

# The role of capital costs in decarbonizing the electricity sector

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## Abstract

Low-carbon electricity generation, i.e. renewable energy, nuclear power and carbon capture and storage, is more capital intensive than electricity generation through carbon emitting fossil fuel power stations. High capital costs, as expressed as high weighted average cost of capital (WACC), thus tend to encourage the use of fossil fuels. To achieve the same degree of decarbonization, countries with high capital costs therefore need to impose a higher price on carbon emissions than countries with low capital costs. This is particularly relevant for developing and emerging economies, where capital costs tend to be higher than in rich countries. In this paper we quantitatively evaluate how high capital costs impact the transformation of the energy system under climate policy, applying a numerical techno-economic model of the power system. We find that high capital costs can significantly reduce the effectiveness of carbon prices: if carbon emissions are priced at USD 50 per ton and the WACC is 3%, the cost-optimal electricity mix comprises 40% renewable energy. At the same carbon price and a WACC of 15%, the cost-optimal mix comprises almost no renewable energy. At 15% WACC, there is no significant emission mitigation with carbon pricing up to USD 50 per ton, but at 3% WACC and the same carbon price, emissions are reduced by almost half. These results have implications for climate policy; carbon pricing might need to be combined with policies to reduce capital costs of low-carbon options in order to decarbonize power systems.

**JEL codes:** C61, Q42, Q54

**Key words:** carbon pricing, renewable energy, capital costs

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## 1. Introduction

Achieving ambitious climate change mitigation targets, for example, keeping temperature increases “well below 2°C” as agreed in the Paris Agreement (1), requires cumulative carbon emissions released in the atmosphere by the end of this century to be kept below 800 Gt CO<sub>2</sub> (2). The electricity sector plays a pivotal role in achieving this goal. Climate change stabilization scenarios that have been assessed by the IPCC (3) generally find that the energy sector needs to be completely decarbonized during the second half of the century. That is, investment into low carbon electricity sources, including renewable energy technologies, carbon capture and storage (CCS) and nuclear power, need to be ramped up significantly, while investment in coal and (to a lesser extent) natural gas, without CCS, will eventually need to be phased out (4).

Current investment patterns in the electricity sector do not reflect the emission reductions required to stabilize global temperature increases. Even though investments in the renewable energy sector have constantly risen in recent years (5), in the most recent decade a renaissance of emissions-intensive coal has led to a carbonization of the global energy system and an acceleration of emissions growth. Developing and newly-industrializing countries have been the main drivers of the global coal renaissance, which is largely needed to feed their fast-growing energy demand (6). Ongoing investments into coal lead to lock-in effects that will make future climate change mitigation efforts potentially difficult to achieve (7,8). Power capacities built today will usually run for the next 40 years or more. Today’s existing capacities of coal, oil and natural gas power plants – assuming they will reach the end of their lifetime –already account for more than 300 Gt of CO<sub>2</sub> (9,10). Coal power plants currently under construction, or at the planning stage, could add approximately 240 Gt CO<sub>2</sub> to the atmosphere and hence significantly challenge the achievement of climate change mitigation targets (11). Most of these emissions would arise in today’s developing countries.

Comparing costs of different energy generation technologies, fossil fuels and in particular coal are still significantly cheaper than low carbon alternatives, under many circumstances (12). Costs associated with power generation can be grouped into three types: i) upfront costs that occur at the beginning of the lifetime of a power station; ii) fixed operation and maintenance costs that occur throughout the lifetime, regardless of how much the plant is used and; iii) variable costs that are (roughly) proportional to output. Upfront costs comprise investment and long-term service contracts; fixed O&M costs include staff and regular maintenance; variable costs comprise fuel costs, emission permits where applicable, and wear and tear of equipment. The literature describes a wide range of cost estimates for each of these components. Based on data from the IEA World Energy Outlook (13), Figure 1 summarizes the cost structure of different power plant types (parameters are reproduced in Table 1). Fossil fuel plants are characterized by relatively high variable costs, representing 50-70% of total

discounted lifetime costs. Natural gas as a fuel is more expensive than coal, but gas-fired plants are cheaper to build than coal-fired power plants, which explains the lower share of capital costs in generation costs of gas-fired power stations (see Figure 1). Renewable energy sources such as wind power and solar photovoltaics (PV) have practically zero variable costs. The proportions of variable costs of other low-carbon power sources, such as nuclear power and coal with CCS, are relatively low at 20% or less.

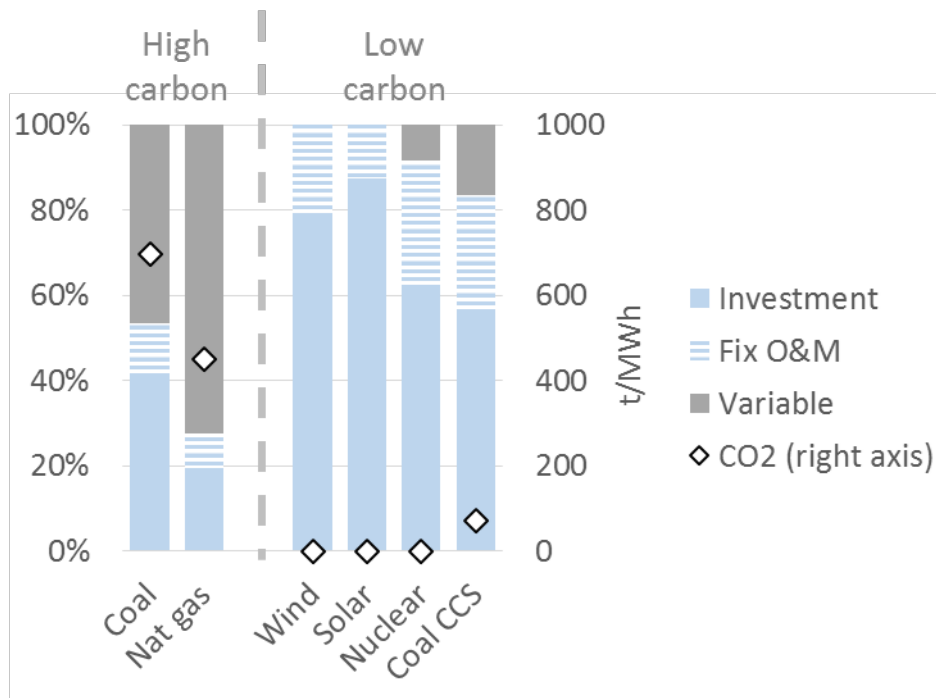


Figure 1: Cost composition of different power generation technologies. Typical parameters were used: 7% WACC and capacity factors of 60% for fossil fueled plants, 35% for wind power, 20% for solar power, and 90% for nuclear. A price of USD 30 per t CO<sub>2</sub> was assumed. Under these assumptions, the levelized electricity costs of all technologies are comparable in level (USD 58-84 per MWh).

This difference in cost structure matters, because costs occur at different points in time. For investment decisions, future costs (i.e. fixed O&M and variable costs) are discounted. In the power industry, the average discounted lifetime costs per unit of output is usually called “levelized costs of electricity” or “levelized energy costs” (LEC). LEC of power generation technology  $i$  can be calculated as

$$LEC_i = \frac{\sum_{y=1}^Y C_{i,y}(1+r)^{-y}}{\sum_{y=1}^Y G_{i,y}(1+r)^{-y}} \quad (1)$$

where  $Y$  is the lifetime,  $C_y$  the costs that occur in year  $y$ ,  $G$  annual generation (electricity output) and  $r$  the discount rate or weighted average cost of capital (WACC)<sup>2</sup>. Technologies with a high proportion of upfront costs benefit more from lower WACC than technologies with low upfront costs. Conversely, high capital costs disproportionately affect capital-intensive technology.

To illustrate this point further, Figure 2 shows the LEC of coal-, natural gas-, and wind-driven power generation for different WACC, otherwise using the same assumptions as for Figure 1. The generation costs of all technologies increase with an increasing WACC, of course, but they do so at different rates; the increase is greatest for wind power generation costs, because of their capital-intensity. Natural gas-fired generation, the least capital intensive technology, displays the flattest curve. On average, an increase of WACC by one percentage point increases the levelized electricity costs of wind power by USD 4 per MWh, of coal-fired power plants by USD 3 per MWh, and of natural gas-fired plants by USD 1 per MWh.

At low WACC, wind power is the cheapest option, while fossil fuels are much more cost-effective than wind power at high capital costs.

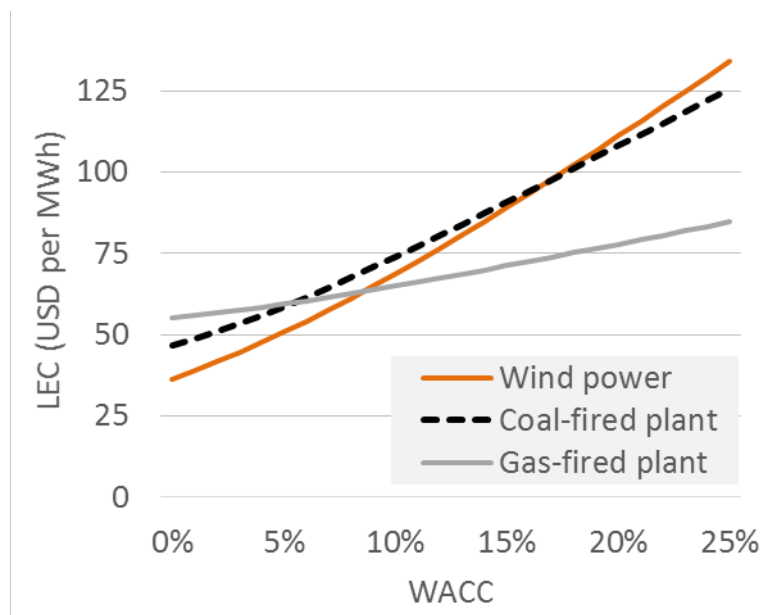


Figure 2: Generation costs of coal-fired, natural gas-fired, and wind-propelled plants for different WACC. Wind power levelized electricity costs (LEC) are the most sensitive to the cost of capital, because the share of upfront-costs is highest. Under these cost assumptions, wind power is the least-cost power source for WACC below 8%, but not at higher capital costs.

<sup>2</sup> Note that in this paper we quantify capital costs as weighted average costs of capital (WACC). In the context of the model used, the WACC corresponds to the discount rate.

As access to capital markets as well as investment risks differ across the world, differences in WACC can be severe. Ondraczek et al. (14) find that variation in country-specific WACC is more important for investment decisions into solar PV than the variation in solar radiation. They find that technology-specific WACC differ by a factor of 8 between different countries, with the lowest values being found in developed countries such as Japan (3.7%), UK (4.1%) or the Netherlands (4.3%) and the highest values being found in developing countries such as Brazil (28%) and Madagascar (29%). Larger differences also exist for wind energy. The DiaCore project (15) reviewed capital costs in European countries, reporting the lowest WACC in Germany (3.8%) and the highest in Greece (12%). The IEA (12), assessing wind power in selected countries, finds that the highest values for WACC are in China, India and Brazil, all being approximately 9%. More generally, Schmidt (16) shows that the LEC for renewable energy, such as wind, become significantly greater in environments where capital costs are high.

Determining how investments in low-carbon energy technologies are triggered is challenging. Economists frequently propose the introduction of carbon pricing (e.g., carbon taxes or emission trading) to ensure that incentives for low-carbon investments are established while also ensuring dynamic efficiency (see 17 for a recent compilation). Models assessed by the IPCC (3) determine median optimal global carbon prices in low stabilization scenarios, i.e. those that have a high probability of achieving the 2°C target, to be approximately USD 90 per ton in 2030 and USD 200 per ton in 2050. These prices would be sufficient to transform the global energy system. However, differences in capital costs across regions and technologies are usually ignored in these models.

In this paper we assess the extent to which “first best” climate policy, i.e. carbon taxes, interferes with a high cost of capital. We find that differences in WACC can lead to very different outcomes in terms of electricity mix and emission intensity, with high capital costs significantly impeding investment into low-carbon technologies despite identical carbon prices.

## 2. Methods and Data

To understand the impact of capital costs on the deployment of renewable energy sources and other low-carbon power generation technologies, it is not sufficient to compare levelized generation costs. One also needs to compare the *value* of electricity (19). This varies from hour to hour and between locations. The economic value of wind and solar energy is often less than that of other sources, because the availability of electricity fluctuates with wind speeds and solar radiation (20–26). Moreover, weather-dependent power generation, such as wind and solar power, is subject to forecast errors. This gives rise to so-called “system costs” for balancing of short-term demand-supply, and for network

investments.<sup>3</sup> Any cost-benefit assessment of electricity technologies needs to account for these complications. We use the numerical power market model EMMA to evaluate the impact of capital costs and carbon prices on the deployment of renewable energy and other low-carbon technologies while accounting for value differences and system costs.

EMMA is a techno-economic power system model that minimizes total system cost. It models both dispatch of and investment in power plants, minimizing total costs of investment, production and trade decisions under a large set of technical constraints. In economic terms, it is a partial equilibrium model of the wholesale electricity market with a focus on the supply side. It calculates the long-term (green field) optimum. The remainder of this section describes this model in more detail.

*Objective function and decision variables.* For a given hourly electricity demand, EMMA minimizes total system cost, i.e. the sum of capital costs, fuel and CO<sub>2</sub> costs, and other fixed and variable costs of power generation. Investment and generation is optimized jointly for one representative year. Decision variables comprise the hourly production of each generation technology including pumped hydro-storage and annualized investment in each technology, including wind and solar power. The important constraints relate to energy balance, capacity limitations, and the provision of ancillary services. For this paper, regions are modeled in isolation – cross-border trade is not accounted for.

*Generation technologies.* Electricity generation is modeled as eight discrete technologies with continuous capacity as follows: (i) two variable renewable energy sources with zero marginal costs – wind and solar power – that are limited in their availability by exogenous generation profiles, but can be curtailed at zero cost; (ii) four thermal technologies with economic dispatch – unabated coal-fired power plants, combined cycle gas turbines (CCGT), open cycle gas turbines (OCGT), and coal-fired carbon capture and storage plants – that produce electricity whenever the price is above their variable costs; (iii) a generic “load shedding” technology; and (iv) pumped hydro-storage, endogenously optimized under turbine, pumping, and inventory constraints.

*Investment decision.* We derive a green-field optimum, without pre-existing assets. In economic terms, the results correspond to a long-term equilibrium under perfect and complete markets. All investments have to recover their annualized capital costs from short-term profits. Capital costs are included as annualized costs. The hourly zonal electricity price is the shadow price of demand, which can be interpreted as the prices of an energy-only market with scarcity pricing. This guarantees that

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<sup>3</sup> These costs have been called “hidden costs” (27,28), “system-level costs” (29), or “integration costs” (5,30–35)

the zero-profit condition holds with long-term equilibrium. In other words, there is no “missing money problem”.

*Demand elasticity.* Demand is exogenous and assumed to be perfectly price inelastic at all prices but the very highest, when load is shed. Price-inelasticity is a standard assumption in dispatch models due to their short timescales. While investment decisions take place over longer timescales, we justify this assumption with the fact that the average electricity price does not vary dramatically between model runs.

*Cycling costs.* The model is linear and does not feature integer constraints. Thus, it is not a unit commitment model and cannot explicitly model start-up costs or minimum load. However, start-up costs are parameterized to achieve a realistic dispatch behavior; an electricity price is bid below the variable costs of assigned base load plants in order to avoid ramping and start-ups.

*Uncertainty.* The model is fully deterministic. Long-term uncertainty surrounding fuel prices, investment costs, and demand development are not modeled. Short-term uncertainty concerning renewable energy generation (day-ahead forecast errors) is approximated by imposing a reserve requirement via the system service constraint, and by charging renewable energy generators balancing costs.

*Data and calibration.* For previous applications, EMMA was calibrated to European power markets. For this paper, we aim to represent a typical emerging economy. We used a load curve from Shandong Province in China (available on request by the authors). Tables 1-3 reproduce the core economic assumptions. Investment cost assumptions were taken from the IEA WEO model.<sup>4</sup> Nuclear power was assumed not to be an option. Fossil fuel prices were 2015 market prices, and we varied carbon prices and the WACC.

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<sup>4</sup> <http://www.worldenergyoutlook.org/weomodel/investmentcosts/>. We took average costs for the Middle East, African, Indian, and Brazilian regions as projected for the year 2020. Note that rather optimistic values for capacity factors are in line with recent estimates (36,37)

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Table 1: Investment cost assumptions.

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Coal-fired power plants	USD 1750 per kW
Natural gas-fired power plants	USD 700 per kW
Coal with CCS	USD 2800 per kW
Wind power	USD 1480 per kW
Solar power	USD 1750 per kW

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Table 2: Cost assumptions for fossil fuels.

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Coal price	USD 8 per MWh
Natural gas price	USD 29 per MWh

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Table 3: Capacity factor assumptions for wind and solar power.

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Wind power capacity factor	0.35
Solar power capacity factor	0.20

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EMMA has been used for various peer-reviewed publications to address a range of research questions (22,23,38–41). EMMA is also open-source; the model code can be downloaded from <http://neon-energie.de/EMMA>. A more detailed model documentation including all equations is available on the same website.

### 3. Results

We calculate the long-term cost-optimal power system for different levels of carbon prices and capital costs with EMMA. Results are presented in three perspectives: i) the electricity generation mix, ii) carbon emission intensity, and iii) share of renewable energy. All three perspectives support one consistent finding: only a *combination* of carbon pricing and low capital costs leads to significant emission reductions and a significant share of wind and solar power in electricity supply. Carbon pricing alone is often insufficient unless *very* high carbon prices are assumed. We first discuss the optimal electricity generation mix. Figure 3 shows the share of electricity generated from different sources for carbon prices of zero and USD 50 per ton, and for WACC between zero and 25%, with otherwise unchanged parameter assumptions. (Further results for a wider range of carbon prices and WACC are



available as Supplementary Material). At a carbon price of zero, coal-fired power plants always supply all consumed electricity, no matter what the capital costs. This remains true at a carbon price of USD 50 per ton if the WACC is high. With lower WACC however, the proportion of both wind and solar power increases. At WACC of zero, they jointly supply nearly 50% of electricity. Moreover, low WACC also favors capital-intensive carbon capture and storage (CCS), such that unabated coal supplies a mere 40% of electricity.

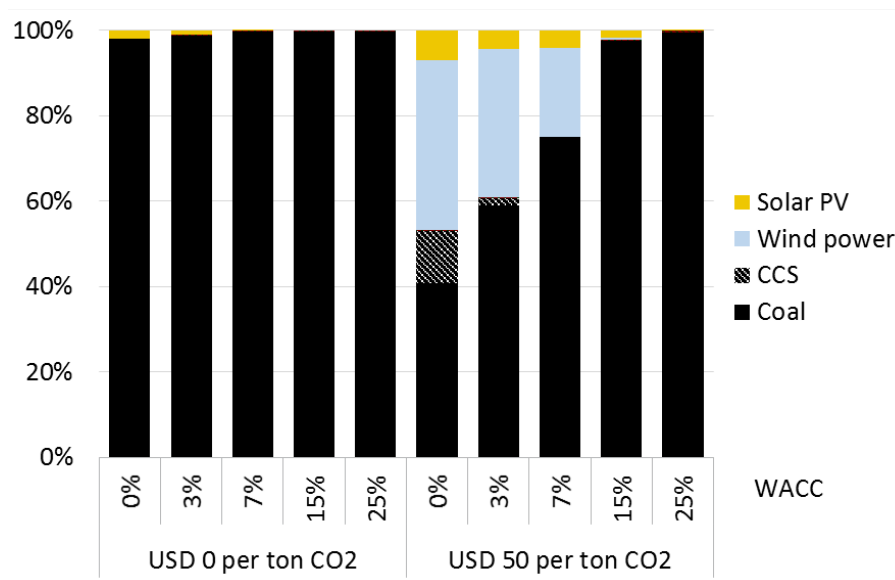


Figure 3: The generation mix for different capital costs and CO<sub>2</sub> prices (natural gas assumed to be unavailable). As expected, higher CO<sub>2</sub> prices and lower capital costs favor wind and solar power. A combination of a CO<sub>2</sub> price of USD 50 per ton and low capital costs is required to push the share of unabated coal below 50%. See Supplementary Figures S1 and S2 for sensitivity analysis on carbon prices and natural gas availability.

Next we discuss the carbon intensity of the power system. Figure 4 shows how carbon emissions, expressed in per-MWh terms, decline as a response to the introduction of carbon pricing. The size of this reduction depends on the prevailing capital costs; at 25% WACC, emissions are virtually unresponsive to carbon pricing. The lower the WACC, the larger the emission reduction for a given CO<sub>2</sub> price. In other words, in the presence of high capital costs moderate carbon pricing cannot be expected to have any significant effect on emissions. It is the combination of carbon pricing and low capital costs that leads to the greatest abatement of emissions. A note of caution: our analysis is restricted to the electricity system and does not include any change in the cost of coal mining. Further research is warranted to assess the indirect effects of capital costs on coal-fired electricity generation via the cost impact on mining and transport of coal.

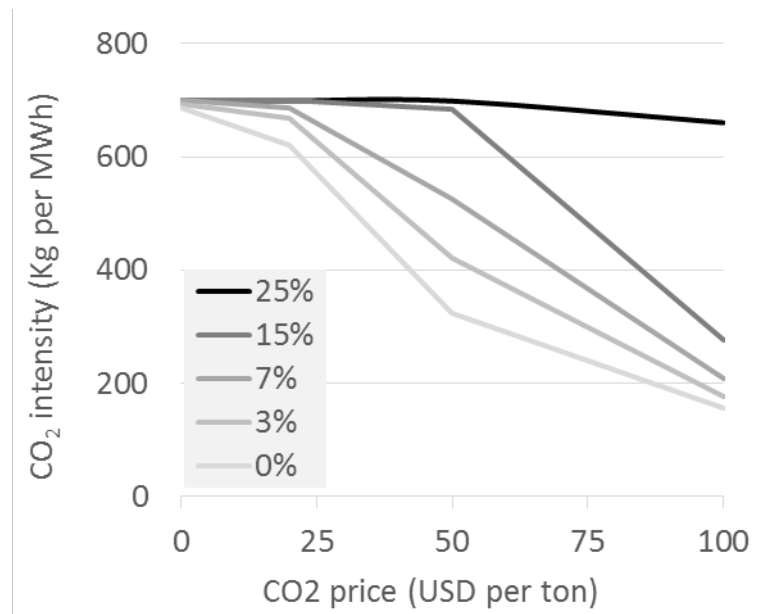


Figure 4: Carbon intensity of power generation. CO<sub>2</sub> emissions are almost completely insensitive to carbon pricing if capital costs are high (WACC of 25%). The lower the capital costs, the more the emissions decline as a response to the same carbon price.

Finally, Figure 5 provides a third perspective on the matter. It shows percentage shares of renewable energy in annual electricity production as a function of the two policy levers identified: the WACC and the carbon price. This illustrates how capital costs and carbon pricing interact. To achieve a certain proportion of renewable energy, one can pick any combination of carbon price and WACC represented by the line. To reach, say, a 10% share of renewable energy, at a WACC of 3%, a carbon price of about USD 30 per ton is required. To reach the same target at a WACC of 10%, carbon needs to be priced at around USD 50 per ton.

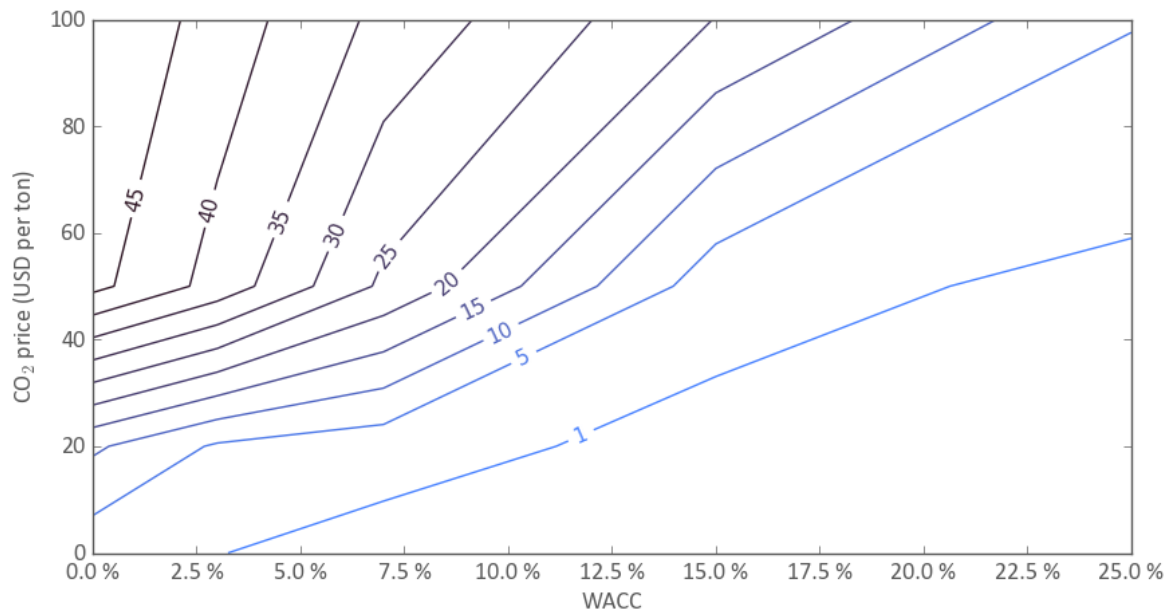


Figure 5: Contour-plot of renewable energy shares in percent. The colored lines show the combinations of discount rate and carbon price that trigger a specific renewable energy share in annual electricity generation.

#### 4. Discussion and Conclusion

In this paper we conceptually and numerically show how carbon prices and capital costs interact when aiming to transform power systems. High carbon prices (obviously) and low WACC (maybe less obviously) tend to favor low-carbon generation technologies. A deep decarbonization of electricity generation requires very high carbon prices if capital costs are substantial. A combination of moderate carbon prices with low capital costs – maybe politically less controversial – leads to significant emission reductions. According to our estimates, at a WACC of 25%, a carbon price of up to USD 100 per ton has virtually no impact. In contrast, if paired with very low capital costs, the same policy intervention reduces emissions by two thirds. Hence, carbon pricing is much more effective if capital costs are low.

Our numerical estimates are well in the range of real world estimates. For PV and wind, a WACC of 10% or more in newly industrializing and developing countries is realistic (see also introduction). At the same time, in order to transform energy systems to be in line with the 2°C target, carbon prices of USD 50 per ton CO<sub>2</sub> (or even higher) are required (3). For a carbon price in this order of magnitude to lead to an effective transformation of the energy system (e.g., inducing shares of renewable energy of 30% or higher), WACC needs to be reduced to levels lower than 5%, according to our estimates.

These results are particularly relevant for developing and emerging countries, where capital costs generally tend to be higher. It is primarily these countries that are currently investing into new coal fired capacities. If lock-in into coal-based energy systems and hence a continued renaissance of carbon-

intensive coal is to be avoided, alternative investments need to be employed in developing and emerging countries.

Carbon pricing is unquestionably important to foster these investments. However, our results show that in order to decarbonize the power sectors of emerging economies, instruments to reduce capital costs need to be considered as complementary policies. Such instruments could aim to reduce the investment risk, for example in the form of export guarantees for foreign investors or technology-specific feed in tariffs. More broadly, the quality and predictability of governance and regulation, being rule-based rather than discretionary, and the rule of law are important to reduce policy risks and bring down capital costs. Further research will be needed to determine which specific instruments would be most effective in the power sector.

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## S1: Sensitivity Analysis

In this supplementary material we show how core results change for different levels of carbon prices and the impact of the availability of natural gas.

Figure S1 includes results for a wider range of carbon prices (USD 0 per ton to USD 100 per ton) without natural gas. Our main finding remains robust: higher capital costs make low-carbon technologies relatively less attractive; only a combination of carbon pricing and low capital costs leads to a high penetration of low-carbon technologies.

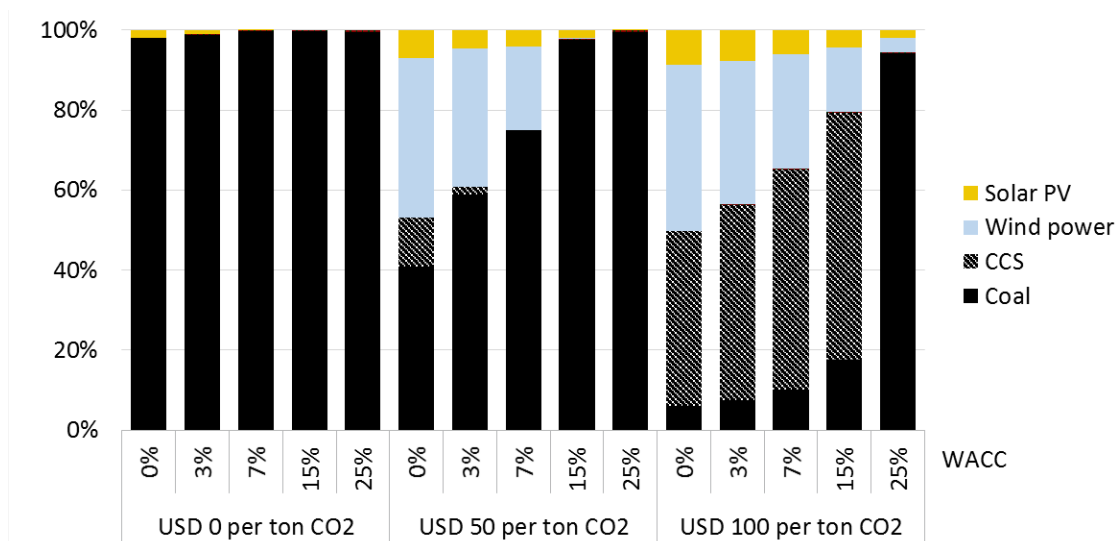


Figure S1: The cost-minimal generation mix for different capital costs and CO<sub>2</sub> prices (natural gas unavailable).

While natural gas is not available in many parts of the developing world, in others it is. Figure S2 shows the same results if natural gas is included as an investment option. Both higher carbon prices and higher capital costs tend to increase the role of natural gas as an electricity source. Our main finding, however, remains robust: higher capital costs make low-carbon technologies relatively less attractive. Only a combination of carbon pricing and low capital costs leads to a high penetration of low-carbon technologies.



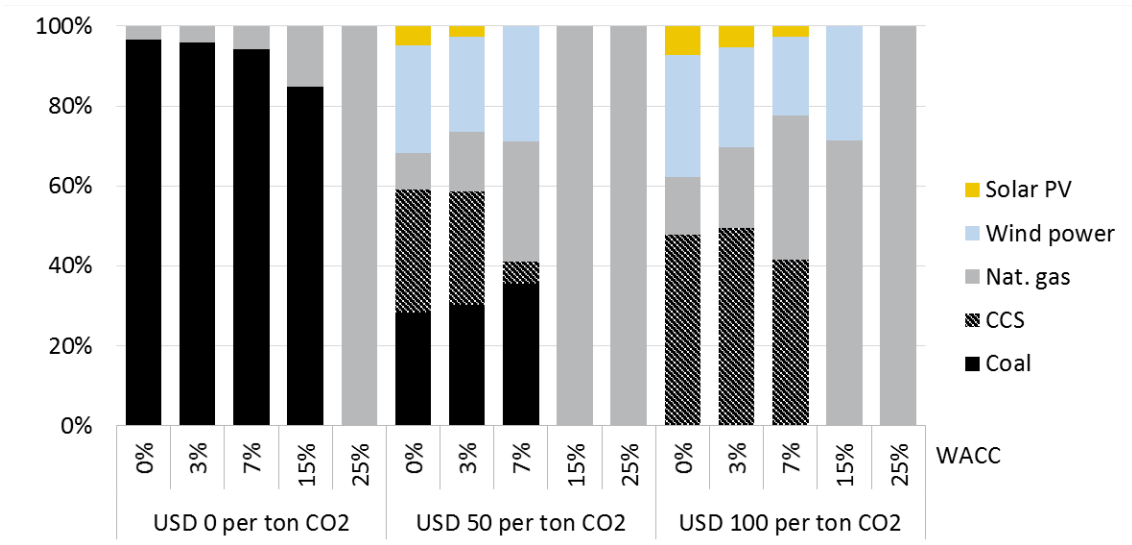


Figure S2: The cost-minimal generation mix for different capital costs and CO<sub>2</sub> prices (natural gas available).