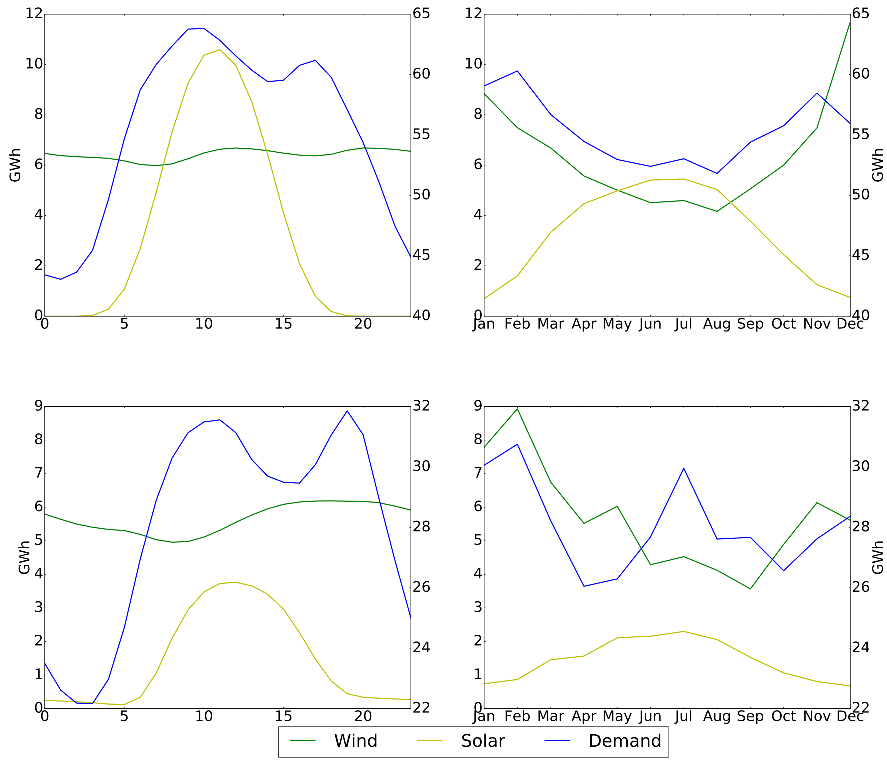
likely to adjust as a response to renewable in-feed because the dispatch decision of CHP plants generally depends on heat demand and is less dependent on residual electricity demand. Third, while in Germany most of the hydro capacity consists of run of river plants, in Spain, a large share is reservoirs. Run-of-river plants produce according to water flows with relatively low marginal cost, and are thus not affected by increased renewable production. Reservoirs, on the other side, adapt their production depending on the market price. Consequently, hydro generation in Spain is more likely to adjust to renewable in-feed compared to Germany.

(ii) Correlation between demand and intermittent RE generation.—Figure 3 illustrates the diurnal and intra-annual (seasonal) variation of wind and solar generation as well as electricity demand. As they all exhibit a substantial variation, the impact of one MWh of renewable electricity on conventional generation depends largely on when exactly the in-feed occurs and how demand and supply are correlated over time. For example, if RE is producing at hours with peak demand, it mostly replaces generation of peak load plants with high marginal cost. In contrast, at low or intermediate levels of demand RE replaces base load plants with relatively low marginal cost.

For both countries, the demand peak at noon largely coincides with the peak of solar generation. While the wind profile in Germany is almost flat and thus shows little correlation with demand, wind generation in Spain somewhat increases in the afternoon and evening time when demand is relatively high. Hence, in both countries it is more likely that solar mainly replaces peak plants while wind is more likely to replace mid and base load plants.

Given that during most of the sample period the marginal costs of gas generation

Figure 3. Daily (left column) and monthly (right column) time series for hourly electricity demand and wind & solar generation



Notes: For Germany and Spain, demand data is based on ENTSO-E (2016) and RED Electriciy de Espana (2016) and generation data is taken from BMWi (2015) and RED Electriciy de Espana (2016), respectively. Monthly data series refer to monthly averages of hourly data. Daily and monthly data series represent averages over the sample period.

were higher compared to coal, gas plants were more likely to act as peak producers in both countries. Hence, solar (wind) energy is expected to mainly replace gas (coal) generation. As a consequence, this would imply a larger marginal carbon abatement of wind compared to solar in-feed.

As solar availability is more strongly correlated with demand as compared to wind, the electricity price decrease due to an increased in-feed of solar is likely to be higher than for wind.

Over the time of a year, German electricity demand is positively (negatively) correlated with wind (solar). In Spain, the demand peak in the summer coincides with a peak in solar generation and the demand peak in winter with a peak in wind generation.

(iii) International market integration.—An increasing amount of intermittent renewable generation with (near) zero marginal cost tends to reduce the domestic electricity price. As domestic wholesale prices are reduced, generation becomes more competitive relative to the neighbouring countries, in turn increasing incen-

tives for exports. Thus, international market integration has generally two effects: First, in a more integrated market, the amount of foreign generation replaced by one additional MWh of wind or solar electricity is larger and, consequently, the domestic replacement effect is smaller. Second, as a consequence of the first, trade possibilities reduce the price effect of renewable in-feed as less (expensive) conventional producers are replaced. As electricity trade is grid-bounded, the magnitude of the competitiveness and price effect depends on the size and utilization of the cross-border transmission infrastructure, which largely differs for Germany and Spain—as shown by the net transfer capacities in Table 2. Germany lies in the center of continental Europe and is well connected to the markets of its neighboring countries in terms of transmission infrastructure. In contrast, the Iberian peninsula is somewhat isolated from the rest of Europe as only one major, often highly congested, inter-connector line between Spain and France exists (see, for example, ENTSO-E, 2014; Abrell and Rausch, 2016). Consequently, we would expect a lower replacement and price effect for Germany compared to Spain due to its higher exposure to international trade.

These three factors, i. e. plant portfolio, correlation of demand with renewable generation and international market integration, will guide the interpretation of our results in the following sections.

IV. Replacement, Price, and CO_2 Emissions Effects of RE Policies

To gain insights into the nature and magnitude of replacement, price, and CO_2 emissions effects as well as the costs of carbon abatement through RE policies, we present our results as follows. First, we describe our estimation results in terms of the quantity impacts associated with the policy-induced increase in the supply of wind and solar power. Second, we describe the price effects. Third, we take a closer look at the heterogeneity of marginal replacement and price effects across fuels, markets, and time. Fourth, we use these estimates to quantify the CO_2 emissions impacts of the RE policies. In the next section we assess the implicit costs of carbon abatement through renewable policies and analyze how the costs are distributed between consumers and producers.

A. Average Replacement Effects

Using the estimated coefficients from equation (13), we can calculate the short-run average impact of one MWh of RE e on output of technology i in market r over the sample, i. e. the *average marginal replacement effect* as:

$$\Delta X_{ir}^{e} = \left.\frac{\partial X_{itr}}{\partial Output_{etr}}\right|_{Output_{etr}=\overline{Output}_{er}} = \beta_{ir1}^{e} + 2\beta_{ir2}^{e}\overline{Output}_{er} + \beta_{ir3}^{e}\overline{D}_{r} \tag{16}$$

where $\overline{Output}_{er}$ and $\overline{D}_r$ are the sample averages of intermittent RE output e and electricity demand in market r, respectively.[26] Table 3 shows the estimated results for the average marginal replacement effect, ΔX^e_{ir}.

GERMAN MARKET.—For Germany, both solar and wind power induce on average the largest marginal generation offset in net imports followed by a reduction of coal- and gas-fired generation. Except for hydro and storage facilities, the impact from solar is higher for all technologies relative to wind. The relatively large impact on net imports seems to be plausible as solar generation largely occurs in peak hours in which prices in the neighboring countries are high, thus creating strong incentives for cross-border trade.

The marginal offset for coal generation induced by wind and solar power is larger than the one for natural gas generation. This finding may be somewhat surprising at first glance as the marginal-cost ranking for these two technologies would suggest exactly the opposite result. For wind power, this is explained by the role of coal power as a classical mid-load plant whereas as natural gas plants tend to serve peak load. As wind power exhibits a rather flat generation profile over the day (see Figure 3), coal or even lignite is crowded out in off-peak hours when gas power plants are not running. For solar power, the result is indeed surprising as one would expect that additional solar in-feed should primarily lead to a decrease in the generation of peak-load plants which run during the mid-day peak. That this does not happen is due to the installed capacity portfolio in Germany (see Table 2): First, a relatively large fraction of electricity generated from natural gas stems from combined heat and power (CHP) plants. As the production of CHP plants is driven by heat, they have to generate even in hours with a high in-feed of solar power. Second, as the gas share in Germany is relatively low, gas might be completely replaced in hours with a high share of RE production. Hence, a further increase of renewable generation cannot replace more gas but would then replace coal.

The impact of wind and solar power on German hydro power plants is negligible. This is unsurprising given that most non-storage hydro facilities in Germany are run-of-river plants (see Table 2), which do not change their production in response to price changes. The same is true for the levels of output of nuclear power plants with very low marginal costs and "Other" technologies. The category "Other" technologies mainly aggregates generation of thermal renewable power plants such as biomass which also receive feed-in tariffs for generated electricity. As a result, the economic incentives to reduce or shift the output are very weak.

SPANISH MARKET.—The largest average marginal generation offsets from wind and solar in Spain occur for hydro power. Hydro power in Spain is mainly produced by reservoir plants. Reservoir plants and pump storage facilities are able to defer their production to hours with less renewable in-feed, i.e. higher prices, thus explaining the relatively large average marginal offsets for both technology categories. In addition, a sizeable replacement effect is found for natural gas plants.

[26]This is equivalent to either (1) the marginal effect one additional MWh of intermittent renewable output $\partial X_{it}/\partial Output_{et}$ evaluated at the average level of output over the sample or (2) the per-period marginal effects averaged over the sample.

Table 3. Average marginal generation offset of RE e by technology by market ΔX_{ir}^{e} (MWh replaced per MWh of intermittent renewable power e)

Technology i	Market r and RE type e			
	Germany		Spain	
	Wind	Solar	Wind	Solar
Coal	-0.13	-0.19	-0.17	-0.09
	(0.01)	(0.01)	(0.01)	(0.01)
Lignite	-0.05	-0.05	–	–
	(0.01)	(0.01)	–	–
Gas	-0.06	-0.09	-0.25	-0.25
	(0.01)	(0.01)	(0.01)	(0.02)
Nuclear	-0.01	-0.02	0.00	0.00
	(0.00)	(0.00)	(0.00)	(0.00)
Hydro	-0.03	-0.02	-0.30	-0.25
	(0.00)	(0.00)	(0.01)	(0.01)
Pump Storage	-0.11	-0.05	-0.23	-0.25
	(0.01)	(0.01)	(0.01)	(0.02)
Other	-0.02	-0.02	-0.01	-0.01
	(0.00)	(0.00)	(0.00)	(0.00)
Net imports	-0.33	-0.38	-0.08	-0.20
	(0.02)	(0.02)	(0.01)	(0.02)
Market (Total)	-0.75	-0.81	-1.04	-1.05
	(0.02)	(0.00)	(0.02)	(0.00)

Notes: (i) Numbers in parentheses refers to robust standard errors. *(ii)* Results for individual regressions are shown in Tables B1 and B2 in Appendix B.

Due to its large capacity share, natural gas is the marginal generator in most of the hours and is thus on average relatively more affected than, for example, coal generation.

The average marginal offset due to changes in net imports differs largely across the types of renewables. While the impact is relatively small for wind, it is large for solar with about one fifth of the solar in-feed being replaced by a decrease in net imports. The reason is, again, that solar produces mostly during the mid-day peak hours when prices in neighboring countries are high, thus making it favorable to export electricity during these hours.

Coal-based generation is on average more affected by wind than by solar power. On the one hand, solar leads to a larger decrease in net imports which means that domestic generation needs to decrease by less. On the other hand, wind in-feed also occurs in off-peak hours in which it is more likely that coal is the marginal generator.

Comparing impacts across markets.—Comparing the estimates for the German and Spanish markets, three differences are particularly noteworthy.[27] First, Germany exhibits a higher increase in exports which can be explained by the better market integration within Europe.

[27] We would expect total effects to add up to one, i.e., one MWh RE would replace one MWh of conventional generation. For Spain the corresponding total values are -1.04 MWh for wind and -1.05 for solar, which is close to one. For Germany, however, the total values only add up to -0.73 MWh for wind and -0.80 MWh for solar. This unexpected result can be explained by the available data source. As shown in Table A1 in Appendix A hourly generation of coal and lignite (gas) fired plants only accounts for around 80 % (55 %) of the respective yearly generation in Germany. In contrast, renewable generation and demand are close to 100 % .

Table 4. Average marginal price effect of wind and solar power by technology by market

	Market r and RE type e			
	Germany		Spain	
	Wind	Solar	Wind	Solar
ΔP_r^e	-1.0 (0.03)	-1.4 (0.05)	-2.4 (0.02)	-2.3 (0.09)

Notes: (i) Newey-West standard errors are reported in parentheses. *(ii)* Results for individual regressions are shown in Tables B1 and B2 in Appendix B. *(iii)* The price effect Δp_r^e is expressed as Euro/MWh$\times$(GWh)$^{-1}$, i.e. the decrease in the per MWh electricity price per GWh of RE added.

Second, German coal power shows the highest reaction among the fossil-fuel powered plants in both markets, whereas in Spain it is gas-fired plants that are pushed out of the market. Due to the large share of natural gas capacity in the Spanish system, gas is often the marginal generator and thus, driven out of the market. In Germany the effect on gas is smaller, reflecting (i) the smaller share of gas capacity and (ii) the fact that a part of electricity generation from gas comes from combined heat and power plants, whose production is not affected by renewable generation because of "must-run" constraints.

Third, hydro power shows a strong reaction in Spain but no reaction at all in Germany. The very different effects on hydro in the two countries can be explained by differences in technologies. While in Germany the largest share of hydro capacity is run-of-river, which produces to cover mostly base load, in Spain there is a large share of reservoirs, which can transfer their production to time periods with high residual demand.

Comparing impacts across technologies.—Due to the correlation of wind availability with low, and solar availability with high demand levels, one would expect wind to replaces more coal, and solar to replace gas. In Spain exactly this pattern can be observed. In Germany, on the contrary, the picture looks different, i. e. wind and solar both replace more coal than gas. This result is due to (i) the large share of coal capacity and (ii) the large share of CHP capacity in Germany.

An other difference between wind and solar is consistent across countries: In both countries solar leads to a larger increase in exports. This is due to the fact that solar is mainly producing at noon when prices in neighbouring countries are high. Hence, a decrease in domestic prices at noon leads to a large increase in exports.

B. *Average Price Effects*

Using the estimated coefficients from equation (15), the impact of the in-feed of one MWh of RE e on the hourly electricity price, i. e. the *average marginal price effect*, can be calculated as:

$$\Delta P_r^e = \left.\frac{\partial P_{tr}}{\partial Output_{etr}}\right|_{Output_{et}=\overline{Output}_{er}} = \alpha_{r1}^e + 2\alpha_{r2}^e\overline{Output}_{er} + \alpha_{r3}^e\overline{D}_r\,. \tag{17}$$

Table 4 shows the estimated marginal effects of renewable in-feed on wholesale market prices. In Spain the impacts of renewable power on the price are generally higher than in Germany.

Comparing the two countries we find that the decrease of the wholesale electricity price due to renewable penetration is substantially lower in Germany compared to Spain. One reason underlying this difference is the reaction of net imports to increases in renewable generation. As Germany is more strongly integrated in the cross-border transmission system, its possibilities for trade are higher compared to Spain. As a result, Germany shows much higher increases in exports due to an increase in the in-feed of RE. This implies a smaller shift in the residual demand curve, in turn leading to smaller price and replacement effects.

In the German market, solar shows a higher price effect than wind. This is a consequence of the correlation of solar with peak electricity demand at noon (see Figure 3), i. e. expensive peak generators are replaced by low marginal cost generation. This interpretation is supported by our estimation of the replacement effect which shows a higher reaction of natural gas and coal-fired power plants to solar generation.

In the Spanish market, the impact of wind on the wholesale price exceeds the impact of solar power. The estimation of the replacement effect showed that solar power, as compared to wind power, induces a higher response in net imports and therefore a smaller reduction of domestic generation. In turn, the price effect due to solar in-feed is smaller than the one related to wind in-feed.[28]

C. Heterogeneity of Replacement and Price Effects Across Time

Focusing on the average marginal generation offset from wind and solar power can mask important heterogeneity that is due to the structure of correlation between demand and availability of each type of RE source. Intuitively, as the demand for electricity shifts, the units on the margin vary. Consequently RE in-feed leads to the replacement of different conventional technologies depending on demand.

To assess how a marginal increase in wind and solar output affects conventional electricity output X_{itr} of technology i in region r and price P_{tr} during different hours h of the day, we use regression estimates from (13) and (15), respectively, to calculate:

(18a)

$$\Delta X^e_{ihr} := \left.\frac{\partial X_{itr}}{\partial Output_{etr}}\right|_{Output_{etr} \in I_h = \overline{Output}_{ehr}} = \beta^e_{ir1} + 2\beta^e_{ir2}\overline{Output}_{ehr} + \beta^e_{ir3}\overline{D}_{hr}$$

[28] Also in Germany the export reaction is higher for solar than for wind. However, the opposing effect that solar replaces more expensive generation dominates. Hence, in Germany solar exhibits a higher price effect than wind.

(18b)

$$\Delta P^e_{hr} := \left.\frac{\partial P_{tr}}{\partial Output_{etr}}\right|_{Output_{etr} \in I_h = \overline{Output}_{ehr}} = \alpha^e_{r1} + 2\alpha^e_{r2}\overline{Output}_{ehr} + \alpha^e_{r3}\overline{D}_{hr}\,,$$

where the respective marginal effects (βs and αs) are evaluated at the averages of intermittent renewables output ($\overline{Output}_{ehr}$) and demand ($\overline{D}_{hr}$) for hour h, $h = 1, \ldots, 24$, over all sample days. I_h is a set which maps hours t to h.

To facilitate comparison of the marginal impacts across different types of technologies and markets, and to exclude non-existent situations—for example, a positive replacement effect of solar energy at night—we normalize the average hourly replacement and price effects ΔX^e_{ihr} and ΔP^e_{hr} by multiplying by the average hourly renewable generation $\overline{Output}_{ehr}$ and dividing with the respective sample average of renewable output, $\overline{Output}_{er}$. The hourly marginal replacement and price effects of interest are thus, respectively, given by:

(19a)
$$\Delta \hat{X}^e_{ihr} = \Delta X^e_{ihr} \times \overline{Output}_{ehr} \times (\overline{Output}_{er})^{-1}$$

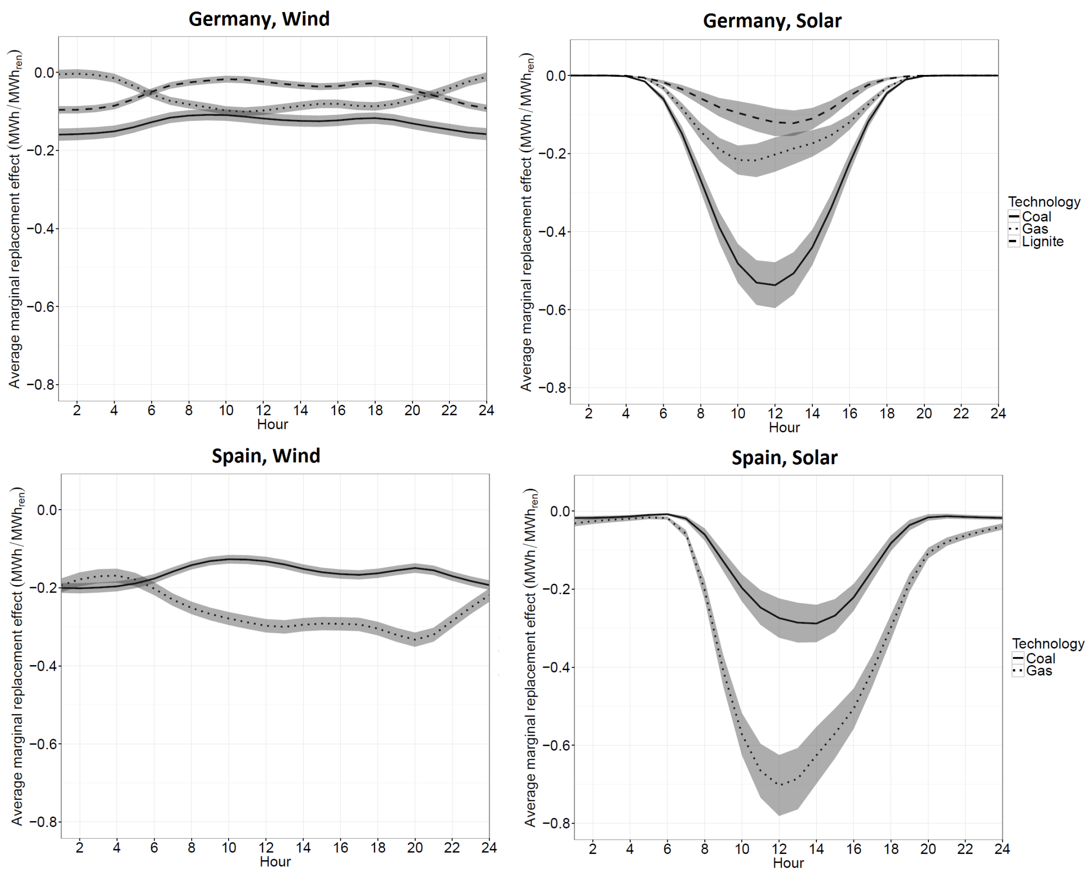
(19b)
$$\Delta \hat{P}^e_{hr} = \Delta P^e_{hr} \times \overline{Output}_{ehr} \times (\overline{Output}_{er})^{-1}\,.$$

HOURLY REPLACEMENT EFFECTS.—Figure 4 plots the hourly marginal replacement effects $\Delta \hat{X}^e_{ihr}$. It is evident that there is a substantial heterogeneity in the marginal impact of intermittent RE on conventional electricity generation across market, type of RE source, technology, and time.

Major differences between solar and wind power generation are evident in both countries. Focusing on the offset induced by solar, first note that the patterns of replacement are highly correlated with the patterns of solar generation which is displayed in Figure 3. Most of the replacement thus occurs around midday. Second, the peak for the natural gas offset is highly correlated with the demand peak due to the fact that high demand implies that natural gas is often the marginal generator. Third, the peak for the coal offset is to the right of the peak for the natural gas offset coinciding with slightly lower levels of demand following the midday demand peak. The peak for the lignite offset occurs at even lower levels of demand. The occurrence of the peaks for the coal and lignite offsets at lower levels of demand is consistent with the observation that at lower levels of demand coal and lignite increasingly replace natural gas as the marginal generator.

The offset pattern over a typical day induced by wind significantly differs from the one induced by solar. The main reason for this is that—in contrast to solar—the average hourly wind generation over a day is basically constant. This leads to the result, that the offset pattern induced by wind in-feed is highly correlated with electricity demand: Due to natural gas being the marginal generator in times when demand is high, the replacement of natural gas is positively correlated with electricity demand showing the highest offsets when demand peaks during noon and in the early evening. In contrast, the offset profiles over a day for coal and lignite are negatively correlated with demand, i. e., higher offsets occur when demand is

FIGURE 4. Marginal generation offset $\Delta\hat{X}^{e}_{ihr}$ by market by type of RE source by technology by hour over an average day (MWh replaced per MWh of renewable power e)



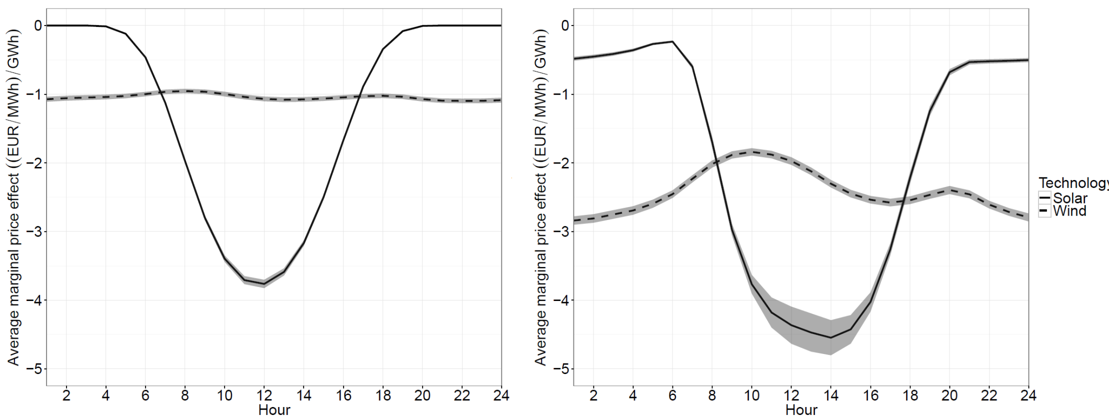
Notes: Shaded area denotes 95 % confidence interval.

low and coal or lignite technologies are the marginal producers. The offset patterns for coal and lignite in Germany are very similar although the cheaper lignite shows a relatively larger offset level due to wind.

In summary, our analysis suggests that the marginal replacement effect over a typical day varies largely depending on the type of RE source. Differences in marginal impacts for wind and solar power mainly reflect the reaction of base vs. peak load plants and the influence of different levels of electricity demand, or more precisely, the correlation between the availability of the RE source and demand. As we will show below, the documented heterogeneity in the generation offset from solar and wind power has important implications for the costs of carbon abatement associated with a RES policies that target specifically the promotion of wind or solar energy.

HOURLY PRICE EFFECTS.—Figure 5 plots the results for hourly marginal price effects $\Delta\hat{P}^{e}_{hr}$. For both markets, the price effect in general follows the availability

FIGURE 5. Marginal price effect $\Delta\hat{P}^e_{hr}$ by market by type of RE source by hour over an average day for Germany (left) and Spain (right)



Notes: Shaded area denotes 95 % confidence interval.

of the renewable resource during the day. Hence, for Germany we find that the marginal price effect of wind is constant during the day. While in the case of solar we observe highest price effects at noon and no effect during night. The same can be seen for the effect of solar energy on the price in Spain. In the case of wind energy, we find that in Spain effects on the price are lowest during the late morning when wind generation is low, and higher during night time.

D. CO_2 Abatement Effects

Using data on technology- and country-specific carbon coefficients, φ_{ir}, and our estimation results, we can calculate the average CO_2 emissions offset per unit of RE output e as:

$$\Delta E^e_r = \sum_i \varphi_{ir}\,\Delta X^e_{ir}\,, \tag{20a}$$

and the total annual CO_2 emissions offset by technology i as:[29]

$$\Delta\hat{E}^e_{ir} = \frac{8760}{T}\sum_t \varphi_{ir}(\beta^e_{ir1} + 2\beta^e_{ir2} Output_{etr} + \beta^e_{ir3}\overline{D}_{tr})\,Output_{etr}\,. \tag{20b}$$

While CO_2 emissions coefficients for the various technologies are based on data (see Section III), we have to make assumptions about the fuels replaced abroad by increased electricity exports following an incremental in-feed of wind and solar output. The problem arises as we do not possess information which would allow

[29] $\Delta\hat{E}^e_r$ is calculated as the per-year average effect over the sample (i.e., multiplying with the number of hours in a year and dividing by the total number of hours in the sample T).

us to trace the destination country for exports.[30]

To provide lower and upper bounds for the international carbon offset, we distinguish three cases which entail different assumptions about the carbon intensity of the foreign generation offset. A first case, labeled *"Domestic offsets only"*, assumes that (net) electricity exports do not offset any carbon in foreign markets, thus adopting a pessimistic view (lower bound) for the international carbon offset. Two additional cases assume that exports do offset CO_2 emissions abroad but differ with respect to the type of fuel being replaced: the case *"Exports replace coal"* assumes that increased (net) exports offset only lignite for the case of Germany and coal generation for the case of Spain, thus adopting an overly optimistic view (upper bound). The case *"Exports replace natural gas"* represents an intermediate case assuming that exports entirely replace foreign gas-fired electricity.[31] The "true" offset is likely to lie in between these two latter cases.

Table 5 shows the average marginal CO_2 emissions offset per MWh of wind and solar power by technology for the German and Spanish market as defined by equation (20a). With the exception for solar in Spain, coal accounts for the largest marginal carbon offset among fossil-based electricity. For Germany, this effect is in line with the large generation offset for coal. Despite the higher emissions intensity of lignite, the marginal carbon offset from these plants is smaller than for coal-based plants as the generation offset from lignite plants is comparably smaller. In Spain, the generation offset works mainly to replace natural gas, followed by coal. Due to the higher emissions coefficient for coal, the wind-induced carbon offset is larger for coal. For solar, however, the higher replacement effect on gas compared to coal dominates which explains why the solar-induced marginal carbon offset is relatively larger for natural gas.

Focusing on the "*Domestic offset only*" suggests that the average marginal reduction from wind is larger than for solar in the Spanish market whereas in Germany the opposite ranking applies. The reason is that in Germany, solar power leads to a higher decrease of both coal- and gas-fired electricity generation relative to the wind-induced replacement. In contrast, in Spain solar in-feed reduces less coal-fired generation than wind while the replacement effects on gas are roughly equal for solar and wind.

Finally, Table 6 shows the total annual carbon offset for each type of intermittent RE source by technology and by market, as defined by equation (20b). As both countries have a larger level of electricity production from wind than from solar, the total annual offset is larger for wind power. Focusing on the conservative case,

[30] For example, determining the carbon offset for Germany would require knowing to which of its nine neighboring countries electricity would be exported in each hour. In addition, we would ideally require information on the hourly dispatch and hourly carbon intensity of the generation mix for each of the trading partner. We leave to future research to examine how explicitly modeling the dispatch decisions in foreign countries would enrich our analysis.

[31] In terms of carbon coefficients φ_{ir}, our assumptions for the three cases are thus as follows:

$$\varphi_{Net\ imports,r} = \begin{cases} 0 & \text{if \textit{"Domestic offsets only"}} \\ \varphi_{Coal,r} & \text{if \textit{"Exports replace coal"}} \\ \varphi_{Natural\ gas,r} & \text{if \textit{"Exports repalce natural gas"}}. \end{cases}$$

TABLE 5. Average marginal CO_2 emissions offset from RE e by technology by market (kg CO_2/MWh of intermittent RE e)

	Market r and RE type e			
	Germany		Spain	
	Wind	Solar	Wind	Solar
Offset by technology ($= \varphi_{ir}\, \Delta X^e_{ir}$)				
Coal	-109.2	-147.6	-150.2	-85.4
	(6.0)	(9.0)	(9.1)	(9.1)
Gas	-21.3	-29.2	-93.9	-91.0
	(1.9)	(2.8)	(3.6)	(7.3)
Lignite	-46.7	-48.8	–	–
	(4.0)	(6.1)	–	–
Net imports				
"Domestic offsets only"	0	0	0	0
"Exports replace coal"	-258.0	-360.1	-69.5	-168.1
	(13.6)	(23.0)	(10.4)	(19.5)
"Exports replace natural gas"	-108.6	-134.9	-27.6	-66.7
	(5.7)	(8.6)	(4.1)	(7.8)
Total annual carbon offset ($= \Delta E^e_r$)				
"Domestic offsets only"	-177.2	-225.6	-244.1	-176.5
	(7.5)	(11.2)	(12.8)	(11.7)
"Exports replace coal"	-388.5	-585.6	-313.6	-344.6
	(15.5)	(25.6)	(14.3)	(22.8)
"Exports replace natural gas"	-239.1	-360.5	-271.7	-243.2
	(9.4)	(14.2)	(10.7)	(14.0)

Notes: Numbers in parentheses refer to robust standard errors.

i.e. assuming that foreign carbon offsets are zero ("*Domestic offsets only*"), the total annual carbon offset in Germany induced by wind (solar) output corresponds to 2.9 % (2.0 %) of annual CO_2 emissions in 2014 in the German electricity sector. In the Spanish market, the total annual wind (solar) power-induced carbon offset is equal to 17.3 % (3.2 %) of annual power sector CO_2 emissions in 2014.[32]

V. The Cost of Carbon Abatement through RES Policies

This section uses our estimates from the empirical analysis together with the concepts for measuring the implicit costs of carbon abatement through promoting RE supply defined by equations (7)–(10) in Section I. We also examine how the cost are distributed between consumers and producers. Table 7 summarizes our main results.

A. Aggregate Economic Cost

We begin by first describing the level of public support per unit of RE output and then present the cost per ton of carbon abatement.

[32]In the year 2014, total emissions of the electricity sector summed up to 340 and 70 Mt CO_2 for Germany and Spain, respectively (EEA, 2016). We use verified emissions for combustion units exceeding 20 MW of installed capacity under the European Emission Trading System as proxy for electricity sector emissions.

TABLE 6. Annual average CO_2 emissions offset from wind and solar power by technology by market ΔE_r^e (million tons of CO_2/year)

	Market r and RE type e			
	Germany		Spain	
	Wind	Solar	Wind	Solar
Offset by technology ($\Delta\hat{E}_{ir}^e$)				
Coal	6.1	3.9	7.2	1.3
	(0.3)	(0.3)	(0.5)	(0.1)
Gas	0.8	0.5	4.1	1.1
	(0.1)	(0.1)	(0.2)	(0.1)
Lignite	3.7	1.2	–	–
	(0.2)	(0.2)	–	–
Net imports				
"Exports replace coal"	3.1	2.2	3.4	2.1
	(0.5)	(0.3)	(0.5)	(0.2)
"Exports replace natural gas"	1.3	0.8	1.4	0.8
	(0.2)	(0.1)	(0.2)	(0.1)
Total annual carbon offset ($= \sum_i \Delta\hat{E}_{ir}^e$)				
"Domestic offsets only"	10.7	5.5	11.2	2.4
	(0.6)	(0.4)	(0.7)	(0.3)
"Exports replace coal"	13.9	7.7	14.7	4.6
	(15.5)	(25.6)	(14.3)	(22.8)
"Exports replace natural gas"	12.0	6.3	12.6	3.3
	(0.4)	(0.3)	(0.5)	(0.2)

Notes: Numbers in parentheses refers to heteroscedasticity-robust standard errors.

FINANCIAL SUPPORT.—Recall from equation (7) that the net financial support measures are defined as the subsidies payments paid to wind and solar energy F_e minus the revenues earned from selling the RE output into the market P^e. The respective data by technology and country are shown in Table 7.

Several key insights emerge. First, the RE support for solar power has vastly exceeded the one for wind by a factor of 4.4 and 9.7 for the German and Spanish market, respectively. Second, the revenues earned by solar power are somewhat higher than those for wind. This simply reflects the stronger positive correlation of solar generation with demand compared to wind, which implies that solar tends to produce more at times when demand and, thus, prices are high. Third, in both markets the net financial support ($F_e - P^e$) for solar compared to wind is substantially higher—as the higher support dominates over the higher revenues for solar. Fourth, the net financial support for wind in Spain is negative. This arises as revenues for wind generation in Spain are relatively high because wind generation in the evening coincides with high demand levels and, thus, high prices in the evening.[33] In Germany, on the other side, the RE support for wind is almost twice as large as in Spain; additionally, revenues from wind generation are smaller, thus making the net financial support for wind in Germany positive.

TOTAL ABATEMENT COSTS (PER AVOIDED TON CO_2).—Expressing the net public support into costs per ton of CO_2 abated Ψ shows that the costs of reducing

[33]Moreover, this finding reflects the high Spanish wholesale market prices during 2015 which were partly due to the low availability of hydro power driven by unusually dry meteorological conditions (RED, 2016).

TABLE 7. CO_2 abatement costs of RES policies for the German and Spanish market

	Market r and RE type e			
	Germany		Spain	
	Wind	Solar	Wind	Solar
Net financial support ($F_{er} - P_r^e$) [€/MWh of RE output]	41.6	292.7	-1.7	330.5
Paid RE support[a] F_{er}	75	331	39	380
Per-unit revenue from RE output P_r^e	33.4	38.3	40.7	49.6
Aggregate costs of carbon abatement (Ψ) [€/ton CO_2]				
"Domestic offset only"	234.7	1'297.6	-7.1	1'872.6
"Exports replace coal"	107.1	499.8	-5.5	959.1
"Exports replace natural gas"	174.0	811.9	-6.4	1'358.9
Producer costs ($\Psi^P/\Delta E$) [€/ton CO_2][b]				
Lower bound ($\Psi^{P_L}/\Delta E$)	284.8	290.4	175.0	275.5
Upper bound ($\Psi^{P_U}/\Delta E$)	314.1	318.8	243.3	308.6
Consumer costs ($\Psi^C/\Delta E$) [€/ton CO_2][b]	-79.4	987.8	-250.4	1564

Notes: [a]Data sources and assumptions underlying our calculation of RE subsidies are detailed in Section III. [b]For *"Domestic offset only"* case.

CO_2 emissions through promoting RE sources are substantial. Table 7 provides estimates portraying three different cases: A pessimistic case with the assumption of no foreign offset (*"Domestic offset only"*), an optimistic case with the assumption of a large foreign offset (*"Exports replace coal"*), and a case with the assumption of medium foreign offset (*"Exports replace gas"*). The following main insights emerge.

First, depending on the assumption of foreign carbon offsets, the costs for solar feed-in tariffs range from about 500–1300 €/ton CO_2 for the German market and from 950–1870 €/ton CO_2 for the Spanish market. The costs for carbon abatement through promoting solar power are larger in Spain compared to Germany due to two reasons: the solar in-feed in Spain produces a smaller carbon offset (see Table 5) and the net financial support is larger in Spain.

Second, the abatement costs from subsidizing wind as opposed to solar generation are considerably lower in both markets. In the German market, the abatement costs for wind subsidies are about five times smaller as compared to solar, although they remain large in absolute terms with 107–234 €/ton of CO_2. Although solar power in Germany yields a larger carbon offset per MWh than wind (see Table 5), the abatement costs of promoting solar are much higher due to the large net financial support. In Spain we find that subsidizing wind generation entails negative CO_2 abatement costs over our sample period as the average revenue per MWh of wind exceeds the feed-in tariff.

B. *Distribution of Cost between Energy Producers and Consumers*

This section examines the economic incidence of the cost of RES policies between energy producers and consumers. As described in Section I, an increase in the RE in-feed unambiguously lowers capacity rents for energy producers that use conventional energy technologies. Consumers, however, may gain or lose overall because they benefit from lower energy prices but also face higher costs to the extent that RE subsidies are re-financed through taxes on electricity demand.

As described in Section I.D, we provide a lower and an upper bound for producer costs, corresponding to areas A or A+B+C in Figure 1, respectively. In Table 7 we report producer costs per ton of CO_2 per technology, which are given by:

$$\Psi_e^P/\Delta\hat{E}^e = \begin{cases} \text{Lower bound } \Psi_e^{P_L}/\Delta\hat{E}^e = (\Delta\hat{E}^e)^{-1}\sum_{i,t}(X_{it} - |\Delta X_{it}^e|)\,|\Delta P_t^e| \\ \text{Upper bound } \Psi_e^{P_L}/\Delta\hat{E}^e = (\Delta\hat{E}^e)^{-1}\sum_{i,t}X_{it}\,|\Delta P_t^e|\ . \end{cases} \tag{21}$$

From equations (7) and (9), consumer costs per ton avoided CO_2 are then given by:

$$\Psi_e^C/\Delta\hat{E}^e = (\Delta\hat{E}^e)^{-1}\sum_{e,t}(F_e - P_t^e)Output_{et} - \Psi_e^{P_U}\ . \tag{22}$$

The size of distributional effects for producers and consumers per ton avoided CO_2 thus depends on: *(i)* the *price effect* $\Delta P_t < 0$, *(ii)* the net financial support for renewables $(F_e - P_t^e)Output_{et}$, *(iii)* the market size X_{it}, and *(iv)* the emissions offset $\Delta\hat{E}$.

We find that the RES policies, depending on which type of RE source is promoted, lead to quite different distributional effects for producers and consumers (see Table 7). Producer rents are always impacted negatively but the magnitude differs depending on whether solar or wind energy is pushed into the market, ranging from 175–319€ per ton of CO_2 abated.

Losses for producers are larger for a policy which supports solar energy as an increased in-feed of solar reduces high peak prices during times when electricity demand is high. Taking into account the substantial heterogeneity in price impacts over a day, as illustrated in Figure 5, is thus important for appropriately measuring the distributional effects. Importantly, basing the assessment instead on the average *price effects*, as shown in Table 4, would lead to a severe mismeasurement. A large *price effect* during high-demand hours then implies a comparably large adverse impact on producers when solar energy is promoted. Subsidizing wind energy brings about smaller losses for producers as compared to subsidizing solar energy as the availability of wind exhibits a smaller positive correlation with demand over a typical day.

Losses for producers not only depend on the RE source that is promoted but also on the market. For both types of RE sources, the producer cost are higher in Germany than in Spain, although the price effect in Spain is significantly larger. The larger size of the German market, however, overcompensates this effect and leads to higher costs for producers in Germany compared to Spain. Lastly, differences in the producer cost per ton avoided CO_2 between technologies and markets are also due to the heterogeneity of RE sources in terms of their environmental impact ($\Delta\hat{E}$). As discussed in Section IV.D, $\Delta\hat{E}$ depends on the correlation between resource availability and demand as well as the CO_2 intensity of the existing plant portfolio and export possibilities.

For consumers, the change in surplus varies in sign depending on the type of RE source: it is positive for wind and negative for solar. The difference is mainly due to the refinancing tax for RE subsidies levied on electricity demand which is higher in the case of solar—reflecting the fact that, given higher production costs for solar, a more stringent policy support is needed to incentivize profitable production. Under a policy targeting the promotion of wind energy, consumers are better off and even experience an increase in consumer surplus. Comparing the relative impacts on economic rents across consumers and producers, we find that with policy support for solar, consumers bear three to five times larger costs than producers. With policy support for wind, producers incur losses whereas consumers even gain.

VI. Conclusions

Despite the observation that RE support policies have become a major means to combat global warming, surprisingly little is known about the effectiveness of these instruments in terms of carbon mitigation and their implicit carbon abatement costs. This paper aims to fill this gap by providing the first ex-post assessment of the cost of carbon abatement and distributional effects between energy producers and consumers through RE policies examining the cases of Germany and Spain—two countries which have employed highly generous RE support schemes over the past ten years.

Our econometric framework exploits the randomness and exogeneity of weather conditions governing the in-feed of solar and wind energy to identify the (short-run) market impacts of RE support policies. We also make use of the fact that the shares of RE supply in the German and Spanish markets are large. Combining the empirical estimates with data on subsidy payments for wind and solar energy enables us to assess the aggregate economic cost of carbon abatement through RE support policies as well as their distributional impacts across energy producers and consumers.

Our estimates suggest that carbon abatement cost for RES policies differ widely depending on the type of RE source which is promoted. The average cost for reducing one ton of CO_2 emissions with subsidies for solar energy is between 500–1870 €. With subsidies for wind, this cost is significantly lower with 110–230 € per ton of CO_2 for the German market and slightly negative cost of -5 to -7 € per ton of CO_2 for the Spanish market. This reflects substantial heterogeneity in production cost, temporal availability of natural resources, and market conditions (i.e., time-varying energy demand, carbon intensity of installed production capacities, and opportunities for cross-border energy trade). We further find that abatement cost are quite differently distributed between energy producers and consumers depending on which type of RE source is promoted. While conventional energy producers incur losses when promoting wind or solar energy, consumers may gain or lose. We find that with policy support for solar, consumers bear three to five times larger costs than producers. With policy support for wind, producers incur losses whereas consumers gain.

Some limitations of our analysis should be kept in mind. A first caveat is that we focus on the short-run market impacts and consider only the "direct" economic cost of carbon abatement, i.e. the cost excluding external costs and benefits associated with using RE technologies. The economic literature provides evidence for the presence of positive externalities of RE technologies due to environmental protection, learning-by-doing, and network effects (Bollinger and Gillingham, 2014). Learning rates may also be asymmetric across RE technologies (Rubin et al., 2015). These benefits, however, have to be weighed against the additional integration and back-up cost of intermittent RE generation (Borenstein, 2012; Marcantonini and Ellerman, 2014). While it is beyond the scope of this paper to provide a comprehensive cost-benefit analysis, our estimates of the direct economic cost could be viewed as a first indication of how large the net benefits from other external effects would have to be to provide a rationale for decarbonization through RE support policies. For example, if one assumes social cost of carbon (SCC) on the order of \$30-100 (Nordhaus, 2017), the positive external net benefits (per ton of CO_2) associated with using solar energy would have to be substantial, i.e. several orders of magnitude higher than the SCC. In contrast, the required external net benefits for wind would be much smaller. A second caveat is that we measure the *average* cost of carbon abatement through RE support policies. The average may be an imprecise proxy for the marginal cost of abatement associated with the first and last MW of RE capacity installed. Additional studies focusing on different time periods and different markets would be helpful to gain insights into how the implicit carbon abatement cost vary depending on the stringency of the RE support policy.

Notwithstanding these caveats, our findings have implications for the design of RE support policies. First, differentiating of RE subsidies according to the type of RE source should reflect the heterogeneous implicit cost of carbon abatement. In particular, the differentiation of feed-in tariffs on the basis of production cost, as it is the case under current policy design, most likely does not incentivize investments in RE capacity towards technologies that provide the greatest social returns. Rather, policy design should take into account the environmental and market value of RE technologies. Second, to enhance the political acceptance and feasibility, future policy designs aimed at promoting RE supply should also consider the distributional consequences between energy producers and consumers which have been shown in this paper to vary widely depending on whether wind or solar energy is promoted.

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Appendix A: Data Quality

Table A1 shows a comparison of our hourly data aggregated to a yearly basis and yearly data by official sources. For Spain yearly and hourly data are consistent. For Germany, however, hourly generation shows less generation for coal and lignite and, in particular, natural gas fired plants. This is partly explained noting that yearly data measure gross while hourly measure net-generation and that yearly data include auto-producers' generation. For example, for natural gas generation for Solar Energy Systems ISE (2015) attributes 41 % of production to auto-producers compared to 51 % in our comparison which still includes the losses, i.e. the difference between gross and net generation. Concerning hydro plants, disaggregated data separate between pump-storage and other hydro while yearly data do not. Thus, the shown difference is caused by the difference in statistical classifications.

Table A1. Comparison of hourly and yearly generation [in %]

	Germany								
	Coal	Lignite	Gas	Hydro	Nuclear	Wind	Solar	Other	Total
2011	86	89	63	105	94	98	100	55	84
2012	87	88	59	106	94	98	100	61	85
2013	87	90	58	102	95	93	96	66	86
2014	81	90	51	104	95	100	91	62	84
2015	80	83	51	105	87	76	88	58	78
	Spain								
	Coal	Lignite	Gas	Hydro	Nuclear	Wind	Solar	Other	Total
2014	99	-	99	119	100	99	101	107	103
2015	99	-	98	118	100	99	102	64	95

Notes: Hourly data are aggregated to yearly totals and compared against official yearly data. For Germany yearly data are provided by AG Energiebilanzen (2016). Yearly data report gross generation while hourly data measure net generation explaining part of the difference. Moreover, yearly generation include auto-producers while hourly does not. Spanish yearly data are taken from the yearly electricity report of the Spanish transmission system operator (RED Electriciy de Espana, 2016). For pump-storage yearly figures are not available neither for Germany nor for Spain. Differences in hydro generation are explained by statistical classifications.

Appendix B: Detailed Regression Results

This appendix contains detailed regression results for German (Table B1) and the Spanish (Table B2) electricity market.

Table B1. Detailed regression results for Germany

	Coal	Lignite	Gas	Nuclear	Hydro	Other	PSP	Imports	Price
(Intercept)	-7.5E+03***	2.80E+03*	-4.50E+02	3.48E+03***	4.33E+02	1.67E+03***	-2.03E+03·	1.63E+03	-3.43E+01***
	-1.9E+03	1.14E+03	1.42E+03	5.70E+02	3.90E+02	3.47E+02	1.22E+03	4.31E+03	6.08E+00
Wind	-2.6E-01***	-2.30E-01***	1.72E-01***	-7.97E-02***	3.03E-03	1.96E-02***	-1.76E-02	-2.41E-01***	-1.01E-03***
	1.9E-02	1.12E-02	1.39E-02	5.61E-03	3.84E-03	3.42E-03	1.20E-02	4.24E-02	4.42E-05
Solar	-1.3E-01***	-1.97E-01***	1.41E-01***	-6.52E-02***	1.65E-02**	2.28E-02***	1.05E-01***	-6.66E-01***	-1.37E-03***
	3.0E-02	1.82E-02	2.26E-02	9.08E-03	6.21E-03	5.53E-03	1.95E-02	6.86E-02	5.30E-05
Demand	5.9E-01***	2.05E-01***	-6.27E-02***	4.26E-02***	-3.42E-02***	-3.68E-02***	-2.39E-01***	1.19E-01***	1.96E-03***
	1.4E-02	8.47E-03	1.05E-02	4.23E-03	2.90E-03	2.58E-03	9.08E-03	3.20E-02	3.89E-05
Temp	-1.1E+03	-2.57E+02	-4.05E+02	-6.54E+01	-1.70E+02	-1.04E+02	-1.16E+03*	-2.47E+00	
	7.7E+02	4.64E+02	5.76E+02	2.32E+02	1.59E+02	1.41E+02	4.97E+02	1.75E+03	
$Wind^2$	-1.4E-07	-2.21E-06***	1.96E-06***	-7.37E-07***	3.45E-07***	4.70E-07***	8.64E-07**	3.49E-06***	-1.09E-08***
	4.3E-07	2.61E-07	3.25E-07	1.31E-07	8.93E-08	7.96E-08	2.80E-07	9.87E-07	1.20E-09
$Solar^2$	1.2E-06*	-3.18E-07	3.69E-06***	-3.57E-07*	-5.67E-07***	-1.82E-07·	-3.07E-06***	-1.66E-06	1.35E-08***
	6.0E-07	3.60E-07	4.47E-07	1.80E-07	1.23E-07	1.10E-07	3.86E-07	1.36E-06	1.14E-09
$Demand^2$	-3.4E-06***	-1.72E-06***	1.99E-06***	-3.85E-07***	6.02E-07***	5.98E-07***	3.45E-06***	3.06E-07	-4.76E-09***
	1.2E-07	7.48E-08	9.29E-08	3.74E-08	2.56E-08	2.28E-08	8.02E-08	2.82E-07	3.57E-10
$Temp^2$	2.1E+02*	2.00E+01	8.86E+01	2.48E+01	2.30E+01	7.62E+00	1.54E+02*	1.12E+01	
	9.9E+01	5.96E+01	7.40E+01	2.98E+01	2.04E+01	1.82E+01	6.39E+01	2.25E+02	
WindDemand	2.3E-06***	3.77E-06***	-4.65E-06***	1.35E-06***	-6.51E-07***	-8.54E-07***	-1.86E-06***	-2.05E-06**	1.83E-09**
	2.8E-07	1.68E-07	2.08E-07	8.38E-08	5.73E-08	5.11E-08	1.80E-07	6.34E-07	6.32E-10
SolarDemand	-9.4E-07*	2.65E-06***	-4.48E-06***	9.29E-07***	-5.48E-07***	-7.48E-07***	-2.50E-06***	5.28E-06***	-1.26E-09
	4.7E-07	2.82E-07	3.50E-07	1.41E-07	9.63E-08	8.58E-08	3.02E-07	1.06E-06	8.68E-10
Lagged variables	yes	yes	yes	yes	yes	yes	yes	yes	no
Day Dummies	yes	yes	yes	yes	yes	yes	yes	yes	no
Multiple R^2	0.993	0.984	0.983	0.996	0.975	0.986	0.848	0.923	0.876
Adjusted R^2	0.993	0.983	0.983	0.996	0.973	0.986	0.840	0.926	0.87

Notes: Signif. codes: 0 '***' 0.001 '**' 0.01 '*' 0.05 '.' 0.1 ' ' 1; Robust standard errors in parentheses

Table B2. Detailed regression results for Spain

	Coal	Gas	Nuclear	Hydro	Other	PSP	Imports	Price
(Intercept)	-6.16E+03	-4.23E+04**	-4.79E+02	1.40E+04	3.60E+04***	1.84E+04	-1.82E+04	-4.71E+01***
	9.00E+03	1.30E+04	1.34E+03	1.25E+04	-3.24E-02***	1.34E+04	1.80E+04	1.80E+00
Wind	-3.70E-01***	4.82E-02*	-3.79E-03	-1.18E-01***	7.48E-03	-4.68E-01***	-1.11E-01***	-3.79E-03***
	1.62E-02	2.34E-02	2.41E-03	2.25E-02	-4.40E-02*	2.40E-02	3.25E-02	9.68E-05
Solar	-2.55E-01***	2.93E-01***	-3.00E-03	-5.08E-01***	1.73E-02	-4.68E-01***	-1.70E-01*	-4.54E-03***
	3.75E-02	5.42E-02	5.57E-03	5.19E-02	3.32E-02***	5.56E-02	7.51E-02	2.21E-04
Demand	2.48E-01***	-1.72E-01***	1.69E-03	1.63E-01***	7.39E-03	6.59E-01***	2.07E-01***	
	1.60E-02	2.32E-02	2.38E-03	2.22E-02	-6.32E+03***	2.37E-02	3.21E-02	
Temp	1.40E+03	7.32E+03**	6.84E+01	-1.79E+03	7.65E+02	-4.03E+03	4.87E+02	4.82E-03***
	1.66E+03	2.40E+03	2.46E+02	2.30E+03	-3.54E-07	2.46E+03	3.32E+03	1.15E-04
Wind^2	1.02E-06	9.37E-06***	2.61E-07**	6.13E-06***	3.11E-07	-6.90E-06***	-8.99E-06***	-6.53E-08***
	6.75E-07	9.75E-07	1.00E-07	9.34E-07	-7.61E-07	1.00E-06	1.35E-06	4.45E-09
Solar^2	-7.92E-06***	1.09E-05**	-4.36E-07	-1.35E-06	1.10E-06	8.47E-06*	-6.75E-06	8.19E-08***
	2.39E-06	3.46E-06	3.56E-07	3.32E-06	-4.04E-07**	3.55E-06	4.80E-06	1.71E-08
Demand^2	-3.52E-06***	7.88E-06***	-3.99E-08	2.59E-06***	1.28E-07	-7.91E-06***	-5.30E-07	
	2.77E-07	4.01E-07	4.12E-08	3.84E-07	2.67E+02***	4.11E-07	5.55E-07	
Temp^2	-5.71E+01	-3.08E+02**	-2.72E+00	7.38E+01	3.18E+01	1.72E+02·	-2.30E+01	-5.15E-08***
	6.88E+01	9.95E+01	1.02E+01	9.53E+01	1.13E-06***	1.02E+02	1.38E+02	2.12E-09
WindDemand	6.94E-06***	-1.47E-05***	-3.13E-08	-9.21E-06***	2.06E-07	1.13E-05***	4.86E-06***	7.52E-08***
	4.46E-07	6.45E-07	6.63E-08	6.18E-07	1.24E-06*	6.61E-07	8.94E-07	2.88E-09
SolarDemand	6.57E-06***	-2.05E-05***	2.53E-07	8.62E-06***	5.79E-07	6.95E-06***	2.19E-07	7.09E-08***
	1.26E-06	1.81E-06	1.87E-07	1.74E-06	1.86E-06	2.52E-06	7.11E-09	
Lagged variables	yes	yes	yes	yes	yes	yes	yes	no
Day Dummies	yes	yes	yes	yes	yes	yes	yes	no
Multiple R^2	0.997	0.998	0.999	0.989	0.999	0.973	0.925	0.928
Adjusted R^2	0.997	0.998	0.999	0.988	0.999	0.971	0.920	0.925

Notes: Signif. codes: 0 '***' 0.001 '**' 0.01 '*' 0.05 '.' 0.1 ' ' 1; Robust standard errors in parentheses