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Taxing Carbon Emissions and Green Transition: The Case of the Italian Electricity Market

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Taxing Carbon Emissions and Green Transition: The Case of the Italian Electricity Market

Marco Amendola* and Marco Valente†

Abstract

The electricity generating sector is the single largest source of climate altering pollution. A country aiming to meet its targets for a net-zero economy needs therefore to radically reduce the emissions stemming from this sector. Charging carbon emissions is the preferred market-friendly policy to promote the diffusion of green technologies assuming that investors find more profitable to adopt technologies not burdened by the cost of carbon emissions. We study empirically the effectiveness of an increase in the cost of carbon emissions in order to favor the replacement of power plants burning fossil fuels with generators powered by renewable energy in Italy.

Based on hourly data from the Italian electricity market we find that a policy increasing the cost of carbon emissions is less effective than expected in promoting clean energy investments. Indeed, increasing the cost of emissions actually *increases* the relative profitability of brown energy sources in respect of green ones in the most likely conditions.

We conclude that increasing the cost of carbon emissions hinders the diffusion of technologies necessary for the green transition in the Italian electricity production sector. More in general, our results suggest that market friendly policies based on biasing incentives for profit-seeking operators need to carefully analyze the mechanisms underpinning the markets of interests to prevent policy failures.

Keywords: Electricity market; Carbon pricing; Hourly-frequency model; Energy transition
JEL Classification: C63; H23; Q42; Q48

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Introduction

The crucial role of renewable energy sources in mitigating global emissions, reducing carbon intensity, and bolstering the chances of maintaining climate change within acceptable boundaries is well-understood (Riahi et al., 2017; Fricko et al., 2017; IPCC, 2023). According to the International Energy Agency (IEA), achieving the net-zero target by 2050 necessitates that roughly two-thirds of the global energy mix must be generated from renewable sources. Renewable electricity, in particular, must account for approximately 90% of global electricity generation (IEA, 2021, 2023a), necessitating a significant increase in the installed capacity of solar and wind plants. The European Union has adopted a similarly ambitious plan, aiming for a significant proportion of its energy needs to be met by renewable sources in the coming decades to sustain a rapid electrification of several sectors. Comparable electrification targets have been proposed by many other nations worldwide.

There is no reason to expect that the huge investments required will be provided spontaneously by private companies. Pollution is the typical case of negative externality that, in a free market economy, no profit-seeking entity would ever consider and therefore we need policy initiatives that internalize the external benefits in private investors' profits.

The design of economic policies is notoriously difficult because of the risk that neglected details may make the policy ineffective or even counterproductive. This paper discusses the most common policy deployed to favor green technologies: charging the carbon emissions of the polluting production process that should promote the diffusion of green energy sources, reducing the returns on investment in polluting sources. We show that, in effect, carbon taxes can be far less effective than generally considered and even, under fairly general conditions, *reduce* the incentive to invest in green technologies by making fossil fuel investments more profitable.

We reach this conclusion by studying the Italian electricity market and, in particular, the hourly distribution of prices and amount of energy for broad classes of generating technologies, namely "green" sources (solar PV and wind turbines) vs "brown" ones (gas-fired power plants). We use the data from a sample year to reconstruct an estimated energy supply curve to endogenize the price as a function of the total energy produced. We use the estimated supply function and the actual market data to compute the potential profitability for prospective investors deciding which technology to use for the hypothetical construction of a new electricity generating plant. We show that, with respect to green energy investments, the profit advantage of gas-fired generators increases with the increasing cost of carbon emissions under the most general cases, leading to the conclusion that charging carbon emissions hinders, rather than promotes, the diffusion of renewable energy generators.

We stress that our result concerns the Italian energy sector given its current organization, in particular in relation to the mechanism determining the market price out of a potential supply made of an heterogeneous set of energy producers. More in general, we believe that our approach may provide valuable insights also for other cases with conditions similar to one used in our work. However, we do not imply, nor believe, that taxing carbon emissions is ineffective in general as a policy to promote green investments. Rather, our work cautions against the blind applications of general principles to specific realities supporting the general methodological approach that designing a policy requires a meticulous understanding of how economic systems actually work.

The paper is organized as follows. The following section describes the current functioning of electricity markets and defines the motivation for this paper. Section 2 presents an econometric model using hourly data from the Italian electricity market to estimate an empirical supply curve of electricity in Italy linking price and amount of energy, conditional on the prices of fuel and carbon emissions. Section 3 uses the estimations from the previous section to compute an index of profitability for plants using different generating technologies (green and brown) in order to assess comparatively the incentive to invest in these plants. Provided that our results show that charging carbon emissions fails to promote the diffusion of renewable energy generators in several cases, section 4 briefly reviews alternative policy approaches. A concluding section sums up the content of the paper and indicates possible extensions from the present work.

1 Energy Production Costs, Prices and Green Policies

Comparing the headline unit costs of energy production may apparently lead to the conclusion that reaching the green transition is fairly easy. Producing energy from renewable sources has exhibited remarkable technological advancements, steep learning curves, and sustained economies of scale over recent decades, apparently making these technologies cost competitive vis-à-vis conventional fossil fuel alternatives (IEA, 2020; IRENA, 2023; IPCC, 2023). Moreover, recent spikes in fossil fuel prices in international markets, coupled with increases in emissions prices in regions such as the EU, have further bolstered the relative cost competitiveness of carbon-free energy that, in many cases, is produced at far cheaper costs than that produced with fossil fuels (IEA, 2023b). Indeed, the success in reducing the cost of green energy generation has even prompted several countries to gradually withdraw existing financial incentives originally implemented to kick start the transition under the assumption that, once green energy is cheaper than carbon-based alternatives, producers of electricity from renewable sources can thrive even without public support (Amendola et al., 2024).

However, for a successful green transition in energy production is not sufficient for green energy to be cheaper than brown one. It is necessary that green investments can be reasonably expected to provide higher profitability than alternative technologies. For this second condition to occur we need to consider additional aspects besides production costs, such as capital construction costs and prices effectively paid to producers. An expanding body of literature is recognizing the limitations of relying solely on cost data to gauge the profitability of electricity sources, advocating for a more comprehensive approach (e.g. Joskow, 2011; Borenstein, 2012; Hirth, 2013; Hirth et al., 2016; IEA, 2018).

The complexity of modern electricity markets, typified by fluctuating market-determined electricity prices and a burgeoning share of renewable energy sources, poses several challenges in evaluating the effective financial returns from investments in electricity generation (Mills and Wiser, 2012; IEA, 2018). One of the reasons is that as the share of cheap renewable electricity increases, average electricity prices tend to decrease due to the displacement of alternative sources with higher marginal production costs, a phenomenon extensively documented in literature as the "merit order effect" (e.g. Jónsson et al., 2010; Gil et al., 2012; Ballester and Furió, 2015; Sapio, 2015, 2019; Figueiredo and da Silva, 2019; De Siano and Sapio, 2022). However, the decreasing average price does not hit all producers in the same way but affects asymmetrically different producers depending, among other factors, on when the energy is produced and sold, factors determined by the generating technology used. In particular, wind and solar generators depend on atmospheric conditions, and all producers using the same technology are forced to compete against each other when conditions are favorable, in effect generating a self-cannibalization effect: the larger the share of renewable energy producers, the more intense is the competition among green producers compressing their earnings. In the limit, if the installed capacity for a renewable source is sufficiently large, the selling price during production times falls to the marginal cost of production, likely to be close to zero. On the contrary, technologies based on hydrocarbon fuels are flexible and can be activated at any time depending on economic interests only (Hirth, 2013; IEA, 2018). As a consequence, the overall average price may affect the profitability of producers in very differentiated ways rewarding polluting technologies and penalizing clean alternatives that become victims of their very success.

The variability of effective energy prices received by different sources can be significant and tends to increase with higher penetration rates of renewable sources (Grubb, 1991; Rahman and Bouzguenda, 1994; Mills and Wiser, 2012; Hirth, 2013, 2016; Eising et al., 2020). Solar energy is particularly vulnerable because of the limitation of production in specific and predictable hours applying to all producers in a certain geographical area, resulting in a substantial decrease in the wholesale price during these periods, especially at high penetration levels and in the absence of cost-effective storage options (Mills and Wiser, 2012). Projections by IEA (2018) suggest that by 2030 in the EU, the average electricity price received by gas-based (CCGT) producers could be 40% higher than the average wholesale price of solar PV sources. From the policy-making perspective, the consequences of selective competition differentiated by sources are likely to make apparently straightforward incentive schemes far less effective than expected (Hirth, 2013).

Alternative cost indicators have been proposed in recent years in order to consider all aspects of energy production relevant to planning a green transition (Shen et al., 2020). Computing the cost of production is notoriously very difficult because energy-generating technologies have different capital costs, obsolescence time, maintenance and operation costs, etc. The Levelized Cost of Energy (LCOE) is the accepted standard representing the average actualized net cost of energy generation, including all relevant elements concerning energy productions, but ignores the differentiated market conditions and, hence, selling prices faced by different technologies. Recently, the IEA has advocated for refining the LCOE to account for variations in the market values of electricity produced, capacities to respond to system needs, and abilities to provide sufficient reserve capacity (IEA, 2018). Consequently, the IEA has introduced a new metric, the value-adjusted LCOE or VALCOE, integrating the LCOE with measures related to the selling conditions of each technology. Cost estimations and, consequently, policy implications may differ widely depending on which metric, LCOE or VALCOE, is adopted (IEA, 2020, 2023b). For instance, although the LCOE of solar PV is projected to consistently undercut that of coal in India over the coming decades, the agency finds the opposite result, i.e. coal-based energy is cheaper than that produced with solar PV, considering the more comprehensive VALCOE metric (IEA, 2018, 2023b). Similarly, in other regions such as the EU, the US, and China, the competitive advantage of renewable sources over traditional ones appears far less evident when considering VALCOE results (IEA, 2023b).

In this paper, we adopt the same perspective of considering the actual value of different technologies to evaluate the hypothetical profitability of investments in different technologies, focusing our analysis on the Italian market. For this purpose, we start by providing a brief description of the main features of the Italian electricity generation system broken down by the generating technology.[1]

Table 1 provides a summary of the generation and installed capacity grouped according to the generating technology and energy sources in 2019.[2] Natural gas is the primary energy source, providing almost half of the energy produced, while wind and solar power alone account for approximately 26% of Italy's capacity and about 15% of production.

The wholesale price of energy is determined by an electricity market managed by a state-owned company, GME[3], running the so-called "Day-Ahead Market" defining a price for each hour of the following day. The starting point to set an hour's price is the definition of the expected energy demand for that hour of the following day. Based on this information, each producer submits a bid indicating the energy it can provide to the grid and the minimum price it would accept. The GME then ranks the bids for ascending prices accepting the bids until saturation of the expected demand. The official wholesale price of electricity for that hour, called PUN ("*Prezzo Unico Nazionale*", National Unique Price) is defined by the marginal accepted bid, i.e. the highest price which satisfies the

[1] Data on electricity generation, demand, supply and import-export flows as well as on installed capacity is retrieved from Terna, which is the grid operator for electricity transmission in Italy: www.terna.it/en/electric-system/transparency-report/download-center.

[2] Although more recent data are available, we choose 2019 because it is the most recent year not affected by the (hopefully) temporary energy market turbulence caused by the COVID-19 and Ukraine invasion.

[3] https://www.mercatoelettrico.org/it/default.aspx.

Source	Generation (thousands of GWh)	Capacity (GW)
Thermal	**195** (**66.9**%)	**61.6** (**52.9**%)
Gas	141 (48.4%)	40.9 (35.1%)
Oil	3.5 (1.2%)	1.8 (1.5%)
Coal	18.8 (6.5%)	7.2 (6.2%)
Bioenergy	19.6 (6.7%)	3.2 (2.7%)
Renewables	**96.3** (**33.1**%)	**54.9** (**47.1**%)
Solar	23.7 (8.1%)	20.9 (17.9%)
Wind	20.2 (6.9%)	10.7 (9.2%)
Hydro	46.3 (15.9%)	22.5 (19.3%)
Geothermal	6.1 (2.1%)	0.8 (0.7%)

Table 1: Electricity generation and installed capacity, absolute and percentage, in 2019. Source: Terna.

demand. All producers who submitted bids with lower prices will receive the PUN for the energy sold.[4]

Figure 1 shows how the GME runs the auction for a typical hour. The estimated electricity demand, typically extremely rigid, is matched to the virtual supply function made of quantities indicated in the bids by suppliers ranked for increasing bid price. The PUN for that hour is determined by the crossing of demand and supply.[5]

	Mean	Min	Max
PUN (€/MWh)	52.3	1	108.4
Gas price (€/MWh)	16.1	8.7	25.5
ETS price (€/MWh)	5.0	3.8	6.0

Table 2: Summary statistics on prices for electricity, gas, and emission allowances price in 2019. Source: GME.

[4]The Italian energy market also includes a second, same-day, spot market dedicated to adjusting possible deviation between the day-ahead expected energy demand and the actual demand observed a few minutes in advance. We will ignore these second markets because of their minor relevance for our purposes.

[5]Actually, the Italian system is divided into five different geographical areas, each independently determining its own price. However, the possibility of trading energy between the five areas reduces sensibly the differences between the prices from the different areas. In the following, we will consider only values as national averages, ignoring the distinction between the five areas.

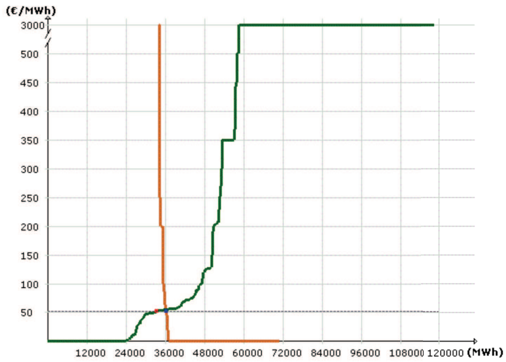

Figure 1: Day-Ahead Italian Market for electricity. The figure reports amount of energy on the horizontal axes and its price on the vertical axis. The orange line reports the expected demand of energy. The green line indicates the cumulated energy from bidders ranked for increasing bidding prices. The graph concerns a midday hour of a typical 2019 spring day. Source: GME.

Table 2 reports summary statistics on the average PUN across all hours for the entire year used in our analysis, indicating the wide variability. For the reasons we will discuss below, we will assume that the natural gas turbines are almost always the marginal supplier, effectively setting the price. Hence, we also report the statistics for two additional variables that we will need to use: the price of natural gas and the price of carbon emissions in Italy, which are expressed as the EU ETS allowance price in 2019. All values are reported in the same unit of measure, i.e. euros per MWh of energy.

As aggregate statistics, the table shows a lot of variability. While on average the cost of fuel and emissions is about 40% of the energy wholesale price, these costs may be as low 10% or as high as 12 times the cost of energy.

A major factor in determining hour results is the intra-day variability in energy prices. This is due to both demand and supply intra-day differentiations. Energy demand obviously follows the cycle of societal activities, but the supply of solar PV is also affected by the time of day. To quickly appreciate the relevance of the intra-day price volatility figure 2 reports the average ratio of hourly PUN divided by the daily PUN.

This is a well-known dynamic showing prices jumping with the increase of economic activities and with the fall of solar energy after sunset, and falling during sleeping hours and at solar peak production time.

In our analysis, in order to estimate the expected profitability of different investments, we need to use the total costs of producing energy from various sources. Table 3 reports estimations produced by using the data in IEA (2020) and averaging over different types of plants for the same technology.[6] The

[6]We considered all types of each technology in the Italian system and produced an average

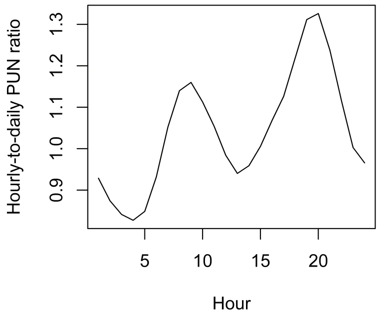

Figure 2: Volatility of hourly PUN: ratio of hourly PUN over daily average.

table indicates the average cost per MWh referred to operating and maintaining plants, the construction costs per MW of generating capacity and the average length of capital lifetime.

Source	OM (€/MWh)	KC (€/MW)	LT (years)
Gas	8	450	30
Solar	18	1000	25
Wind	15	1900	25

Table 3: Operation costs (OM) excluding fuel; construction costs per unit of capacity (KC); expected capital lifetimes of average new plants (LT). Source: IEA.

2 An Empirical Estimation of the Electricity Supply Curve

Taxing carbon emissions increases the costs of production for the generators using fossil fuels, who will likely react by raising the price requested to produce electricity. How much the price is raised in respect of increasing costs is obviously fundamental to determine the profitability of producers.

with weights roughly proportional to the relative installed capacity.

Using the hourly data of the amount of energy produced and the final price resulting from the bidding process, we can estimate the relation between electricity price, amount of electricity produced and unit costs of burning gas, including the cost of carbon emissions. For this purpose, we need two assumptions.

The first assumption is that in the vast majority of our statistical data points (i.e. hours) the marginal plant setting the price is a gas-fired power plant. We cannot prove this assumption with certainty because the GME does not release the composition of supply used for the determination of the price (the data forming the green line in figure 1). However, we can rule out every type of renewable energy as a marginal source because, from the general literature, we know this is always cheaper than any thermal source. Additionally, renewable energy supply has historically been insufficient to fully meet energy demand. We are then left with plants burning coal, gas and oil. Coal-fired plants are both generally cheap and, in any case, slow to fire up and down, so they are an unlikely source for marginal supply generation.[7] Oil-fired plants are known to be more expensive, and in the Italian system, they are used only exceptionally to meet strong demand peaks when no other energy provider is available. Therefore, gas-fired plants, comprising the majority of installed capacity, are the most likely technology to provide the marginal energy supply.[8]

The second assumption is that bid prices by producers with gas-fired power plants vary depending on their generating efficiency, i.e., the amount of energy produced with a unit of fuel. It is not possible to gain access to the strategic decision process of different producers, and we have only an approximated knowledge of plants' efficiency (such as construction years and overall technology adopted). However, it seems plausible to assume that all producers apply the same bidding strategy and that bid price differentials reflect underlining efficiency differences. In any case, this assumption can be indirectly tested by assessing the robustness of the statistical results we will obtain from our estimated supply function as compared with the actual data.

Adopting these assumptions we can use the record of hourly prices (by definition equal to the bid price of the marginal unit of energy) associated to the total amount of energy provided by gas-fired power plants to reconstruct the distribution of plants' efficiency in the Italian system. The underlining logic is the following: when the amount of energy supplied by gas-fired plant is small, then only the most efficient plants will be used, and hence the observed price will be comparatively low. In the opposite case, when large amount of electricity is produced by gas-powered plants, less and less efficient plants will go online, and hence the PUN will be increasingly more expensive.

To estimate our model, we assume that the bid price of gas-fired power plants is a function of the fuel cost and the cost of carbon emissions, which we assume is entirely passed on the price. Under these assumptions, gas-fired efficiency

[7] Besides, the cost of coal was extremely lower than that of gas in the period considered further supporting the assumption that if coal-burning plants are used they are not marginal supplies and hence they are not setting the price.

[8] As we will see, we will discard about 10% of data points as outliers, most likely generated by auctions resulting in non-gas fired plants setting the price.

distribution can be inferred by regressing the official price, the PUN, on the amount of energy produced by the gas-fired plants sold for each hour in the Day-Ahead market (G^h), controlling for prices of gas and of carbon emissions.[9]

Formally, we assume that the observed price is equal to the marginal cost of gas composed of the amount of gas required to generate a unit of energy (inverse of efficiency) times the sum of the cost of gas and emissions:

$$Pe^h = MC(G^h) = UG(G^h) * (Pg^h + Pc^h * EF) \tag{1}$$

which states that - when the gas-fired technology is the price-setting marginal one - the PUN is equal to the $MC(x)$, the marginal cost of producing an MWh of energy by gas-fired plants. In turn, the marginal cost equals the product of the amount of gas needed to produce a MWh of electricity ($UG(G^h)$) in the marginal plant multiplied by the sum of gas price Pg and carbon cost $Pc*EF$, computed as the unit cost of emission Pc times the amount of emissions generated by a unit gas EF.

The equation can be rearranged as:

$$\frac{Pe^h}{Pg^h + Pc^h * EF} = UG(G^h) \tag{2}$$

stating that, according to our assumptions, the ratio between electricity price and the sum of gas and carbon emission price equals the amount of gas required to produce a unit of energy, a variable increasing with the total amount of energy produced from gas-fired plants.

Yet, a significant challenge in estimating this equation arises from the lack of detailed data on electricity sold in the Day-Ahead Market. Specifically, the data does not provide a breakdown by energy source or macro-categories, such as thermal versus renewable energy. As a result, we must infer the quantity of gas-fired electricity sold in Day-Ahead Market transactions (G^h) based on the limited information available.

To approximate this variable, we explore two methodological approaches. Our first strategy exploits data on realized thermal production levels to add some structure to the Day-Ahead data. The underlying assumption is that, as no systematic disparities between Day-Ahead and realized production levels are expected, this variable is a reasonable proxy for the thermal energy sold in the Day-Ahead Market. The gas-fired component of that quantity can then be isolated by making some assumptions on the composition of the thermal energy sold in the market. Specifically, we assume a flat time production profile for coal and biomass sources and that the quantities offered by these sources are always sold in the market. This allows us to determine hourly energy sales from these sources by distributing their annual production levels evenly across hours. Oil is activated only during periods of high pressure on the electricity system. We identify these periods as those with very high thermal production.

[9] For temporal consistency, we need to assume that these prices must be those determined on their respective markets some time before the bidding time. We tested our statistical model for both 24 and 48 anticipation of gas and ETS prices producing essentially identical results.

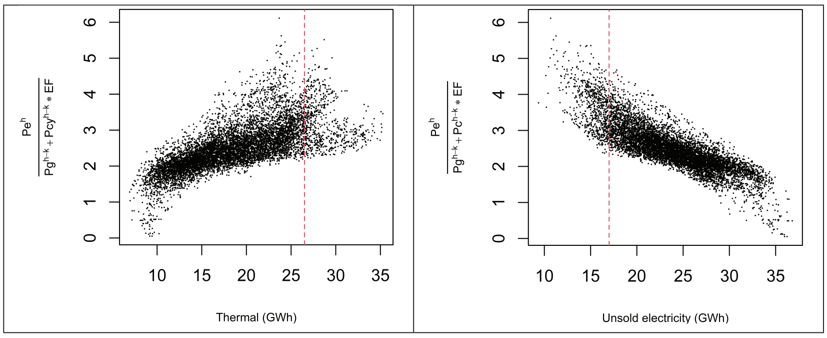

Figure 3: Scatter-plot of the electricity price (relative to the sum of gas and carbon price) on the vertical axis, and the amount of thermal production (left) and unsold electricity (right) in the Day-Ahead Market on the horizontal axis. Hourly data for Italy in 2019.

Our second approach leverages information on unsold energy volumes in Day-Ahead negotiations, relying on prices and quantities within the same institutional context, the Day-Ahead market, ignoring the data concerning the realized production. The intuition in this case is that, assuming a constant maximum offer of electricity in Day-Ahead market negotiations for the most expensive sources (gas and oil), information on the unsold energy volume allow identifying the position on the supply curve, measured as the distance from the final point of the supply curve, where the demand curve intersects. The quantity of gas-produced energy sold in the market can then be identified by estimating the level on the supply curve at which oil is activated. Since oil-firing generators are the most expensive source and is thus located at the end of the merit order curve, this level is characterized by very low unsold electricity volumes. Knowing this threshold, the variable of interest, energy produced using gas-firing turbines, can be reconstructed by subtracting the amount of gas-based unsold energy from the energy offered by this source, calibrating the latter to produce an overall gas-fired energy sold in the market that aligns with realized annual data.

In order to appreciate the different types of problems stemming from the two alternatives, figure 3 illustrates the relationship between the ratio of prices (our dependent variable) on the y-axis and the level of thermal energy production and unsold electricity in Day-Ahead negotiations on the x-axis. Both sets of data reveal a clear relationship between the variables, which appears predominantly linear or, at most, quadratic. At the extremes, for very low and very high production levels, the relationship between the variables is severely altered. This is likely due to coal- or oil-burning plants setting the price and hence following a different price/quantity pattern with respect to the gas-fired plants. Considering that oil and coal jointly account for less than 8% of total production over the year, we focus on the bulk of cases when gas is the marginal technology.

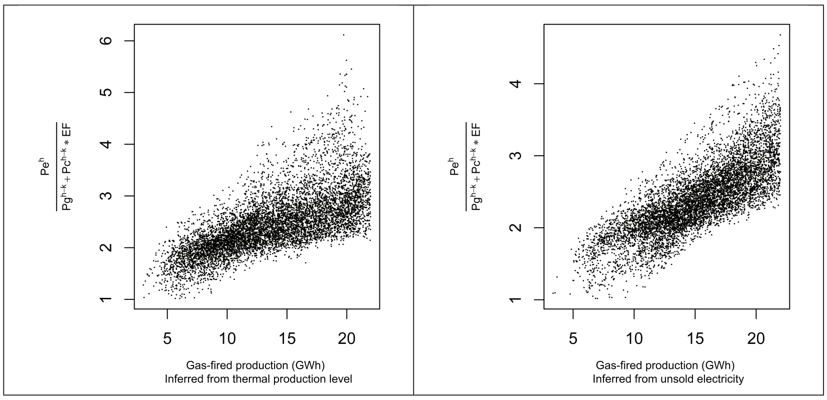

Figure 4: Scatter-plot of the electricity price (relative to the sum of gas and carbon price) on the vertical axis, and the reconstructed amount of gas-based electricity sold in the Day-Ahead Market in periods – inferred from thermal realized levels (left panel) and unsold electricity (right panel) – when this technology is the marginal price-setter. Hourly data for Italy in 2019.

In the graph, the red dashed lines indicate the cut-off values for likely activation of oil-fired plants, resulting in approximately 10% of data points. These points are excluded from the the regression analysis since, during these periods, the PUN is not determined by gas-firing plants.[10]

The resulting inferred gas-based energy volumes sold in the Day-Ahead Market, in periods when the gas-fired technology is likely the price-setting marginal one, are reported in figure 4. These are the data sets on which we apply the following regression model:

$$\frac{Pe^h}{Pg^h + Pc^h * EF} = a + b \times X^h + c \times (X^h)^2 + \epsilon_h \tag{3}$$

where X^h indicates the amount of energy produced by gas-fired plants, scaled to start from zero to facilitate the interpretation of the results. A linear version of the model is also tested, ignoring the quadratic term, i.e., imposing $c = 0$.

In table 4 we report the linear and quadratic regressions for the two models. Given the transformation of the data and the assumptions adopted, intercepts can be interpreted as the inverse of thermal efficiency (amount of gas needed

[10]The thresholds have been determined by estimating at which level the series of electricity prices ceased to be strongly correlated to the price of gas and started to show a significant correlation with the price of oil. The reliability of the identified thresholds has been further validated by noting the consistency between the total predicted and actual oil-based energy production. At the opposite end, for very low production levels, we remove a handful of additional outliers corresponding to cases when energy prices fall to zero, likely occurring during sunny and windy holidays. Robustness results, including all data points, have been performed, resulting in only a small degradation of the significance for the coefficients. These additional results can be provided upon request.

	Realized production		Unsold electricity	
	Linear model	Quadratic model	Linear model	Quadratic model
Intercept	1.525***	1.399***	1.222***	1.434***
	(0.034)	(0.053)	(0.041)	(0.027)
Linear term	0.088***	0.116***	0.098***	0.056***
	(0.005)	(0.013)	(0.004)	(0.005)
Quadratic term		−0.001*		0.002***
		(0.001)		(0.000)
Observations	7803	7803	7583	7583
Adjusted R^2	0.45	0.47	0.61	0.62
Note:	*p<0.1; **p<0.05; ***p<0.01			

Table 4: Regression coefficients for amount of energy from gas-fired plants explaining the electricity price relative to the cost of fuel and carbon emissions. HAC standard errors in parenthesis.

to produce a GWh of electricity) in the most efficient gas-fired marginal plant observed in the sample.

From the econometric perspective, the coefficients are significant at very high confidence levels. The overall fit of the models is particularly good, especially for the models based on the Day-Ahead unsold electricity quantities.

To assess the plausibility of the estimated parameters $\hat{a}$, $\hat{b}$ and $\hat{c}$ we use their values to compute two functions whose approximate values are known in the general literature.

In the first case, we use our estimations to express an empirically estimated relation between the thermal efficiency of the marginal plant in use and the total amount of energy produced by gas-firing power plants. Formally, we used the estimated coefficients to plot the following function:

$$\frac{1}{\widehat{UG(X^h)}} = \frac{Pg^h + \widehat{Pc^h} * EF}{Pe^h} = \frac{1}{\hat{a} + \hat{b} \times X^h + \hat{c} \times (X^h)^2} \tag{4}$$

According to the best fitting model (the quadratic model based on unsold electricity), thermal efficiency results are in the range of 32% to 69% (see Figure 5). These estimates are perfectly compatible with technical and engineering data of the Italian electricity structure indicating a thermal efficiency above 30% for old OCGT plants, about 60% for new CCGT plants, and above that value for CCGT-CHP plants (IEA, 2020; ISPRA, 2020).

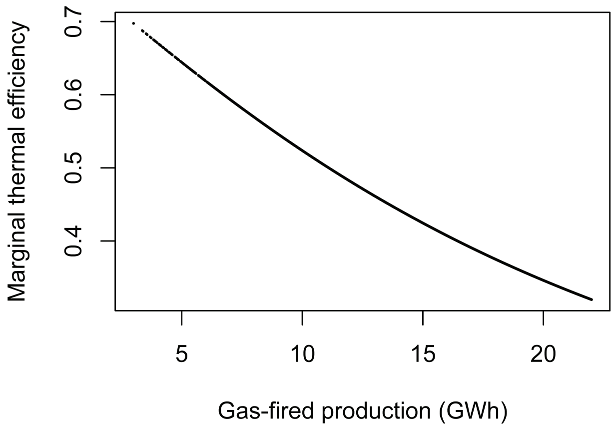

Figure 5: Estimated marginal thermal efficiency. Quadratic regression model, unsold electricity.

As a second validating exercise, we use our regression results to express the supply function of gas-generated electricity as a function of the price, i.e. the portion of the merit order curve served by gas-powered plants.

$$\hat{Pe^h} = (\hat{a} + \hat{b} \times X^h + \hat{c} \times (X^h)^2) \times (Pg^h + Pc^h * EF) \tag{5}$$

Figure 6 plots the estimated supply curve that can be interpreted as the most relevant central segment of the observed merit order curves, such as that reported in 1. In the empirically observed case, up to about 30 GWh are supplied by renewable energy or other suppliers bidding very low prices and hence always accepted. The gas-fired portion, supplying between 3 and 22 GWh of additional electricity, constitutes the segment of the overall supply of energy that almost always determines the market price, and again, our results indicate that the range of the price matches the values observed.

Figure 6: Estimated gas-fired merit order curve based on average gas and carbon emissions prices. Coefficients from the quadratic regression model estimated on the series for unsold electricity.

We can conclude that the empirical analysis provides a robust and broadly validated functional relation linking the price of electricity to the amount of gas-fired energy generated, depending on the price of gas and the price of carbon emissions as exogenous factors. To our knowledge, this is an original result that can be very useful for a large number of applications in both empirical and theoretical studies. In our case, we use this result to assess the hypothetical profitability of new power-generating plants using different energy sources under alternative values of the cost of carbon emissions. This analysis allows to determines the expected effectiveness of an environmental policy meant to favor the diffusion of renewable sources by increasing the cost of carbon emissions.

3 Assessing the Effectiveness of Taxing Carbon

The electricity generation sector is already the largest source of emissions and its importance for the environment will become even more relevant when other parts of the economy, such as transportation and heating, will be fully or mostly electrified. It is therefore crucial to ensure that the both existing and the additional electricity generating capacity is made of carbon-free technologies. Even though the literature does not explicitly discuss how precisely this result could be obtained, the implicit assumption is that private investment spurred by the financial incentives created by taxing carbon would be the main policy leverage

(Metcalf, 2019).

In this section, we use the supply function estimated in the previous section to study whether increasing the cost of carbon can trigger an increase in the amount of investments in expanding renewable energy capacity in the Italian system. We adopt the assumption that hypothetical investors considering a potential construction of new electricity capacity generator choose the technology providing the highest expected profitability. For this purpose, we define an indicator of economic performance, a version of the ROI, and test the profitability of the alternative electricity-generating technologies simulating the ROI based on the empirical analysis described in the previous section and using three policy scenarios concerning the level of the cost of carbon emissions.[11]

3.1 Financial indicator of performance

Our goal is to estimate the financial incentives for potential investors to adopt a given electricity generation technology, namely thermal (gas-fired power plants) or renewable (solar PV or wind turbines). For this purpose we need to find an economically significant indicator representing the attractiveness for a hypothetical potential investor for the different technologies. We choose the widely used ROI (return on investment) consisting in the average net cash flow generated per unit of capital invested. The formulation of ROI we compute is a rather crude approximation of the actual profitability of an investment, for example because it does not include a discount rate or the cost of interests. Nonetheless, it serves our purposes because we need to make a comparative analysis, and so we just need to assume that an investment option with a higher ROI can be considered more financially attractive than alternatives with a lower ROI.

To compute the ROI for electricity-generating plants, we need both technical and economic information, some of which are not directly available. In particular, as we have explained above, the price of energy depends on the marginal bid price, which we can imagine depends on the distribution of efficiency of the set of generating plants. However, we can statistically approximate the missing information using the data set of market energy prices.

To compute the ROI we need a measure of revenues, costs and capital invested, each computed for one year, produced by an electricity-generating industrial plant. The total revenues consist of the sum over every hour of the year of electricity produced and sold multiplied by the hourly price. The costs include three components: i) operational and maintenance (O&M) costs; ii) the cost of fuel and emissions (for thermal technologies only); iii) the depreciation cost of capital, assumed evenly distributed for each year of activity of the plant.

[11] We assume for simplicity that the policymaker can directly set the cost of carbon emissions. In Europe this cost is actually determined by the market for allowances, the ETS, and the policymaker can therefore influence their cost indirectly varying the number of items traded in the market.

$$ROI_i = \frac{\sum_h (Pe^h - FC_i^h - EC_i^h - OM_i) * E_i^h - \dfrac{KC_i * CAP_i}{LT_i}}{KC_i * CAP_i} \tag{6}$$

where: i is the index for electricity source (e.g., solar, gas, and other sources); $h = 1, ..., 8760$ indicates a specific hour of the year; Pe^h is the electricity price (PUN) for the hour h; E_i^h denotes the volume of electricity sold at the hour h from the source i; FC_i^h and EC_i^h are unit fuel and emissions costs at hour h for technology i, respectively; OM_i is the for operational and maintenance costs per unit of energy produced for technology i; KC_i is the capital construction costs per unit of capacity of technology i; CAP_i is the installed capacity of technology i required to ensure the production; LT_i is the expected lifetime of the capital.

We can rearrange the definition of ROI by defining the capacity factor (CF) as the amount of energy produced per unit of capital, i.e. E/CAP, so that the definition of ROI becomes, after some simplifications:

$$ROI_i = \frac{\sum_h (Pe^h - FC_i^h - EC_i^h - OM_i) * CF_i^h}{KC_i} - \frac{1}{LT_i} \tag{7}$$

This formulation facilitates interpretation of our metric as the return on investment per additional MWh of a specific electricity source installed comprising four elements: i) unit margins, defining the gross profits for each MWh of electricity produced and sold in the market; ii) capacity factors, converting unit margins into unit profits for each MW of capacity installed; iii) construction cost to install a MW of capacity, converting unit profits for each MW of capacity installed into unit profits for each euro invested; iv) depreciation rate, converting gross profits into net ones.

We start by computing the ROI of gas, solar PV and wind plants based on the current levels of the prices of gas and carbon emissions. We later assess how increasing the cost of emissions modifies the relative levels of the ROI for the different technologies.

3.2 Financial Attractiveness at Current Carbon Emission Price

Table 5 reports the measures of the ROI for different energy-generating technologies, along with two indicators providing suggestions on the properties of the sources related to their financial attractiveness.

The first column reports the so-called "value factor" of energy, indicating the ratio of the average price paid to the energy from that source with respect to the average general price of energy. The table shows that gas-powered producers receive, on average, a higher price than solar and wind plants. The reason, already noted in the literature, is that intermittent sources are forced to compete in specific periods while dispatchable sources can choose to enter the market when it is more economically convenient (e.g. Joskow, 2011; Sioshansi, 2011; Borenstein, 2012; Mills and Wiser, 2012; Hirth, 2013, 2016; Eising et al., 2020; IEA, 2018, 2020, 2023b).

For instance, gas power plants predominantly generate electricity during periods of high demand, as summarized in the second column of the table, which reports the correlation coefficient between the production of that technology and demand. The results show a positive correlation between solar production and market demand, aligning with evidence from other countries (e.g. Borenstein, 2008; Eising et al., 2020). However, the dominance of the self-cannibalization/merit-order effect supersedes this correlation, resulting in a value factor below unity for solar energy. Conversely, wind energy demonstrates a more equitable distribution of production across temporal segments, with no discernible concentration during peak demand periods.

Source	Value factor	Demand correlation	ROI (%)
Gas	1.06	0.75	2.72
Solar	0.97	0.40	−0.35
Wind	0.99	0.02	−0.38

Table 5: Value factors, demand correlation and financial returns (ROI) for different sources. Baseline scenario, 2019.

The last column reports the ROI value as defined by equation (7). However crude, such a measure allows us to compare the expected profitability from investment in the different generating technologies. The obvious result is that gas-fired turbines are far more profitable than gas and solar PV plants, making them a very poor investment without additional incentives. The table shows that part of the explanation for the poorer ROI of the green technologies resides in the softness of energy prices fetched by these technologies, in particular solar PV. However, this is not the only reason, since there are also differences in the techno-economic properties of the electricity-generating technologies that, collectively, produce an evident advantage in favor of gas-fired power plants.

Source	Unit margin (€/MWh)	Capacity factor (%)	Depreciation rate (%)	Construction costs (€/kWe)
Gas	6.4	36.9	3.33	450
Solar	36.2	12.8	4.0	1000
Wind	37.6	21.4	4.0	1900

Table 6: Average data on unit margins, capacity factors, depreciation rates, and construction costs per unit of generating capacity. Source: IEA; our elaboration on data from GME for 2019.

Table 6 reports some data contributing to explaining the differences in ROI for the different technologies. The first column shows the headline average margin per unit of energy sold. Gas-fired power plants need to pay fuel and carbon emission costs, so they are far less profitable in this respect than solar and wind plants, which have essentially zero variable costs.

However, this advantage is reduced by the evidence reported in second column, labeled "capacity factor". The values indicate the share of time the plant is actively generating electricity. Gas powered plants are recorded as being active more than 1/3 of the time (36.9%), which is three times as frequently as solar PV (12.8%) and more than 50% than wind turbines (21.4%). Thus, the higher profitability of clean energy must compensate for the longer idle times of its plants.

The lower depreciation rate indicates that a dollar paying for a fossil fuel generating plant can be spread over a longer lifetime than the other two green technologies, providing a slight additional advantage. Finally, an extremely relevant reason for the higher profitability of gas-fired plants is shown in the last column, indicating the construction costs per unit of generating capacity. The cost per unit of capacity to build a gas-fired generator is less than half of the cost for an equivalent solar PV plant and almost 1/4 of a wind plant. This is a huge advantage that, on top of the higher utilization rate, makes an investment in this polluting-generating technology far more profitable than any available green alternative.

It is worth noting that this general conclusion is based on average conditions but does not rule out the possibility that, in specific cases, solar and wind technologies may turn out more profitable. Indeed, by focusing on solar and wind technologies characterized by the lowest LCOE in Italy, as documented in IEA (2020), we compute positive profitability metrics for utility-scale solar photovoltaic systems (0.83 MW) and particularly large onshore wind turbines (10.0 MW), yielding ROIs of approximately 1.76% and 1.35%, respectively. However, these returns remain below those achieved by gas-fired alternatives, further emphasizing the dominance of conventional options even over the most competitive solar and wind technologies available. This discrepancy is further accentuated if we analyze the individual gas-firing power plants. The newest generations adopting the most efficient technology - CCGT - produce a ROI of around 7.5%.

Once ascertained the superior profitability of gas-fired electricity generating plants at the current condition, there remains the possibility that this superiority may be reversed, or at least reduced, by increasing the cost of using polluting fuel. In the following paragraph we estimate the ROI of the different technologies assuming higher cost of carbon emissions.

3.3 Effectiveness of Carbon Pricing

Charging carbon emissions stands as a pivotal and highly efficient policy instrument for curbing carbon emissions by conveying price signals to both consumers, encouraging sustainable consumption choices, and firms, prompting the adoption of less polluting production processes and fostering innovation to abate emissions (Stern, 2007; Stiglitz et al., 2017; IPCC, 2023; Popp, 2002; Aghion et al., 2016). Within the sector of electricity generation, carbon pricing imposes supplementary costs on carbon-intensive sources, and it is therefore expected to deter investments in such technologies catalyzing the de-carbonization of the electricity production sector (Brown and Li, 2019).

However, we have seen how fossil fuel generators enjoy a large advantage in respect of the two most common green generating technologies. Moreover, we have seen that the market for electricity is engineered in such a way that energy from renewable sources, forced to respect rigid availability constraints, has a lower competitiveness in respect of the more flexible gas-fired technology. So, the question for policy makers is what level, if any, of carbon emission costs is necessary to spur profit seeking investors in financing green energy producing projects rather than traditional plants burning fossil fuels.

To answer this question, we adapt the model described in the previous section to simulate different scenarios characterized by varying levels of carbon pricing, computing source-specific ROI values for each scenario. The baseline scenario uses the actual carbon emission prices observed in 2019 and computing the ROI based on the simulated prices produced by our model.[12]

We consider two hypothetical scenarios that are alternative to the baseline case. In the first, we simulate the ROI under the assumption that the cost of ETS is 50% higher than in the baseline scenario, reflecting a policy of moderate increase of carbon costs. In the second case, we use a cost of carbon three times as expensive as in 2019, indicating a radical but still realistically plausible policy.[13]

Table 7 reports the findings indicating the ROI of different technologies under the three scenarios, also reporting the gap of the ROI for each technology and that of gas-fired plants. We also include the results for hydroelectric and geothermal plants to appreciate the effect of increasing the cost of emissions on these technologies. Before commenting on the economic implications of the results, it is worth noting that the baseline ROI values produced using the simulated prices rather than the actual ones (see table 5) introduces only minor distortions in the values of the ROI, confirming the simulated prices derived by our empirical analysis are very close to the real prices used before.

Regarding the impact of carbon pricing on profitability, our analysis yields three key insights. Firstly, an increase in the carbon price boosts the ROI of all renewable energy sources. This phenomenon stems from the direct impact of carbon pricing on electricity prices, resulting in amplified revenue streams for renewable sources. Specifically, the wholesale average electricity price rises from 52€/MWh in the baseline scenario to 58€/MWh and 78€/MWh in the

[12] Concerning the baseline scenario, we may use the actual electricity prices. However, we prefer to use the simulated prices also for this case for two reasons. First, we can test the capacity of the simulated prices to replicate the observed values, increasing the confidence in the robustness of the empirical model. Second, using the simulated prices for all three scenarios ensures higher comparability of the results between the baseline scenario with observed costs of carbon and the others defined by higher carbon costs.

[13] This extreme case is roughly similar to the peak level of carbon costs recorded in recent years and is consistent with the carbon tax levels recommended by most of the literature (e.g. Stiglitz et al., 2017; IPCC, 2023).

	Baseline		Moderate ETS price		High ETS price	
Source	ROI (%)	ΔGas	ROI (%)	ΔGas	ROI (%)	ΔGas
Gas	2.96	-	4.41	-	8.75	-
Solar	-0.28	-3.24	0.44	-3.97	2.56	-6.19
Wind	-0.33	-3.30	0.25	-4.16	1.98	-6.76
Hydro	0.98	-1.98	1.48	-2.93	2.99	-5.76
Geothermal	0.31	-2.65	0.85	-3.56	2.47	-6.28

Table 7: Simulated ROI for different sources. Varying EU ETS prices. ΔGas signifies the difference in profitability between each sources and natural gas.

two alternative scenarios. Given that renewable energy sources do not incur additional costs from carbon pricing, their unit margin increases, bolstering their absolute profitability indexes. Thus, we can confirm that, as expected, increasing the cost of carbon emissions increases the profitability of carbon-free energy sources because of higher energy prices and, for green technologies, invariant costs.

The second piece of evidence is less comforting from a green policy perspective. While renewable energy increases its profitability, gas-burning producers also increases theirs. This apparently paradoxical outcome is explained by the combined effect of high emissions costs pass-through and thermal efficiency heterogeneity of gas-fired plants. The rationale is as follows: assuming that the increasing cost of carbon emissions is passed mostly or entirely on the bid prices, the market-set electricity price rises to offset the increased emissions costs borne by the marginal (i.e., least efficient) gas-fired plants. The remaining active gas-firing generators, more energy efficient, enjoy the benefit of the higher final price with only a partial increase in carbon costs. Consequently, the average profitable margin of gas-firing producers *increases* following an increase in the cost of carbon emissions.

Finally, our third result shows that, while both green and brown energy producers increase their margins, the latter have a clear advantage so that, collectively, the expected profit gap in favor of fossil fuel increases when the cost of carbon emission is increased. Our results indicate a doubling of the profitability gap between gas and solar and wind in the *High ETS prices scenario* compared to the baseline. Consequently, the disparity in profitability between gas and renewable energy widens rather than shrinking as a consequence of carbon pricing. This result leads to the counterintuitive conclusion that policies meant to favor the diffusion of green energy by increasing the cost of carbon effectively generate the opposite effect, making brown investments even more profitable than green ones.

This result can be rationalized as follows. While carbon pricing clearly favors renewable producers over fossil fuel-based sources in terms of production costs, two main mechanisms mitigate the effectiveness of this policy in increasing the relative attractiveness of green investments.

Firstly, increasing carbon pricing boosts the wholesale average price gained by gas-fired producers more than that gained by renewable sources because of the rigidity of the latter technology. In our experiment, considering the *High ETS prices scenario*, the average wholesale price increases by 26.3€, 25.5€, and 23.7€ for gas, solar, and wind respectively. This phenomenon occurs because higher impacts on the wholesale price of a carbon price are expected when less efficient thermal plants are operational, a less frequent scenario when renewable generators are online. This is another consequence of the cannibalization effect among producers of renewable and intermittent energy, partly offsetting the unit margin advantage for green energy due to increasing carbon emission costs.

Secondly, although the unit margin on each MWh produced increases more for renewable energy than for gas, the significantly lower capacity factors of solar and wind plants, combined with their higher capital construction costs, dilute the advantage generated for renewable sources in terms of returns for each MW of capacity installed.

The results presented so far have been produced under the assumption that producers using fossil fuel pass the entire increment of the cost of carbon emission on their bid price, i.e. a complete pass-through. Below we consider whether assuming a partial pass-through, where the increased cost of carbon emission is partly absorbed by gas-firing producers as reduced profits, modifies our conclusions.

3.3.1 Policy Effectiveness Under Partial Cost Pass-through Rates

Economic intuition stipulates that, in general, the share of increasing variable costs transferred to the final price depends on the elasticity of individual seller's demand. If the cost increment is generalized, affecting all producers in similar ways, individual demand for a producer can be expected to be fairly rigid, and hence there is little incentive to reduce the profit margins because there is no competitive risks in raising prices.

The literature studying the electricity markets suggests that producers apply a complete or almost complete pass-through in the case of carbon emission costs (Fabra and Reguant, 2014; Hintermann, 2016; Dagoumas and Polemis, 2020; Maryniak et al., 2019; Nazifi et al., 2021; Guo and Gissey, 2021). However, some contributions do not rule out the possibility of lower pass-through rates (Bonacina and Gullı, 2007; Sijm et al., 2012; Gullì and Chernyavs' ka, 2013; Ding, 2022). Without entering the debate on the actual rate of pass-through in the real markets, we can address a question more relevant to policymakers: does it matter? In other words, given that a policy based on taxing carbon emission is ineffective (actually, counterproductive) with a complete pass-through, does it become effective with lower pass-through rates?

To answer this question, we evaluate the profitability indexes for all the sources assuming varying emissions cost pass-through rates. The analysis is limited to considering the *High ETS prices scenario* since both cases are qualitatively identical.

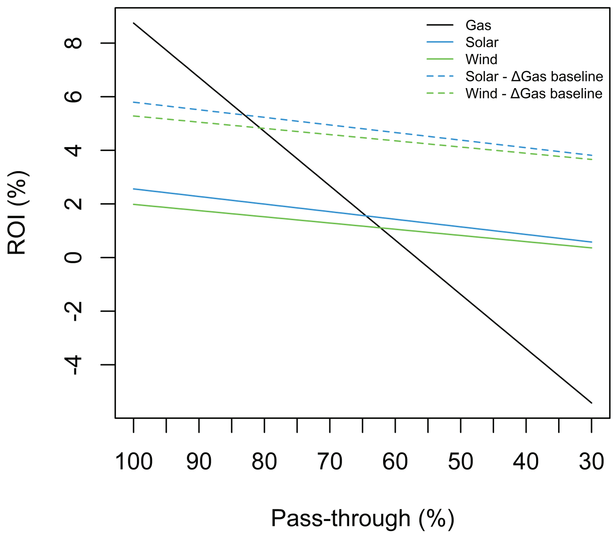

Figure 7: ROI for gas, solar, and wind, under different levels of carbon emission pass-through rates. High EU ETS price scenario.

Figure 7 provides a comparative analysis of ROI for gas, solar, and wind energy plants under different cost pass-through rates. The continuous lines indicate the three ROI values (the dashed lines are commented below). Several interesting results emerge.

Firstly, and obviously, lower pass-through rates reduce the price and, hence, the profitability for all energy producers, irrespective of the technology adopted.

Second, the negative relationship between ROI and cost pass-through is far steeper for producers using gas-fired plants than for solar and wind energy generators. This result can be attributed to two key factors. First, the average wholesale price of solar and wind energy is less sensitive to variations in pass-through rates compared to gas. This is because solar and wind energy are, on average, sold during periods when prices are set by more efficient and less polluting gas-fired power plants. Consequently, variations in pass-through rate have a smaller impact on wholesale prices during these periods, characterized by lower additional carbon costs. Second, the higher cost of capital per unit of energy produced by solar and wind, relative to gas, results in a more stable ROI for these sources in response to variations in absolute revenue flows. This result implies a number of interesting consequences. We can identify four different conditions in relation to effectiveness of the carbon cost policy in reducing the incentive to invest in fossil fuel generators.

The first condition is generated in our setting for pass-through rates higher than about 80%. The two dashed lines indicate the ROI of the two green energy generation technologies, reported by the continuous lines, increased by the profitability gap as in the baseline scenario, i.e. without increment of carbon emission costs. As long as the gas-powered generators provide a higher ROI than the level indicated by the dashed lines, the policy must still be considered counterproductive because the profitability gap between gas and renewables increases as a result of a more stringent climate policy.

The second condition is determined by pass-through rates in the range between about 65% and 80%. In this region we find that while gas-fired electricity provides producers with a higher ROI than green electricity, the difference is smaller in respect of the baseline scenario. In this sense, the policy can be considered as a partial success since it reduces the profitability advantage of gas-firing investments, even though they would still be more rewarding than green energy investments.

For pass-through rates between about 65% and 55% carbon emission cost policies become effective, turning the ROI of gas-firing plants still positive but lower then green energy generators.

Finally, for pass-through rates below 55%, the ROI of gas power projects becomes negative, causing increasing losses for decreasing rates.

Concluding this final experiment, we can state that while decreasing pass-through rates make increasing carbon emission costs generally more punitive to fossil fuel energy producers, we cannot expect to reverse the general conclusion that gas-fired plants are almost always more profitable than green energy producers independently from the cost of emissions. The rate at which the carbon tax policy starts to have some effect is lower than that reported by most empirical studies.

4 Policy Implications

The theoretical principle of a carbon tax is to exploit the efficiency guaranteed by competitive markets even in cases of strong externalities. According to the textbooks, the cost of carbon should match the external cost of pollution in order to nudge the market close to the socially efficient equilibrium.

Concerning the policy goal of ensuring sufficient private, profit-seeking, investments in green electricity generating plants, such as solar PV and wind farms, our analysis shows that the carbon tax risks may be an ineffective tool. We have been forced to use some approximations and adopt assumptions in order to compensate for the lack of data, thus it may be possible that, even though we are very confident in the robustness of our work, our analysis contains some errors. Besides, our analysis is tailored to the Italian electricity market, so the results may differ in other countries compared to our case study. However, independently from our analysis, there are two general reasons suggesting caution in the widespread deployment of carbon taxes to promote green investments in the energy sector.

First, the underlining logic of our approach holds independently from the specific data: as long as the marginal cost of the marginally efficient producers is (almost entirely) reflected on the energy price, the more efficient producers will necessarily increase their profit margin with the increasing cost of carbon, thus increasing their profits. The spike in profits recorded by energy producers using fossil fuel generators during the recent crises that raised the price of gas proves that this is a real phenomenon.

The second reason is that carbon taxes, by design, are meant to work by *increasing* the cost of production, so that demand is expected to pay more, even if this may be for a good cause. In the case of electricity generation, even if implementing policies increasing the price were effective in cleaning up the energy sector (a notion we challenge), it would still be very negative for the broader goal of electrifying the economy and promoting the replacement of fossil fuels with electricity in vehicles, heating systems, industrial processes, etc.

As a consequence, we conclude that there are many reasons for policymakers to consider alternatives to carbon taxes. While this work cannot discuss in detail the implications of every alternative to the carbon tax, we provide a brief list of possible alternative policies.

i) The mechanism to set the price of electricity is one of the elements contributing to the ineffectiveness of the carbon tax. Moreover, this mechanism can be expected to be increasingly more problematic while the share of green energy increases, as expected and advocated. The reason is that, as it is, the market price is expected to be set at the level of the marginal cost of energy generation. However, green energy has an essential null marginal cost, so the mechanism of price setting based on a bidding process is likely to become ever more erratic and, potentially, captured by special interests. Since it must be reformed, it may be possible to identify alternative price-setting mechanisms, such as imposing post-trade transfers from polluting generators to carbon-free ones, to increase the financial incentives of the necessary investments.

ii) In order to make investments in renewable energy generation more attractive it may be possible to introduce subsidies targeted to reduce the cost of capital for these investments. The costs for these subsidies may be spread to the participants of the market in proportion to specific policy targets, possibly determined on the basis of extra profits gained in contrast to the public interest.

iii) As we mentioned before, green investments require far more expensive capital costs for a unit of energy produced, explaining a large portion of the profitability gap with respect to fossil fuel-burning investments. However, while financially more expensive, the construction of energy capacity for green investments has a different advantage with respect to gas-fired power plants: they can be produced at a far smaller scale. Thus, renewable plants of smallish sizes may be attractive to investors with limited financial means who may find such green energy generation investments attractive because of synergies with their specific conditions. For example, individual households or local communities may accept to pay for an investment that may be loss-making at general market conditions but that, in their specific case, provides cheap electricity for self-consumption and hence large savings overcompensating the opportunity costs of not investing in brown projects. Past and current experiments in leveraging households and small community green projects suggest a large potential from small investors available to foot the bill of green capital costs. Such projects may be further promoted with the goal of extending beyond the level of local self-consumption and becoming a diffused relevant contributor to the general electricity system.

iv) Another possible policy measure is a direct intervention by a state-owned enterprise to produce the necessary investments. From the theoretical perspective, while such types of organisations can be expected to be somewhat less efficient than profit-seeking firms, the technological and operational competence requirements for such types of firms are well-known, so it would be fairly easy to ensure a decent level of managerial efficiency even without private ownership. From a pragmatic perspective, the electricity market is only apparently served by a majority of private companies, but, in effect, it is already extremely regulated, including a large and determinant presence of organisations controlled by the state. Just as an example, state-owned or majority-controlled companies such as Terna, Enel, GME, and Arera play a crucial role in both the day-to-day functioning of generating, pricing and distributing electricity and determining the strategic long-term development. Adding an additional entity pursuing the public interest under constraints of economic sustainability rather than maximising profits to distribute to shareholders would not constitute a radical departure from the status quo.

v) Finally, the interest in green energy is relatively recent and, in particular, the technologies have been mostly developed considering green energy as a minority contribution to the total electricity consumption. It is only in a few years that it has been clearly expressed the target of decarbonising the largest possible number of activities. From the Economics of Innovation perspective, we can expect that the technological developments designed to produce individual plants are likely not sufficient, or possibly even suited, to contribute to a carbon-free entire economy. Policymakers should abandon a perspective to individual interventions targeting single aspects of the green transition, such as using carbon taxes to promote green energy production investments, and consider the energy system as a whole to remove bottlenecks and exploit potential synergies. It is necessary to adopt a new approach based on a complex system perspective where any component interacts with others, and the overall efficiency of the system cannot be assessed considering the individual elements in isolation. Just to make a few examples, the diffusion of electric vehicles, each carrying around a vast energy storage potential, may be commandeered to smooth the availability of renewable energy on the grid. Large and innovative energy storage systems have been proposed and are near the stage of industrial-scale applications. Long-distance cables carrying high voltage DC current can multiply the amount of non-programmable renewable energy effectively employed in general electricity systems.

In general, technological innovations concerning jointly engineering solutions and social organizations are required and can be produced by a research system, both fundamental and applied, involving every aspect of society. Research and innovations are necessary elements of economic growth in general but are particularly relevant to design radical changes such as those required to upgrade the energy systems of large economies to a carbon-free future. Policymakers would better ensure that the research systems are sufficiently involved in designing, monitoring and assessing policies with such ambitious targets and critical consequences in case of failure.

5 Conclusions

In this paper, we investigate the effectiveness of pricing carbon emissions as a tool to increase investments in electricity-generating plants using renewable sources, such as solar PV or wind.

We used hourly data from the Italian market for electricity to estimate an empirical supply curve of energy generated by gas-fired power plants, representing the largest source of electricity in the country and, almost always, the technology providing the marginal contribution determining the market price.

Using this result, we are able to compare an index of profitability for gas-fired, solar PV and wind investments under three scenarios where every aspect of the market for every hour is replicated as in the baseline year, but for the cost of carbon emission. We compare the observed data (actual cost of carbon) with two alternative scenarios: 50% and 200% increment of carbon emission costs. We found that plants based on renewable energy provide lower profitability than gas-fired power plants. Moreover, simulating the results for increasing the cost of carbon emissions enhances the profitability of gas-fired power plants and widens the profitability gap in favor of fossil fuel generators when the emission cost pass-through is within the range reported by most empirical studies. Hence, we conclude that a policy meant to increase the diffusion of renewable energy by increasing the cost of emission may be not only useless but also counterproductive under the most likely conditions.

There are two main reasons motivating the results that carbon taxes increase the profitability gap in favor of polluting technologies. Firstly, non-programmable energy sources, such as solar PV and wind turbine, are forced to compete against each other, so that these producers systematically fetch a price of their energy below the general average. Coherently, when a carbon tax is implemented, the increase in wholesale energy prices is less significant for renewables than for fossil fuel-based energy, as shown in the paper. Secondly, while a carbon tax boosts the unit margins of renewable energy plants more than those of gas plants, the significantly higher capital costs per unit of energy produced by solar and wind technologies considerably reduce the benefits of the carbon tax for these sources, when evaluated in terms of return on investment. In the paper, we sketchily suggest some possible alternative policies to drive effectively the transition to renewable energy generation systems.

The results and methodology presented in this work may help investigate some of these alternatives, contributing to a better understanding of mechanisms underlining the dynamics of the electricity generation sector, and hence potentially designing more effective policies. In particular, our method to estimate the supply curve for electricity could be applied to other countries to test the validity of our main result, i.e. assessing the effectiveness of taxing carbon emissions to promote the diffusion of green technologies. It could also be used to design an alternative pricing mechanism for electricity that could effectively produce the correct incentives for investors to promote the decarbonization of the sector. It is also possible to use our results in a broader context, evaluating the possible consequences of system-level interventions, such as the integration of the fleet of electric vehicles into the grid in order to provide a diffused storage system integrated with non-programmable energy sources. More in general, we believe that our work provides a case study warning against the blind application of policy recommendations based on idealized and simplistic textbook theories. Any hypothesis of intervention should be carefully verified, considering the complexity of real-world systems.

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