WORKING PAPERS

N° TSE-591

Juillet 2015

"Do costs fall faster than revenues? Dynamics of renewables entry into electricity markets"

Richard J. Green, Thomas-Olivier Léautier

Toulouse School of Economics

Do costs fall faster than revenues?
Dynamics of renewables entry into electricity markets

Richard J. Green* Thomas-Olivier Léautier†

June 26, 2015

Abstract

In many countries, entry of renewable electricity producers has been supported by subsidies and financed by a tax on electricity consumed. This article is the first to analytically derive the dynamics of the generation mix, subsidy, and tax as renewable capacity increases. This enables us to complement and extend previous work by providing analytical expressions for previously obtained simulation results, and deriving additional results. The analysis yields three main findings. First, the subsidy to renewable may never stop, as the value of the energy produced may decrease faster than the cost as renewable capacity increases. Second, high renewable penetration leads to a discontinuity in marginal values, after which the subsidy and tax grow extremely rapidly. Finally, reducing the occurrence of negative prices, for example by providing renewable producers with financial instead of physical dispatch insurance, yields significant benefits.

Keywords: electric power markets, renewables, public policy

JEL Classification: L11, L94, D61

1 Introduction

In many European countries and American states, support for renewable electricity production has been an essential energy policy initiative of the last decade. In the United States, 30 states and the District of Columbia have renewable portfolio standards that require electricity retailers to procure a minimum percentage of their supplies from renewable generators, while seven states have voluntary goals. The European Union's climate-energy package requires 20% of all the energy consumed in the EU to come from renewable sources in 2020. The most cost-effective way of meeting this goal will be to source much more than 20% of electricity from renewable generators. As a result of such policies, the share of non-hydro renewables in world electric power production has grown tremendously, from 1.7% in 2000 to 9.1% in 2014.[1]

*Imperial College, London. r.green@imperial.ac.uk

†Corresponding author. Toulouse School of Economics (IAE, IDEI, CRM). thomas.leautier@tse-fr.eu

[1] `http://fs-unep-centre.org/publications/global-trends-renewable-energy-investment-2015`.

Through a variety of mechanisms, governments have subsidized the installation of renewable production. The simplest justification for subsidizing renewables is that they contribute to reducing carbon emissions. The correct economic argument is more subtle and relies on learning. The most efficient approach to reduce carbon emissions is to price carbon, either through a tax or an emissions market (see Gollier and Tirole, 2015 for a recent and comprehensive discussion of the tax vs. market debate). However, even with a high carbon tax, the first MW of most types of renewable capacity costs more to install than the market value of the electricity it produces. On the other hand, installing that first MW generates a positive externality, since learning-by-doing reduces the cost of installing the next MW. Furthermore, if equipment manufacturers anticipate that a large volume of renewables will be installed, they invest in large facilities, which can also significantly reduce the cost of installing future MW of renewables.

This argument justifies subsidizing at least the first MW of renewable installed capacity. It is widely anticipated that the required subsidy will decrease over time as costs decrease and if fuel and (particularly) carbon prices rise over time, and drop to zero when the cost of renewable capacity is equal to the market value of the electricity produced. Therefore, policy makers in many jurisdictions have implemented renewable support mechanisms, typically financed through a unit tax on electricity sales. The magnitude of these subsidies is significant: the International Energy Agency[2] estimates \$ 101 billion was spent on renewables subsidies in 2012, including \$ 57 billion in the European Union, and \$ 21 billion in the United States, and anticipates subsidies will rise to \$ 220 billion by 2035. These subsidies are usually financed through a unit tax on power consumed. For example, the renewable energy levy in Germany is around 62 €/MWh in 2015, 50% higher than the wholesale power price.

The irruption of renewables has had a significant impact on the electricity industry, and has generated a rich academic literature, reviewed in Section 2. Despite this wealth of analyses and the magnitude of the sums involved, this article is the first to derive analytically the joint dynamics of the generation mix, subsidy, tax, and resulting net surplus. Thus it complements and extends previous work by providing analytical expressions for previously obtained simulation results, and deriving additional results. In addition we test these results and provide empirical estimates for the specific case of Great Britain.

This article produces analytical and policy contributions. Our analytical results fall into three broad categories. First, we derive the marginal impact of renewables entry. We start by representing the dominant renewable support regime used in Europe, characterized by fixed-price support mechanisms (i.e., renewables receive a pre-agreed fixed payment per MWh to cover their cost) and physical dispatch insurance (i.e., renewables are always dispatched, unless system security is threatened). We first derive the dynamics of equilibrium conventional capacity (Proposition 1). As renewable capacity increases, two effects (usually) reduce conventional capacity: (i) renewable capacity replaces conventional capacity, and (ii) the renewable tax (usually) increases, hence reduces demand. We then derive the dynamics of the marginal value of renewable capacity (Proposition 2).

[2] `http://www.iea.org/media/files/WEO2013factsheets.pdf`

As the capacity of renewable technology j increases, the marginal value of renewable technology i decreases proportionally to the covariance between the availabilities of technologies i and j on the vertical segments of the supply curve.

We then examine the dynamics of renewable subsidies. For a marginal renewable unit, the subsidy is the difference between its total cost, which is decreasing as renewable capacity increases, and the value of the energy it produces, which is also decreasing by Proposition 2. As long as the installed capacity of renewables is small, the cost reduction effect dominates and the subsidy to the marginal unit decreases. However, when the renewable capacity installed is large enough the second effect may dominate and the subsidy to the marginal unit may increase, contrary to previous expectations. This argument is formalized in Proposition 3.

Furthermore, installing a marginal renewable energy unit reduces the value of all (infra-marginal) energy produced by this technology, and may reduce the value of all energy produced by other renewable technologies. For example, installing a new off-shore wind farm reduces the market value of wind energy produced, hence increases the subsidy required by for all wind farms. Therefore, the tax required must increase to cover the subsidy of the marginal unit as well as the change of subsidy for all inframarginal units (Proposition 4).

Finally, we derive the marginal net surplus loss (Proposition 5). We prove it is the marginal subsidy, plus the deadweight loss resulting from the marginal demand reduction, and use the previous results to derive an analytical expression.

Second, we examine cumulative effects. If renewable entry is large enough, the baseload technology, which usually produces for every hour of the year, may stop doing so. This creates a discontinuity in the marginal values: for example, the marginal subsidy increases much faster if the baseload technology no longer produces. We derive this result under two polar situations: (i) fully inflexible baseload technology, i.e., producers are willing to receive a price lower than marginal costs for some hours to avoid shut-down and start-up costs, in which case high renewable capacity may lead baseload technology to disappear from the long-term equilibrium (Proposition 6); and (ii) fully flexible baseload technology (Proposition 7), in which case high renewable capacity may lead baseload technology to stop producing, even if it remains included in the long-term equilibrium generation mix. Ours is the first article to analytically characterize this discontinuity.

Our third analytical result is the impact of financial dispatch insurance, an alternative renewable support scheme: renewables are always paid for their available output, but only dispatched as long as the wholesale price is positive. We prove that, by putting a floor under power prices, it increases the marginal value of renewable capacity and thus reduces the required subsidy and tax (Proposition 8).

Applying this analysis, we compute the impact of renewable subsidies in Great Britain, using the model developed by Green and Vasilakos (2011), with an updated dataset. It is essential to specify that the value of renewable generation is boosted by our inclusion of a 70 £/ton carbon price in the model, reflecting projections which see this price rising significantly from current levels over the lifetime of power stations now being planned. We include two renewable technologies: onshore and offshore wind turbines.

We first consider entry of 30 GW renewable capacity, leading to 25% of electricity being produced from renewables, the level implied by the more ambitious UK targets for the early 2020s. The market value of the first increment of onshore wind capacity is 200 £/kW per year, decreasing to 150 £/kW per year for 30 GW renewable capacity, and 280 £/kW per year decreasing to 220 £/kW per year for offshore wind capacity.[3] The marginal subsidy to onshore wind remains constant around 50 £/kW per year, and decreases from 350 £/kW per year to 150 £/kW per year for offshore wind. The cumulative subsidy is financed by a unit tax on all MWh sold, that increases to 13 £/MWh.

The inflexible baseload technology (nuclear) is driven out of the market when renewable entry reaches 45 GW, which corresponds to 38% of electricity produced from renewables. As suggested by Proposition 6, marginal values are discontinuous when this occurs. For example, when renewable capacity increases from 40 GW to 50 GW, the marginal subsidy increases from 50 £/kW per year to 150 £/kW per year for onshore wind, from 130 £/kW per year to 240 £/kW per year for offshore wind, while the unit tax more than doubles from 17 £/MWh to 38 £/MWh, and continues to increase to 128 £/MWh for 60 GW. The cumulative loss in net surplus increases to £ 11 billions per year.

This result shows that the current support mechanism cannot be used to accommodate large scale renewable entry. Thus, we propose an alternative support policy, financial dispatch insurance: renewables producers receive a fixed payment for every MWh available, wether it is actually produced or not. This approach significantly reduces the cost of supporting renewables: for 60 GW of renewables installed, the required tax is 25 £/MWh, and the net surplus loss £ 6.5 billions per year.

Our policy recommendations are the following. First, to compute renewable subsidies, policy makers should compare the cost of a renewable unit to the value of the electricity it produces, and not to the average value of electricity, and incorporate the impact of marginal renewables on the value of the energy from infra-marginal renewables when designing policies. This is essential to anticipate the tax that customers will have to pay.

Second, policy makers should design renewable support mechanisms that minimize the impact of negative prices. Financial dispatch insurance is one such solution, that increases the financial viability of baseload technologies and reduces the subsidy required for renewables. This is essential to de-carbonize electricity production, since in many countries the baseload technology is inflexible low CO_2 emitting nuclear generation.

Finally, if renewables are to be subsidized, the renewable capacity target should be set to avoid the convex part of the welfare loss. This would imply less than 40 GW of total wind capacity in Great Britain, assuming the current learning rate and the other parameters used here.

This article is structured as follows: Section 2 briefly discusses renewables support policies implemented in Europe and the United States. Section 3 presents the general model. Section 4 derives the marginal impact of renewables when they are supported through a fixed-price contract

[3]Market values and subsidies are rounded up to the nearest £10.

and receive physical dispatch insurance. Section 5 applies the analysis to Great Britain. Section 6 examines different support mechanisms. Technical proofs are presented in the Appendix.

2 Renewable support policies

Hydro-electric generators have been a feature of the electricity industry since its earliest days, but the large-scale adoption of other types of renewable generator is a relatively recent phenomenon. It has inspired a very large literature, summarized in Edenhofer et al. (2011) and Bruckner et al. (2014); we pick out some key themes relevant to this paper.

2.1 Justification for renewable support

Several arguments are used to justify renewable support. While the focus of this work is on the impact of the support mechanism, not their justification, it is nevertheless worth summarizing them. The obvious argument is that renewable energy displaces carbon emissions and reduces the risk of severe climate change. This is in fact a second-best argument, since the effects of carbon emissions are a negative externality that ought to be corrected directly with a carbon price arising from a tax or a market for emissions (Gollier and Tirole, 2015). This advice may not be politically feasible, however, since it would lead to significant increases in the price of energy, with costs to consumer-voters. Fabra and Reguant (2014) show that the pass-through of emissions costs in a European electricity market has been close to 100%. The risk of carbon leakage, driving production to countries that have not imposed carbon prices is also perceived to be significant, rightly or wrongly. In this paper, however, we assume that a carbon price *is* in effect and need other justifications for separately supporting renewable energy. Cullen (2013) found that the cost of emissions avoided by wind power in Texas was currently greater than most estimates of the cost of carbon and other pollutants, implying that such support would be needed.

As mentioned in the introduction, the most common argument for supporting renewables in the presence of a carbon price arises from the magnitude of the learning curve to develop the renewable technologies (reported for example by Baker et al., 2013, Lindman and Söderholm, 2012, and van der Zwaan et al., 2012). The first units deployed cost more than the conventional technology, but as more renewable generators use new technologies, learning by doing and the chance of obtaining economies of scale means that future units will cost less. Neuhoff (2008) shows that if at some future date it will be optimal to deploy large amounts of renewable capacity, but that there are limits to the rate at which investment can rise, a further justification for subsidy now is that this will create a larger renewable industry, better able to expand production in future.

Proponents of industrial policy argue that supporting renewable energy can create jobs in manufacturing wind turbines or solar panels. This is most likely to be a good policy where a strong exporting industry can be established, as with the Danish wind turbine company Vestas. Making renewable generators purely for the domestic market will create jobs in that sector, but the resulting higher price of power risks destroying jobs in energy-using sectors, and it is unclear whether the net gain is positive[4].

Another argument for supporting renewable energy is that increased use of domestically-generated renewable power can reduce the amount of fuel that must be imported from abroad, with benefits for energy security. This is true, but it is also the case that the availability of many renewable generators depends on the weather, and this can create a security risk of its own, unless adequate backup is available.

2.2 Renewable support approaches

There are three main approaches to supporting renewable generation. One is to require the local grid company (or some other agency) to purchase all the output from a renewable generator at a fixed price and to sell it on to retailers and ultimately to consumers. The cost of these purchases is added to consumers' bills.

The fixed price can be set administratively, or be market-based. The first situation is usually called a Feed-in Tariff (FiT), and has been the primary support mechanism used in France for example. A FiT gives price security to the generator, but has often created an open-ended promise to pay this price to any generator that meets the eligibility conditions. An over-generous price can lead developers to add a large amount of capacity in a short period of time, risking the affordability of the scheme. A more market-based approach is to have the fixed-price arise from a competitive outcome. For example, the UK uses Contracts for Differences for renewable generators which will make payments that vary inversely with an appropriate wholesale price, so that the contract payment and the wholesale price together should give a predictable income stream, equivalent to a FiT. Renewables producers compete[5] for these CfDs.

A second approach concentrates on the quantity of renewable power to be procured, rather than its price. The US Renewable Portfolio Standards require retailers to procure output from renewable generators but need not lay down any conditions on how this is done. In Europe, tradable green certificate schemes require retailers to acquire certificates equal to a set proportion of their sales, or to pay a buy-out fee. Generators are given certificates for each unit of renewable power they produce, which they can sell to retailers; they also have to sell their power in the wholesale market or through long-term contracts. Long-term contracts can give revenue security to the renewable generator, but selling in the wholesale market creates a price risk.

The third approach requires the generator to sell its power in the wholesale market (or via a contract) but tops up this revenue with additional payments. In Europe, this is typically in the form of a fixed payment derived from electricity consumers, a premium FiT or Feed-in Premium (FIP). In the United States, a renewable tax credit gives a rebate on corporate taxes for each MWh

[4] For example, a consulting report published in 2009 found an ambiguous impact in Europe http://temis.documentation.developpement-durable.gouv.fr/documents/Temis/0064/Temis-0064479/17802.pdf

[5] The Department of Energy and Climate Change published on 26 February 2015 the result of the first auction , available at https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/407059/Contracts_for_Difference_-_Auction_Results_-_Official_Statistics.pdf

generated, and comes at the expense of taxpayers. In its renewable support guidelines[6] published in 2014, the European Commission is recommending a move towards FIP, and many countries, such as Spain and Germany, already use both FITs and FIPs.

2.3 Impact on electricity markets

Impact on average prices Over the last few years, the rapid rise in renewable capacity in Europe has depressed market prices. Since the marginal cost of wind (or solar) generation is effectively zero, it pushes the industry's supply curve to the right, so that this intersects with demand at a lower equilibrium price, a feature named the merit-order effect.

The merit-order effect is a disequilibrium phenomenon, however, because the lower prices mean that some (or all) conventional stations will be unable to recover their full economic costs. This may lead to retirements, or at the very least a shortage of new investment, and so the industry's conventional capacity should fall over time. The capacity mix should also change, with less baseload capacity (with low variable costs but high fixed costs which are only worth incurring if the station can run for long periods) and more peaking stations that are cheap to build, but expensive to use (Green and Vasilakos, 2011).

The time-weighted average price of power in a long-run equilibrium should not depend on the amount of renewable capacity, since this price will tend to the average cost of a baseload station. The demand-weighted average price might change. If there is more renewable output, on average, at times of high demand (for example, solar power in a system with summer-peaking demands) then the demand-weighted price will be reduced as renewable capacity grows.

Impact on operating reserves Electricity must be generated (or taken from storage) at the exact moment that it is required, but the output of many kinds of renewable generator is intermittent, depending on the varying strength of the wind or the sun. This means that it is not possible to retire 1 GW of conventional capacity when 1 GW of wind capacity is added to the industry's capital stock, since the wind stations may not generate at the time of peak demand. Furthermore, if the wind changes over a large area of the country at once, this could lead to a significant and rapid fall in the amount of wind generation. System Operators (SOs) cope with unpredictable unavailability by securing operating reserves: they always run some stations part-loaded so that they can increase output if another station fails.

It is expected that increasing the share of renewables in a market will increase the required operating reserves. Recent engineering studies (for example, Bertsch et al., 2015) suggest that the availability of these operating reserves should not be an issue: renewables will lead to a higher share of mid-merit and peaking-plants, which will be able to provide the required flexibility.

However, the costs of providing these reserves is not negligible. Gowrisankaran et al. (2013) show that the cost of intermittency for solar power in Arizona is around 12 \$/MWh if the SO adjusts its reserve levels to cope with the fluctuations (particularly short-term changes) in solar output, but

[6] `http://europa.eu/rapid/press-release_IP-14-400_en.htm`

far higher if the SO continues with traditional levels of reserves. A well-connected country like Denmark can manage this issue by trading power with its neighbors, although at a cost of between 4 and 8 per cent of the value of the energy produced (Green and Vasilakos, 2012).

Impact on the value of renewable generation The reason that Denmark loses money when trading wind with its neighbors is the negative short-run correlation between wholesale electricity prices and the amount of wind energy generated. If renewable generation is above average for the time of day and the season, then the market price will be below average *(ceteris paribus)*, creating this negative correlation. The greater the renewable capacity, the stronger this effect will be (Twomey and Neuhoff, 2010).

The pattern of average output may counteract this correlation for small amounts of renewable capacity. For example, the average wind speed in Great Britain is higher in the winter than in the summer, and so are average electricity prices, so that the average price received by a wind farm will be higher than the time-weighted average wholesale price - as long as there is not too much renewable capacity. As the level of capacity grows, however, the negative correlation brought about by short-run variations around the seasonal average becomes more important and the wind farms' average revenues will fall. Joskow (2011) points out that these interactions between the time of generation and the value of the electricity produced mean that their levelized costs of generation are a very poor measure of the relative competitiveness of different technologies. Numerical estimates of the size of these effects have been estimated for California by Mills and Wiser (2012) and for Germany by Hirth (2013), among other studies.

Whether it starts above or below the time-weighted average price, the average market price weighted by renewable output will fall as renewable capacity increases. A rich literature, reviewed for example by Hirth (2015) has characterized this value drop of renewables as their penetration increases. These works differ from ours in several important dimensions: (i) they rely on numerical simulations, while we provide analytical results, (ii) most consider inelastic demand, hence minimize generation costs, while we consider elastic demand, hence maximize net surplus and include the impact of the renewable tax, and (iii) most do not include learning-by-doing, while we do.

3 A model of the electric power market with renewables

3.1 Demand

All customers are homogenous. Individual demand is $D(p+\tau,\theta)$, where p is the wholesale electricity price, $\tau \geq 0$ is a per-unit tax levied to cover the cost of subsidizing renewable generators, and θ is the state of the world, distributed on $\mathbb{R}^+$ according to cumulative densify function $F(.)$, and probability density function $f(.) = F'(.)$. The distribution of states of the world combines two effects. First, demand varies across the year: demand is higher during the week than during the weekend, higher in the winter than in the summer in Europe due to electric heating, higher in the summer than in the winter in the United States due to air conditioning. Second, demand for a given hour varies randomly, for example due to temperature variations.

Inverse demand $P(Q,\theta)$ is assumed to be downward sloping: $\forall\theta \geq 0$, $\forall Q$, $P_q(Q,\theta) < 0$. This condition is met for example if inverse demand is linear with constant slope $P(Q,\theta) = a(\theta) - bQ$, with $b > 0$.

3.2 Supply

$(N+I)$ generation technologies are available: N conventional technologies indexed by $n \in [1,N]$, and I renewable technologies corresponding to $n = 0$ and indexed by $i \in [1,I]$. For $n \geq 1$, c_n is the constant marginal operating cost and r_n is the constant hourly marginal fixed cost of technology n (i.e., annual marginal annuitised capital cost plus fixed annual operating and maintenance costs expressed in $£/MW/year$ divided by $8,760$ hours per year), both expressed in $£/MWh$. Without loss of generality, conventional generation technologies are ordered by increasing operating cost: $c_n > c_m \; \forall \; n \geq m$. There is a trade-off between capital and operating costs: if a technology requires lower capital cost, it then produces at higher operating cost, i.e., $r_n < r_m \; \forall \; n \geq m$. In general, not all available technologies are present at the long-term equilibrium. To simplify the exposition, $n = 1$ (resp. $n = N$) denotes the first (resp. the last) conventional technology before renewables are introduced.

For conventional technologies $n \geq 1$, k_n is the installed capacity of technology n, and $K_n = \sum_{m=1}^{n} k_m$ is the cumulative installed conventional capacity up to technology n.

In practice, the base load technology 1 has often very high startup costs, which reduces its startup and shutdown flexibility. For example, nuclear units are extremely costly to start up after shutting down, hence their operators attempt to run them permanently. A full representation of these startup costs requires complex modeling. Green and Vasilakos (2011) propose a simplifying approach: inflexibility is represented by a minimum production level $m_1 k_1$. This article follows the same approach. The base case is no baseload flexibility, i.e., $m_1 = 1$. This reflects the past situation in the UK, when it was difficult to operate gas-cooled reactors at less than full capacity. On the other hand, pressurized water reactors, as used in France (and the likely candidates for future UK stations) can be ramped down to relatively low levels of output. The cost of doing so is an incomplete fuel "burn", reducing the total output available from a given set of fuel rods. We have no data on the size of this effect, which would tend to reduce the marginal cost of generation and raise the fixed cost by an offsetting amount. We choose to model the case of full flexibility, i.e., $m_1 = 0$, with no change in costs, even though we are aware that this over-estimates the actual situation. Since reality is somewhere between the two extremes we consider, we are therefore confident that our results are robust.

3.3 Renewable generators

We consider I renewable technologies, for example onshore wind, offshore wind, and photovoltaic panels. For $i = 1, ..., I$, denote by K_0^i the installed capacity of renewable technology i, $\mathbf{K}_0 \in \mathbb{R}^I$ the vector of installed renewable capacities K_0^i, $r_0^i\left(K_0^i\right)$ the marginal capital cost of renewable technology i, $R_0^i\left(K_0^i\right)=\int_0^{K_0^i} r_0^i(x)\,dx$ the cumulative capital cost of renewable capacity K_0^i, and $R_0(\mathbf{K}_0)=\sum_{i=1}^{I} R_0^i\left(K_0^i\right)$ the aggregate cumulative capital cost of renewable capacities $\mathbf{K}_0$.

For all renewable technologies, variable operating cost is negligible, i.e., $c_0^i=0$. Learning by doing and economies of scale imply that $r_0^i(.)$ is decreasing in K_0^i: installing an additional offshore wind turbine reduces the cost of the next offshore wind turbine. We assume that there are no cross-technology externalities from learning or economies of scale: installing an additional onshore wind turbine does not significantly reduce the cost of the next offshore wind turbine. Thus,

$$R_0(\mathbf{K}_0)=\sum_{i=1}^{I}\int_0^{K_0^i} r_0^i(x)\,dx \Leftrightarrow \frac{\partial R_0}{\partial K_0^i}=r_0^i\left(K_0^i\right).$$

This assumption can be relaxed in further work, should empirical evidence prove it does not hold.

Renewable technology is often intermittent (e.g., wind and solar). Availability of renewable technology i in state θ is $\alpha^i(\theta)\in[0,1]$, hence available production from renewable technology i in state θ is $\alpha^i(\theta)\,K_0^i$. This could reflect two dimensions of intermittency. First, renewables can be predictably unavailable, for example, the sun does not shine at night, or the wind is forecast to be low. The impact on the residual demand, i.e., demand net of renewable production, varies with the type of renewables available and the shape of the demand curve. For example, in California or Arizona, demand is highest when the sun shines and Air Conditioning is on, which precisely coincides with the highest production from solar panels (Gowrisankaran et al., 2013). This is not the case in northern Europe, where most (installed) renewables are wind turbines, which produce more in winter than in summer (with higher average wind speeds then) but generate very little on the cold, calm days which often see the very highest demands (Oswald et al., 2008).

This implies that adding 1 MW of renewable capacity does not lead to a $\mathbb{E}\left[\alpha^i(\theta)\right]$ MW reduction in conventional generation capacity (let alone a 1 MW reduction). This substitution effect is captured in equations (5) below.

Second, renewables may be unpredictably unavailable to an extent which requires the SO to procure additional flexibility. This aspect is not included in the model, given that doing so would add significant complexity and that the long-term cost of providing this may be small, as discussed in Section 2.3.

3.4 Wholesale market structure and equilibrium

We suppose the market is centralized, i.e., an SO receives bids from all producers and consumers, selects the optimal dispatch (defined later), and declares a unique market price. This constitutes an adequate description of US markets. European markets are decentralized, hence buyers and sellers transact either in power exchanges or bilaterally, then communicate their negotiated transactions to the SO, who takes any actions needed to ensure a feasible and secure dispatch. Since we focus this analysis on the distortions caused by renewables support policy, we assume competition is perfect, hence both approaches are equivalent. We also abstract from transmission constraints.

Thus, in every state of the world, the SO assigns the dispatch rate $u_n(\theta) \in [0,1]$ to each technology $n \geq 0$. Production from technology $n \geq 1$ is $u_n(\theta) k_n$, and production from renewable technology i is $u_0^i(\theta) \alpha^i(\theta) K_0^i$. If technology 1 inflexible, $u_1(\theta) = 1$. Up until Section 6, renewable technologies receive physical dispatch insurance. They have dispatch priority, i.e., $u_0^i(\theta) = 1$. This is the case in most jurisdictions, where the SO can cut renewables off only when the operational security of the system is threatened, a situation we do not model. Section 6 discusses an alternative approach, that allows the SO to cut renewables off when price drops down to zero, while still paying for the energy they would have produced.

The supply curve is a "staircase" (Figure 1): on the horizontal portions, the wholesale price is the marginal cost of the marginal technology producing; on the vertical portions, the marginal technology produces at capacity, and the wholesale price is set by the intersection of the demand curve and the vertical supply curve, minus the tax.

FIGURE 1 ABOUT HERE

The long-run equilibrium wholesale price in state θ when $\mathbf{K}_0$ has already been installed is $p(\mathbf{K}_0, \theta)$. Recalling that $c_0 = 0$ and using the convention $c_{N+1} \to +\infty$, the steps of the staircase are formally defined for $0 \leq n \leq N$ by $v_n = \{\theta : c_n < p(\mathbf{K}_0, \theta) < c_{n+1}\}$ and $h_n = \{\theta : p(\mathbf{K}_0, \theta) = c_n\}$. The sets v_n and h_n are functions of $\mathbf{K}_0$. To simplify the notation, the reference is omitted.

While technology 1 earns a negative operational margin when $p(\mathbf{K}_0, \theta) < c_1$, it still produces since it cannot reduce its output. As we will see below, invested capacity in technology 1 is determined to precisely balance the positive and negative margins. When baseload generation is inflexible, $h_1 = \emptyset$ since price is never set at c_1. Similarly, when renewables receive physical dispatch insurance, $h_0 = \emptyset$ since price is never set at 0.

On h_n for $n \geq 2$ technology n produces at the margin, and

$$K_{n-1} + u_n(\theta) k_n + \sum_{i=1}^{I} \alpha^i(\theta) K_0^i = D(c_n + \tau, \theta).$$

On v_n, technology $n \geq 1$ produces at capacity and technology $(n+1)$ does not produce, price is determined by the intersection of the vertical supply curve and the demand curve:

$$K_n + \sum_{i=1}^{I} \alpha^i(\theta) K_0^i = D(p(\mathbf{K}_0, \theta) + \tau, \theta) \Leftrightarrow p(\mathbf{K}_0, \theta) = P\left(K_n + \sum_{i=1}^{I} \alpha^i(\theta) K_0^i, \theta\right) - \tau.$$

Finally, in a competitive equilibrium, investors in non-renewable generators invest until their marginal profit is equal to zero, which yields

$$\mathbb{E}\left[(p(\mathbf{K}_0, \theta) - c_n) u_n(\theta)\right] = r_n, \ \textit{for } n \geq 1. \tag{1}$$

In the long-term equilibrium, the conventional generation mix optimally adapts to renewable technology installed capacities $\mathbf{K}_0$.

3.5 Renewable support policy

The market value of energy produced by renewable technology i is $\mathbb{E}\left[\alpha^i(\theta)\,p(\mathbf{K}_0,\theta)\right]$. In many cases, it is less than the generator's cost, and it would not be viable without some kind of state support. The simplest method, used in many markets, is for policy makers to commit to purchase power generated by renewables at a pre-agreed rate, which insulates them from the wholesale market and its price risk. We assume that this rate can be exactly adjusted as capacity is added and renewable costs fall, so that the fixed price $f^i\left(K_0^i\right)$ for the marginal investor is the minimum required amount to precisely cover the marginal capital cost:

$$f^i\left(K_0^i\right)\mathbb{E}\left[\alpha^i(\theta)\right] = r_0^i\left(K_0^i\right).$$

This approach constitutes a first-best benchmark. For example, the SOs (or a government agency) runs a series of calls for tenders until cumulative capacity is $\mathbf{K}_0$, and competition among developers is perfect, hence the price is driven down to the cost. When FITs are used, policy makers find it hard to control capacity increments. If the FIT is set to cover $r_0^i(0)$, a very large number of producers will wish to enter, since by construction $r_0^i\left(K_0^i\right) < r_0^i(0)$. This creates rents for renewable investors who can add capacity before the FIT is reduced, which reduce net surplus, since the taxes to pay for them create a Dead Weight Loss. We therefore estimate a lower bound of the net surplus loss from subsidizing renewables.

For installed renewable capacity K_0^i, the cumulated expected revenues from the fixed price contracts cover exactly the cumulative capital cost

$$\int_0^{K_0^i} f^j(x)\,\mathbb{E}\left[\alpha^i(\theta)\right]dx = R_0^i\left(K_0^i\right).$$

The subsidy required by a marginal unit of technology i when $\mathbf{K}_0$ has been installed, denoted $\varphi^i(\mathbf{K}_0)$, is the difference, when positive, between the marginal cost and the marginal value:

$$\varphi^i(\mathbf{K}_0) = \max\left(r_0^i\left(K_0^i\right) - \mathbb{E}\left[\alpha^i(\theta)\,p(\mathbf{K}_0,\theta)\right], 0\right). \tag{2}$$

For technology i, the cumulative subsidy up to K_0^i, denoted $\Phi^i(\mathbf{K}_0)$, is the difference between the fixed payments to producers and the revenues from sale of renewable energy:

$$\Phi^i(\mathbf{K}_0) = R_0^i\left(K_0^i\right) - \mathbb{E}\left[\alpha^i(\theta)\,p(\mathbf{K}_0,\theta)\right]K_0^i.$$

This relation can be aggregated over all renewable technologies. The cumulative subsidy up to $\mathbf{K}_0$ is the difference between the fixed payments to producers and the revenues from sale of renewable energy:

$$\Phi(\mathbf{K}_0) = R_0(\mathbf{K}_0) - \sum_{i=1}^{I} \mathbb{E}\left[\alpha^i(\theta)\, p(\mathbf{K}_0, \theta)\right] K_0^i. \tag{3}$$

This subsidy is financed through a unit tax on the retail power price of τ paid by all users. Denoting the expected demand by $\bar{D}(\mathbf{K}_0) = \mathbb{E}[D(p(\mathbf{K}_0,\theta) + \tau(\mathbf{K}_0), \theta)]$, the unit tax is determined by

$$\tau(\mathbf{K}_0)\, \mathbb{E}[D(p(\mathbf{K}_0,\theta) + \tau(\mathbf{K}_0), \theta)] = \Phi(\mathbf{K}_0). \tag{4}$$

In practice, the realized availability rate and demand may be higher or lower than expected, and the tax may adjust for the previous year's out-turn. We abstract from this issue, as we ignore potential risk aversion.

Even with a carbon tax, the first MW of renewable production must be subsidized: $\varphi^i(0) > 0$ for all i. However, it is widely believed that $r_0^i(.)$ is decreasing sufficiently rapidly that $\varphi^i(.)$ is decreasing, and there exists $\bar{\mathbf{K}}_0 > 0$ such that $\varphi^i\left(\bar{\mathbf{K}}_0\right) = 0$, hence subsidies will no longer be required for all $K_0^i \geq \bar{K}_0^i$. Expression (2) illustrates that this common wisdom may not stand up to rigorous economic analysis. There may exist a $\bar{\mathbf{K}}_0 > 0$ such that $\varphi^i\left(\bar{\mathbf{K}}_0\right) = 0$. However, as K_0^i increases, $p(\mathbf{K}_0, \theta)$ decreases (as will be proven below), and so $\varphi^i(\mathbf{K}_0)$ may become negative again. This article precisely explores this dynamic.

In the remainder of this article, we assume that costs are such that all technologies must be subsidized, i.e., $\varphi^i(\mathbf{K}_0) > 0$. This simplifies the notation without altering the economic insights. It is verified empirically on the examples we consider.

We present a static model: policy makers set a target renewable capacity $\mathbf{K}_0$, and perfectly adjust the subsidy to cover the marginal investment cost $r_0^i(x)$ for all $x \leq K_0^i$. Thus, we ignore the temporal dimension: all periods are collapsed into one. Extending the model to different periods would simply make the notation more complex, and lead to the same economic intuition.

4 Marginal impact of renewables

This Section derives the marginal impact of renewable capacity on conventional capacities, subsidies, taxes, and welfare. The analysis follows the standard peak load pricing model (see for example Boiteux, 1949). For the reader's convenience, the derivations are presented in Appendix A.

The main difference with the standard model is that a tax on the electricity price is levied to finance the subsidy. The tax covers only the cost of the renewable production. The cost of grid enhancements required to accommodate renewables are included in the grid rate, hence not covered by this analysis.

The economic optimum would be for the SO to set the retail price (which determines consumption) equal to the marginal cost of power. The wholesale price would then be the retail price minus the tax, lower than the short-term marginal cost c_n when technology n is marginal. This is unrealistic. Producers are unwilling to participate in a market that guarantees price lower than c_n when they are marginal. Therefore we include a producers' participation constraint. Denote $u_n(\theta) \in [0,1]$ the utilization factor of technology n. For $n > 1$, the participation constraint for producer n is

$$(p(\mathbf{K}_0, \theta) - c_n) u_n(\theta) \geq 0.$$

Inflexible technology 1 is slightly different, for it faces significant startup costs. To avoid shutting down, producer 1 is willing to accept a price lower than c_1 for a few hours. Therefore, the participation constraint for producer 1 is that average profit is equal to zero, as will later be discussed.

Two mutually exclusive situations are possible: positive investment in the baseload technology occurs at the long-term equilibrium, or renewables entry is so large that no baseload technology is present at the long-term equilibrium. The economic intuition is identical, but the details of the analysis are slightly different for each case. For ease of exposition, we examine each in turn. Finally, we extend the results to flexible baseload.

4.1 Baseload technology present at the long-term equilibrium

Throughout this subsection, renewable capacity is assumed to be small enough that baseload technology is present at the equilibrium. We first establish the following:

Lemma 1. *The expected price on the vertical segments of the supply curve does not vary with installed renewable capacity. Specifically, for all $i \geq 1$*

$$\mathbb{E}\left[\frac{\partial p(\mathbf{K}_0, \theta)}{\partial K_0^i} | p(\mathbf{K}_0, \theta) < c_2\right] = 0,$$

and for all $n \geq 2$,

$$\mathbb{E}\left[\frac{\partial p(\mathbf{K}_0, \theta)}{\partial K_0^i} | v_n\right] = 0.$$

The time weighted average price is constant:

$$\frac{\partial}{\partial K_0^i} \mathbb{E}\left[p(\mathbf{K}_0, \theta)\right] = 0.$$

Proof. The results are standard in the peak load pricing literature. At the long-run equilibrium, the expected price on the vertical segments of the supply curve is set to yield profits equal to the capital cost of the marginal technology, and hence does not depend on the renewable capacity. Similarly, since the baseload technology cannot be turned off, it produces all the time. At the long-run equilibrium, the time-weighted average price is equal to the long-run marginal cost of the baseload technology, hence does not depend on the renewable capacity. For the reader's convenience, formal proofs are presented in Appendix B.1. □

4.1.1 Marginal impact on conventional capacity

Proposition 1. *Installed conventional capacity changes as renewable capacity increases for two reasons: demand changes through the change in unit tax, and renewable capacity substitutes for conventional capacity. Specifically,*

$$\frac{\partial K_1}{\partial K_0^i} = \frac{\frac{\partial \tau}{\partial K_0^i} - \mathbb{E}\left[P_q \alpha^i(\theta) \,|p(\mathbf{K}_0,\theta) < c_2\right]}{\mathbb{E}\left[P_q \,|p(\mathbf{K}_0,\theta) < c_2\right]},$$

and for $n \geq 2$,

$$\frac{\partial K_n}{\partial K_0^i} = \frac{\frac{\partial \tau}{\partial K_0^i} - \mathbb{E}\left[P_q \alpha^i(\theta) \,|v_n\right]}{\mathbb{E}\left[P_q \,|v_n\right]}. \tag{5}$$

Proof. For $n \geq 2$, $\mathbb{E}\left[\frac{\partial p}{\partial K_0^i} \,|v_n\right] = 0$ yields

$$\mathbb{E}\left[\left(P_q\left(K_n + \sum_{j=1}^{I} \alpha^j(\theta) K_0^j, \theta\right) \times \left(\frac{\partial K_n}{\partial K_0^i} + \alpha^i(\theta)\right) - \frac{\partial \tau}{\partial K_0^i}\right) |v_n\right] = 0.$$

Rearranging yields equations (5). The same argument applies for $n = 1$ on the vertical $\{\theta : p(\mathbf{K}_0, \theta) < c_2\}$. □

Intuition for equation (5) is easier to obtain when assuming inverse demand is linear with constant slope, $P(Q,\theta) = a(\theta) - bQ$, in which case it simplifies to

$$\frac{\partial K_n}{\partial K_0^i} = -\frac{1}{b}\frac{\partial \tau}{\partial K_0^i} - \mathbb{E}\left[\alpha^i(\theta) \,|v_n\right]$$

for $n \geq 2$, and

$$\frac{\partial K_1}{\partial K_0^i} = -\frac{1}{b}\frac{\partial \tau}{\partial K_0^i} - \mathbb{E}\left[\alpha^i(\theta) \,|p(\mathbf{K}_0,\theta) < c_2\right].$$

The change in K_n is the sum of two effects. First, the tax usually increases, hence demand decreases, and so does K_n. Second, technology n is replaced by the renewable technology. Cumulative capacity is determined by the expected margin when the technologies produce at capacity. If $\alpha^i(\theta)$ is constant on v_n, increasing K_0 by 1 reduces K_n by α^i. If $\alpha^i(\theta)$ is not constant, increasing K_0 by 1 reduces K_n by the expectation of $\alpha^i(\theta)$, conditional on K_n being at capacity.

If demand is not linear with constant slope, these substitution effects are weighted by the slope of the demand function.

If renewable capacity is very large, we may reach a point where $K_n(\mathbf{K}_0) = 0$. This is examined in Section 4.2.

Finally, Proposition 1 enables us to determine the impact of renewable capacity on expected demand $\bar{D}(\mathbf{K}_0)$:

Corollary 1. *The marginal impact of* K_0^i *on expected demand* $\bar{D}(\mathbf{K}_0)$ *is*

$$\frac{\partial \bar{D}}{\partial K_0^i} = -\frac{1}{B}\frac{\partial \tau}{\partial K_0^i} + \Gamma^i, \tag{6}$$

where

$$\frac{1}{B} = -\sum_{n=2}^{N}\left(\mathbb{E}\left[\frac{\partial D(c_n+\tau,\theta)}{\partial p}\,|h_n\right] \times \Pr(h_n) + \frac{\Pr(v_n)}{\mathbb{E}[P_q\,|v_n]}\right) - \frac{\Pr(p<c_2)}{\mathbb{E}[P_q\,|p<c_2]},$$

and

$$\begin{aligned}\Gamma^i \;=\; & \sum_{n=2}^{N}\left(\mathbb{E}\left[\alpha^i(\theta)\,|v_n\right] - \frac{\mathbb{E}\left[\alpha^i(\theta)\,P_q\,|v_n\right]}{\mathbb{E}[P_q\,|v_n]}\right)\Pr(v_n)\\ & + \left(\mathbb{E}\left[\alpha^i(\theta)\,|p<c_2\right] - \frac{\mathbb{E}\left[\alpha^i(\theta)\,P_q\,|p<c_2\right]}{\mathbb{E}[P_q\,|p<c_2]}\right)\Pr(p<c_2).\end{aligned}$$

Proof. The proof is presented in Appendix B.2. □

Suppose again inverse demand is linear with constant slope $P(Q,\theta) = a(\theta) - bQ$. Then, $B = b$, $\Gamma^i = 0$, and equation (6) simplifies to

$$\frac{\partial \bar{D}}{\partial K_0^i} = -\frac{1}{b}\frac{\partial \tau}{\partial K_0^i}.$$

An increase in K_0^i leads to a change in tax. If demand is linear with constant slope, this leads to a proportional change in expected demand. As will be shown later, under reasonable assumptions, $\frac{\partial \tau}{\partial K_0^i} \geq 0$: the tax increases to finance an increase in renewable target capacity. The tax effect is thus negative: as renewable capacity increases, so does the tax, and demand decreases.

4.1.2 Marginal impact on the value of renewable capacity

We now determine the impact of the level of renewable capacity on its marginal value:

Proposition 2. *The marginal impact of* K_0^i *on the marginal value of renewable technology* j *is*

$$\frac{\partial}{\partial K_0^i}\mathbb{E}\left[\alpha^j(\theta)\,p(\theta,\mathbf{K}_0)\right] = \mathbb{E}\left[\alpha^j(\theta)\,\frac{\partial p}{\partial K_0^i}\right] = -\Gamma^j\frac{\partial \tau}{\partial K_0^i} - E^{ij}, \tag{7}$$

where

$$\begin{aligned}E^{ij} \;=\; & \sum_{n=2}^{N}\left(\frac{\mathbb{E}\left[P_q\alpha^i\,|v_n\right]\mathbb{E}\left[P_q\alpha^j\,|v_n\right]}{\mathbb{E}[P_q\,|v_n]} - \mathbb{E}\left[P_q\alpha^i,\alpha^j\,|v_n\right]\right)\Pr(v_n)\\ & + \left(\frac{\mathbb{E}\left[P_q\alpha^i\,|p<c_2\right]\mathbb{E}\left[P_q\alpha^j\,|p<c_2\right]}{\mathbb{E}[P_q\,|p<c_2]} - \mathbb{E}\left[P_q\alpha^i,\alpha^j\,|p<c_2\right]\right)\Pr(p<c_2).\end{aligned}$$

Proof. The proof is presented in Appendix B.3. □

If demand is linear with constant slope,

$$E^{ij} = b\left(\sum_{n=2}^{N} cov\left[\alpha^i, \alpha^j \left|v_n\right.\right]\Pr\left(v_n\right) + cov\left[\alpha^i, \alpha^j \left|p < c_2\right.\right]\Pr\left(p < c_2\right)\right) = b\widehat{cov}_{\mathbf{K}_0}\left[\alpha^i\left(\theta\right), \alpha^j\left(\theta\right)\right],$$

hence equation (7) simplifies to

$$\mathbb{E}\left[\alpha^j\left(\theta\right)\frac{\partial p}{\partial K_0^i}\right] = -b\widehat{cov}_{\mathbf{K}_0}\left[\alpha^i\left(\theta\right), \alpha^j\left(\theta\right)\right]. \tag{8}$$

An increase in K_0^i has two impacts on the amount of capacity producing on v_n: it increases renewable output by $\alpha^i\left(\theta\right)$ in state θ, and it reduces cumulative conventional capacity by $\mathbb{E}\left[\alpha^i\left(\theta\right)\left|v_n\right.\right]$. Multiplying by $\alpha^j\left(\theta\right)$ and taking the expectation yields the covariance. The result follows since inverse demand is linear with constant slope. The subscript $_{\mathbf{K}_0}$ is added since v_n depends on $\mathbf{K}_0$.

If demand is not linear with constant slope, additional terms corresponding to the variation of the slope are added to equations (6) and (7).

4.1.3 Subsidy for the marginal unit

Proposition 2 leads to the following:

Proposition 3. *If demand is linear with constant slope, the subsidy required by a marginal unit of technology i may increase as renewable capacity i increases, and increases as renewable capacity j increases if and only if availabilities on the vertical segments of the supply curve are positively correlated .*

Proof. The subsidy to the marginal unit is

$$\varphi^i\left(\mathbf{K}_0\right) = r_0^i\left(K_0^i\right) - \mathbb{E}\left[\alpha^i\left(\theta\right)p\left(\mathbf{K}_0, \theta\right)\right],$$

hence

$$\frac{\partial\varphi^i\left(\mathbf{K}_0\right)}{\partial K_0^i} = \frac{d}{dK_0^i}r_0^i\left(K_0^i\right) + b\widehat{var}_{\mathbf{K}_0}\left[\alpha^i\left(\theta\right)\right].$$

The first term is negative since marginal cost is decreasing, while the second is positive. This proves the first point. Then,

$$\frac{\partial\varphi^i\left(\mathbf{K}_0\right)}{\partial K_0^j} = b\widehat{cov}_{\mathbf{K}_0}\left[\alpha^j\left(\theta\right), \alpha^i\left(\theta\right)\right]$$

proves the second point. □

The first point of Proposition 3 illustrates the race between falling costs and falling prices. For low capacity, significant learning effects are present, hence falling costs probably outweigh falling prices. As capacity increases, costs fall much more slowly, and maybe not sufficiently to compensate the price decrease. The subsidy will then increase.

The second point of Proposition 3 illustrates the complementarity and substitutability of technologies: if the outputs from two technologies are positively correlated, increasing the capacity of one increases the supply and hence reduces the price available to the other one, and so increases the required subsidy.

4.1.4 Marginal impact on tax

Differentiation of equation (4) with respect to K_0^i yields

$$\frac{\partial \tau}{\partial K_0^i} \bar{D}(\mathbf{K}_0) + \tau \frac{\partial \bar{D}}{\partial K_0^i} = r_0^i \left(K_0^i\right) - \mathbb{E}\left[\alpha^i(\theta) p(\mathbf{K}_0, \theta)\right] - \sum_{j=1}^{I} \mathbb{E}\left[\alpha^j(\theta) \frac{\partial p}{\partial K_0^i}\right] K_0^j$$

$\Leftrightarrow$

$$\frac{\partial \tau}{\partial K_0^i} \bar{D}(\mathbf{K}_0) = \varphi^i \left(K_0^i\right) - \tau \frac{\partial \bar{D}}{\partial K_0^i} - \sum_{j=1}^{I} \mathbb{E}\left[\alpha^j(\theta) \frac{\partial p}{\partial K_0^i}\right] K_0^j. \tag{9}$$

To finance incremental renewable capacity, the gross tax receipts $\frac{\partial \tau}{\partial K_0^i} \bar{D}(\mathbf{K}_0)$ must change to cover the subsidy to the marginal unit $\varphi^i \left(K_0^i\right)$ and the reduction in tax receipts, due to the demand reduction $\tau \frac{\partial \bar{D}}{\partial K_0^i}$. If increasing renewable capacity i decreases the value of all inframarginal units, a third cost is added: the reduction in market value of all inframarginal renewables benefitting from the feed-in tariff.

While the decreasing market value of renewables has been observed in practice and discussed in the literature, we believe the link to the subsidy dynamics is original to this work. When granting a fixed price contract, policy makers commit the customers to a fixed payment to a renewable producer, hence their net liability is this payment minus the market value of this renewable capacity. As more fixed price contracts are granted, the market value of renewable energy (usually) decreases, and the liability (usually) increases.

Using previous results, we now establish the following:

Proposition 4. *The marginal change in tax is*

$$\frac{\partial \tau}{\partial K_0^i} = \frac{B\left(\varphi^i(\mathbf{K}_0) + \sum_{j=1}^{I} E^{ij} K_0^j + \tau(\mathbf{K}_0) \Gamma^i\right)}{B \bar{D}(\mathbf{K}_0) - \tau(\mathbf{K}_0) + B \sum_{j=1}^{I} \Gamma^j K_0^j}. \tag{10}$$

Proof. Inserting equations (6) and (7) into expression (9) yields

$$\frac{\partial \tau}{\partial K_0^i} \left(\bar{D} - \frac{\tau}{B} + \sum_{j=1}^{I} \Gamma^j K_0^j\right) - \Gamma^i \tau + \mathbb{E}\left[p(\mathbf{K}_0, \theta) \alpha^i(\theta)\right] - \sum_{j=1}^{I} E^{ij} K_0^j = r_0^i \left(K_0^i\right)$$

which leads to equation (10). □

If demand is linear with constant slope, equation (10) yields

$$\bar{D}\left(\mathbf{K}_0\right) \frac{\partial \tau}{\partial K_0^i} = \frac{1}{1 - \frac{\tau(\mathbf{K}_0)}{b\bar{D}(\mathbf{K}_0)}} \left(\varphi^i\left(\mathbf{K}_0\right) + b \sum_{j=1}^{I} \widehat{cov}_{\mathbf{K}_0}\left[\alpha^i\left(\theta\right), \alpha^j\left(\theta\right)\right] K_0^j \right),$$

which illustrates the marginal impact of K_0^i on tax. First, the tax must increase to cover the marginal subsidy $\varphi^i\left(\mathbf{K}_0\right)$. Second, the tax must change to cover the changes in the value of all other renewable capacity. Finally, this change is magnified by the factor $\frac{1}{1-\frac{\tau(\mathbf{K}_0)}{b\bar{D}(\mathbf{K}_0)}} > 1$ to account for the deadweight loss from taxes.

4.1.5 Marginal impact on net surplus

We now compute the change in net surplus caused by a marginal increase in renewable capacity. Since this analysis focusses on net surplus, and not overall welfare, it ignores distributional issues. Significant rents are being created and destroyed by the rapid and large increase of renewable capacity in Europe. Renewable generators and equipment manufacturers share rents when the prices paid for their output exceed the true cost of production. Conventional generators have lost a significant amount of money when the expansion of renewable capacity has depressed wholesale market prices and forced them to close existing capacity before the end of its technical lifetime. In a few cases, of course, the same person or company may own both conventional and renewable assets. These effects (and the externalities created for those who live near wind farms) are very important for the political economy of renewable energy, but are not the primary focus of this analysis.

Proposition 5. *The marginal net hourly surplus, including investment cost, is*

$$\frac{\partial H}{\partial K_0^i} = -\left(\varphi^i\left(\mathbf{K}_0\right) + \tau\left(\mathbf{K}_0\right)\Gamma^i + \frac{\tau\left(\mathbf{K}_0\right)\left(\varphi^i\left(\mathbf{K}_0\right) + \sum_{j=1}^{I} E^{ij} K_0^j + \tau\left(\mathbf{K}_0\right)\Gamma^i\right)}{B\bar{D}\left(\mathbf{K}_0\right) - \tau\left(\mathbf{K}_0\right) + B\sum_{j=1}^{I}\Gamma^j K_0^j} \right). \tag{11}$$

Proof. The full proof is presented in Appendix B.4. The envelope theorem (and a bit of algebra) yields

$$\frac{dH}{\partial K_0^i} = -\varphi^i\left(\mathbf{K}_0\right) + \tau \frac{\partial \bar{D}}{\partial K_0^i}.$$

A marginal increase in renewable capacity reduces the surplus by the subsidy $\varphi^i\left(\mathbf{K}_0\right)$, and, since the subsidy leads to a tax increase, by a deadweight loss $\left(\tau \frac{\partial \bar{D}}{\partial K_0^i} < 0\right)$. Then, inserting equations (6) and (10) leads to equation (11). □

4.2 Conventional technologies disappearing at the long-term equilibrium

As indicated by Proposition 1, conventional capacity is likely to decrease as renewable capacity increases. How are the previous results modified when technology n is no longer present at the long-term equilibrium?

Proposition 6. *If technology $n \geq 2$ is no longer present at the long-term equilibrium, the above results still hold, with the convention that $v_n = h_n = \emptyset$. Marginal value is continuously differentiable everywhere (i.e., $\frac{\partial}{\partial K_0^i}\mathbb{E}\left[\alpha^j(\theta)\, p(\theta, \mathbf{K}_0)\right]$ is continuous for $\mathbf{K}_0$ such that $K_n(\mathbf{K}_0) = 0$).*

If technology $n = 1$ is no longer present at the equilibrium, an additional term is included in all expressions. For example, the general expression for the marginal impact of renewables on expected price is

$$\frac{\partial}{\partial K_0^i}\mathbb{E}\left[p(\mathbf{K}_0, \theta)\right] = \mathbb{E}\left[\left(P_q \alpha^i(\theta) - \frac{\partial \tau}{\partial K_0^i}\right)\mathbb{I}_{\{p(\mathbf{K}_0,\theta)<c_2\}}\right]\mathbb{I}_{\{K_1=0\}},$$

where $\mathbb{I}_{\{\mathrm{x}\geq 0\}}$ is the indicator function that takes the value 1 if $x \geq 0$, and 0 otherwise. The general expression for the slope of the marginal value of renewable capacity is

$$\mathbb{E}\left[a^j(\theta)\frac{\partial p}{\partial K_0^i}\right] = \Gamma^j \frac{\partial \tau}{\partial K_0^i} - E^{ij} + \left(\frac{\mathbb{E}\left[P_q \alpha^j(\theta)\,|p < c_2\right]}{\mathbb{E}\left[P_q\,|p < c_2\right]}\mathbb{E}\left[\left(P_q \alpha^i(\theta) - \frac{\partial \tau}{\partial K_0^i}\right)\mathbb{I}_{\{p(\mathbf{K}_0,\theta)<c_2\}}\right]\right)\mathbb{I}_{\{K_1=0\}}. \tag{12}$$

Proof. The proof is presented in Appendix C.1. □

The first result confirms the intuition that there is nothing unique about the technologies included in the dispatch. In other words, more (or fewer) technologies can be included, without modifying the expressions. Continuity of the derivatives when one technology disappear arises because the supply curve is continuous.

A baseload technology that always run at full capacity is different. When $K_1 > 0$, the decrease in K_1 mitigates the supply effect of increasing K_0^i. When $K_1 = 0$, this mitigating effect disappears, and the price decrease on v_1 is larger by a factor $\left(-\mathbb{E}\left[P_q \alpha^i(\theta)\,|v_1\right] + \frac{\partial \tau}{\partial K_0^i}\right)$.

The marginal value is no longer continuous at the boundary $K_1 = 0$. Since it decreases faster for $K_1 = 0$, the subsidy for the marginal unit, the unit tax, and the marginal welfare loss increase faster. This is verified empirically by the simulation for Great Britain presented in Section 5.

4.3 Flexible baseload technology

One could conclude from the previous analysis that the simplicity of the expressions previously obtained is mostly attributable to the assumption that the baseload technology is completely inflexible. This is not accurate, as shown below:

Proposition 7. *Suppose the baseload technology is flexible. The average price is no longer constant:*

$$\frac{\partial}{\partial K_0^i}\mathbb{E}\left[p(\mathbf{K}_0, \theta)\right] = \mathbb{E}\left[\left(P_q\left(\sum_{j=1}^{I}\alpha^j(\theta)\,K_0^j, \theta\right)\alpha^i(\theta) - \frac{\partial \tau}{\partial K_0^i}\right)\mathbb{I}_{\{p(\mathbf{K}_0,\theta)<c_1\}}\right].$$

The slope of the value of renewable technology j is:

$$\mathbb{E}\left[a^j(\theta)\frac{\partial p}{\partial K_0^i}\right] = \Gamma^j \frac{\partial \tau}{\partial K_0^i} - E^{ij} + \frac{\mathbb{E}\left[\alpha^j(\theta)\, P_q\,|p(\mathbf{K}_0,\theta) < c_1\right]}{\mathbb{E}\left[P_q\,|p(\mathbf{K}_0,\theta) < c_1\right]}\mathbb{E}\left[\alpha^j(\theta)\left(P_q \alpha^i(\theta) - \frac{\partial \tau}{\partial K_0^i}\right)\mathbb{I}_{\{p(\mathbf{K}_0,\theta)<c_1\}}\right]. \tag{13}$$

Proof. The proof is presented in Appendix C.2. □

When the baseload technology is inflexible, average price is constant, equal to the long-run marginal cost of this baseload technology. When the baseload technology is flexible, it stops producing if $p < c_1$. On this set, increasing renewable capacity (usually) reduces price. Hence, average price (usually) decreases as renewable capacity increases. The same effect explains why the marginal value of renewable technology j decreases faster when $p < c_1$.

The flexible baseload technology is equivalent to the other technologies, hence, once the new definition of the supply curve is used, the expression of $\frac{\partial K_1}{\partial K_0^i}$ is formally identical to any $\frac{\partial K_n}{\partial K_0^i}$.

Expressions in Propositions 6 and 7 share the same structure. If nuclear is inflexible, Proposition 6 shows that average price decreases with K_0^i when the baseload technology is no longer included in the long-term equilibrium. If demand is linear with constant slope b, the average price's slope is

$$\frac{\partial}{\partial K_0^i}\mathbb{E}\left[p\left(\mathbf{K}_0,\theta\right)\right] = -\mathbb{E}\left[\left(b\alpha^i\left(\theta\right) + \frac{\partial \tau}{\partial K_0^i}\right)\mathbb{I}_{\{p(\mathbf{K}_0,\theta)<c_2\}}\right].$$

If nuclear is flexible, the average price starts to decrease when $p < c_1$. When this occur, the slope (for linear demand) is

$$\frac{\partial}{\partial K_0^i}\mathbb{E}\left[p\left(\mathbf{K}_0,\theta\right)\right] = -\mathbb{E}\left[\left(b\alpha^i + \frac{\partial \tau}{\partial K_0^i}\right)\mathbb{I}_{\{p(\mathbf{K}_0,\theta)<c_1\}}\right].$$

In both cases, the baseload technology is no longer present on the first vertical segment of the supply curve ($p < c_2$ when baseload has disappeared, $p < c_1$ when baseload is flexible), hence the average price is longer held at $(c_1 + r_1)$.

A similar argument explains the evolution of marginal values of renewables. When baseload technology is no longer present in the long-term equilibrium (and demand linear with constant slope),

$$\mathbb{E}\left[a^j\left(\theta\right)\frac{\partial p}{\partial K_0^i}\right] = -E^{ij} - \mathbb{E}\left[P_q\alpha^j\left(\theta\right)|p<c_2\right]\mathbb{E}\left[\left(b\alpha^i\left(\theta\right) + \frac{\partial \tau}{\partial K_0^i}\right)\mathbb{I}_{\{p(\mathbf{K}_0,\theta)<c_2\}}\right],$$

while when baseload technology is flexible,

$$\mathbb{E}\left[a^j\left(\theta\right)\frac{\partial p}{\partial K_0^i}\right] = -E^{ij} - \mathbb{E}\left[P_q\alpha^j\left(\theta\right)|p<c_1\right]\mathbb{E}\left[\left(b\alpha^i\left(\theta\right) + \frac{\partial \tau}{\partial K_0^i}\right)\mathbb{I}_{\{p(\mathbf{K}_0,\theta)<c_1\}}\right].$$

Since $c_1 < c_2$, average price and marginal value of renewable start to decrease for lower renewable penetration when nuclear technology is flexible than when it is not. However, when inflexible nuclear is no longer present at the equilibrium, average price and marginal value of renewable decreases faster. Inflexible nuclear generates negative operating margins as renewable penetration increases, hence we expect it to decrease rapidly. Thus, the sets $\{\theta : p\left(\mathbf{K}_0,\theta\right) < c_2\}$ and $\{\theta : p\left(\mathbf{K}_0,\theta\right) < c_1\}$ should rapidly be close, and converge when inflexible nuclear is absent of the long-term equilibrium.

Thus, we expect baseload flexibility does not have a significant impact on the marginal value of renewables, hence on the subsidies and tax. This result is confirmed by the numerical simulations conducted for the UK presented in Section 5.

5 Application to the case of Great Britain

To illustrate these effects in practice, we present a simulation of the electricity industry in Great Britain, calibrated for the 2020s.

5.1 Data

Wind data The values of $\alpha(\theta)$ are clearly vital for the numerical results that we will obtain; we are fortunate to have some excellent data for wind output patterns. Staffell and Green (2014) use wind speed estimates from $NASA's\ MERRA$ data set to simulate the hourly output of every wind farm in Great Britain. We use 18 years of their data and match it to the actual hourly demands over the same period. This gives us 157,680 observations from which to calculate the relationship between the level of demand and the load factors of onshore and offshore wind stations, the two renewable technologies that we consider.

The $MERRA$ dataset estimates the wind speed at several heights above ground at a grid of points covering the entire globe, using computer modeling to match observations from satellites and weather stations. The Virtual Wind Turbine model (Staffell and Green, 2014) interpolates between these points to the location of any chosen wind farm, and extrapolates the wind speed to the height of its turbines. The manufacturer's power curve for the type of turbine used at the farm (where known) gives the relationship between the estimated wind speed and the station's output. The hourly output for a given wind farm is estimated with a degree of error, but the monthly output for a farm, or the hourly output for a fleet of turbines spread across Great Britain, is remarkably close to actual values. We have estimated the load factors for fleets of onshore and offshore stations equivalent to those in the "Gone Green" scenario published by National Grid, the System Operator for Great Britain.

We assume that these load factors do not change as more capacity is added, even though it would be natural to expect the best sites to be developed first (an effect which might be offset by technical progress and the gradual move to larger turbines on taller masts, which capture more of the wind). In the Figures below, many of our results are plotted against the total amount of wind capacity installed. Our minimum capacity is 4 GW, made up of 3 GW onshore and 1 GW offshore (the situation in 2009). By 2014, 8 GW of onshore wind and 4 GW of offshore capacity had been installed. As capacity grows beyond this point, we assume that more will be added offshore than onshore, so that 30 GW would consist of 14 GW onshore and 16 GW offshore. The highest level that we consider is 60 GW, made up of 20 GW onshore and 40 GW offshore, a "round numbers" variant of the Medium case for the level of deployment in 2030, as reported by a study commissioned by the Department of Energy and Climate Change.[7] This is enough to generate 52% of the industry's total output.

Demand data We matched these estimated hourly load factors to 18 years of actual demand data. Because electricity demand has grown significantly over this period, each year's observations were scaled to a common level of underlying demand, 350 TWh a year. This was done by multiplying every hourly observation by the ratio of the year's weather-corrected demand (published by National Grid) to the underlying level. In other words, if the weather-corrected demand in 1995 was 280 TWh, every observation for that year was multiplied by 1.25 when creating our scaled demand. If 1995 had in fact been a cold year with more above-average demands than usual, this would be preserved in our dataset and the modeled demand would exceed 350 TWh. The demand is scaled to give an annual total of 350 TWh, with a peak of around 60 GW and a minimum of 25 GW. Demand is assumed to be linear, with constant slope $b = 100$ £/MWh per GW change in consumption.

To make our modeling calculations more tractable than using all $157,680$ observations, we grouped our data points into bins of equal width. Each hour was allocated to one of 20 bins for demand, 10 for the onshore load factor and 10 for the offshore load factor. This gave $2,000$ possible states of the world, each represented by the average demand and load factors for the hours within that set of bins. In practice, the probability of many of these states was zero - it would be an extraordinary weather pattern that gave a load factor of less than 10 per cent for onshore wind farms and one of more than 90 per cent for offshore farms at the same time, for example. The model therefore used the 1268 combinations of bins that actually arose over the period as our states of the world, with probabilities based on their relative frequencies.

Wind turbine costs The marginal cost of wind turbines is derived from a learning curve model. Currently, around 10 GW of wind turbines are installed in Great Britain. Their marginal cost is 210 £/kW per year for onshore, and 455 £/kW per year for offshore. Assuming exponential learning, the marginal cost of wind turbines is

$$r_0^i\left(K_0^i\right) = r_0^i\left(\bar{K_0^i}\right) \times \left(\frac{\bar{K_0^i}}{K_0^i}\right)^{\beta}$$

where β is a measure of the learning rate, and $\bar{K_0^i}$ the current renewable capacity. Learning is typically measured by the reduction in costs achieved for a doubling of production. The IEA's Blue Map scenario (quoted in the DECC study mentioned above) observes that a doubling of onshore wind turbine capacity leads to a 7% reduction in cost. This leads to

$$\frac{r_0\left(2K_0\right)}{r_0\left(K_0\right)} = \left(\frac{1}{2}\right)^{\beta} = 0.93 \Leftrightarrow \beta = -\frac{\ln\left(0.93\right)}{\ln\left(2\right)} = 0.104.$$

[7] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/66176/Renewables_Obligation_consultation_-_review_of_generation_costs_and_deployment_potential.pdf

For offshore wind, the same study proposes an estimate of a 12% reduction in costs with each doubling of UK capacity, which gives $\beta = 0.184$. These estimates of the learning rate are in line with the literature (for example by Baker et al., 2013, Lindman and Söderholm, 2012, and van der Zwaan et al., 2012).

Conventional generation technologies We consider three investment options apart from wind power: nuclear power, combined cycle gas turbines ($CCGTs$) and open cycle gas turbines ($OCGTs$) for peaking use.

We assume carbon is priced at £70/$tonne$, the level that the government's Carbon Price Support is due to reach in 2030. In looking for a long-run equilibrium, we disregard existing capacity, observing that the UK's remaining coal and oil stations will be uneconomic with such a carbon price. The cost estimates are taken a report on generation costs prepared by the Department of Energy and Climate Change [8]. Inflexible nuclear stations have a fixed cost of £575/*kW*/*year* and a variable cost of £8/MWh. We also model flexible nuclear technology, with the same costs, as discussed above. CCGT stations have a fixed cost of £106/*kW*/*year* and a variable cost of £73/MWh, while the peaking OCGT stations have a fixed cost of £50/*kW*/*year* and a variable cost of £109/MWh. It should be noted that these costs are based on the value of fuel and carbon prices over the station's lifetime, according to DECC's central scenario, rather than predictions for a particular year in the 2020s. This lifetime perspective is the appropriate one when considering investment decisions, but the resulting electricity prices are greater than those likely to be seen in the near future.

Given these costs, nuclear stations are the most effective option if they can operate for at least 8,000 hours a year. OCGT stations are the cheapest way of meeting demands that last for less than 1,700 hours a year. With no wind stations, the optimal mix of thermal capacity contains 30 GW of nuclear stations, 21 GW of CCGTs and 8 GW of OCGT peaking plant. The time-weighted electricity price is equal to 81 £/MWh, while the demand-weighted price is 87 £/MWh.

5.2 Closing the model for any vector of renewables capacities

As previously discussed, the expressions simplify significantly if inverse demand is linear with constant slope $P(Q,\theta) = a(\theta) - bQ$. Equation (6) leads to

$$\frac{\partial \bar{D}}{\partial K_0^i} = -\frac{1}{b}\frac{\partial \tau}{\partial K_0^i} \Leftrightarrow \bar{D}(\mathbf{K}_0) - \bar{D}(\mathbf{0}) = -\frac{1}{b}\tau(\mathbf{K}_0)$$

since $\tau(\mathbf{0}) = 0$.

[8] https://www.gov.uk/government/publications/decc-electricity-generation-costs-2013

Combining equations (3) and (4) then yields

$$\tau\left(\mathbf{K}_0\right)\left(\bar{D}\left(\mathbf{0}\right)-\frac{1}{b}\tau\left(\mathbf{K}_0\right)\right)=R_0\left(\mathbf{K}_0\right)-\sum_{j=1}^{I}\mathbb{E}\left[\alpha^j\left(\theta\right)p\left(\mathbf{K}_0,\theta\right)\right]K_0^j.$$

Since $p\left(\mathbf{K}_0,\theta\right)$ also depends on $\tau\left(\mathbf{K}_0\right)$ on the vertical segments of the supply curve, the above equation is a fixed point problem, which is solved iteratively using the following simple algorithm, equivalent to one described by Borenstein (2005). For a given tax rate, we first set the cumulative capacity of all N generators. Profits are monotonically decreasing in capacity, and so if the peaking generators are making an economic profit, the industry's capacity must be increased. Once the profits of $OCGT$ stations are zero, we adjust the cumulative capacity of generators 1 to $(N-1)$ (in this case, nuclear and $CCGT$ stations) until the profits of type $(N-1)$ are zero. We continue in the same way until all generators are making zero profits. We then check how much revenue the tax is raising, and if this is less than the cost of the renewable subsidy, we increase the tax rate and re-optimize the capacity levels. In practice, the model can be solved quickly in an excel spreadsheet using VBA macros.

As indicated above, exactly closing the model requires a robust and detailed long-term model of a power market. Alternatively, a simple linear approximation is available, presented in Appendix D.

5.3 Results

5.3.1 Ambitious renewable penetration

As renewable penetration increases, the capacity mix changes, as illustrated on Figure 2. With 30 GW of wind capacity, corresponding to 25% of electricity being produced from renewables, the level implied by the more ambitious UK targets for the early 2020s, the capacity of nuclear stations would decrease to around 13 GW. The capacity of CCGT stations would increase to 29 GW, while that of OCGT plant would increase to 10 GW.

FIGURE 2 ABOUT HERE

The reduction in inflexible nuclear capacity is a direct consequence of Proposition 1: renewable producing at zero marginal costs replace existing technologies. Nuclear capacity has to fall if the industry is not to suffer from many periods of negative prices, which would make those stations (forced to generate at those times) unprofitable.

On the other hand, gas-fired capacity increases, which may seem counter-intuitive. Equation (5) provides an explanation: the difference between the marginal reduction in nuclear capacity K_1 and the marginal reduction in cumulative conventional capacity K_3 is the difference between the expected amounts of renewable output on the vertical segment of the supply curve v_1, corresponding to prices lower than 73 £/MWh, and segment v_3, corresponding to prices higher than 109 £/MWh. The results suggest that the former is larger than the later i.e., that the wind is stronger when the price is low than when it is high, or equivalently the wind is stronger when residual demand (i.e., total demand less renewable production) is low than when it is high.

When little renewable capacity has been installed, residual demand is very close to actual demand. Nuclear capacity K_1 and cumulative conventional capacity K_3 decrease at about the same rate, consistent with a small correlation between wind availability and electricity demand. As renewable capacity increases, residual demand differs from actual demand, and decreases significantly with wind availability. Then, nuclear capacity K_1 decreases at a faster rate than cumulative conventional capacity K_3. The split between CCGT and OCGT capacity can be similarly explained.

Would this result still hold if renewable was strongly positively correlated to electricity demand, for example when solar panels are added into a market where air conditioning represents a significant share of the load? In that case, solar panels would initially substitute for gas fired plants, as both technologies would produce mostly on-peak. When significant solar panel capacity has been installed, the residual demand effect would become significant, and solar panels would also compete with baseload technologies. Quantifying this effect in an important avenue for further work.

The substitution of natural gas for nuclear production raises the question of the evolution of CO_2 emissions. It is important to note that we are modeling a carbon price which is high enough to give a relatively low-carbon electricity system, even with very low levels of renewable output - we obtain emissions of 38 million tonnes of CO_2 with 4 GW of wind capacity, compared to actual emissions of 147.9 million tonnes CO_2 equivalent in 2013.[9] Adding renewable capacity to this low-carbon system has the counter-intuitive effect of increasing emissions at first, because they displace more nuclear output than they generate themselves. At the first point where nuclear stations are fully crowded out of the market, with 45 GW of renewable capacity, emissions have risen to 76 million tonnes of CO_2. Beyond this point, however, the wind output is entirely crowding out gas-fired generation, and with our maximum deployment of 60 GW, emissions have fallen back to 60 million tonnes of CO_2. If the additional gas-fired stations were fitted with carbon capture and storage (CCS), their emissions would be far lower; it is also worth pointing out that the 30 GW of nuclear capacity assumed in the absence of wind generation is well above the levels currently being discussed for the UK. With less nuclear capacity on the system, renewable generators would be crowding out gas- or coal-fired stations and cutting emissions.

The time-weighted wholesale price remains at 81 £/MWh, but the demand-weighted price falls slightly, to 85 £/MWh (Figure 3). What is driving these changes? In states of the world with high levels of available wind, the electricity price will be reduced if K_0 is large. However, as shown in Lemma 1, capacity adjusts until the time-weighted price covers the average cost of a nuclear station running continuously on base load. The states in which less wind is available must therefore see higher prices in order to maintain this average. If there was no relationship between wind speeds and demand, the demand-weighted price would be unaffected by the level of wind capacity in long-

[9] `https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/407432/20150203_2013_Final_Emissions_statistics.pdf`

run equilibrium, like the time-weighted price. In Great Britain, however, wind speeds are higher, on average, in the winter months than in the summer, and this is also the pattern of electricity demand. In other words, the states of the world with high levels of wind availability and hence in which prices will fall if wind capacity is built tend to be those in which demand is high. Since this means that wind generation tends to reduce prices during high-demand hours, the demand-weighted price will fall as wind capacity is added, even when the time-weighted price is constant.

FIGURE 3 ABOUT HERE

The market value of the first increment of onshore wind capacity is 200 £/kW per year, decreasing to 150 £/kW per year for 30 GW renewable capacity (Figure 4), and 280 £/kW per year decreasing to 220 £/kW per year for offshore wind capacity (Figure 5). Comparing Figures 3, 4 and 5, note that the marginal value of renewable capacity becomes negative at a point when its average value (as measured by its output-weighted wholesale price) is still positive.

FIGURE 4 AND 5 ABOUT HERE

This decrease is almost linear, as predicted by Proposition 2. The average slope is b times the average variance-covariance matrix of the availabilities on the vertical segments of the supply curve:

$$\begin{bmatrix} 1.6 & 1.5 \\ 1.5 & 3.2 \end{bmatrix}.$$

Thus, a 1 GW increase in onshore wind capacity decreases the marginal value of onshore wind by 1.6 £/kW per year, and the marginal value of offshore wind by 1.5 £/kW per year, while a similar increase in offshore wind capacity decreases the marginal value of offshore wind by 3.2 £/kW per year, and the marginal value of onshore wind by 1.5 £/kW per year.

Given the structure of our learning curve, the cost of the first kW of renewable capacity, hence the subsidy, is infinite. We therefore start computing the marginal subsidy from the 2009 values: 3 GW onshore and 1 GW offshore. Over this interval, the marginal subsidy to onshore wind remains constant around 50 £/kW per year (Figure 6): the cost reduction from learning is not sufficient to compensate the reduction in value of the energy produced. For offshore, wind the subsidy decreases from 350 £/kW per year to 150 £/kW per year (Figure 7), suggesting that the gains from learning outweigh the loss of value of the energy produced.

The cumulative subsidy is financed by a unit tax on all MWh sold, that increases to 13 £/MWh (Figure 8).

FIGURES 6, 7 AND 8 ABOUT HERE

The marginal surplus loss is almost exactly equal to the opposite of the subsidy over the interval. For example, for 30 GW of renewables, 1 MW of offshore wind reduces net surplus by 103,000 £ per year. The cumulative loss in net surplus is £ 3.4 billions per year (Figure 9).

FIGURE 9 ABOUT HERE

5.3.2 Disappearing nuclear technology

If the wind capacity reaches 45 GW, the inflexible nuclear technology is pushed out of the market. This result is not just theoretical, since 45 GW of wind capacity implies that it produces 38% of electricity, well within the reasonable range for renewable deployment.

As suggested by Proposition 6, marginal values are discontinuous when nuclear disappears. For example, the value of wind-turbines, that decreased slowly as long as nuclear was present, decreases abruptly when nuclear disappears: when renewable capacity increases from 40 GW and 50 GW, the marginal value decreases from 150 £/kW per year to 50 £/kW per year for onshore wind (Figure 4), and from 210 £/kW per year to 180 £/kW per year for offshore wind (Figure 5).

Over the same interval, the marginal subsidy increases from 50 £/kW per year to 150 £/kW per year for onshore wind (Figure 6), and from 130 £/kW per year to 240 £/kW per year for offshore wind (Figure 7), while the unit tax more than doubles from 17 £/MWh to 38 £/MWh, and continues to increase to 128 £/MWh for 60 GW (Figure 8). The marginal surplus loss increases slightly faster than the marginal subsidy, as the deadweight loss associated with demand reduction starts to matter. For example, if renewable installed capacity is 60 GW, the marginal surplus loss is 710 £/kW per year, while the marginal subsidy is 680 £/kW per year. The cumulative loss in net surplus increases to £ 11 billions per year (Figure 9).

This result matters for two reasons. First, it shows that the current renewable support mechanism cannot be used to support for large scale entry, as it would lead average electricity prices to become negative, which is clearly not realistic. Thus, renewable support policies must evolve, as discussed in Section 6.

Second, the previous illustrates that nuclear and wind, which are essential components of a low CO_2 emitting electricity production fleet, do not coexist well. Significant wind turbines entry produces periods of low residual demand, hence low prices, which reduces long-term equilibrium installed nuclear capacity. This effect is particularly strong for Great Britain, where renewable will almost exclusively be wind, raising the question of the feasibility (and the cost) of Britain's decarbonization objectives.

One could object that nuclear in Great Britain will not disappear, since new plants are covered by Contracts for Difference, which guarantee a fixed price. The analysis presented here suggests the liability generated by these contracts will increase as renewable capacity increases, and will increase significantly after 40 GW of renewable has been installed.

Finally, this result shows that the dynamics of renewables entry are non linear.

5.3.3 Flexible nuclear technology

We now consider the other polar case: fully flexible nuclear technology. First, for a high renewable penetration, flexible baseload capacity is much larger at equilibrium: for example if renewable capacity is 40 GW, flexible baseload is 13 GW, while it is only 4 GW if nuclear is inflexible (Figure 10).

Figure 10 about here

Second, baseload flexibility has a small effect on the (time-weighted) average price, the marginal value of renewables (Figures 4 and 5), hence on the required subsidies (Figures 6 and 7) and tax (Figure 8), at least as long as renewable capacity is not too great. This result may appear surprising, as one would expect that flexible baseload would lead to fewer instances of negative prices, hence higher average prices and marginal value of renewables. However, it was predicted by Propositions 6 and 7 - the capacity mix adjusts so that all kinds of station receive zero profits. As long as there are nuclear stations in the mix, their output-weighted price has to equal their average cost.

Third, once renewable capacity exceeds 35 GW, however, there are many hours in which nuclear output is completely crowded out of the market by renewables and prices are negative. The time-weighted price can fall below the average cost of nuclear stations and does so, as expected from Proposition 7.

In summary, nuclear flexibility has a significant impact on the long-term compatibility of nuclear with renewables, but does not significantly reduce the required tax. To achieve that goal, changes to the support mechanism are required, which are discussed next.

6 Alternative support mechanisms

The previous Sections have examined the most commonly used renewable support mechanism: a fixed-price contract coupled with physical dispatch insurance. In this Section, we analyze two possible modifications: a Feed-in Premium (FiP) to replace the fixed-price contract, and a financial dispatch insurance to replace the physical dispatch insurance.

6.1 Feed-in Premium

Faced with strongly increasing cost of renewables support, policy makers are exploring various alternative mechanisms. One specific proposal is to replace fixed-price contracts by a Feed-in Premium (FiP)‡: each MWh produced by renewable producers receives the market price plus a fixed premium.

While a FiP is intuitively appealing, it raises a series of issues. First, investors have objected that, since renewable producers will be exposed to market prices, their risk level, hence their cost of capital, will increase.

Second, a FiP does not completely resolve the issue of negative prices. Renewable producers bid up to minus their FiP in the wholesale market, hence negative prices will still occur, (usually) bounded by the FiP granted.

Finally, the analysis conducted in the previous Sections highlights the complexity of computing a fair FiP. To simplify the discussion, suppose FiPs are subject to tenders. Learning-by-doing implies that costs, hence the required FiP, are reduced as renewable capacity increases. The previous analysis has shown that the marginal value of a technology is a function of the cumulative renewable capacity installed. Thus, to compute their fair FiP, market participants need to know the aggregate renewable capacity that will be installed. This requires policy makers to issue a credible target, and to hold on to it, which has proven challenging at best in many jurisdictions.

Even if the target is known and credible, another challenge arises from the shape of the supply curve. Renewable producers receiving a FiP are willing to produce up to a price equal to minus their FiP. Thus, the effective supply curve has a upward sloping portion on its left, corresponding to the values of the FiP (Figure 11). When demand intersects with this portion of the supply curve, a renewable producer's profit will be determined by the FiP of the more efficient renewable producers. Thus, to compute their fair FiP, market participants need to compute the fair FiP of all more efficient renewable producers. This appears quite a challenging process, hence is likely to result in producers requesting a very high FiP.

Figure 11 about here

A complete analysis of FiP is left for further work. At this stage, it is fair to say that, for reasons highlighted above, the net gains from replacing fixed-price contracts with FiP are probably lower than expected.

6.2 Financial dispatch insurance

Concept As was previously discussed, the physical dispatch insurance granted to renewables leads to more frequent occurrences of negative prices, which cannot be welfare improving. Negative prices are particularly damaging for inflexible nuclear power producers, and almost drive them out of the market. Since nuclear plants generate electricity without emitting CO_2, this is not consistent with the goal of decarbonizing electricity generation. Thus, *SOs* and policy makers have incentives to reduce the occurrence of negative prices.

One possible reform is to replace the physical dispatch insurance by a financial one: renewable producers receive payment $f^i(\mathbf{K}_0)$ per MWh available, whether it is actually produced or not. In that case, the *SO* values renewable energy at its true marginal cost, and starts reducing the renewable dispatch rate when the price falls to zero. Perfectly implementing this policy requires (i) the *SO* be able to determine precisely the available production from each renewable facility, even if it is not actually producing, and, (ii) the producers be able to shut down their facilities remotely. These conditions appear more likely to be met for large wind farms than for individual solar panels.

Financial dispatch insurance does not modify expected revenues for renewables producers, nor does it expose them to additional risk. Hence it does not increase their cost of capital, and can be substituted to physical dispatch insurance for existing renewable assets. The main drawback of financial insurance of course is that producers are paid not to produce, hence it may not be politically acceptable. Still, we conduct the analysis to get a sense for the impact of eliminating (or at least greatly reducing) the occurrence of negative prices.

Analysis The shape of the supply curve is unchanged for $p(\mathbf{K}_0, \theta) > 0$. When $p(\mathbf{K}_0, \theta) = 0$, the *SO* reduces renewable production to meet demand at a retail price of τ. Negative prices occur if and only if there exists states of the world for which demand at price τ is lower than the capacity of inflexible baseload production. This should produce two changes. First, since negative prices are less frequent, the market value of renewable energy increases, which reduces the required subsidy. Second, for the same reason, equilibrium inflexible baseload capacity also increases. Cumulative capacities for technologies 2 and above are not impacted.

Our analytical model enables us to confirm analytically this intuition. The analysis presented in Sections 3 and 4 applies with the new supply curve (Figure 12). To shorten the notation, introduce $u_2 = \{\theta : 0 < p(\mathbf{K}_0, \theta) < c_2\}$.

FIGURE 12 ABOUT HERE

We then have:

Proposition 8. *If financial dispatch insurance is implemented, the marginal impact on baseload technology is*

$$\frac{\partial K_1}{\partial K_0^i} = \frac{\frac{\partial \tau}{\partial K_0^i} - \mathbb{E}\left[P_q \alpha^i(\theta)\,|u_2\right](1-\mu)}{\mathbb{E}\left[P_q\,|u_2\right](1-\mu) + \mathbb{E}\left[P_q\,|p<0\right]\mu},$$

where $\mu = \frac{\Pr(p<0)}{\Pr(u_2)+\Pr(p<0)}$. *For* $n \geq 2$, $\mathbb{E}\left[\frac{\partial p}{\partial K_0^i}\alpha^j(\theta)\,|v_n\right]$ *is unchanged. Then,*

$$\begin{aligned}\mathbb{E}\left[\frac{\partial p}{\partial K_0^i}\alpha^j(\theta)\,|u_2\right] &= \left(\frac{\mathbb{E}\left[P_q\alpha^j(\theta)\,|u_2\right]}{\mathbb{E}\left[P_q\,|u_2\right](1-\mu)+\mathbb{E}\left[P_q\,|p<0\right]\mu} - \mathbb{E}\left[\alpha^j(\theta)\,|u_2\right]\right)\frac{\partial \tau}{\partial K_0^i} \\ &\quad + \mathbb{E}\left[P_q\alpha^j(\theta)\,\alpha^i(\theta)\,|u_2\right] - \frac{\mathbb{E}\left[P_q\alpha^i(\theta)\,|u_2\right]\mathbb{E}\left[P_q\alpha^j(\theta)\,|u_2\right]}{\mathbb{E}\left[P_q\,|u_2\right]+\mathbb{E}\left[P_q\,|p<0\right]\frac{\mu}{1-\mu}}.\end{aligned}$$

Proof. The derivations are presented in Appendix E. Intuition is as follows. There could be instances when baseload capacity exceeds demand at price 0, in which case $p(K_1, \theta) < 0$. If this never occurs, $\mu = 0$, and $\frac{\partial K_1}{\partial K_0^i}$ takes the familiar form:

$$\frac{\partial K_1}{\partial K_0^i} = \frac{\frac{\partial \tau}{\partial K_0^i} - \mathbb{E}\left[P_q\alpha^i(\theta)\,|u_2\right]}{\mathbb{E}\left[P_q\,|u_2\right]}.$$

Capacities K_n for $n \geq 2$ depend only on prices higher than c_n, hence are unchanged by the introduction of financial dispatch insurance. Then if $\mu = 0$, $\mathbb{E}\left[\frac{\partial p}{\partial K_0^i}\alpha^j(\theta)\,|u_2\right]$ takes the familiar form

$$\mathbb{E}\left[\frac{\partial p}{\partial K_0^i}\alpha^j(\theta)\,|u_2\right] = \left(\frac{\mathbb{E}\left[P_q\alpha^j(\theta)\,|u_2\right]}{\mathbb{E}\left[P_q\,|u_2\right]} - \mathbb{E}\left[\alpha^j(\theta)\,|u_2\right]\right)\frac{\partial \tau}{\partial K_0^i} + \mathbb{E}\left[P_q\alpha^j(\theta)\,\alpha^i(\theta)\,|u_2\right] - \frac{\mathbb{E}\left[P_q\alpha^i(\theta)\,|u_2\right]}{\mathbb{E}\left[P_q\,|u_2\right]}.$$

Additional terms are included if $\mu > 0$. □

To better understand the impact of financial dispatch insurance, consider the case of linear demand with constant slope. Then,

$$\frac{\partial K_1}{\partial K_0^i} = -\frac{1}{b}\frac{\partial \tau}{\partial K_0^i} - \mathbb{E}\left[\alpha^i\left(\theta\right)|0 < p < c_2\right],$$

and

$$\mathbb{E}\left[\frac{\partial p}{\partial K_0^i}\alpha^j\left(\theta\right)|u_2\right] = -b cov\left[\alpha^i\left(\theta\right), \alpha^j\left(\theta\right)|0 < p < c_2\right].$$

Excluding the effect of taxes, $\frac{\partial K_1}{\partial K_0^i}$ is proportional to $\mathbb{E}\left[\alpha^i\left(\theta\right)|p < c_2\right]$ under physical dispatch insurance, and to $\mathbb{E}\left[\alpha^i\left(\theta\right)|0 < p < c_2\right]$ under financial dispatch insurance. If availability of renewable technology i and prices are negatively correlated, at least when prices are very low, *ceteris paribus*, the former is larger than the latter, hence financial insurance leads to a slower decrease in baseload capacity.

We should also expect that the marginal value of renewables is decreasing more slowly under financial insurance. The difference in slopes is proportional to the difference

$$cov\left[\alpha^i\left(\theta\right), \alpha^j\left(\theta\right)|p < c_2\right] Pr\left(p < c_2\right) - cov\left[\alpha^i\left(\theta\right), \alpha^j\left(\theta\right)|0 < p < c_2\right] Pr\left(0 < p < c_2\right).$$

There is a priori no reason why the conditional covariance would differ markedly on the different verticals, however, *ceteris paribus*, $Pr\left(p < c_2\right) > Pr\left(0 < p < c_2\right)$, hence marginal values should decrease faster under physical insurance, in particular when negative prices arise.

Application to the case of Great Britain The numerical analysis confirms the predictions of Proposition 8. The financial dispatch insurance alleviates the negative impact of renewables on the value of nuclear generation: while nuclear capacity is reduced, it remains present in the long-term equilibrium until more than 50 GW of renewables have entered (Figure 13).

Figure 13 about here

Financial insurance, by almost eliminating the occurrence of negative prices, also significantly improves the economics of renewables: their marginal value decreases, but at a much lower rate. For 60 GW of renewables installed, the marginal value of onshore wind is 140 £/kW per year (Figure 4), 200 £/kW per year for offshore wind (Figure 5), the marginal subsidy is 50 £/kW per year for onshore wind (Figure 6), and 110 £/kW per year for offshore wind (Figure 7), while the required tax is 25 £/MWh (Figure 8), and the net surplus loss £ 6.5 billions per year (Figure 9).

Again, this result has significant policy implications. Given the magnitude of the gains generated, policy makers should design and implement support mechanisms that reduce the impact of negative prices, such as financial dispatch insurance.

7 Conclusion

In many countries, entry of renewable electricity producers has been supported by subsidies and financed by a tax on electricity consumed. This article is the first to analytically derive the dynamics of the long-term equilibrium generation mix, subsidy, and tax as renewable capacity increases. This enables us to complement and extend previous work by providing analytical expressions for previously obtained simulation results, and deriving additional results. The analysis yields three main findings. First, the subsidy to renewable may never stop, as the value of the energy produced may decrease faster than the cost as renewable capacity increases. Second, high renewable penetration leads to a discontinuity in marginal values, after which the subsidy and tax grow extremely rapidly. Finally, reducing the occurrence of negative prices, for example by providing renewable producers with a financial instead of physical dispatch insurance, yields significant benefits.

This article can be expended in several directions. First, we will derive the dynamics of Feed-in Premia. As indicated earlier, preliminary analysis suggests that their impact on net surplus is ambiguous, yet there are pursued in many jurisdictions. It is therefore essential to analyze them formally.

Second, we will apply our results to other markets, where renewables are differently correlated to load and prices, for example states in the Southwest of the United States or the South of Europe, where air conditioning demand is strongly correlated to solar panels availability. A striking result from this analysis is the substitutability of nuclear power and wind production, which renders the "decarbonization challenge" harder to meet. It is therefore essential to test this result in other markets, so as to better guide public policies.

References

[1] E. Baker, M. Fowlie, D. Lemoine, and S. S. Reynolds. The economics of solar electricity. *Annual Review of Resource Economics*, 5:387–426, 2013.

[2] J. Bertsch, C. Growitsch, S. Lorenczik, and S. Nagl. Flexibility in europe's power sector - an additional requirement or an automatic complement? *Energy Economics*, 2015. Forthcoming.

[3] M. Boiteux. La tarification des demandes en pointe: application de la theorie de la vente au cout marginal. *Revue Generale de l'Electricite*, pages 321–40, August 1949.

[4] S. Borenstein. The long-run efficiency of real time pricing. *The Energy Journal*, 26(3):93–116, April 2005.

[5] T. Bruckner, I. A. Bashmakov, Y. Mulugetta, H. Chum, A. de la Vega Navarro, J. Edmonds, A. Faaij, B. Fungtammasan, A. Garg, E. Hertwich, D. Honnery, D. Infield, M. Kainuma, S. Khennas, S. Kim, H. B. Nimir, K. Riahi, N. Strachan, R. Wiser, and X. Zhang. *Climate Change 2014: Mitigation of Climate Change. Contribution of Working Group III to the Fifth*

Assessment Report of the Intergovernmental Panel on Climate Change, chapter Energy Systems. Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA, 2014.

[6] J. Cullen. Measuring the environmental benefits of wind-generated electricity. *American Economic Journal: Economic Policy*, 5(4):107–133, 2013.

[7] O. Edenhofer, R. Pichs-Madruga, Y. Sokona, K. Seyboth, P. Matschoss, S. Kadner, T. Zwickel, P. Eickemeier, G. Hansen, S. Schlomer, and C. von Stechow, editors. *IPCC Special Report on Renewable Energy Sources and Climate Change Mitigation*. Cambridge University Press, Cambridge, 2011.

[8] N. Fabra and M. Reguant. Pass-through of emissions costs in electricity markets. *American Economic Review*, 104(9):2872–2899, 2014.

[9] C. Gollier and J. Tirole. Effective institutions against climate change. *Economics of Energy & Environmental Policy*, April 2015.

[10] G. Gowrisankaran, S. S. Reynolds, and M. Samano. Intermittency and the value of renewable energy. *Journal of Political Economy*, 2015. Forthcoming.

[11] R. Green and N. Vasilakos. The economics of offshore wind. *Energy Policy*, 39(2):496–502, 2011.

[12] R. Green and N. Vasilakos. Storing wind for a rainy day: What kind of electricity does denmark export? *The Energy Journal*, 33(3):1–22, 2012.

[13] L. Hirth. The market value of variable renewables: The effect of solar wind power variability on their relative price. *Energy Economics*, 38(7):218–236, 2013.

[14] L. Hirth. The optimal share of variable renewables. *The Energy Journal*, 36(1):127–162, 2015.

[15] P. L. Joskow. Comparing the costs of intermittent and dispatchable electricity generating technologies. *American Economic Review*, 101(3):238–41, 2011.

[16] A. Lindman and P. Soderholm. Wind power learning rates: A conceptual review and meta-analysis. *Energy Economics*, 34:754–761, 2012.

[17] A. Mills and R. Wiser. Changes in the economic value of variable generation at high penetration levels: A pilot case study of california, 2012. Report LBNL-5445E, Ernest Orlando Lawrence Berkeley National Laboratory.

[18] K. Neuhoff. Learning by doing with constrained growth rates: An application to energy technology policy. *The Energy Journal*, 29(2):165–182, 2008.

[19] J. Oswald, M. Raine, and H. Ashraf-Ball. Will british weather provide reliable electricity? *Energy Policy*, 36(8):3212–3225, 2008.

[20] I. Staffell and R. Green. How does wind farm performance decline with age? *Renewable Energy*, 66:775–786, 2014.

[21] P. Twomey and K. Neuhoff. Wind power and market power in competitive markets. *Energy Policy*, 37(7):3198–3210, 2010.

[22] B. van der Zwaan, R. Rivera-Tinoco, S. Lensink, and P. van den Oosterkamp. Cost reductions for offshore wind power: Exploring the balance between scaling, learning and r&d. *Renewable Energy*, 41:389–393, 2012.

A Optimal production, prices, and investment

Taking into account the constraint $u_n(\theta) = 1$ and the unit tax τ, the *SO* dispatch program is

$$\begin{array}{rl} \max\limits_{p(\theta),\{u_n(\theta)\}_{n\geq 2}} & \mathbb{E}\left[S\left(p\left(\theta\right)+\tau,\theta\right)-\sum_{n=1}^{N}c_n u_n\left(\theta\right)k_n\right] \\ st: & D\left(p\left(\theta\right)+\tau,\theta\right)\leq \sum_{n=1}^{N}u_n\left(\theta\right)k_n+\sum_{j=1}^{I}\alpha^j\left(\theta\right)K_0^j \quad \lambda\left(\theta\right) \end{array}.$$

The Lagrangian is

$$\mathcal{L}=\mathbb{E}\left[S\left(p\left(\theta\right)+\tau,\theta\right)-\sum_{n=1}^{N}c_n u_n\left(\theta\right)k_n+\lambda\left(\theta\right)\left(\sum_{n=1}^{N}u_n\left(\theta\right)k_n+\sum_{j=1}^{I}\alpha^j\left(\theta\right)K_0^j-D\left(p\left(\theta\right)+\tau,\theta\right)\right)\right].$$

The first-order condition for price is

$$\frac{\partial\mathcal{L}}{\partial p\left(\theta\right)}=\left(p\left(\theta\right)+\tau-\lambda\left(\theta\right)\right)\frac{\partial D\left(p\left(\theta\right)+\tau,\theta\right)}{\partial p}=0\Leftrightarrow p\left(\theta\right)+\tau=\lambda\left(\theta\right):$$

price paid by consumers is equal to the opportunity cost of power. For $n \geq 2$, the first-order derivative with respect to dispatch rate is

$$\frac{\partial\mathcal{L}}{\partial u_n}=\left(\lambda\left(\theta\right)-c_n\right)k_n.$$

The opportunity cost of power on the horizontal portions of the supply curve is equal to the marginal cost of production. This yields the dispatch

$$u_n\geq 0\Leftrightarrow\lambda\left(\theta\right)-c_n\geq 0\Leftrightarrow p\left(\theta\right)\geq c_n-\tau$$

which violates the producers' participation constraint. The tax creates a wedge between retail and wholesale prices. To account for the constraint $p(\theta) \geq c_n$ when producer n is dispatched, the *SO* adds the unit tax τ to the opportunity cost of power. The Lagrangian becomes

$$\mathcal{L} = \mathbb{E}\left[S\left(p\left(\theta\right)+\tau,\theta\right) - \sum_{n=1}^{N}\left(c_n+\tau\right)u_n\left(\theta\right)k_n + \lambda\left(\theta\right)\left(\sum_{n=1}^{N}u_n\left(\theta\right)k_n + \sum_{j=1}^{I}\alpha^j\left(\theta\right)K_0^j - D\left(p\left(\theta\right)+\tau,\theta\right)\right)\right].$$

The first-order condition with respect to price is unchanged. For $n \geq 2$, the first-order derivative with respect to dispatch rate is

$$\frac{\partial \mathcal{L}}{\partial u_n} = \left(\lambda\left(\theta\right) - \left(c_n+\tau\right)\right)k_n = \left(p\left(\theta\right) - c_n\right)k_n,$$

which is consistent with the producers' participation constraint.

When technology $n \geq 2$ is marginal, the wholesale price is $p\left(\theta\right) = c_n$ and $u_n\left(\theta\right) > 0$ is determined to balance supply and demand:

$$K_{n-1} + u_n\left(\theta\right)k_n + \sum_{j=1}^{I}\alpha^j\left(\theta\right)K_0^j = D\left(c_n+\tau,\theta\right).$$

When technology $n \geq 1$ produces at capacity and technology $(n+1)$ does not produce, the wholesale price is determined by the intersection of the vertical supply curve and the demand curve:

$$K_n + \sum_{j=1}^{I}\alpha^j\left(\theta\right)K_0^j = D\left(p\left(\mathbf{K}_0,\theta\right)+\tau,\theta\right) \Leftrightarrow p\left(\mathbf{K}_0,\theta\right) = P\left(K_n + \sum_{j=1}^{I}\alpha^j\left(\theta\right)K_0^j,\theta\right) - \tau.$$

This includes states of the world for which the price is lower than c_1.

B Marginal impact of renewables

B.1 Proof of Lemma 1: impact on prices

For $n \geq 2$, equations (1) can be rewritten as:

$$\mathbb{E}\left[\left(p\left(\mathbf{K}_0,\theta\right) - c_n\right)\mathbb{I}_{\{p(\mathbf{K}_0,\theta)\geq c_n\}}\right] = r_n.$$

For $n = N$, differentiation yields

$$\frac{\partial}{\partial K_0^i}\mathbb{E}\left[\left(p\left(\mathbf{K}_0,\theta\right) - c_N\right)\mathbb{I}_{\{p(\mathbf{K}_0,\theta)\geq c_N\}}\right] = \mathbb{E}\left[\frac{\partial p}{\partial K_0^i}\mathbb{I}_{\{p(\mathbf{K}_0,\theta)\geq c_N\}}\right] = 0$$

since by construction the integrand is equal to zero at the lower bound: $p\left(\mathbf{K}_0,\theta\right) = c_N$.

For $1 < n < N$, subtractions yields

$$\mathbb{E}\left[\left(p\left(\mathbf{K}_0,\theta\right) - c_n\right)\mathbb{I}_{\{p(\mathbf{K}_0,\theta)\geq c_n\}}\right] - \mathbb{E}\left[\left(p\left(\mathbf{K}_0,\theta\right) - c_{n+1}\right)\mathbb{I}_{\{p(\mathbf{K}_0,\theta)\geq c_{n+1}\}}\right] = r_n - r_{n+1}.$$

Differentiating with respect to K_0^i yields:

$$\begin{aligned}\mathbb{E}\left[\frac{\partial p}{\partial K_0^i}\mathbb{I}_{\{p(\mathbf{K}_0,\theta)\geq c_n\}}\right]-\mathbb{E}\left[\frac{\partial p}{\partial K_0^i}\mathbb{I}_{\{p(\mathbf{K}_0,\theta)\geq c_{n+1}\}}\right] &= \mathbb{E}\left[\frac{\partial p}{\partial K_0^i}\mathbb{I}_{\{c_n\leq p(\mathbf{K}_0,\theta)<c_{n+1}\}}\right]\\ &= \mathbb{E}\left[\frac{\partial p}{\partial K_0^i}\left|v_n\right.\right]\times\Pr\left(v_n\right)=0.\end{aligned}$$

For $n=1$, equation (1) yields

$$\mathbb{E}\left[\left(p\left(\mathbf{K}_0,\theta\right)-c_1\right)\right]=r_1\Leftrightarrow\mathbb{E}\left[p\left(\mathbf{K}_0,\theta\right)\right]=c_1+r_1.$$

Average price is constant. Then, by subtraction

$$\mathbb{E}\left[\left(p\left(\mathbf{K}_0,\theta\right)-c_1\right)\right]-\mathbb{E}\left[\left(p\left(\mathbf{K}_0,\theta\right)-c_2\right)\mathbb{I}_{p(\mathbf{K}_0,\theta)\geq c_2}\right]=r_1-r_2.$$

Differentiation yields

$$\mathbb{E}\left[\frac{\partial p}{\partial K_0^i}\left|p\left(\mathbf{K}_0,\theta\right)<c_2\right.\right]=0.$$

B.2 Proof of Corollary 1: impact on expected demand

Start with

$$\begin{aligned}\frac{\partial}{\partial K_0^i}\mathbb{E}\left[D\left(p+\tau,\theta\right)\right] &= \mathbb{E}\left[\frac{\partial}{\partial K_0^i}D\left(p+\tau,\theta\right)\right]=\mathbb{E}\left[\frac{\partial D}{\partial p}\left(\frac{\partial p}{\partial K_0^i}+\frac{\partial\tau}{\partial K_0^i},\theta\right)\right]\\ &= \sum_{n=2}^{N}\left(\frac{\partial\tau}{\partial K_0^i}\mathbb{E}\left[\frac{\partial D}{\partial p}\left|h_n\right.\right]\Pr\left(h_n\right)+\mathbb{E}\left[\left(\frac{\partial K_n}{\partial K_0^i}+\alpha^i\left(\theta\right)\right)\left|v_n\right.\right]\Pr\left(v_n\right)\right)\\ &\quad+\mathbb{E}\left[\left(\frac{\partial K_1}{\partial K_0^i}+\alpha^i\left(\theta\right)\right)\left|p<c_2\right.\right]\Pr\left(p<c_2\right)\end{aligned}$$

since price is constant on h_n and $D\left(p+\tau,\theta\right)=K_n+\sum_{j=1}^{I}\alpha^j\left(\theta\right)K_0^j$ on v_n. For $n\geq 2$

$$\frac{\partial K_n}{\partial K_0^i}+\alpha^i\left(\theta\right)=\frac{\frac{\partial\tau}{\partial K_0^i}+\alpha^i\left(\theta\right)\mathbb{E}\left[P_q\left|v_n\right.\right]-\mathbb{E}\left[\alpha^i\left(\theta\right)P_q\left|v_n\right.\right]}{\mathbb{E}\left[P_q\left|v_n\right.\right]},$$

thus

$$\mathbb{E}\left[\frac{\partial K_n}{\partial K_0^i}+\alpha^i\left(\theta\right)\left|v_n\right.\right]=\frac{\partial\tau}{\partial K_0^i}\frac{1}{\mathbb{E}\left[P_q\left|v_n\right.\right]}+\left(\mathbb{E}\left[\alpha^i\left(\theta\right)\left|v_n\right.\right]-\frac{\mathbb{E}\left[\alpha^i\left(\theta\right)P_q\left|v_n\right.\right]}{\mathbb{E}\left[P_q\left|v_n\right.\right]}\right).$$

Deriving a similar expression for $n=1$ yields:

$$\mathbb{E}\left[\frac{\partial K_1}{\partial K_0^i}+\alpha^i\left(\theta\right)\left|p<c_2\right.\right]=\frac{\partial\tau}{\partial K_0^i}\frac{1}{\mathbb{E}\left[P_q\left|p<c_2\right.\right]}+\left(\mathbb{E}\left[\alpha^i\left(\theta\right)\left|p<c_2\right.\right]-\frac{\mathbb{E}\left[\alpha^i\left(\theta\right)P_q\left|p<c_2\right.\right]}{\mathbb{E}\left[P_q\left|p<c_2\right.\right]}\right)$$

Then, summing over all intervals yields equation (6).

B.3 Proof of Proposition 2: impact on marginal value of renewable capacity

We have:

$$\begin{aligned}\mathbb{E}\left[\alpha^j(\theta)\frac{\partial p}{\partial K_0^i}\right] &= \sum_{n=2}^{N}\mathbb{E}\left[\alpha^j(\theta)\left(P_q\times\left(\frac{\partial K_n}{\partial K_0^i}+\alpha^i(\theta)\right)-\frac{\partial\tau}{\partial K_0^i}\right)|v_n\right]\Pr(v_n).\\ &\quad+\mathbb{E}\left[\alpha^j(\theta)\left(P_q\times\left(\frac{\partial K_1}{\partial K_0^i}+\alpha^i(\theta)\right)-\frac{\partial\tau}{\partial K_0^i}\right)|p<c_2\right]\Pr(p<c_2)\end{aligned}$$

For $n\geq 2$,

$$\begin{aligned}\mathbb{E}\left[P_q\times\left(\frac{\partial K_n}{\partial K_0^i}+\alpha^i(\theta)\right)\alpha^j(\theta)|v_n\right] &= \frac{1}{\mathbb{E}[P_q|v_n]}\left(\begin{array}{c}\frac{\partial\tau}{\partial K_0^i}\mathbb{E}\left[P_q\alpha^j|v_n\right]-\mathbb{E}\left[P_q\alpha^i|v_n\right]\mathbb{E}\left[P_q\alpha^j|v_n\right]\\ +\mathbb{E}\left[P_q\alpha^i\alpha^j|v_n\right]\mathbb{E}[P_q|v_n]\end{array}\right)\\ &= \frac{\mathbb{E}\left[P_q\alpha^j|v_n\right]}{\mathbb{E}[P_q|v_n]}\frac{\partial\tau}{\partial K_0^i}\\ &\quad+\left(\mathbb{E}\left[P_q\alpha^i,\alpha^j|v_n\right]-\frac{\mathbb{E}\left[P_q\alpha^i|v_n\right]\mathbb{E}\left[P_q\alpha^j|v_n\right]}{\mathbb{E}[P_q|v_n]}\right).\end{aligned}$$

A similar derivation obtains for $p(K_0,\theta)<c_2$. Summing over all vertical segments of the supply curve yields

$$\mathbb{E}\left[\alpha^j(\theta)\frac{\partial p}{\partial K_0^i}\right]=-\Gamma^j\frac{\partial\tau}{\partial K_0^i}-E^{ij},$$

which is equation (7).

B.4 Proof of Proposition 5: impact on net surplus

The expected net hourly surplus is

$$H(\mathbf{K}_0)=\mathbb{E}\left[S(p(\mathbf{K}_0,\theta)+\tau,\theta)-\sum_{n=1}^{N}c_nu_n(\theta)k_n\right]-\sum_{n=1}^{N}r_nk_n-R_0(\mathbf{K}_0).$$

As usual, we introduce the first order conditions (1) to simplify the expression of the net surplus. Multiplying by k_n, then summing first-order conditions (1) yields

$$\sum_{n=1}^{N}(\mathbb{E}[c_nu_n(\theta)]+r_n)k_n=\sum_{n=1}^{N}\mathbb{E}[p(\mathbf{K}_0,\theta)u_n(\theta)k_n].$$

Equation (4) can be rewritten as

$$\begin{aligned}R_0(\mathbf{K}_0) &= \mathbb{E}[(p(\mathbf{K}_0,\theta)+\tau)D(p(\mathbf{K}_0,\theta)+\tau,\theta)]-\mathbb{E}\left[p(\mathbf{K}_0,\theta)\left(\begin{array}{c}D(p(\mathbf{K}_0,\theta)+\tau,\theta)\\ -\sum_{j=1}^{I}\alpha^j(\theta)K_0^j\end{array}\right)\right]\\ &= \mathbb{E}[(p(\mathbf{K}_0,\theta)+\tau)D(p(\mathbf{K}_0,\theta)+\tau,\theta)]-\sum_{n=1}^{N}\mathbb{E}[p(\mathbf{K}_0,\theta)u_n(\theta)]k_n\end{aligned}$$

$\Leftrightarrow$

$$R_0\left(\mathbf{K}_0\right)+\sum_{n=1}^{N}\mathbb{E}\left[p\left(\mathbf{K}_0,\theta\right)u_n\left(\theta\right)\right]k_n=\mathbb{E}\left[\left(p\left(\mathbf{K}_0,\theta\right)+\tau\right)D\left(p\left(\mathbf{K}_0,\theta\right)+\tau,\theta\right)\right].$$

hence the expected net surplus is

$$H\left(\mathbf{K}_0\right)=\mathbb{E}\left[S\left(p\left(\mathbf{K}_0,\theta\right)+\tau,\theta\right)-\left(p\left(\mathbf{K}_0,\theta\right)+\tau\right)D\left(p\left(\mathbf{K}_0,\theta\right)+\tau,\theta,\right)\right].$$

The net surplus is the "standard" net surplus from consumption, including the distortion caused by the tax. Then,

$$\frac{\partial H}{\partial K_0^i}=-\left(\mathbb{E}\left[\left(\frac{\partial p}{\partial K_0^i}+\frac{\partial \tau}{\partial K_0^i}\right)D\left(p\left(\mathbf{K}_0,\theta\right)+\tau,\theta\right)\right]\right).$$

Since $\frac{\partial p}{\partial K_0^i}\neq 0$ only when each technology produces at capacity,

$$\begin{aligned}
\mathbb{E}\left[\frac{\partial p}{\partial K_0^i}D\left(p\left(\mathbf{K}_0,\theta\right)+\tau,\theta\right)\right] &= \sum_{n=2}^{N}\mathbb{E}\left[\frac{\partial p}{\partial K_0^i}\times\left(K_n+\sum_{j=1}^{I}\alpha^j\left(\theta\right)K_0^j\right)|v_n\right]\Pr\left(v_n\right)\\
&\quad+\mathbb{E}\left[\frac{\partial p}{\partial K_0^i}\left(K_1+\sum_{j=1}^{I}\alpha^j\left(\theta\right)K_0^j\right)|p<c_2\right]\Pr\left(p<c_2\right)\\
&= \sum_{n=2}^{N}\left(\mathbb{E}\left[\frac{\partial p}{\partial K_0^i}|v_n\right]K_n+\sum_{j=1}^{I}\mathbb{E}\left[\frac{\partial p}{\partial K_0^i}\alpha^j\left(\theta\right)|v_n\right]K_0^j\right)\Pr\left(v_n\right)\\
&\quad+\left(\mathbb{E}\left[\frac{\partial p}{\partial K_0^i}|p<c_2\right]K_1+\sum_{j=1}^{I}\mathbb{E}\left[\frac{\partial p}{\partial K_0^i}\alpha^j\left(\theta\right)|p<c_2\right]K_0^j\right)\Pr\left(p<c_2\right)\\
&= \sum_{j=1}^{I}\begin{pmatrix}\sum_{n=2}^{N}\mathbb{E}\left[\frac{\partial p}{\partial K_0^i}\alpha^j\left(\theta\right)|v_n\right]\Pr\left(v_n\right)\\+\mathbb{E}\left[\frac{\partial p}{\partial K_0^i}\alpha^j\left(\theta\right)|p<c_2\right]\Pr\left(p<c_2\right)\end{pmatrix}K_0^j\\
&= \sum_{j=1}^{I}\mathbb{E}\left[\frac{\partial p}{\partial K_0^i}\alpha^j\left(\theta\right)\right]K_0^j,
\end{aligned}$$

since $\mathbb{E}\left[\frac{\partial p}{\partial K_0^i}|v_n\right]=\mathbb{E}\left[\frac{\partial p}{\partial K_0^i}|p<c_2\right]=0$. Thus,

$$\begin{aligned}
\frac{\partial H}{\partial K_0^i} &= -\left(\frac{\partial \tau}{\partial K_0^i}\bar{D}\left(K_0\right)+\sum_{j=1}^{I}\mathbb{E}\left[\frac{\partial p}{\partial K_0^i}\alpha^j\left(\theta\right)\right]K_0^j\right)\\
&= -\varphi\left(K_0\right)+\tau\frac{\partial \bar{D}}{\partial K_0^i}
\end{aligned}$$

by inserting equation (9). Observing that

$$\frac{\partial \bar{D}}{\partial K_0^i} = -\frac{1}{B}\frac{\partial \tau}{\partial K_0^i} - \Gamma^i = -\frac{\varphi^i(\mathbf{K}_0) + \sum_{j=1}^I E^{ij} K_0^j + \tau \Gamma^i}{B\bar{D}(\mathbf{K}_0) - \tau + B\sum_{j=1}^I \Gamma^j K_0^j} - \Gamma^i$$

yields

$$\frac{\partial H}{\partial K_0^i} = -\left(\varphi^i(\mathbf{K}_0) + \tau \frac{\varphi^i(\mathbf{K}_0) + \sum_{j=1}^I E^{ij} K_0^j + \tau \Gamma^i}{B\bar{D}(\mathbf{K}_0) - \tau + B\sum_{j=1}^I \Gamma^j K_0^j} + \tau \Gamma^i\right)$$

which is equation (11).

C Changes in baseload technology

C.1 Proof of Proposition 6: conventional technology disappearing at equilibrium

Suppose first that technology $m \geq 2$ is no longer present at the long-term equilibrium, i.e., $k_m = 0$. Denote $\tilde{v}_n$ the vertical segments of the new supply curve. Since $k_m = 0$, $\tilde{v}_m = \varnothing$ and $\tilde{v}_{m-1} = \{\theta : c_{m-1} < p(\mathbf{K}_0, \theta) < c_{m+1}\}$. Derivations similar to the previous case prove that

$$\mathbb{E}\left[\alpha^j(\theta)\frac{\partial p}{\partial K_0^i}\right]\bigg|_{k_m=0} = \tilde{\Gamma}^j \frac{\partial \tau}{\partial K_0^i} - \tilde{E}^{ij},$$

where

$$\begin{aligned}\tilde{\Gamma}^j \quad &= \sum_{\substack{2\leq n\leq N \\ n\neq m}} \left(\mathbb{E}\left[\alpha^j \,|\tilde{v}_n\right] - \frac{\mathbb{E}\left[P_q \alpha^j \,|\tilde{v}_n\right]}{\mathbb{E}\left[P_q \,|\tilde{v}_n\right]}\right)\Pr(\tilde{v}_n) \\ &+ \left(\mathbb{E}\left[\alpha^j \,|p < c_2\right] - \frac{\mathbb{E}\left[P_q \alpha^j \,|p < c_2\right]}{\mathbb{E}\left[P_q \,|p < c_2\right]}\right)\Pr(p < c_2),\end{aligned}$$

and

$$\begin{aligned}\tilde{E}^{ij} \quad &= \sum_{\substack{2\leq n\leq N \\ n\neq m}} \left(\frac{\mathbb{E}\left[P_q \alpha^i \,|\tilde{v}_n\right]\mathbb{E}\left[P_q \alpha^j \,|\tilde{v}_n\right]}{\mathbb{E}\left[P_q \,|\tilde{v}_n\right]} - \mathbb{E}\left[P_q \alpha^i, \alpha^j \,|\tilde{v}_n\right]\right)\Pr(\tilde{v}_n) \\ &+ \left(\frac{\mathbb{E}\left[P_q \alpha^i \,|p < c_2\right]\mathbb{E}\left[P_q \alpha^j \,|p < c_2\right]}{\mathbb{E}\left[P_q \,|p < c_2\right]} - \mathbb{E}\left[P_q \alpha^i, \alpha^j \,|p < c_2\right]\right)\Pr(p < c_2).\end{aligned}$$

Since $v_{m-1} \cup v_m = \{\theta : c_{m-1} < p(\mathbf{K}_0, \theta) < c_{m+1}\}$ and $p(\mathbf{K}_0, \theta)$ is continuous in its arguments,

$$\lim_{k_m \to 0}(v_{m-1} \cup v_m) = \tilde{v}_{m-1}.$$

Thus,

$$\lim_{k_m\to 0}\Gamma^j=\tilde{\Gamma}^j \ and \ \lim_{k_m\to 0}E^{ij}=\tilde{E}^{ij}.$$

Inserting in the other expressions proves that all derivatives are continuous.

Suppose now the baseload technology is no longer present at the equilibrium, i.e., $K_1=0$. The free entry condition for technology 2 is

$$\mathbb{E}\left[\left(p\left(\mathbf{K}_0,\theta\right)-c_2\right)\mathbb{I}_{\{p(\mathbf{K}_0,\theta)\geq c_2\}}\right]=r_2\Leftrightarrow\mathbb{E}\left[p\left(\mathbf{K}_0,\theta\right)\right]=c_2+r_2+\mathbb{E}\left[\left(p\left(\mathbf{K}_0,\theta\right)-c_2\right)\mathbb{I}_{\{p(\mathbf{K}_0,\theta)<c_2\}}\right].$$

Thus,

$$\frac{\partial}{\partial K_0^i}\mathbb{E}\left[p\left(\mathbf{K}_0,\theta\right)\right]=\mathbb{E}\left[\frac{\partial p\left(\mathbf{K}_0,\theta\right)}{\partial K_0^i}\mathbb{I}_{\{p(\mathbf{K}_0,\theta)<c_2\}}\right]=\mathbb{E}\left[\left(P_q\alpha^i\left(\theta\right)-\frac{\partial\tau}{\partial K_0^i}\right)\mathbb{I}_{\{p(\mathbf{K}_0,\theta)<c_2\}}\right]$$

as indicated.

Consider now the marginal impact of renewable capacity on the availability weighted price when $p\left(\mathbf{K}_0,\theta\right)<c_2$.

Since $K_1=0$, the term $\frac{\partial K_1}{\partial K_0^i}$ no longer appears in the derivations:

$$\begin{aligned}
\mathbb{E}\left[\alpha^j\left(\theta\right)\frac{\partial p}{\partial K_0^i}\left|p<c_2\right.\right] &= \mathbb{E}\left[\alpha^j\left(\theta\right)\times\left(P_q\alpha^i\left(\theta\right)-\frac{\partial\tau}{\partial K_0^i}\right)\left|p<c_2\right.\right]\\
&= -\mathbb{E}\left[\alpha^j\left(\theta\right)\left|p<c_2\right.\right]\frac{\partial\tau}{\partial K_0^i}+\mathbb{E}\left[P_q\alpha^j\left(\theta\right)\alpha^i\left(\theta\right)\left|p<c_2\right.\right]\\
&= \left(\frac{\mathbb{E}\left[P_q\alpha^j\left(\theta\right)\left|p<c_2\right.\right]}{\mathbb{E}\left[P_q\left|p<c_2\right.\right]}-\mathbb{E}\left[\alpha^j\left(\theta\right)\left|p<c_2\right.\right]\right)\frac{\partial\tau}{\partial K_0^i}\\
&\quad -\left(\frac{\mathbb{E}\left[P_q\alpha^j\left(\theta\right)\left|p<c_2\right.\right]\mathbb{E}\left[P_q\alpha^i\left(\theta\right)\left|p<c_2\right.\right]}{\mathbb{E}\left[P_q\left|p<c_2\right.\right]}-\mathbb{E}\left[P_q\alpha^j\left(\theta\right)\alpha^i\left(\theta\right)\left|p<c_2\right.\right]\right)\\
&\quad +\frac{\mathbb{E}\left[P_q\alpha^j\left(\theta\right)\left|p<c_2\right.\right]}{\mathbb{E}\left[P_q\left|p<c_2\right.\right]}\left(\mathbb{E}\left[P_q\alpha^i\left(\theta\right)\left|p<c_2\right.\right]-\frac{\partial\tau}{\partial K_0^i}\right).
\end{aligned}$$

Thus,

$$\mathbb{E}\left[a^j\left(\theta\right)\frac{\partial p}{\partial K_0^i}\right]=\Gamma^j\frac{\partial\tau}{\partial K_0^i}-E^{ij}+\left(\frac{\mathbb{E}\left[P_q\alpha^j\left(\theta\right)\left|p<c_2\right.\right]}{\mathbb{E}\left[P_q\left|p<c_2\right.\right]}\mathbb{E}\left[\left(P_q\alpha^i\left(\theta\right)-\frac{\partial\tau}{\partial K_0^i}\right)\mathbb{I}_{\{p(\mathbf{K}_0,\theta)<c_2\}}\right]\right).$$

C.2 Proof of proposition 7: flexible baseload technology

When the baseload technology is flexible, the expected price is no longer equal to the long-term marginal cost of baseload technology. Instead, the expected price is computed as follows:

$$\begin{aligned}
\mathbb{E}\left[p\left(\mathbf{K}_0,\theta\right)-c_1\right] &= \mathbb{E}\left[\left(p\left(\mathbf{K}_0,\theta\right)-c_1\right)\mathbb{I}_{\{p(\mathbf{K}_0,\theta)<c_1\}}\right]+\mathbb{E}\left[\left(p\left(\mathbf{K}_0,\theta\right)-c_1\right)\mathbb{I}_{\{p(\mathbf{K}_0,\theta)\geq c_1\}}\right]\\
&= \mathbb{E}\left[\left(p\left(\mathbf{K}_0,\theta\right)-c_1\right)\mathbb{I}_{\{p(\mathbf{K}_0,\theta)<c_1\}}\right]+r_1
\end{aligned}$$

$\iff$

$$\mathbb{E}\left[p\left(\mathbf{K}_0,\theta\right)\right]=c_1+r_1+\mathbb{E}\left[\left(p\left(\mathbf{K}_0,\theta\right)-c_1\right)\mathbb{I}_{\{p(\mathbf{K}_0,\theta)<c_1\}}\right]\leq c_1+r_1.$$

Then,

$$\frac{\partial}{\partial K_0^i}\mathbb{E}\left[p\left(\mathbf{K}_0,\theta\right)\right]=\frac{\partial}{\partial K_0^i}\mathbb{E}\left[\left(p\left(\mathbf{K}_0,\theta\right)-c_1\right)\mathbb{I}_{\{p(\mathbf{K}_0,\theta)<c_1\}}\right]=\mathbb{E}\left[\left(P_q\alpha^i\left(\theta\right)-\frac{\partial\tau}{\partial K_0^i}\right)\mathbb{I}_{\{p(\mathbf{K}_0,\theta)<c_1\}}\right].$$

For $n\geq 2$, the derivation of $\frac{\partial K_n}{\partial K_0^i}$ is unchanged. For $n=1$, the expression of $\frac{\partial K_1}{\partial K_0^i}$ is formally identical to the other $\frac{\partial K_n}{\partial K_0^i}$. As usual when technologies are flexible, only states in which $p>c_1$ have an impact on K_1.

The impact of renewable capacity i on the marginal value of renewable technology j is

$$\begin{aligned}\mathbb{E}\left[\alpha^j\left(\theta\right)\frac{\partial p}{\partial K_0^i}\right] &= \sum_{n=1}^{N}\mathbb{E}\left[\alpha^j\left(\theta\right)\left(P_q\times\left(\frac{\partial K_n}{\partial K_0^i}+\alpha^i\left(\theta\right)\right)-\frac{\partial\tau}{\partial K_0^i}\right)|v_n\right]\Pr\left(v_n\right)\\ &\quad+\mathbb{E}\left[\alpha^j\left(\theta\right)\left(P_q\alpha^i\left(\theta\right)-\frac{\partial\tau}{\partial K_0^i}\right)|p<c_1\right]\Pr\left(p<c_1\right).\end{aligned}$$

Derivations similar to the no baseload technology case show that

$$\begin{aligned}\mathbb{E}\left[\alpha^j\left(\theta\right)\frac{\partial p}{\partial K_0^i}|p<c_1\right] &= \left(\frac{\mathbb{E}\left[P_q\alpha^j\left(\theta\right)|p<c_1\right]}{\mathbb{E}\left[P_q\,|p<c_1\right]}-\mathbb{E}\left[\alpha^j\left(\theta\right)|p<c_1\right]\right)\frac{\partial\tau}{\partial K_0^i}\\ &\quad-\left(\frac{\mathbb{E}\left[P_q\alpha^j\left(\theta\right)|p<c_1\right]\mathbb{E}\left[P_q\alpha^i\left(\theta\right)|p<c_1\right]}{\mathbb{E}\left[P_q\,|p<c_1\right]}-\mathbb{E}\left[P_q\alpha^j\left(\theta\right)\alpha^i\left(\theta\right)|p<c_1\right]\right)\\ &\quad+\frac{\mathbb{E}\left[P_q\alpha^j\left(\theta\right)|p<c_1\right]}{\mathbb{E}\left[P_q\,|p<c_1\right]}\left(\mathbb{E}\left[P_q\alpha^i\left(\theta\right)|p<c_1\right]-\frac{\partial\tau}{\partial K_0^i}\right).\end{aligned}$$

Thus,

$$\mathbb{E}\left[a^j\left(\theta\right)\frac{\partial p}{\partial K_0^i}\right]=\Gamma^j\frac{\partial\tau}{\partial K_0^i}-E^{ij}+\frac{\mathbb{E}\left[P_q\alpha^j\left(\theta\right)|p<c_1\right]}{\mathbb{E}\left[P_q\,|p<c_1\right]}\left(\mathbb{E}\left[P_q\alpha^i\left(\theta\right)|p<c_1\right]-\frac{\partial\tau}{\partial K_0^i}\right)\Pr\left(p<c_1\right).$$

D Linear approximation

Suppose $\widehat{cov}_{\mathbf{K}_0}\left[\alpha^i\left(\theta\right),\alpha^j\left(\theta\right)\right]$ remains constant (or at least does not vary too much) as $\mathbf{K}_0$ changes, i.e., the conditional covariances are not too affected by the level of renewable: $\widehat{cov}_{\mathbf{K}_0}\left[\alpha^i\left(\theta\right),\alpha^j\left(\theta\right)\right]=\widehat{cov}\left[\alpha^i\left(\theta\right),\alpha^j\left(\theta\right)\right]$. Since most expressions are linear, it is helpful to use vectorial notation. For any matrix $\mathbf{M}$, denote $\mathbf{M}_{ij}$ the element located on line i, column j. Introduce $\mathbf{C}\in\mathbb{R}^I\times\mathbb{R}^I$ the matrix of covariances, i.e., $\mathbf{C}_{ij}=\widehat{cov}\left[\alpha^i\left(\theta\right),\alpha^j\left(\theta\right)\right]$, and $\mathbf{V}\left(\mathbf{K}_0\right)\in\mathbb{R}^I$ the vector of marginal values, i.e., $\mathbf{V}_i\left(\mathbf{K}_0\right)=\mathbb{E}\left[\alpha^i\left(\theta\right)p\left(\mathbf{K}_0,\theta\right)\right]$.

From equation (8), the vector of marginal values is a linear function of the vector of renewable capacities:

$$\mathbf{V}(\mathbf{K}_0) = \mathbf{V}(\mathbf{0}) - b\mathbf{C}\cdot\mathbf{K}_0.$$

The slope of the own effect is the opposite of the variance of availability, restricted to being on the vertical portions of the supply curve. The slope of the cross effect is the covariance between availabilities (also restricted to being on the vertical portions of the supply curve).

Then, the vector of marginal subsidies $\varphi(\mathbf{K}_0) \in \mathbb{R}^I$ is

$$\varphi(\mathbf{K}_0) = r_0(\mathbf{K}_0) - \mathbf{V}(\mathbf{0}) + b\mathbf{C}\cdot\mathbf{K}_0,$$

and the cumulative total subsidy $\Phi(\mathbf{K}_0) \in \mathbb{R}$ is

$$\Phi(\mathbf{K}_0) = R_0(\mathbf{K}_0) + \mathbf{K}_0^T \cdot (b\mathbf{C}\cdot\mathbf{K}_0 - \mathbf{V}(\mathbf{0})).$$

Since we obtain a closed form expression of $R_0(\mathbf{K}_0)$, the linear approximation yields a closed form expression of $\Phi(\mathbf{K}_0)$. The marginal subsidy $\varphi(.)$ and the cumulative subsidy $\Phi(.)$ are respectively linear and a quadratic functions of the capacity vector $\mathbf{K_0}$.

We derive a closed form solution for $\tau(\mathbf{K}_0)$. As previously,

$$\tau(\mathbf{K}_0)\left(\bar{D}(\mathbf{0}) - \frac{1}{b}\tau(\mathbf{K}_0)\right) = \Phi(\mathbf{K}_0).$$

With the linear approximation, $\mathbf{C}$ no longer varies with τ, hence the fixed point problem disappears. Thus,

$$b\bar{D}(\mathbf{0})\tau - \tau^2 = b\Phi(\mathbf{K}_0) \Leftrightarrow \tau^2 - b\bar{D}(\mathbf{0})\tau + b\Phi(\mathbf{K}_0) = 0.$$

The discriminant of the quadratic equation is

$$\Delta(\mathbf{K}_0) = \left(b\bar{D}(\mathbf{0})\right)^2 - 4b\Phi(\mathbf{K}_0).$$

We assume (and shall verify later) that $\Delta\left(\bar{K}_0\right) > 0$. The quadratic equation admits two roots. We choose the root increasing in each K_0^i

$$\tau(\mathbf{K}_0) = \frac{b\bar{D}(\mathbf{0}) - \sqrt{\Delta(\mathbf{K}_0)}}{2} = \frac{b\bar{D}(\mathbf{0}) - \sqrt{\left(b\bar{D}(\mathbf{0})\right)^2 - 4b\Phi(\mathbf{K}_0)}}{2}.$$

The tax is an "approximately" linear function of the capacity vector $\mathbf{K_0}$, since it is the square root of a quadratic form.

This expression of $\tau(\mathbf{K}_0)$ enables us to obtain a "simple" expression for the marginal welfare change:

$$\begin{aligned}\frac{\partial H}{\partial K_0^i} &= -\left(\varphi^i\left(\mathbf{K}_0\right)+\frac{\tau\left(K_0\right)\left(\varphi^i\left(\mathbf{K}_0\right)+b\mathbf{C}\cdot\mathbf{K}_0\right)}{b\bar{D}\left(\mathbf{K}_0\right)-2\tau\left(\mathbf{K}_0\right)}\right)\\ &= -\frac{\left(b\bar{D}\left(\mathbf{0}\right)+\sqrt{\Delta\left(\mathbf{K}_0\right)}\right)\varphi^i\left(\mathbf{K}_0\right)+b\left(b\bar{D}\left(\mathbf{0}\right)-\sqrt{\Delta\left(\mathbf{K}_0\right)}\right)\mathbf{C}\cdot\mathbf{K}_0}{2\sqrt{\Delta\left(\mathbf{K}_0\right)}}\end{aligned}$$

Finally, we obtain a closed form expression of the welfare loss:

$$H\left(\mathbf{0}\right)-H\left(\mathbf{K}_0\right)=R_0\left(\mathbf{K}_0\right)+\mathbf{K}_0^T\cdot\left(\frac{b}{2}\mathbf{C}\cdot\mathbf{K}_0-\mathbf{V}\left(\mathbf{0}\right)\right)+\frac{1}{2b}\tau^2\left(\mathbf{K}_0\right).$$

Of course, the linear approximation is not exact, and the analyst must trade-off simplicity against precision. The numerical analysis conducted for the UK shows that the actual marginal values and their linear approximation are reasonably close as long as the baseload technology produces every hour.

E Proof of Proposition 8: financial dispatch insurance

The free entry conditions, hence marginal price and capacity impact conditions are unchanged for $n \geq 2$. Similarly, the time-weighted average price is still equal to the long-run marginal cost of the baseload technology, $(c_1 + r_1)$:

$$\mathbb{E}\left[p\left(\mathbf{K}_0,\theta\right)\right]=c_1+r_1.$$

For $n \geq 2$, we start from

$$\mathbb{E}\left[p\left(\mathbf{K}_0,\theta\right)\right]=c_1+r_1 \textit{ and } \mathbb{E}\left[\left(p\left(\mathbf{K}_0,\theta\right)-c_2\right)\mathbb{I}_{p\left(\mathbf{K}_0,\theta\right)\geq c_2}\right]=r_2.$$

Differentiating the difference with respect to K_0^i yields

$$\mathbb{E}\left[\frac{\partial p}{\partial K_0^i}\right]-\mathbb{E}\left[\frac{\partial p}{\partial K_0^i}\mathbb{I}_{p\left(\mathbf{K}_0,\theta\right)\geq c_2}\right] = \mathbb{E}\left[\frac{\partial p}{\partial K_0^i}\mathbb{I}_{p\left(\mathbf{K}_0,\theta\right)< c_2}\right]=0$$

$\iff$

$$\mathbb{E}\left[\frac{\partial p}{\partial K_0^i}\left|0<p<c_2\right.\right]\Pr\left(0<p<c_2\right)+\mathbb{E}\left[\frac{\partial p}{\partial K_0^i}\left|p<0\right.\right]\Pr\left(p<0\right)$$

$\iff$

$$\mathbb{E}\left[P_q\left(\frac{\partial K_1}{\partial K_0^i}+\alpha^i\left(\theta\right)\right)-\frac{\partial\tau}{\partial K_0}\left|u_2\right.\right]\Pr\left(u_2\right)+\mathbb{E}\left[P_q\frac{\partial K_1}{\partial K_0^i}-\frac{\partial\tau}{\partial K_0}\left|p<0\right.\right]\Pr\left(p<0\right)=0$$

$\iff$

$$
\begin{aligned}
\frac{\partial K_1}{\partial K_0^i} &= \frac{\frac{\partial \tau}{\partial K_0^i} - \frac{\Pr(u_2)}{\Pr(u_2)+\Pr(p<0)}\mathbb{E}\left[P_q \alpha^i(\theta)|u_2\right]}{\frac{\mathbb{E}[P_q|u_2]\Pr(u_2)+\mathbb{E}[P_q|p<0]\Pr(p<0)}{\Pr(u_2)+\Pr(p<0)}} \\
&= \frac{\frac{\partial \tau}{\partial K_0^i} - (1-\mu)\mathbb{E}\left[P_q \alpha^i(\theta)|u_2\right]}{\mathbb{E}\left[P_q|u_2\right](1-\mu) + \mathbb{E}\left[P_q|p<0\right]\mu}.
\end{aligned}
$$

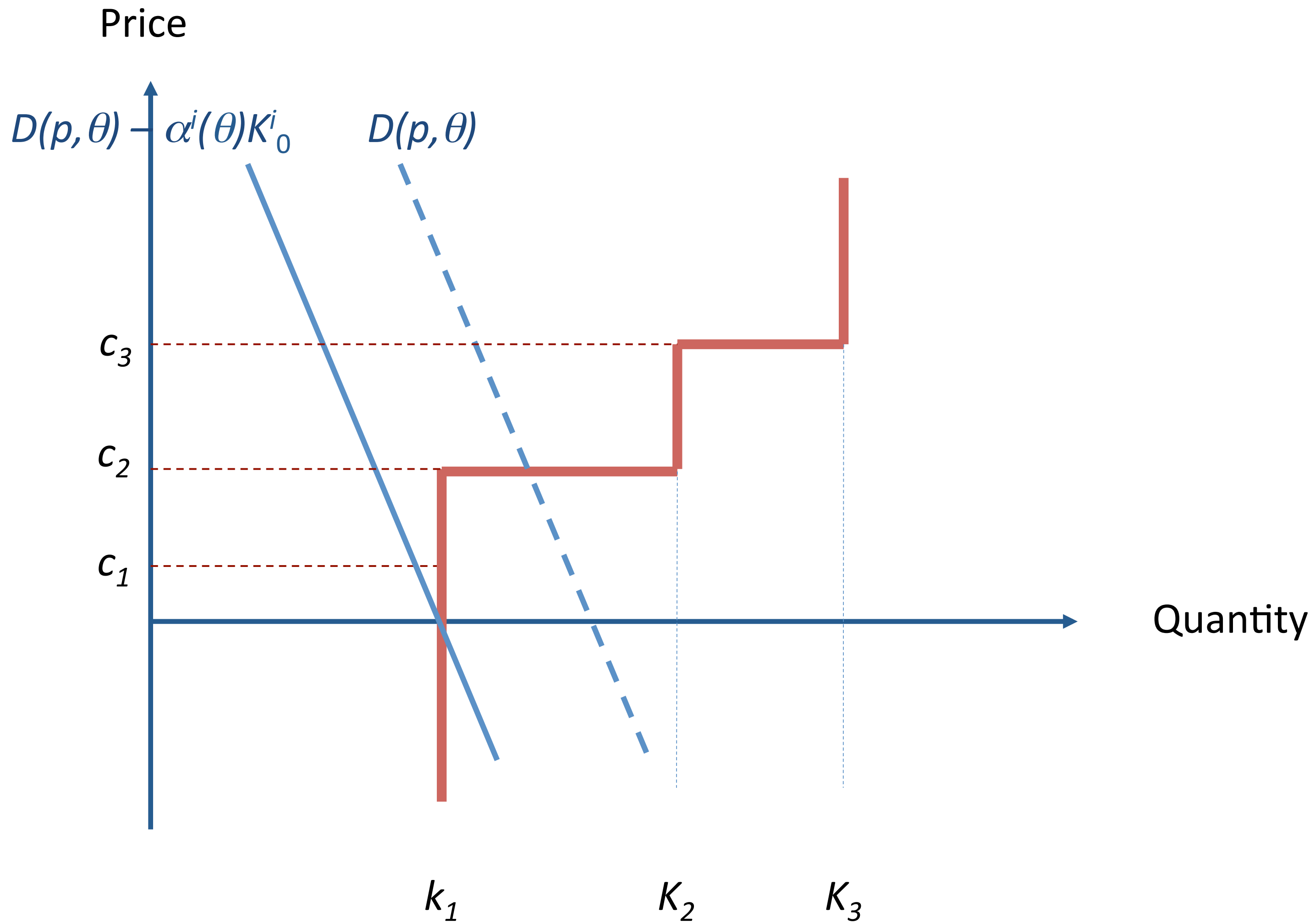
We now derive the (marginal) change in the marginal value of energy produced by the j renewable technology, $\frac{\partial}{\partial K_0^i}\mathbb{E}\left[p(\mathbf{K}_0,\theta)\alpha^j(\theta)\mathbb{I}_{p(\mathbf{K}_0,\theta)\geq 0}\right]$. Since the expectation is taken on the subset of the states of the world such that $p(\mathbf{K}_0,\theta) \geq 0$, we need to account for the the boundary term when differentiating. However, since by construction $p(\mathbf{K}_0,\theta) = 0$ at the boundary, the boundary term is equal to zero, and

$$
\begin{aligned}
\frac{\partial}{\partial K_0^i}\mathbb{E}\left[p(\mathbf{K}_0,\theta)\alpha^j(\theta)\mathbb{I}_{p(\mathbf{K}_0,\theta)\geq 0}\right] &= \mathbb{E}\left[\alpha^j(\theta)\frac{\partial p}{\partial K_0^i}\mathbb{I}_{p(\mathbf{K}_0,\theta)\geq 0}\right] \\
&= \sum_{n=2}^{N}\mathbb{E}\left[\frac{\partial p}{\partial K_0^i}\alpha^j(\theta)|v_n\right]\Pr(v_n) + \mathbb{E}\left[\frac{\partial p}{\partial K_0^i}\alpha^j(\theta)|u_2\right]\Pr(u_2).
\end{aligned}
$$

Derivations are unchanged for $n \geq 2$. For $0 < p < c_2$,

$$
\begin{aligned}
\mathbb{E}\left[\frac{\partial p}{\partial K_0^i}\alpha^j(\theta)|u_2\right] &= \mathbb{E}\left[\alpha^j(\theta)\left(P_q \times \left(\frac{\partial K_1}{\partial K_0^i} + \alpha^i(\theta)\right) - \frac{\partial \tau}{\partial K_0^i}\right)|u_2\right] \\
&= \mathbb{E}\left[P_q\alpha^j(\theta)|u_2\right]\frac{\partial K_1}{\partial K_0^i} + \mathbb{E}\left[P_q\alpha^j(\theta)\alpha^i(\theta)|u_2\right] - \frac{\partial \tau}{\partial K_0^i}\mathbb{E}\left[\alpha^j(\theta)|u_2\right] \\
&= \left(\frac{\mathbb{E}\left[P_q\alpha^j(\theta)|u_2\right]}{\mathbb{E}\left[P_q|u_2\right](1-\mu) + \mathbb{E}\left[P_q|p<0\right]\mu} - \mathbb{E}\left[\alpha^j(\theta)|u_2\right]\right)\frac{\partial \tau}{\partial K_0^i} \\
&\quad + \left(\mathbb{E}\left[P_q\alpha^j(\theta)\alpha^i(\theta)|u_2\right] - \frac{\mathbb{E}\left[P_q\alpha^i(\theta)|u_2\right]\mathbb{E}\left[P_q\alpha^j(\theta)|u_2\right]}{\mathbb{E}\left[P_q|u_2\right] + \mathbb{E}\left[P_q|p<0\right]\frac{\mu}{1-\mu}}\right).
\end{aligned}
$$

Figure 1: Demand and Costs, Base Case



Nuclear stations fully inflexible; Physical dispatch insurance

Figure 2: Capacities (status quo)

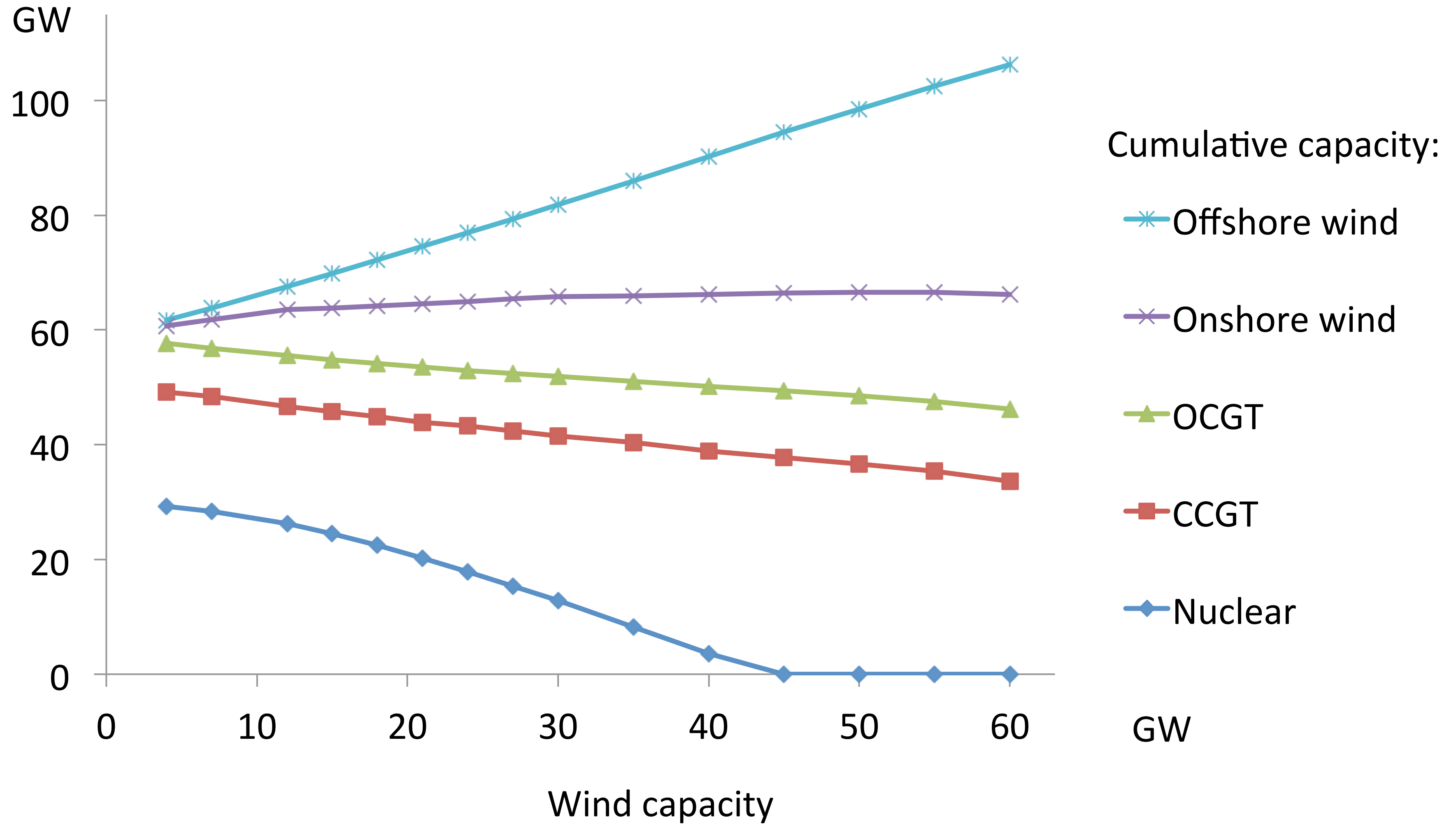


Figure 3: Average Prices (status quo)

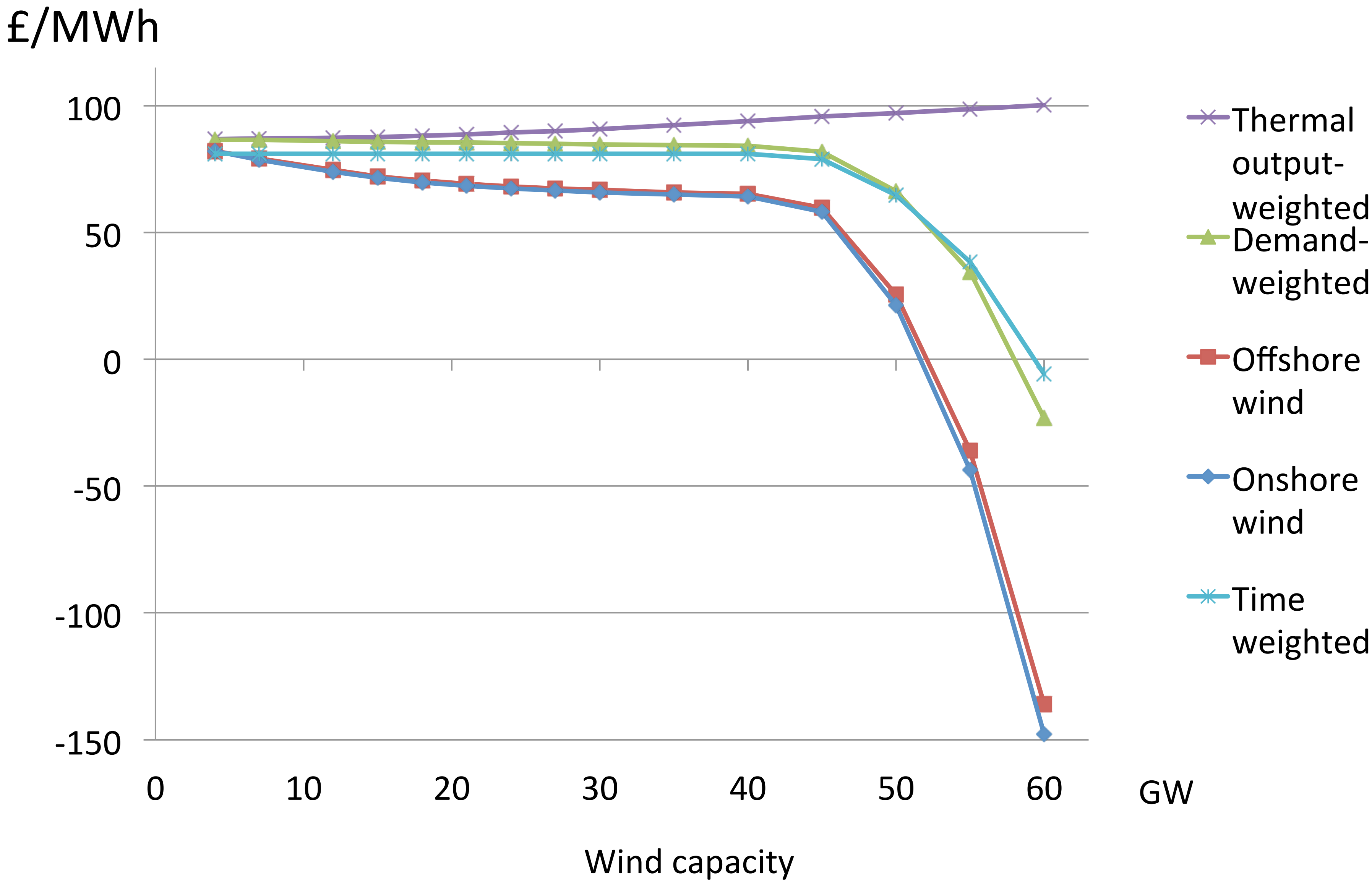


Figure 4: Marginal value of onshore wind under different scenarii

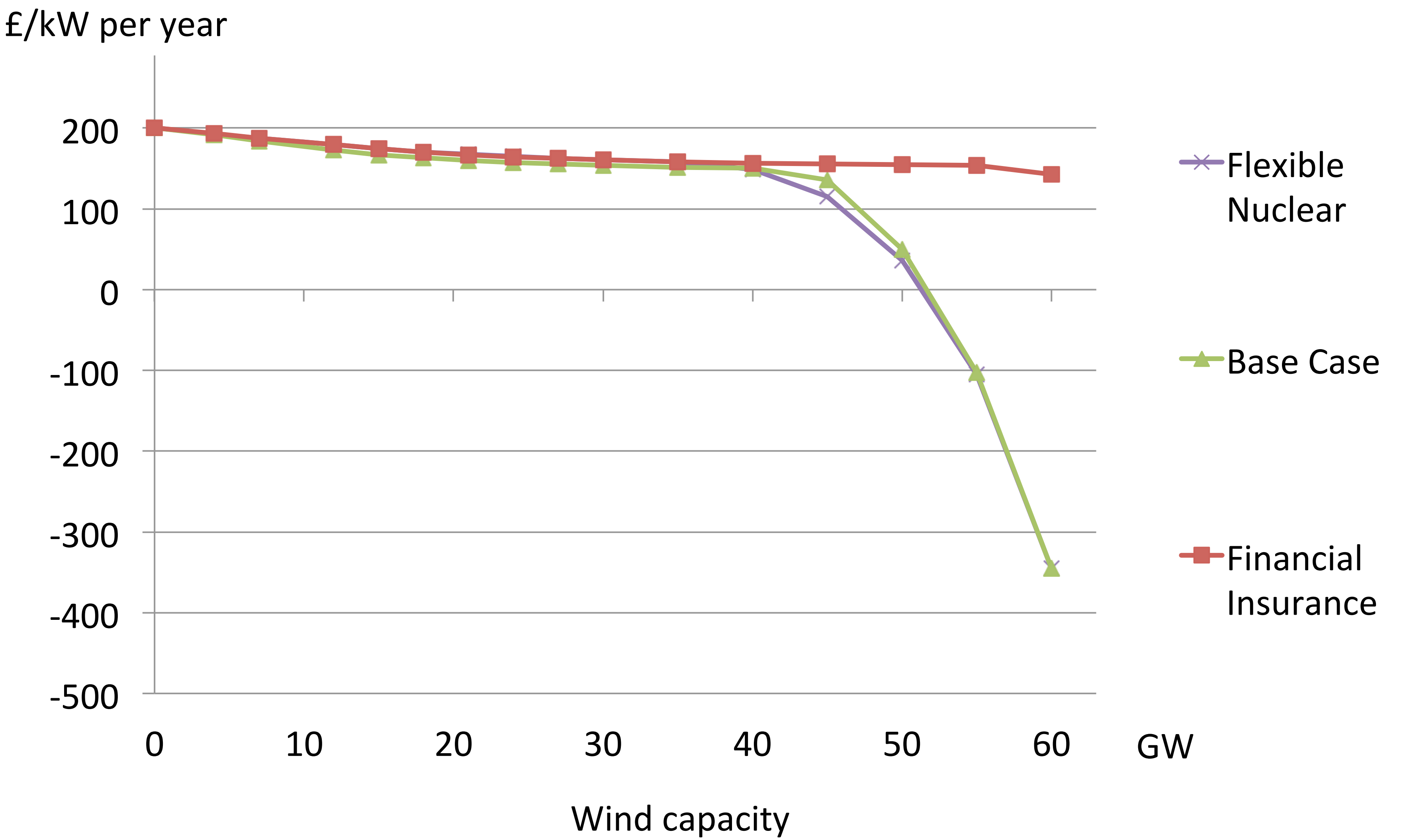


Figure 5: Marginal value of offshore wind under different scenarii

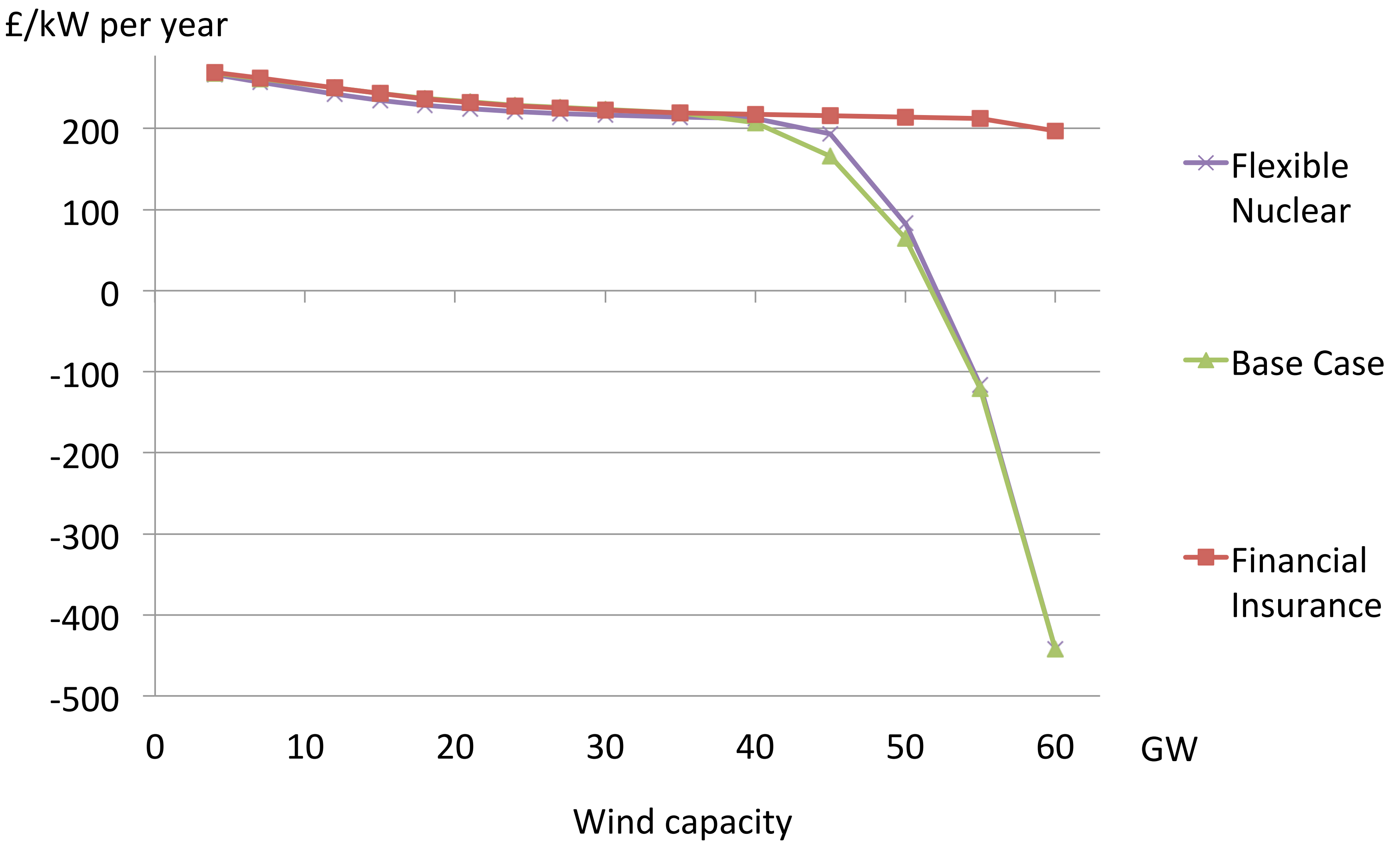


Figure 6: Marginal subsidy to onshore wind under different scenarii

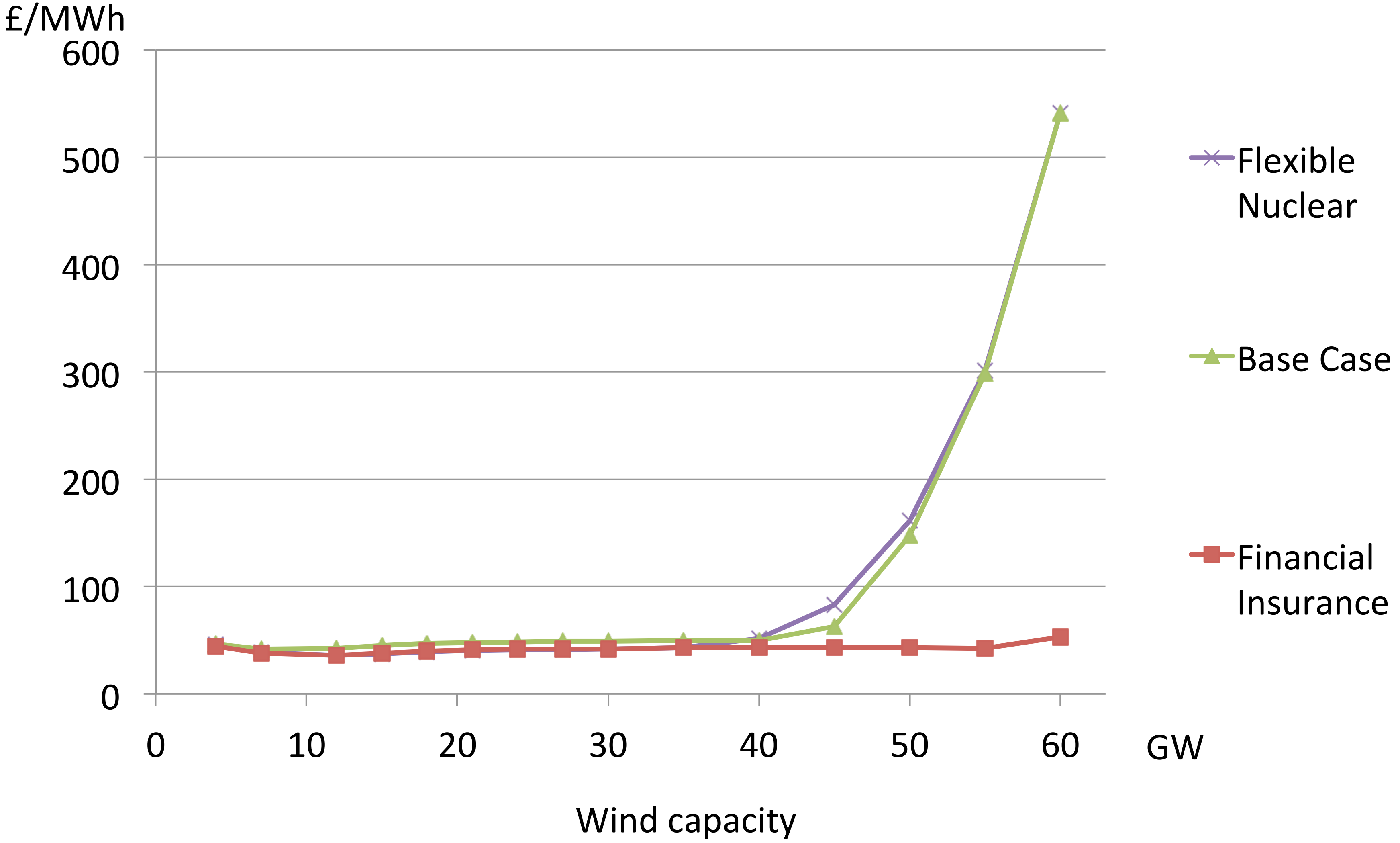


Figure 7: Marginal subsidy to offshore wind under different scenarii

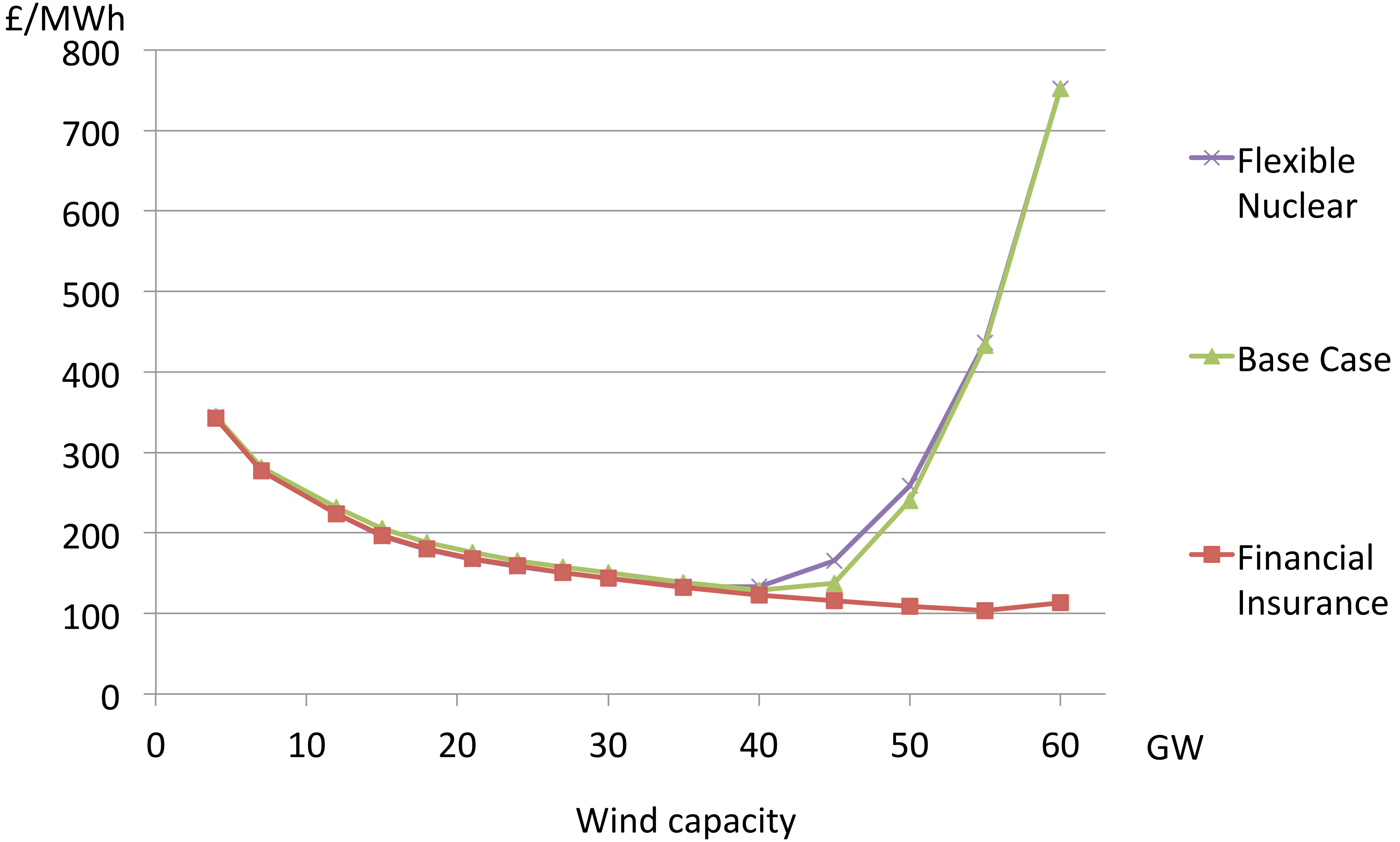


Figure 8: Tax Required

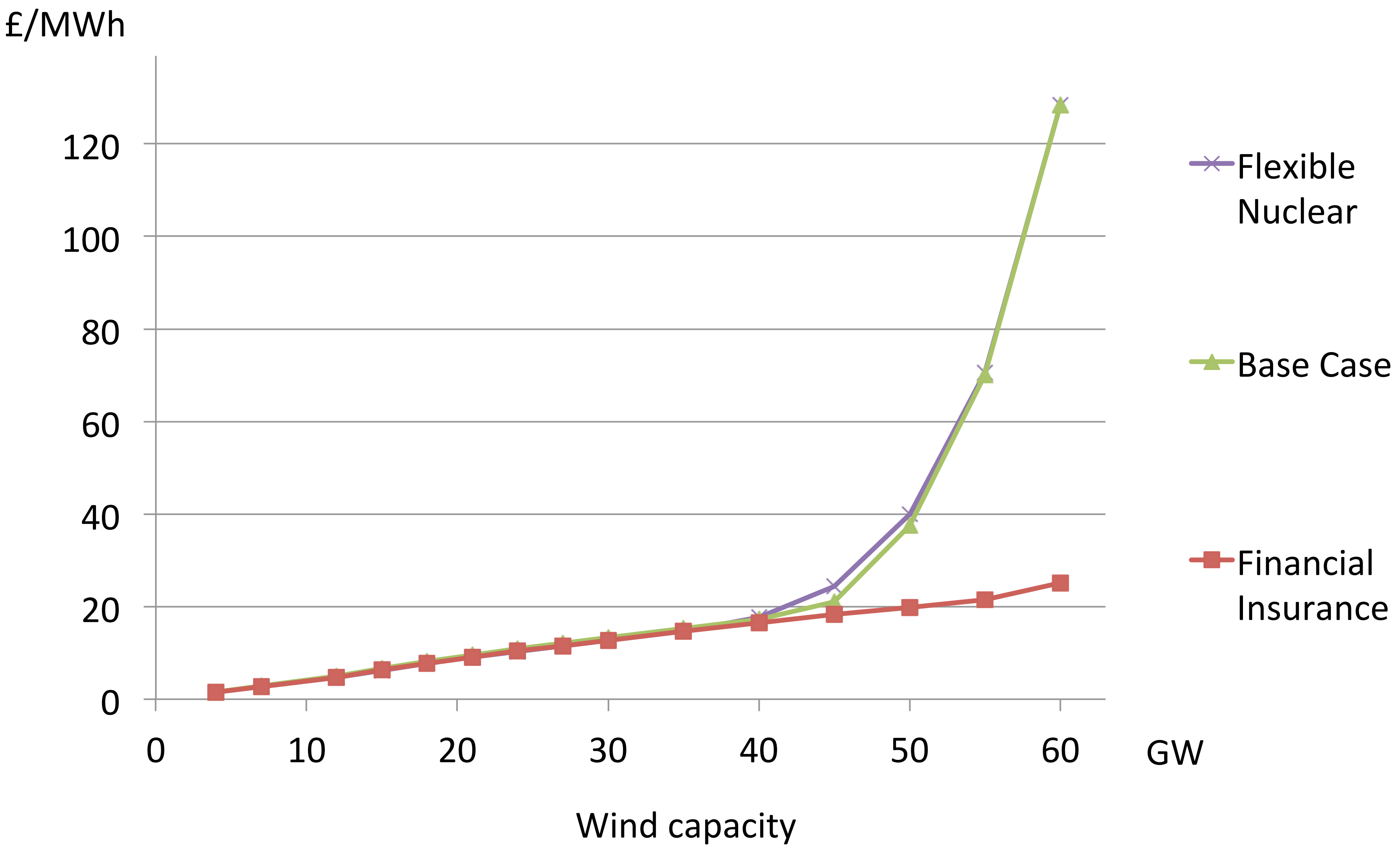


Figure 9: Net surplus loss

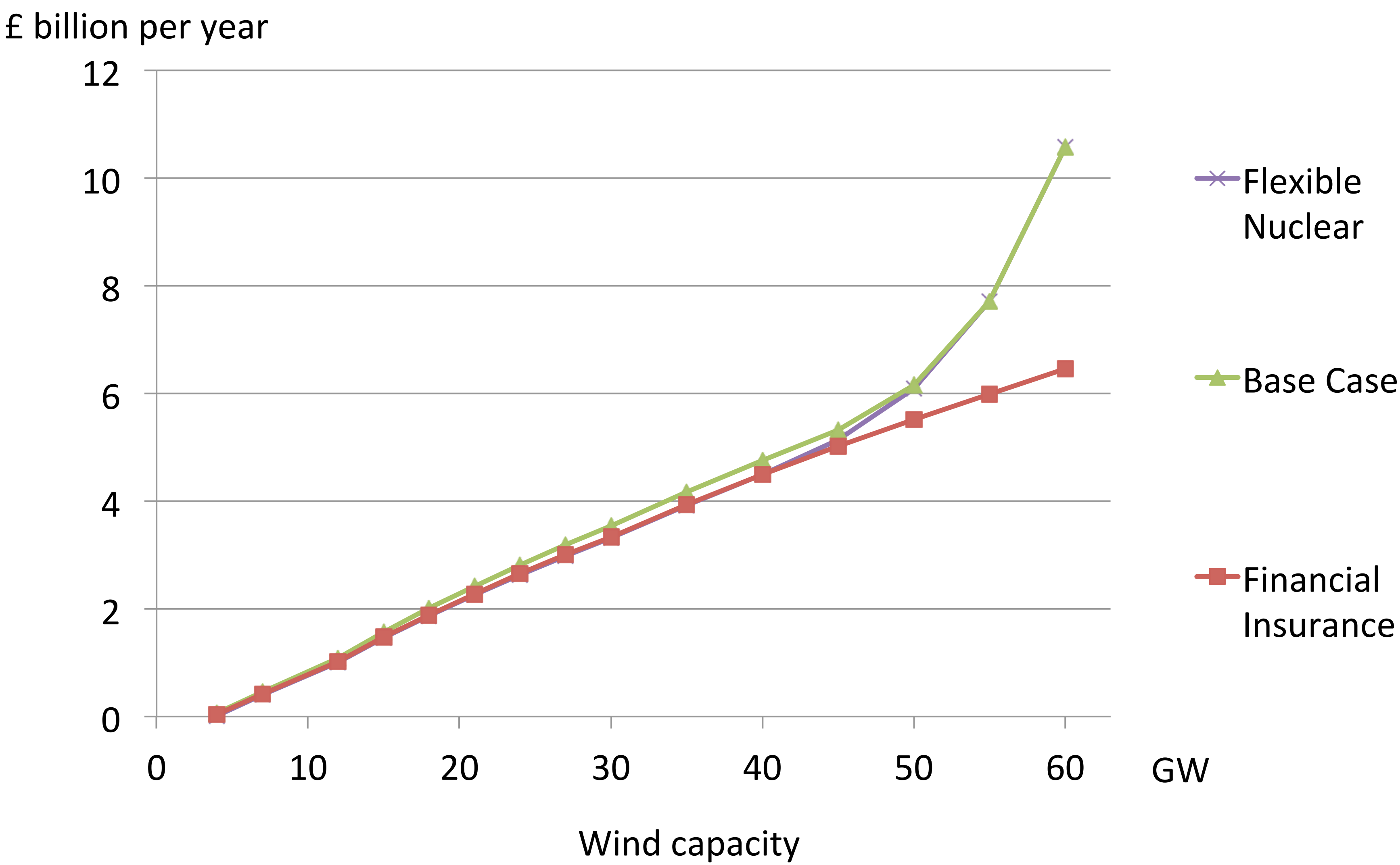


Figure 10: Capacities (flexible nuclear; physical renewables insurance)

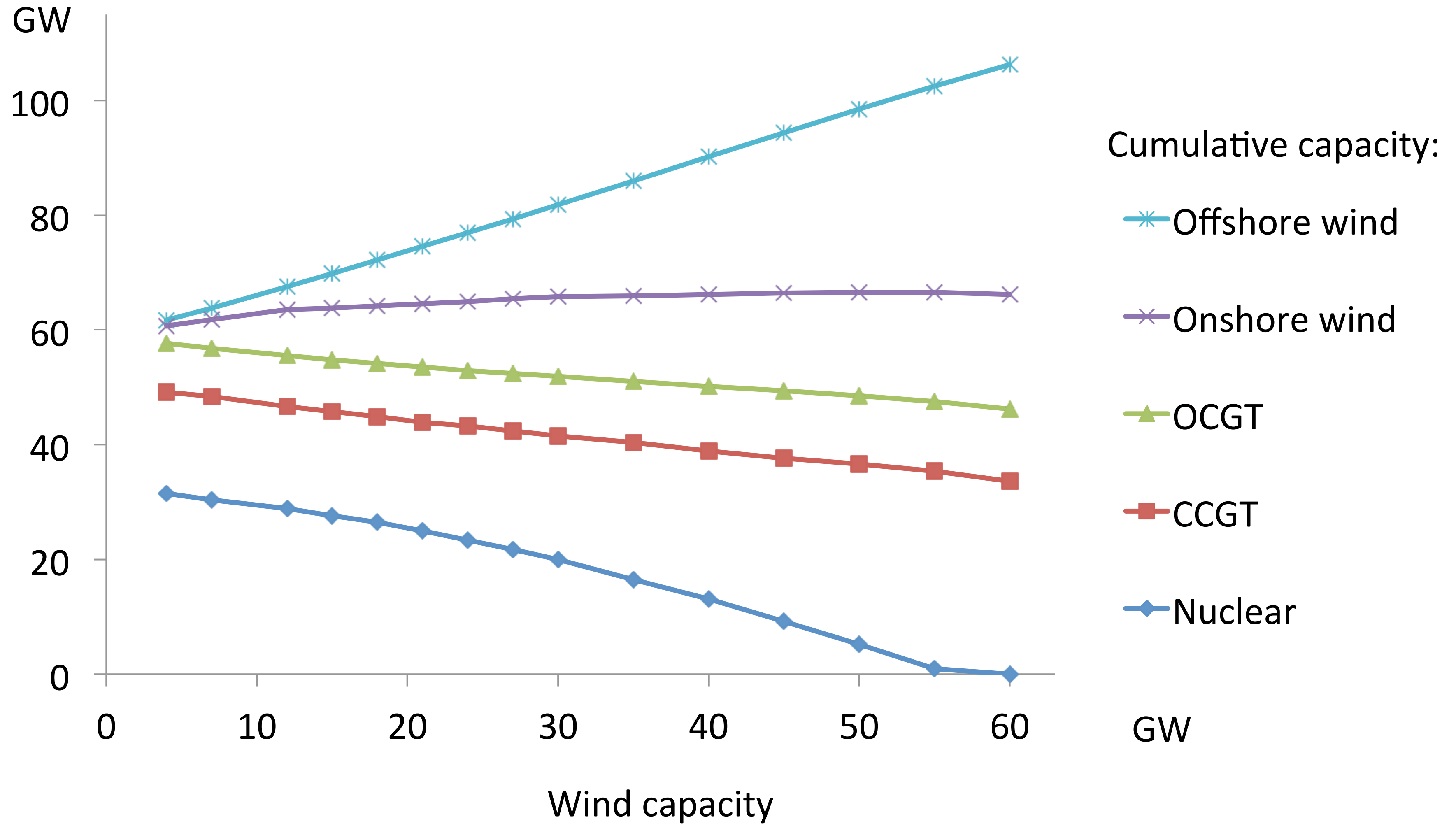
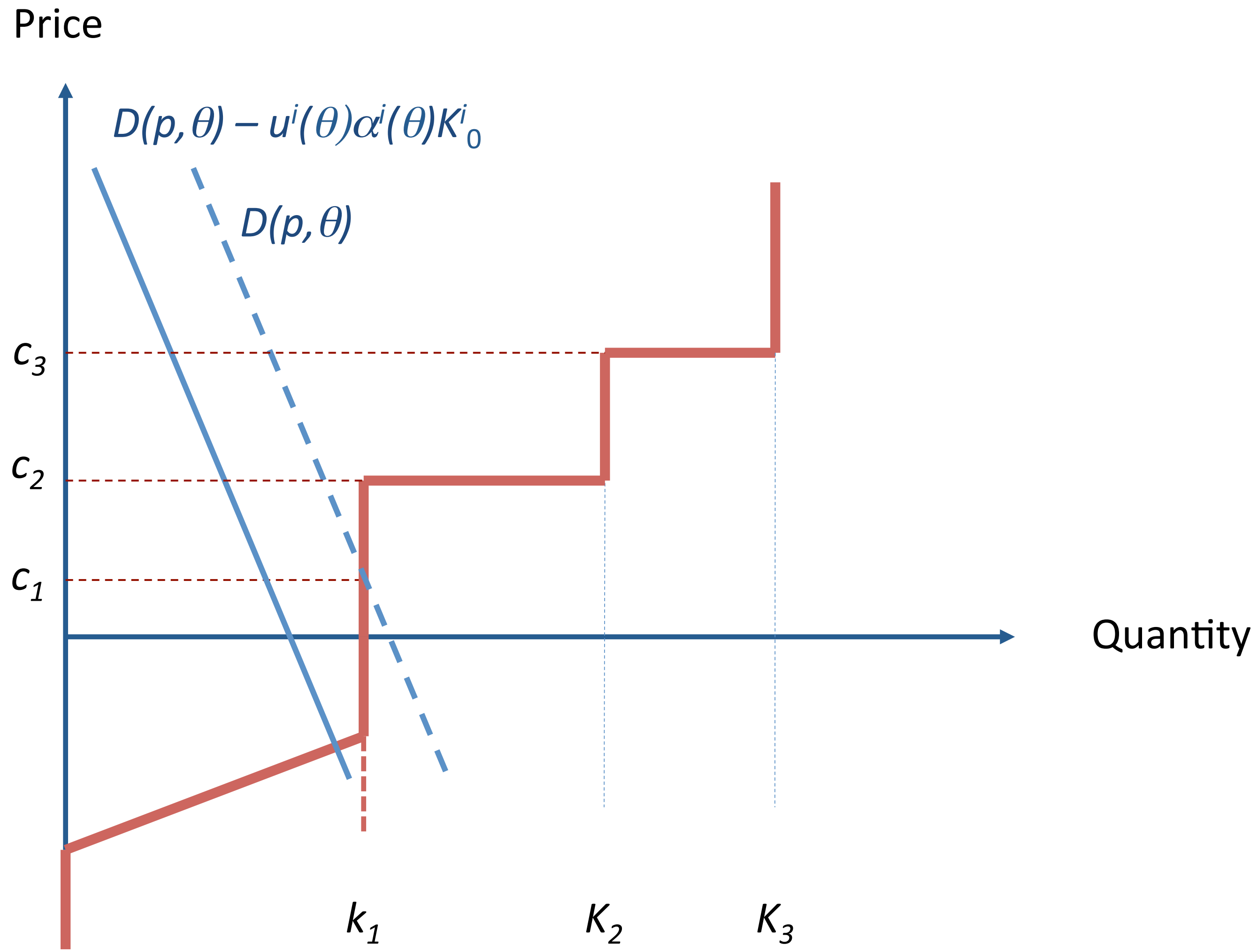
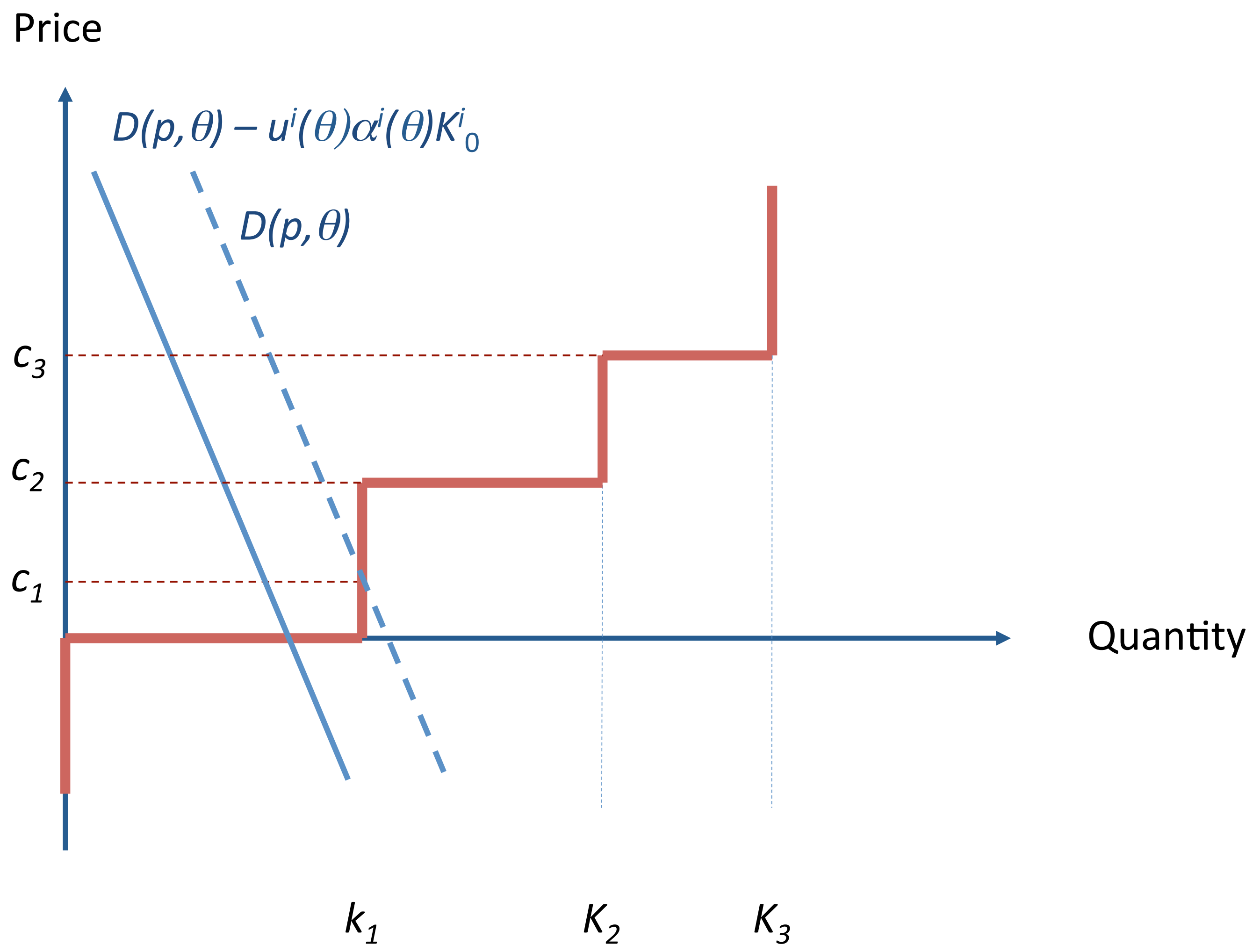


Figure 11: Demand and Costs, Feed-in Premium



Nuclear stations fully inflexible; Physical dispatch insurance

Figure 12: Demand and Costs, Financial insurance



Nuclear stations fully inflexible; Physical dispatch insurance

Figure 13: Capacities (financial renewables insurance)