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Climate policy and power producers: The distribution of pain and gain

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ABSTRACT

Climate policies do not affect all power producers equally. In this paper, we evaluate the supply-side distributional consequences of emissions reduction policies using a simple and novel partial equilibrium model where production takes place in technology-specific sites. In a quantitative application hydro, wind and solar firms generate power combining capital and sites which differ in productivity. In contrast, the productivity levels of coal, gas and nuclear technologies are constant across sites. We parameterise the model to analyse the effects of stylised tax and subsidy schemes. Carbon pricing outperforms all other instruments and, crucially, leads to more equitable outcomes on the supply side. Technology-specific and uniform subsidies to carbon-free producers result in a greater welfare cost and their supply-side distributional impacts depend on how they are financed. Power consumption taxes have exceptionally high welfare costs and should not be the instrument of choice to reduce emissions or to finance subsidies aiming to reduce emissions.

1. Introduction

Fossil fuel use by the power sector is the largest source of carbon emissions in most countries. According to the International Energy Agency, power and heat production currently accounts for about 40% of carbon emissions from fuel combustion globally and among the OECD and EU member countries (IEA, 2018). In addition, the demand for power is expected to grow when transport, heating and perhaps parts of industry are electrified as part of their decarbonisation strategies (Fankhauser, 2013). Therefore, the decarbonisation of the power sector is crucial to meet countries' climate targets under the Paris Agreement, motivating many governments to introduce policies tailored to this end.

It is well-known that the distribution of the costs and benefits of these policies vary across producers, consumers and the government (Goulder and Parry, 2008). However, there are also differing impacts within those groups which can be very heterogeneous. The existing literature has focused predominantly on the demand side.[1] In this paper we study an oft-neglected aspect of the problem, namely the supply-side distributional impacts of climate policies within the power sector.

We propose a simple deterministic partial equilibrium model of the power sector with multiple generation technologies. We use the model to compare policy instruments deployed by governments around the world to reduce emissions. These instruments include carbon pricing, taxes on and subsidies to inputs or outputs of various generators, and power consumption taxes, all standardised to achieve the same reduction in emissions. Throughout we keep track of the policies' fiscal implications.

The model is stylised and has a macroeconomic flavour. Given exogenous government policies, input prices and a demand function, it determines the power market equilibrium. The time horizon for the analysis is long enough to abstract from sub-hourly to annual fluctuations in supply and demand, but short enough to take technology as approximately constant. We abstract from market imperfections and externalities that arise in the climate change context and focus only on emissions reductions. There are several such market failures including innovation and network externalities, learning-by-doing, barriers to the adoption of energy efficiency measures, each potentially warranting policy intervention (Bowen and Fankhauser, 2017). We assume other instruments are deployed to address these market failures.

A novel feature of our model is that production takes place at technology-specific sites, which can differ in productivity. This is a standard element of the more detailed dispatch models and we introduce it here because site-specific differences in productivity are a key characteristic of renewable technologies. In response to policy intervention, a representative firm per technology decides whether to develop new sites (i.e. the extensive margin) and/or adjust the quantity of inputs at each operational site (i.e. the intensive margin) to maximise

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[1] See for example reviews by Dechezleprêtre and Sato (2017) for industrial power consumers, particularly those which are energy intensive and trade exposed, and Farrell and Lyons (2016) for households at different points of the income distribution.

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the discounted value of its profits. The firm's profits are positive in our model due to decreasing returns to scale at each site.

Site-specific factors have a bearing on power sector decisions in three important ways. First, a site's *physical geography* is relevant for a given generation technology's productivity at that site. For example, a deep valley with a robust and predictable water flow in Norway can be a highly productive hydro power site but is not suitable at all for solar generation. Second, as the share of power generated from intermittent sources rises, it becomes increasingly costly to provide ancillary services using the existing grid technology and infrastructure as well as institutional/market arrangements. These factors, which we refer to as *system-level technology* constraints, affect a site's technology-specific productivity based on the amount of power already being generated using the technology. Finally, regardless of a site's intrinsic productivity *political-economy* constraints may preclude its development. For example, a country may ban the development of additional fossil fuel or nuclear sites for reasons other than climate policy which is equivalent to new sites having zero productivity.

When we explore our model quantitatively, we consider six technologies in two broad groups. The productivity of wind, hydro and solar generation differs across sites whereas for coal, gas and nuclear the productivity of all available sites are the same. We parameterise the productivity of the technologies in the first group assuming that physical geography factors are most relevant for hydro, and that system-level technological constraints are increasingly costly for wind and solar when the market penetration by these technologies is high. For the second group of technologies, we assume that firms are free to adjust the scale of production at the existing sites but cannot develop additional sites due to political-economy constraints. Note that in reality when all three constraints are relatively slack for a given technology, one would expect to observe *almost-corner solutions* such as hydro in Norway, nuclear in France and coal in Poland. We parameterise the model in a way that site-specific constraints are binding, as is the case for example in Spain.

In our quantitative analysis we do not attempt a detailed calibration targeting a specific power sector. This is because our stylised model simply does not have the high institutional, technological and temporal resolution required to make its predictions align with the historical observations. While one can add these features, as in power dispatch and generation expansion models, or more generally in energy system, computable general equilibrium (CGE) and integrated assessment models (IAMs), doing so adds complexity rendering these models something of a black box.[2] In contrast, the mechanisms at work in our model are transparent and focus on the key interactions between the consumers, producers and government.

We use the model's consistent equilibrium framework to compare the welfare effects of alternative policies. We design these policies as stylised proxies for real-world instruments. For example, the carbon price we model is much like the allowance price in the EU's Emissions Trading System or the UK's carbon price support. The favourable loans that Germany's government-owned development bank KfW provides to renewable energy projects are akin to our capital input subsidies. Similarly, our output subsidies to carbon-free firms could stand in for renewable obligations, feed-in-tariffs or feed-in-premiums. When their costs are passed on to power consumers, as in Germany and the UK for example, the effective price of power is higher, which we model as a power consumption tax. Against this backdrop, our welfare measure in comparing alternative policies is the sum of changes, relative to the benchmark, in discounted value of (i) consumer surplus; (ii) firms' profit streams net of site development costs; and (iii) government's net revenues.

We highlight four main results. First, carbon pricing achieves the targeted emissions reductions at the least cost to society. This is not new but our model highlights the benefit of a carbon price in treating carbon-free firms neutrally. Specifically, in equilibrium carbon pricing increases the carbon-free firms' value by raising the market price of power for all firms equally.

Second and conversely, the welfare cost of a power consumption tax is very high because it reduces the value of all firms by shrinking the market and destroys a substantial share of consumer surplus by raising the power price. From a welfare perspective it should not be the instrument of choice to reduce emissions or finance subsidies aiming to reduce emissions.[3]

Third, technology-specific subsidies are significantly more costly than carbon pricing. Such subsidies provide a competitive edge to the recipient relative to the others. Crucially, the latter group includes carbon-free firms which lose market share and face a decline in value. A uniform subsidy to carbon-free technologies performs better than technology-specific subsidies. However, its welfare cost is still much higher than carbon pricing.

Finally, technology-specific subsidies financed by carbon pricing imply a more equitable distribution of the benefits and costs of climate policies than when they are financed by general tax revenues, borrowing or power consumption taxes. This is because the negative impact on the profits of the carbon-free firms which do not receive the subsidy is more than offset by the increase in power price implied by the carbon price required to pay for the subsidy.

These four results leverage the simplicity of our model which permits a joint treatment of not only power producers and consumers but also the government whose fiscal position is impacted. Taken together, the results show that for power producers carbon pricing delivers a more equitable distribution of the pain and gain associated with climate policies without placing undue burden on the society in aggregate.

Next we provide a brief overview of the related literature. Section 3 describes the theoretical model and its equilibrium. Sections 4 and 5 explain our quantitative approach and discuss the results of the quantitative analysis. Section 6 concludes. There are four online appendixes. Appendix A contains further details on model parameterisation. Appendix B offers examples of government policies in the context of the model. Appendix C contains modelling results with site development subsidies. Appendix D provides a sensitivity analysis.

2. Related literature

Power is essential for virtually every modern economic activity so the literature on the power sector is voluminous. Two specific challenges of power markets are that first, demand and supply must balance in real time; and second, the existing capital stock and infrastructure used in generating, transmitting and distributing power is carbon-intensive. Against this backdrop, the very-short-run energy security concerns associated with the intermittent but carbon-free renewable generation interact with the very-long-run concerns related to climate change which requires that dispatchable but carbon-intensive thermal generation must be phased out.

The government's role in addressing these concerns and the tools available to it to promote reliable carbon-free generation have attracted considerable attention in the literature. Borenstein (2012) and Joskow (2011) provide a general overview of the economics of renewable generation. Mechanisms to induce the optimal generation mix between intermittent renewables and dispatchable thermal generation is the focus of Ambec and Crampes (2012) who highlight the trade-offs between

[2] Pindyck (2017) argues against the use of complex IAMs and recommends instead reliance on "relatively simple, transparent, and easy-to-understand models" to inform export opinion for climate policy making. Gambhir et al. (2019) make the case for using simple analytical models to supplement IAMs.

[3] We overestimate the impact on consumer surplus because any second order effects due to R&D investments triggered by higher prices are absent. By improving the productivity of technologies converting power to power services, these investments would limit, but not eliminate, the decline in consumer surplus.

various options if state-contingent pricing is not feasible. Goulder and Parry (2008), Fischer and Preonas (2010) and Schmalensee (2012) evaluate, albeit informally, several policy instruments that have been popular with governments.

More formally, applied theoretical approaches rely on computer models with a detailed description of power supply and demand to evaluate renewable policies ex ante (e.g. Rausch and Mowers (2014), Palmer and Burtraw (2005)) and ex post (e.g. Abrell et al. (2017)). A broad conclusion of these studies is that renewable subsidies or portfolio standards are costly. Reguant (2019) analyses the interaction between large-scale renewable energy policies and retail pricing schemes. Solving the model for Californian power sector, the paper finds that combinations of renewable energy and retail price policies which pass on the costs to consumers at the margin are preferable from a welfare standpoint, much like in the current paper. Although the distributional implications of policies for generators is not its focus, the conclusions of Reguant (2019) along this dimension also align with our findings.

CGE and electricity models have also been used widely to study energy sector implications of the transition to a low-carbon economy. Two recent Special Issues, one in Energy Economics (EE-SI) introduced by Murray et al. (2018) and the other in Climate Change Economics (CCE-SI) introduced by Fawcett et al. (2018), report the results of the model comparison exercise EMF32 for the US economy. The EE-SI focuses on the impact of imposing a carbon price on only the power sector under alternative assumptions for future technology and economic environment, while the CCE-SI considers the repercussions from economy-wide carbon taxes of different specifications under alternative revenue recycling options.

The high-level conclusion of the EE-SI is that the EMF32 models agree the US power sector decarbonisation through carbon pricing is feasible, cost-effective and robust to economic and technological uncertainty. Distributional implications for households and for energy intensive trade exposed sectors are at the forefront of the analysis in the CCE-SI. The Special Issue concludes that the magnitude of emissions reductions are not sensitive to the type of recycling scheme. However, Jorgenson et al. (2018) find that it is more efficient but also more regressive to reduce capital taxes because of their positive and persistent effect on the stock of capital than labour taxes which provide real wage incentives for greater labour supply. Lump sum transfers to households fare the worst among the recycling options considered. Zhu et al. (2018) in CCE-SI evaluates an additional recycling option, namely subsidies to renewable energy production and concludes that its welfare cost is particularly high. None of these analyses focus on the distributional implications for power generators.

The models used in this and similar model comparison exercises analyse the transition over many decades, and often embed a detailed description of the power sector within an energy sector, which in a CGE model itself is but one of the several moving parts. Other country-specific CGE models, such as Weigt et al. (2013) for Germany and Goulder et al. (2016) for the USA, are used to evaluate renewable energy policies. Böhringer et al. (2017) and Garcia-Muros et al. (2017) go a step further and couple CGE modelling with microsimulation analysis to take a closer look at the distributional impacts of policies for households. Respectively, they find that in Germany and Spain existing policies have been regressive.

Using a dynamic general equilibrium model which features much less sectoral detail than CGE models, Kalkuhl et al. (2012) and Kalkuhl et al. (2013) evaluate the welfare cost of alternative climate change policies. In their setup, energy is produced using a generic carbon-emitting technology and two carbon-free technologies, renewable and nuclear. Kalkuhl et al. (2012) studies how to best address the learning-by-doing externality which only affects the renewable technology. The authors compare the welfare cost of canonical technology support policies. They find that a carbon tax is a poor instrument to address the learning-by-doing externality and that subsidies financed by lumpsum taxes, feed-in-tariffs and well-designed renewable portfolio standards typically perform better. Kalkuhl et al. (2013) abstracts from the learning-by-doing externality but introduces the policy constraint that optimal carbon prices can only be imperfectly implemented, if at all. The authors find that replacing optimal carbon prices with permanent renewable subsidies implies "disastrous welfare losses" and provide a welfare ranking of alternative policies, echoing some of our conclusions.

Liski and Vehviläinen (2016) is similar in spirit to our paper but analyses the specific circumstances of the Nordic power market. The authors argue that the cost of subsidies to the entry of new wind capacity is biased upwards if it fails to take into account the decline in the rents extracted by incumbent generators. In a carefully constructed quantitative analysis of the Nordic case, the authors find that taking this channel into account, there are in fact gains for consumers at the expense of the incumbent generators' pure rents. Focusing on the Irish Single Electricity Market, Di Cosmo and Malaguzzi Valeri (2014) finds that additional wind capacity coming online reduces the profits of the incumbent fossil fuel generators but to a greater extent for the more flexible gas plants.

3. Model

The model is a deterministic partial equilibrium model of the power sector, where representative firms operate N distinct power generation technologies to satisfy a price-elastic demand in a frictionless market. Firms choose the production sites to develop for each technology as well as the quantity of factor inputs to deploy at each site to maximise their profits. The government aims to implement carbon emission reductions relative to a benchmark equilibrium by introducing taxes and/or subsidies that alter the incentives facing the firms. The power price adjusts endogenously to clear the market and we use the new equilibrium allocations to compute the implied changes in the value of firms, the consumer surplus and the government's fiscal position. We abstract from transition dynamics and solely focus on the differences between these two stationary equilibria.

Production technologies

There are N distinct power generation technologies indexed by $i = 1, 2, \ldots, N$. Production takes place at technology-specific sites indexed by $s_i \geq 0$. We treat s_i as continuous for simplicity, and assign the indexes so that $s_i = 0$ is the most productive site and that productivity declines as s_i increases. We assume a previously undeveloped site can be developed by incurring an immediate one-time fixed cost of $\psi_i \geq 0$ which accounts for the resource costs associated with environmental impact assessments, establishing the productivity of a site, legal and administrative process that may need to be completed etc. Capital must then be installed at this site to produce power and it depreciates at the constant rate δ_i after production. Capital stock evolves according to $k_{it+1} = (1 - \delta_i)k_{it} + x_{it}$ where x_{it} denotes investment in period t.

A developed site s_i combines k_{it} and possibly fossil fuel input e_{it} to generate power using

$$q_i(k_{it}, e_{it}; s_i) = A_i(s_i)F_i(k_{it}, e_{it})$$

where technology- and site-specific productivity is given by $A_i(s_i)$ and $F_i(k_{it}, e_{it})$ is a production function satisfying the Inada conditions. Since sites are ordered by productivity as s_i increases, site productivity declines, i.e. $dA_i(s_i)/ds_i \leq 0$.

Firms and profit maximisation

Generation technology i is operated by a representative firm, also indexed by i. Firm i maximises the discounted value of its profits. When solving firm i's problem, we suppress the technology and firm indexes in this section to avoid clutter. The focus is on the solution to the profit maximisation problem of the firm in a stationary environment where all variables the firm takes as given are constant over time. These variables include the output and input prices the firm faces $\{p, p_k, p_e\}$

as well as the site development cost ψ. To maximise profits, the firm chooses whether or not to develop a site and, if developed, the quantity of inputs to use at that site. That is, the firm chooses the optimal values of s, k and e.

It is helpful to study the firm's problem in two steps. We first consider the intensive margin where capital and fuel inputs are chosen to maximise profit in a given (developed) site, s. The per-period profit from this site is

$$\pi(k,e;s) = pA(s)F(k,e) - p_k\delta k - p_e e$$

where we have already imposed the restriction that in the stationary environment we analyse capital will be constant over time and so $x_t = \delta k$ in all periods other than the initial period. The value of the site must include the original site development cost ψ and the cost of capital $p_k k$ paid in the initial period denoted $t = 0$. The discounted value of profits from the site is given by

$$\begin{aligned} v(k,e;s) &= \sum_{t=0}^{\infty} \beta^t \pi(s,k,e) - p_k k - \psi \\ &= \frac{1}{1-\beta}\pi(s,k,e) - p_k k - \psi \end{aligned} \tag{1}$$

where β is the firm's discount factor. Then the profit maximising choices $k^*(s)$ and $e^*(s)$ must satisfy

$$F_1\left(k^*(s), e^*(s)\right) = \frac{1}{A(s)}\frac{p_k}{p}(1-\beta+\delta) \tag{2}$$

$$F_2\left(k^*(s), e^*(s)\right) = \frac{1}{A(s)}\frac{p_e}{p} \tag{3}$$

It is straightforward to show that Eqs. (2), (3) and the Inada conditions imply $k^*(s) > 0$ and $e^*(s) > 0$. Moreover, if $dA(s)/ds < 0$, both $k^*(s)$ and $e^*(s)$ are decreasing. Finally, under the same premise the envelope theorem implies $dv(k^*, e^*; s)/ds < 0$. In words, less productive sites generate smaller profits for the firm.

Having determined the optimal input choices at the intensive margin, we next consider the extensive margin. That is, the second step in the profit maximisation problem is to determine the sites which are profitable to operate. Ignoring the trivial case when $v(k^*, e^*; 0) \le 0$ and the technology is idle, the firm decides whether or not to develop a given site based on the site's potential contribution to profits.

Formally, when $v(k^*, e^*; 0) > 0$ and $dA(s)/ds < 0$, there exists a site $\bar{s} > 0$ such that

$$v\left(k^*(\bar{s}), e^*(\bar{s}); \bar{s}\right) = 0. \tag{4}$$

Below we refer to the site $\bar{s}$ that satisfies (4) as the *marginal site*. All sites with $s \le \bar{s}$ are profitable to develop and the firm's input choices in these sites satisfy (2) and (3). Conversely, the discounted value of profits from the sites with $s > \bar{s}$ is negative so the firm leaves them undeveloped with $k^*(s) = 0$ and $e^*(s) = 0$.

With the marginally profitable site $\bar{s}$ so determined, we can express the implications of profit maximisation for key endogenous variables in full. Using capital letters to distinguish firm-level variables from site-level variables and re-introducing technology/firm index i, we have

$$Y_i = \int_0^{\bar{s}_i} y_i(s_i)ds_i \tag{5}$$

where the variable y_i can stand in for any element of $\{k_i^*(s_i), e_i^*(s_i), q_i^*(s_i), v_i^*(s_i)\}$. For example, $Q_i^* = \int_0^{\bar{s}_i} q_i(s_i)ds_i$ is the total power generation by all the sites firm i operating technology i has developed and is operating. This implies that the value of the firm is given by $V_i^* = \int_0^{\bar{s}_i} v_i(s_i)ds_i$ and that the aggregate value of all firms is $V^* = \sum_i V_i^*$

Government

Government policy is exogenous and has two components. First, the government can restrict site space available to firms using a licensing parameter (σ_i) so that only sites $s_i \le \sigma_i$ can be operated. Second, the government can introduce a collection of technology-specific ad valorem taxes/subsidies on output (τ_i), capital (τ_i^k), fossil fuels (τ_i^e) and site development costs (τ_i^ψ) of firm i. The government policies are collected in the matrix

$$\Gamma = \begin{bmatrix} \sigma_1 & \sigma_2 & \dots & \sigma_N \\ \tau_1 & \tau_2 & \dots & \tau_N \\ \tau_1^k & \tau_2^k & \dots & \tau_N^k \\ \tau_1^e & \tau_2^e & \dots & \tau_N^e \\ \tau_1^\psi & \tau_2^\psi & \dots & \tau_N^\psi \end{bmatrix} \tag{6}$$

One can think of $s_i \in [0, \sigma_i]$ as sites for which the government has issued a license, a precondition for site development by assumption.[4] For example, if the government sets $\sigma_i = 0$, it precludes generation by firm i by fiat. Conversely, if σ_i is greater than $\bar{s}_i$ that would obtain under laissez-faire, it will have no effect on equilibrium allocations. We will later use σ_i to incorporate in the model the political-economy constraints highlighted in the Introduction.

Regarding the taxes and subsidies, each entry can be positive representing a tax, negative representing a subsidy, or zero representing no intervention. A carbon price τ^c satisfies $\tau^c = \tau_c^e = 2\tau_g^e$ because per unit of energy coal approximately has twice the carbon content of gas. In our *deterministic* model, carbon prices can be equivalently implemented using a carbon tax and emissions trading. For brevity, hereafter we use carbon tax to refer to a carbon price imposed using either type of instrument.

The matrix Γ_{LF} denotes the absence of any intervention by the government. Specifically, the entries in Γ_{LF} are such that all σ_i are large *and* all $\{\tau_i, \tau_i^k, \tau_i^e, \tau_i^\psi\}$ are zero, so the government does not impose any additional constraints on the firms or affect their incentives. We can now provide a more precise description of the firm-specific capital, fossil fuel and power prices as well as site development costs

$$p_{ki} = (1+\tau_i^k)\tilde{p}_k, \quad p_{ei} = (1+\tau_i^e)\tilde{p}_e, \quad p_i = \tilde{p}/(1+\tau_i) \tag{7}$$

$$\psi_i = (1+\tau_i^\psi)\tilde{\psi}_i \tag{8}$$

where $\tilde{p}_k$ and $\tilde{p}_e$ are the *exogenous* capital and fossil fuel prices, $\tilde{p}$ is the *equilibrium* power price paid by the consumer per unit of energy. Note that under Γ_{LF} all firms face the same prices indicated by the absence of subscript i from $\{\tilde{p}_k, \tilde{p}_e, \tilde{p}\}$. In contrast, site-development costs $\tilde{\psi}_i$ may in principle vary across firms, even in the absence of government intervention.

Demand

The demand for power is extremely simple and only depends on the price the consumers face

$$D(\tilde{p}) = A_d G(\tilde{p})$$

where $A_d > 0$ is an exogenous shift factor and $G(\tilde{p})$ is a decreasing function. This demand function implicitly assumes that the energy efficiency of consumers, that is, the rate at which they transform energy to energy services as well as the technology with which they do so, do not respond to changes in the price of power. Put differently, we assume that the change in consumer surplus evaluated using the demand for power, rather than the more appropriate demand for power services, is a good approximation for consumer welfare.

Assumptions and equilibrium

Before providing a definition of the equilibrium, we discuss some key assumptions and the simplifications they permit. First, we assume that the equilibrium is preceded by a long enough period of constant prices, policies and technologies. The assumption allows us to focus on the stationary equilibrium in the long run where firms have fully

[4] We assume sites are identical except in their technology-specific productivity. If alternatively some sites feature outstanding historical value, natural beauty or biodiversity resources, σ_i imposed to protect them may imply discontinuities in the permissible site space.

and freely adjusted their energy and capital use at a given site and have developed all profitable sites. This conception of the long run is standard (Varian, 2014, Ch. 18) and can be contrasted with the short run where at least one productive input is fixed and the very long run where in addition to all productive inputs, the technologies, populations and institutions are variable.[5]

Second, we assume that there is perfect competition in the wholesale market and focus on a representative firm per technology. In general, this can be restrictive because wholesale power markets are characterised by a few big suppliers which may exercise market power. Moreover, a given firm may own and operate multiple technologies and allocate its production strategically to maximise its profits. These deviations from perfect competition are potentially important in the short run but are rendered less significant in the long run by the entry of new firms, development of new sites and antitrust regulation by the government.

Third, we study the partial equilibrium in the power sector. That is, we assume the input prices are determined exogenously; there is no explicit restriction on the government budget balance unless specified otherwise; and there are no spillovers between power and other sectors of the economy. Together these assumptions deliver a simple and tractable model with an analytical solution for the long run equilibrium allocations. We note that while our model generates valuable insights about the implications of policies over this time horizon, it is virtually silent on the real-time equilibrium dynamics of the wholesale power market.

Definition (*Equilibrium*).

Given technologies $i = 1, 2, \ldots, N$, exogenous government policy Γ defined in (6), and constant input prices $(\tilde{p}_k, \tilde{p}_e)$, a market equilibrium consists of

- a marginal site $\bar{s}_i$ for each i which
  - solves equation (4) with $\bar{s}_i \le \sigma_i$ or
  - $\bar{s}_i = \sigma_i$
- capital input $k_i(s)$ satisfying (2) for $s_i \le \bar{s}_i$ and $k_i(s) = 0$ for $s_i > \bar{s}_i$ for all i
- energy input $e_i(s)$ satisfying (3) for $s_i \le \bar{s}_i$ and $e_i(s) = 0$ for $s_i > \bar{s}_i$ for all i
- a power price $\tilde{p}$ which clears the market i.e. $D(\tilde{p}) = \sum_i Q_i(p_i)$

In equilibrium the generation mix across technologies and distribution of profits across firms are well-defined and one can perform a comparative static analysis of how allocations respond to alternative policies. Below we approach these issues quantitatively.

4. Quantifying the model

The quantitative model developed below includes six technologies: wind (w), hydro (h) and solar (pv), which feature site-specific productivity; and coal (c), gas (g) and nuclear (n), which do not. In most real-world power systems, these technologies account for almost all power generation. For simplicity, we assume productivity is linear in the site index. That is,

$$A_i(s_i) = A_i - \omega_i s_i \tag{9}$$

with $A_i > 0$ and $\omega_i \ge 0$. We further assume that $F_i(k_i, e_i)$ is Cobb–Douglas

$$F_i(k_i, e_i) = k_i^{\alpha_i} e_i^{\theta_i} \tag{10}$$

[5] In Appendix D.2, we discuss the implications of a discrete change in the productivity of individual technologies, i.e. in $A_i(s_i)$. Expanding the set of technologies is beyond the scope of the current paper.

Table 1
Imposed parameters.
Source: Authors' calculations based on IEA (2015a).

	β_i	α_i	θ_i	δ_i	ω_i	ψ_i	A_d	ϵ
Wind	0.93	0.73	0	0.17	Table 4			
Hydro	0.93	0.82	0	0.06	Table 4			
Solar	0.93	0.78	0	0.17	Table 4			
Coal	0.93	0.31	0.58	0.11	0	0		
Gas	0.93	0.12	0.82	0.14	0	0		
Nuclear	0.93	0.84	0	0.07	0	0		
Demand							1	−0.35

Table 2
Average generation mix in eight selected EU countries (2012–2016).
Source: Authors' calculations based on Eurostat.

	ESP	DEU	DNK	FRA	GBR	ITA	POL	PRT	EU28
Wind	**0.20**	0.11	0.48	0.03	0.10	0.06	0.05	0.25	0.09
Hydro	**0.14**	0.05	0.00	0.12	0.03	0.20	0.02	0.27	0.13
Solar	**0.05**	0.06	0.02	0.01	0.02	0.09	0.00	0.01	0.03
Coal	**0.17**	0.48	0.40	0.02	0.30	0.18	0.87	0.27	0.27
Gas	**0.22**	0.14	0.11	0.04	0.34	0.47	0.06	0.20	0.19
Nuclear	**0.22**	0.16	0.00	0.77	0.22	0.00	0.00	0.00	0.29

with cost shares of capital and fossil fuels given by α_i and θ_i, respectively. We ignore labour input because its cost share in power generation is small. These functional forms impose sufficient structure to capture the high-level features of the six generation technologies under some restrictions on ω_i and θ_i.

The distinguishing features of hydro, wind and solar are site-specific productivity and the absence of fossil fuel inputs from the production. We implement this by setting $\omega_i > 0$ and $\theta_i = 0$ for $i \in \{w, h, pv\}$.[6] The productivity of coal, gas and nuclear generation is site-*in*dependent but only the former two technologies require fossil fuel inputs. Therefore, we set $\omega_i = 0$ and $\theta_i > 0$ for $i \in \{c, g\}$, and $\omega_n = 0$ and $\theta_n = 0$.[7]

For coal, gas and nuclear, the solution strategy for the marginal site $\bar{s}_i$ no longer works because if $v_i(k_i, e_i; 0) > 0$, then it is positive for all $s_i > 0$ and the more profitable technology among the three captures the entire market. However, complete specialisation is not observed in practice. We capture this in the model with political-economy constraints due to social (e.g. NIMBYism) and/or political (e.g. lobbying by would-be competitors) pressures that induce the government to restrict the coal, gas and nuclear sites, even when additional sites would have been profitable. Specifically, we assume that the government restricts the site space to $[0, 1]$ for these firms by setting $\sigma_i = 1$ for $i \in \{c, g, n\}$.[8] This is equivalent to shutting down site-specificity at the outset by imposing $A_i(s_i) = A_i$ so that s_i is not a choice.

Given these functional form assumptions and parameter restrictions, we now discuss how the other parameters are selected. We impose the values of the (i) discount factors, (ii) cost share parameters, and (iii) depreciation rates based on IEA (2015b) as well as the parameters of the demand function A_d and ϵ. These are reported in Table 1 and additional details regarding their selection can be found in Appendix A.1.

The remaining parameters of the model are jointly selected so that the model's equilibrium matches the high-level features of a well-diversified power system, such as that of Spain. To be clear, this is not a detailed calibration but merely ensures that the parameters of the model are not too far from the relevant region of the parameter space. Spain is a suitable target for a number of reasons. First, Table 2 shows that it has a relatively balanced generation mix. Second, it has ample

[6] With $\theta_i = 0$, the solution to (3) trivially implies $e_i^*(s_i) = 0$.

[7] Nuclear fuel costs are included in the capital costs since trade in nuclear fuel is regulated and price-inelastic.

[8] $\sigma_i = 1$ is without loss of generality when $\omega_i = 0$ because (5) implies that in any specific parameterisation only the product $\sigma_i A_i$ matters for firm-level variables.

Table 3
Evolution of generation and emission mix in Spain.
Source: Authors' calculations based on Eurostat and IEA.

		1990	2000	2010	2011	2012	2013	2014	2015	2016	2012–16
Generation (%)	Wind	0.00	0.02	0.16	0.16	0.18	0.21	0.20	0.19	0.19	**0.20**
	Hydro	0.18	0.16	0.16	0.12	0.09	0.15	0.17	0.12	0.16	**0.14**
	Solar	0.00	0.00	0.03	0.03	0.04	0.05	0.05	0.05	0.05	**0.05**
	Coal	0.42	0.40	0.09	0.16	0.20	0.15	0.17	0.20	0.14	**0.17**
	Gas	0.02	0.11	0.34	0.32	0.27	0.22	0.19	0.21	0.21	**0.22**
	Nuclear	0.38	0.31	0.22	0.21	0.22	0.21	0.22	0.22	0.23	**0.22**
Emis.	$\frac{\text{Coal}}{\text{Gas}}$	96.67	12.05	0.74	1.44	2.03	1.93	2.63	2.53	1.86	**2.20**
	$\frac{\text{Coal+Gas}}{\text{Total}}$	0.29	0.30	0.23	0.28	0.30	0.25	0.26	0.28	0.23	**0.26**

Notes: The final two rows show power sector emissions from coal and gas combustion relative to each other and their sum as a share of economy-wide emissions, respectively.

potential to expand its renewable generation, in particular hydro. In contrast, Germany and the UK have used up a large share of their hydro potential, which is quite small to start with (Eurelectric, 2011).

It is also not unreasonable to assume that Spain satisfies the condition for a stationary equilibrium when the data are averaged over 2012–2016 to minimise the effect of year-to-year fluctuations. The top panel of Table 3 illustrates the evolution of the Spanish power generation mix over the 1990–2016 based on the same underlying Eurostat data as in Table 2. Prior to 2012 one observes important and persistent trends in the share of individual technologies. However, these trends are much less prominent after 2012 despite the economic and policy upheaval the country experienced in early 2010s (IEA, 2015a). Using data from the International Energy Agency, the bottom panel of the table shows that emissions from coal and gas are also roughly stable after 2012, both relative to each other and as a share of aggregate emissions.

The generation mix averaged over 2012–2016 is by itself not sufficient to determine the intercept and slope parameters in $A_i(s_i) = A_i - \omega_i s_i$ for wind, hydro and solar. In fact, three additional targets are required to determine ω_i for these technologies. To that end we use the maximum feasible generation that can be achieved given the constraints imposed by physical geography as well as by the existing grid technology and institutional arrangements. In Appendix A.2 we discuss in detail how we these constraints determine the maximum feasible generation potential. Here we note that the factors restricting the technologies' potential are different for hydro versus wind and solar. Hydro potential is primarily constrained by a country's physical geography, e.g. its precipitation patterns, topography and river/fluvial system. For wind and solar, physical geography also plays a role but there are additional constraints imposed by intermittency. These are absent from the model but interact with physical geography constraints in practice. For example, storage capacity is currently extremely limited, and the existing grid infrastructure and power market arrangements are not optimised for the intermittency or the spatial dispersion of wind and solar sites.

Next we introduce four normalisations. We use capital as numeraire, i.e. set the price of a unit of capital $\tilde{p}_k = 1$. We also set the fixed site development cost $\psi_i = 1$ for wind, hydro and solar. This normalisation is equivalent to letting site size vary across the technologies and is innocuous so long as we are careful in interpreting the levels of $\bar{s}_i$.

Finally, we determine the fossil fuel prices p_{ec} and p_{eg} assuming that the total power sector emissions in Spain is 1. Using this along with the fact that coal generates twice the carbon emissions that gas does per unit of useful energy, i.e. $2E_c + E_g = 1$, we match the observed ratio of carbon emissions from Spain's coal and gas plants which averages 2.20 over 2012–16 as shown in the lower panel of Table 3. Given the imposed parameters, we solve the equations which characterise the model's equilibrium for the remaining parameter values. Table 4 reports these parameter values and targets.

To summarise, Tables 1 and 4 provide the values of all parameters required to compute the benchmark (hereafter BM) equilibrium of the model. The values of the endogenous variables in the BM equilibrium are provided in Table 5. Given our normalisations, the level of the price, quantity and emissions are 1 in the BM equilibrium so are not shown in the table. By construction, the generation mix in the first column is identical to the Spanish average mix over 2012–2016. The next three columns report the index of the marginal site for each firm[9]; aggregate capital used in production; and fossil energy input for coal and gas firms, respectively. The final column reports the value of each firm in the BM equilibrium, which is obtained by integrating (1) over the interval $[0, \bar{s}_i]$. It can be interpreted as the firm's stock market value.

In the next section, we keep all parameters constant but introduce *new* policies. We emphasise the adjective 'new' because all existing policies and distortions that have a bearing on the power market equilibrium are subsumed into the BM parameters. Observe that with our normalisations the levels of variables in equilibrium are not straightforward to interpret in monetary and physical units. Accordingly, our focus below is on changes relative to the BM equilibrium.

Table 4
Parameters and normalisations in benchmark model.
Source: Authors' calculations based on the paper's model, Eurostat and IEA.

Parameter	Value	Note
A_w	0.36	Target $\sum_i Q_i = 1$ and i's share in generation mix Q_i
A_h	0.21	
A_{pv}	0.35	
A_c	0.47	
A_g	0.74	
A_n	0.18	
ω_w	0.09	Target $Q_i/Q_i^{max} = 0.50$ for $i = w, pv$ and $Q_h/Q_h^{max} = 0.58$
ω_h	0.11	
ω_{pv}	0.35	
$\tilde{p}_k$	1	Normalisation
$\tilde{\Psi}_w$	1	
$\tilde{\Psi}_h$	1	
$\tilde{\Psi}_{pv}$	1	
$\tilde{p}_{ec}$	0.29	Target $2E_c + E_g = 1$ and $2E_c/E_g = 2.20$
$\tilde{p}_{eg}$	0.58	

Table 5
Benchmark equilibrium allocations.

	Q_i^{BM}	$\bar{s}_i^{BM}$	K_i^{BM}	E_i^{BM}	V_i^{BM}
Wind	0.195	0.566	0.596	na	0.192
Hydro	0.138	0.240	0.897	na	0.117
Solar	0.051	0.121	0.166	na	0.043
Coal	0.172	1	0.295	0.344	0.268
Gas	0.221	1	0.126	0.313	0.177
Nuclear	0.223	1	1.301	na	0.510
Aggregate	1.000		3.382	0.656	1.305

[9] Recall that the binding political-economy constraints are implemented by setting $\sigma_c = \sigma_g = \sigma_n = 1$.

5. Results and discussion

Our quantitative analysis fixes the stringency of new policies at 40% emissions reduction. This target is broadly in line with the EU GHG emission targets for 2030, both in aggregate and for those sectors covered by the EU ETS which includes the power sector.[10] The fact that the stringency is the same across policies allows us to abstract from their climate change benefits in our analysis. A novel aspect of our analysis is the model's ability to keep track of the government's fiscal position which is described in Appendix B using examples.

We present our main results in Tables 6 and 7, which have a standardised structure. The first two rows report the percentage deviation of aggregate variables, namely the equilibrium price and quantity. The next three rows provide information on the response of wind, hydro and solar generation to policy intervention. Specifically, they highlight the relative importance of the extensive margin by reporting the additional generation coming from the newly developed sites Q_i^{ns} as a share of the policy-induced increase in generation ($Q_i - Q_i^{BM}$). The percentage change in firm i's value in response to the policy-induced changes in equilibrium prices and allocations is given in the next six rows.

The final four rows are relevant for comparing the welfare impact of policy interventions. They report the level differences in welfare components relative to the BM equilibrium. Specifically, these components are the changes in the discounted value of: the power sector $\Delta_V = \sum_i (V_i - V_i^{BM})$ in aggregate; the net revenues of the government $\Delta_{NR} = NR - NR^{BM}$; and the consumer surplus $\Delta_{CS} = CS - CS^{BM}$. The overall measure of welfare Δ is the sum of the preceding three components. Welfare is measured in real terms although its units are unspecified given our normalisations. However, the magnitudes are comparable across components given a policy intervention, and across policies for a given component.

5.1. Taxes and subsidies

Consider Table 6 first. The carbon, coal and power consumption taxes in columns (i), (ii) and (iii) are set to reduce emissions by 40%. A carbon tax increases the equilibrium power price paid by the consumer by 2.9% and reduces demand by 1.0%, whereas a coal tax results in a more modest increase of 1.2% in the price. In contrast, under the power consumption tax the price paid by the consumer increases by more than 140%. An important difference between input taxes on fossil fuels and the consumption tax is that the former increase value of all firms that are not subject to the tax by shifting generation towards them.

The increase in generation by wind, hydro and solar firms in response to the carbon and coal taxes comes from both the intensive margin (i.e. by increasing capital input in existing sites) and the extensive margin (i.e. by developing new sites and installing capital) margins. For each firm, more than half of the output expansion is produced in newly developed sites. The consumption tax reduces the overall size of the market and generation by each firm so no new sites are developed. The value of all firms decline relative to the BM equilibrium because firms receive only a fraction of the price paid by consumers.

Among the policies we consider in this and the next section, the carbon tax in column (i) achieves the targeted reduction in emissions at the lowest cost. The cost is split between the coal and gas firms whose values decline, and consumers who experience a decline in consumer surplus. However, we note that the policy increases the values of the carbon-free wind, hydro, solar and nuclear firms. These increases more than compensate for the decline in the of value coal and gas firms, i.e. $\Delta_V > 0$. Moreover, the carbon tax generates revenues for the government. To put it in perspective, this value is approximately equal to the combined values of the solar and gas firms in the BM equilibrium. It is, however, not large enough to compensate the consumers for the loss in consumer surplus.

The substantial welfare cost of the power consumption tax is due to the decline in consumer surplus relative to the BM equilibrium and likely overestimates the actual drop in consumer surplus. This is because we are assuming a one-to-one relationship between power and power services. If instead power consumers can invest in improving their energy efficiency, the loss in consumer surplus will be more limited. However, in this case the aggregate costs of energy efficiency investments would have to be accounted for in the welfare measure.

The takeaway message from columns (i)–(iii) is that the carbon tax has the lowest welfare cost and does not adversely affect the values of carbon-free firms. This is in contrast to the power consumption tax, which is an extremely costly instrument for reducing emissions despite the sizeable tax revenues it generates. As we demonstrate below, the overall welfare cost of all other policies analysed below lie in between these two extremes.

Next in columns (iv)–(x), we turn to the implications of subsidy schemes benefiting carbon-free technologies. In column (iv) only the wind firm is offered an output subsidy while in column (v) it is given a capital input subsidy. Columns (vi)–(viii) provide the results for technology-specific capital input subsidies to hydro, solar and nuclear, respectively. These types of subsidies are all observed in practice (CEER, 2015). The final two columns report uniform subsidies to renewable and carbon-free technologies.

The changes in the equilibrium price and quantity are the same across all subsidy schemes: each scheme reduces the equilibrium price by 4.3%, increases power consumption by 1.6%. This is intuitive because without directly altering the incentives of the coal and gas firms, the government can only induce emissions reductions by engineering a lower equilibrium price. That is, the government implements the subsidy necessary to induce the power price which is consistent with the scaling back of coal and gas generation to reduce emissions. In turn this implies that the change in the value of coal and gas firms is also the same across columns (iv)–(x), namely −33.4% for coal and −54.6% for gas. Interestingly, given a choice between a carbon tax and various subsidies, both coal and gas firms would prefer the carbon tax, although the former would do so by only a small margin. This result is driven by the qualitatively different impact the policies have on the equilibrium price.

Focusing on the output and capital input subsidies to wind in columns (iv) and (v) we underline differences in the value of the wind firm and the government's net revenues. An output subsidy raises the returns to all inputs used in production, creating a windfall for the existing sites and capital stock. A capital input subsidy can discriminate between existing and new capital. It also introduces a small distortion between capital and sites by incentivising too high a reliance on the intensive margin. This can be observed in the Δ for these policies and in the lower share of new wind generation by newly-developed sites under the capital input subsidy.[11] The wind firm unambiguously prefers the output subsidy. Conversely, the government prefers the capital subsidy because its outlays are lower under the second and it is costly to raise the revenues required to pay for the subsidies.

Therefore, in the rest of the paper we report only the results for capital input subsidies because they are cheaper to finance than output subsidies. Comparing Δ and Δ_{NR} across columns (v) and (viii), we observe that if the government is restricted to support only one technology, trade-offs emerge. Subsidising nuclear to expand its production

[10] Coincidentally, the target is also consistent with Spain's draft National Energy and Climate Plan, which is available at https://ec.europa.eu/energy/sites/ener/files/documents/spain_draftnecp.pdf.

[11] The joint use of capital input *and* site development subsidies can remove the distortion and replicate the allocations under output subsidy in column (iv) with a smaller change in the value of the wind firm and in government revenues. The result are omitted for brevity.

Table 6
Implications of taxes and subsidies that reduce emissions by 40%.

	Tax			Technology-specific subsidy					Uniform Subsidy	
	Carbon (input) (i)	Coal (input) (ii)	Power (output) (iii)	Wind (output) (iv)	Wind (input) (v)	Hydro (input) (vi)	Solar (input) (vii)	Nuclear (input) (viii)	RES (input) (ix)	RES+N (input) (x)
$\%\Delta(\tilde{p}, p^{BM})$	2.9	1.2	144.4	−4.3	−4.3	−4.3	−4.3	−4.3	−4.3	−4.3
$\%\Delta(\sum_i Q_i, \sum_i Q_i^{BM})$	−1.0	−0.4	−26.9	1.6	1.6	1.6	1.6	1.6	1.6	1.6
$Q_w^{ns}/(Q_w - Q_w^{BM}) \times 100$	62.9	63.3	0.0	60.2	52.8	0.0	0.0	0.0	50.2	45.5
$Q_h^{ns}/(Q_h - Q_h^{BM}) \times 100$	50.5	50.9	0.0	0.0	0.0	43.8	0.0	0.0	42.8	40.7
$Q_{pv}^{ns}/(Q_{pv} - Q_{pv}^{BM}) \times 100$	60.5	60.9	0.0	0.0	0.0	0.0	51.9	0.0	50.6	47.4
$\%\Delta(V_w, V_w^{BM})$	46.8	18.5	−59.4	419.7	216.6	−59.4	−59.4	−59.4	43.9	8.5
$\%\Delta(V_h, V_h^{BM})$	55.8	21.7	−66.2	−66.2	−66.2	227.3	−66.2	−66.2	38.3	−6.7
$\%\Delta(V_{pv}, V_{pv}^{BM})$	56.2	22.0	−68.7	−68.7	−68.7	−68.7	1334.1	−68.7	67.6	18.0
$\%\Delta(V_c, V_c^{BM})$	−32.9	−62.2	−33.4	−33.4	−33.4	−33.4	−33.4	−33.4	−33.4	−33.4
$\%\Delta(V_g, V_g^{BM})$	−34.5	24.1	−54.6	−54.6	−54.6	−54.6	−54.6	−54.6	−54.6	−54.6
$\%\Delta(V_n, V_n^{BM})$	19.6	7.9	−24.2	−24.2	−24.2	−24.2	−24.2	55.2	−24.2	0.3
Δ_V	0.130	−0.014	−0.529	0.388	−0.001	−0.187	0.068	−0.125	−0.151	−0.168
Δ_{NR}	0.217	0.099	15.543	−1.419	−1.044	−0.838	−1.732	−0.843	−0.659	−0.565
Δ_{CS}	−0.413	−0.174	−17.313	0.623	0.623	0.623	0.623	0.623	0.623	0.623
Δ	−0.067	−0.088	−2.299	−0.408	−0.422	−0.402	−1.041	−0.345	−0.187	−0.110

Notes: Whether a tax/subsidy applies to input or output of the firm is indicated in parenthesis. Subsidies reduce the price of capital except in column (iv), where the subsidy augments the power price for the wind firm only. RES(+N) indicates uniform capital subsidies to renewable energy sources (+ Nuclear).

substantially, say by adding new reactors at existing sites, achieves the targeted emissions reduction at the lowest cost to society if government is restricted to use technology-specific subsidies only but might run into the same political-economy constraints captured by $\sigma_n = 1$. Moreover, it is more costly to the government than subsidising hydro. The total welfare and fiscal costs of subsidies to solar in column (vii) are about twice as large as other technology-specific subsidies. In fact, in order to reduce emissions using technology-specific subsidies to solar, the amount that the government must spend is so large that it is greater in magnitude than the aggregate value of all power sector firms in the BM equilibrium in Table 5. This is because the share of solar in generation is small to start with so its output must increase more than six-fold. Even though subsidising wind or hydro implies much lower welfare costs, these costs are much larger than that of a carbon tax achieving the same target.

A final observation on the technology-specific subsidies to carbon-free firms in columns (v)-(viii) relates to their side effects. In equilibrium, a technology-specific subsidy increases aggregate production and depresses the market price for all firms. At the same time it triggers a substantial reallocation of generation and profits across firms. This is because facing lower input costs than its competitors, the subsidy recipient increases production at each site, develops new sites and captures market share from its competitors. In contrast, the competitors, who face a lower market price, reduce their production and earn lower profits. The net result is a more unequal distribution of profits as a direct consequence of the subsidy.

The technology-neutral subsidy schemes in columns (ix) and (x), where all renewable and carbon-free technologies receive the same ad valorem subsidy, can limit the total cost of the scheme to the government, the welfare cost it imposes on society and the negative distributional consequences on the supply side. The welfare cost of these schemes, which simultaneously support multiple technologies, are approximately 30%–50% lower than a subsidy to the nuclear firm, the technology-specific alternative with the least welfare impact, in part because they make use of the extensive margin for all renewable technologies. While this suggests technology-neutral subsidies should be preferred to technology-specific ones, the welfare cost of a carbon tax is lower still, and in addition, it generates revenues for the government.[12]

[12] Site development subsidies are considered in Appendix C with results similar to capital input subsidies.

5.2. Subsidies financed by carbon or power taxes

In Table 7 we consider policy packages where the revenues for the subsidies must be raised within the power sector rather than using general tax revenue or borrowing. Specifically, the first four columns, (a)–(d) review the implications of technology-specific subsidies to renewable and nuclear technologies which are financed by a carbon tax, while columns (e) and (f) do the same for a uniform subsidy to all renewable and carbon-free technologies. In the final two columns, we report the results when the revenues from power consumption taxes pay for the uniform subsidies. In practice, both carbon prices and power consumption taxes have been used to pay for subsidy outlays in EU countries.

The value of coal and gas firms decline in columns (a)–(d) as they are adversely affected by both the carbon tax and a subsidy to one of their competitors. For a carbon-free firm that is not receiving the subsidy, the outcome is less clear a priori. On the one hand, the carbon tax gives them a comparative advantage relative to coal and gas. On the other hand, the subsidy to a carbon-free competitor can reverse some or all of this advantage. Quantitatively, each of these interventions increases the value of the non-emitting firms because the net effect of a technology-specific subsidy and a carbon tax is to increase the equilibrium power price. In other words and in stark contrast to the results with only a technology-specific subsidy (cf. columns (v)–(viii) of Table 6) carbon-tax-financed subsidies deliver an increase in the value of all carbon-free firms regardless of who is being subsidised while moderating the increase in the value of the firm receiving the subsidy. Finally, consumers also pay a share of the policy costs by reducing their consumption in response to a higher power price. That is, the result is a more equitable burden- and reward-sharing arrangement relative to technology-specific subsidies alone.

By offering neutral support to renewable or carbon-free technologies rather than a single one, uniform subsidies in columns (e) and (f) go further and imply even more equitable benefit- and burden-sharing. The excess welfare cost of policies in columns (a)–(f) range between 9%–90% with the uniform subsidies to carbon-free technologies financed by a carbon tax in column (f) coming closest to the cost-effective policy. In all cases, the policies induce an expansion in generation by all carbon-free technologies, which compensates for the decline in coal and gas generation to a large extent. For renewable technologies the expansion in output is achieved by increasing production along both the intensive and extensive margins.

The last two columns report the results when the uniform subsidies are financed using the proceeds from a power consumption tax. The

Table 7
Implications of capital input subsidies financed by carbon or power taxes to reduce emissions by 40%.

	Carbon tax to pay						Power tax to pay	
	Technology-specific subsidy				Uniform subsidy		Uniform subsidy	
	Wind (a)	Hydro (b)	Solar (c)	Nuclear (d)	RES (e)	RES+N (f)	RES (g)	RES+N (h)
$\%\Delta(\bar{p}, p^{BM})$	1.3	1.0	1.6	1.3	0.9	0.8	0.0	−0.6
$\%\Delta(\sum_i Q_i, \sum_i Q_i^{BM})$	−0.5	−0.4	−0.6	−0.4	−0.3	−0.3	0.0	0.2
$Q_w^{ns}/(Q_w - Q_w^{BM}) \times 100$	56.7	63.4	63.2	63.3	57.2	57.7	49.8	44.7
$Q_h^{ns}/(Q_h - Q_h^{BM}) \times 100$	50.9	46.0	50.8	50.9	46.7	47.0	42.7	40.3
$Q_{pv}^{ns}/(Q_{pv} - Q_{pv}^{BM}) \times 100$	60.9	61.0	54.3	60.9	55.8	56.2	50.3	46.8
$\%\Delta(V_w, V_w^{BM})$	89.4	15.2	25.4	19.3	47.1	35.8	38.6	5.7
$\%\Delta(V_h, V_h^{BM})$	24.0	107.3	29.9	22.7	50.4	37.7	31.3	−9.9
$\%\Delta(V_{pv}, V_{pv}^{BM})$	24.3	18.0	291.5	23.0	60.4	45.2	60.2	14.2
$\%\Delta(V_c, V_c^{BM})$	−32.9	−32.9	−32.9	−32.9	−32.9	−32.9	−33.4	−33.4
$\%\Delta(V_g, V_g^{BM})$	−39.0	−39.9	−38.1	−39.2	−40.3	−40.5	−54.6	−54.6
$\%\Delta(V_n, V_n^{BM})$	8.7	6.5	10.7	32.7	5.5	14.0	−24.2	−0.9
Δ_V	0.097	0.036	0.107	0.083	0.044	0.043	−0.173	−0.185
Δ_{NR}	0	0	0	0	0	0	0	0
Δ_{CS}	−0.191	−0.144	−0.235	−0.181	−0.123	−0.116	0.006	0.088
Δ	−0.094	−0.107	−0.127	−0.098	−0.080	−0.073	−0.167	−0.097

Notes: Subsidies reduce the price of capital. RES(+N) indicates uniform capital subsidies to renewable energy sources (+ Nuclear).

differences between them and columns (e)–(f) are substantial. Comparing columns (e) and (g), the difference is driven by the significant decline in the nuclear firm's generation share and market value, even though the aggregate market outcomes are indistinguishable from the BM equilibrium. Comparing (f) and (h), we underline that the positive effect of subsidies and the negative effect of power consumption taxes net out differently for different technologies. Specifically, the value of hydro and nuclear firms decline approximately 10% and 1% respectively despite the subsidy they receive while the wind and solar firms increase in value by 6% and 14% relative to the BM equilibrium.

To summarise, there are two main messages emerging from Table 7. First, taking the financing method as given, it is preferable to offer subsidies to as broad a set of carbon-free technologies as possible. Second, taking the set of subsidy recipients as given, it is preferable to finance the subsidies using the revenues from a carbon tax.

Finally, we note that Appendix D discusses the sensitivity of our results to alternative country contexts and parameterisations. Specifically, we reparameterise using data for France and Poland, where the generation mix is significantly different from Spain. Moreover, we vary key parameters in a systematic way. These changes have quantitative implications, however, our qualitative conclusions regarding the cost-effectiveness of policies and their supply-side distributional impacts are unaltered.

6. Conclusion and policy implications

This paper studies the distributional impact of carbon emissions reduction policies on power suppliers. We construct, parameterise and solve a partial equilibrium model of the power sector. A novel feature of the model is site-specific generation in key renewable technologies where productivity differs across sites. We use the model to analyse the differential effects of alternative policy instruments used by governments to reduce emissions. We also pay attention to how they affect the firms' value and the government's fiscal position.

Our analysis yields several policy messages. A carbon price is the cost-effective instrument to reduce power sector emissions. In our setup it can equivalently be implemented using a carbon tax or emissions trading. This is well-known but our model sheds light on the factors behind this result. Carbon pricing treats carbon-free firms equally, uses the extensive margin of renewable generation efficiently, and therefore improves the firms' market value.

A power consumption tax implies a very high welfare cost because it reduces the size of the power market, and by doing so decreases the value of all firms (both carbon-emitting and carbon-free) and reduces consumer surplus. From a welfare perspective, power consumption taxes should not be the instrument of choice, neither to reduce emissions, nor to finance subsidies aiming to reduce emissions.

Technology-specific input subsidies can be designed to achieve emissions reduction at the same welfare cost as output subsidies. From a welfare perspective, therefore, they are substitutes. However, firms will prefer output subsidies, because they increase their market value by more, while the government would rather offer input subsidies, because they are cheaper to finance. Importantly, these subsidies can hurt carbon-free generators that are not subsidised by making them lose market share and profits. Technology-specific subsidies financed by a carbon tax result in a more equitable distribution of the burden and rewards of climate policies than those financed by general tax revenues. However, while they are more cost-effective than subsidies financed by general tax revenues or borrowing, they are not as effective as carbon pricing alone.

We abstract from many relevant aspects of reality to isolate the distributional channels we are interested in. There are no externalities in the model which are often the main justification for subsidies in real-world contexts. For example, the innovation externalities in renewables generation are well documented but we assume technology is constant, deterministic and exogenous. Similarly, the higher power prices induced by power consumption taxes are often justified as a means of encouraging energy efficiency. To the extent that higher power prices remove barriers to energy conservation, their negative welfare effect will be diminished. Energy storage, e.g. greater hydro capacity or batteries, is absent from the model. Adding it would improve the productivity of intermittent generation. Our model takes as given the existence of a grid infrastructure, the vintage and sophistication of which affects generators differently and may result in under- or delayed investment in modernising it. Methodologically, time and uncertainty are important but missing. By considering these explicitly, the model can go beyond characterising the broad features of a policy-driven low-carbon economy and study the challenging issues in the dynamic transition to it.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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Appendix. Supplementary information

Supplementary material related to this article can be found online at https://doi.org/10.1016/j.enpol.2019.111205. The references cited in the Appendix can be found below under Further reading.

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