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D4.2 Economic costs and benefits of renewables deployment in the EU

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PREFACE

The **CARISMA** project ("**C**oordination and **A**ssessment of **R**esearch and **I**nnovation in **S**upport of climate **M**itigation **O**ptions") intends to benefit research and innovation efficiency, as well as international cooperation on research and innovation and technology transfer, through effective stakeholder consultation and communication leading to improved coordination and assessment of climate change mitigation options.
Additionally, it aims to assess policy and governance questions that shape the prospects of climate change mitigation options and to discuss the results with representatives from the target audiences to incorporate what can be learned for the benefit of climate change mitigation.
Knowledge gaps will be identified for a range priority issues related to climate change mitigation options and climate policy making in consultation with stakeholders.

PROJECT PARTNERS

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CO1	Radboud University Nijmegen	SKU	NL
CB2	University of Piraeus Research Center	UPRC	EL
CB3	Joint Implementation Network	JIN	NL
CB4	Institute for Climate Economics	I4CE	FR
CB5	University of Graz	UNI Graz	AT
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CB8	Center for European Policy Studies	CEPS	BE
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CB10	Technical University of Denmark	DTU	DK

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1. Introduction

As part of the CARISMA project, the aim of this report is to (re)assess the cost for selected renewable energy technologies, with the goal of incorporating the recent discussion on system and macroeconomic costs of those technologies to the narrower view of levelized cost of electricity (LCOE). As noted in recent literature (see, for example, Hirth et al., 2015; Joskow, 2011; Milligan et al., 2011, and others) the direct costs of generating electricity (as captured e.g. by LCOE) are not sufficient to compare renewables with fossil fuel options. LCOEs when used with variable renewables ignore variability and integration costs into the larger electricity grid, thereby possibly underestimating the eventual costs of such electricity generation, especially as their capacity increases. A broader energy system perspective must be used in order to capture the economic challenges of power sector transformation.

This report is tasked with evaluating the coverage and reliability of existing data (cost/benefit scenarios developed and assessments conducted) for selected technology options, and conducting the appropriate assessments where existing literature is found to be insufficient. We use the recent discussion on the shortfalls of LCOE as they relate to renewables as a way to frame and motivate our assessment. Beginning with an overview of the current direct costs of renewables, we expand upon current assessments and incorporate system costs, the additional costs incurred by renewables being incorporated into the larger energy grid and costs of energy storage in case of intermittent renewable energy sources, as well as the macroeconomic effects of deploying renewables at larger scales. The work uses quantitative economic CGE modeling to assess the system impacts of deployment of renewables into the broader economy, to assess social costs and benefits, and to help compare cost and benefit attributes across different mitigation pathways and country contexts.

Two technology options were selected for analysis, which address different stages of deployment, and contribute to different mitigation pathways:

1. Wind power (onshore wind): EU energy and climate policy is characterized by higher target shares of renewables in national energy mixes. Wind power is expected to play an important role to reach these targets, with different potentials in different European regions. Common scenarios, such as OECD/IEA and others, assert that wind power could bel expanded to cover just under 25% of the EU's electricity demand by 2030.
2. Solar photovoltaic: Solar PV has seen exponential growth in the 21st century, rising from almost zero to just under 140 GW of global installed capacity in 2014. Costs have also dropped dramatically, and further cost reductions are forecast, especially in light of PV being seen – along with wind power - as a critical technology to meet emission reductions targets.

1.1. Different dimensions of cost for renewables

With the EU 2030 Energy and Climate and Energy Package EU member states have agreed on substantial reductions in greenhouse gas (GHG) emissions as well as on shares of renewables in energy consumption. More precisely, by 2030 GHG emissions should be cut by 40% compared to 1990 levels and the share of renewables in energy consumption should be at least 27% for the EU (EC, 2014). Note that studies indicate that such targets are insufficient to achieve the temperature rise limits of well below 2 or of 1.5 degrees, as outlined in the Paris Agreement (Climate Action Tracker, 2017). Reaching the EU goals demands a significant expansion of renewable electricity and cuts of conventional electricity with far reaching indirect economic effects.

Hence, economy-wide analysis is crucial both given the significant expansion under way and since the introduction or expansion of certain technologies can lead to unexpected consequences for other economic agents and sectors via shifts in relative (international) market prices and demanded quantities. These economy-wide consequences can be of different directions, also diverse across indicators (such as on GDP or social welfare). For example, when introducing cost-competitive PV at a large scale, traditional fossil fuel based electricity suppliers might lose market shares and eventually have to close down their businesses. However, other sectors, such as the suppliers for the construction of PV panels, might benefit from such a development. Also on the households' side, there might be both winners and losers, depending on households' endowments and skills. Another facet of economy-wide implications is foreign trade. Foreign trade patterns might change due to the introduction/expansion of mitigation technologies. For example, traditional oil and gas exporting countries might face reduced demand for their products. Eventually the combination of all these indirect effects leads to changes of macroeconomic indicators such as regional GDP, welfare, or employment.

Such comparisons are usually based only on generation costs or "levelized costs of electricity" (LCOE) (Borenstein (2012) and Joskow (2011)), which are calculated using a bottom-up approach, measuring technology costs and not the overall net costs, e.g. without the incorporation of possible benefits of renewables. One weakness of LCOE calculations is that they typically do not cover system integration costs (Baker et al., 2013; Hirth et al., 2015a; Joskow, 2011), although integration costs are expected to be significant at high penetration rates of variable renewable electricity (Hirth et al., 2015a). As a consequence, also macroeconomic studies, which usually rely on bottom-up assessments for cost estimates, do not include integration costs. This might overestimate the potential positive macroeconomic effects of renewable energies, underestimate the barriers and co-benefits, and lead to ineffective policy recommendations (Hirth et al., 2015b).

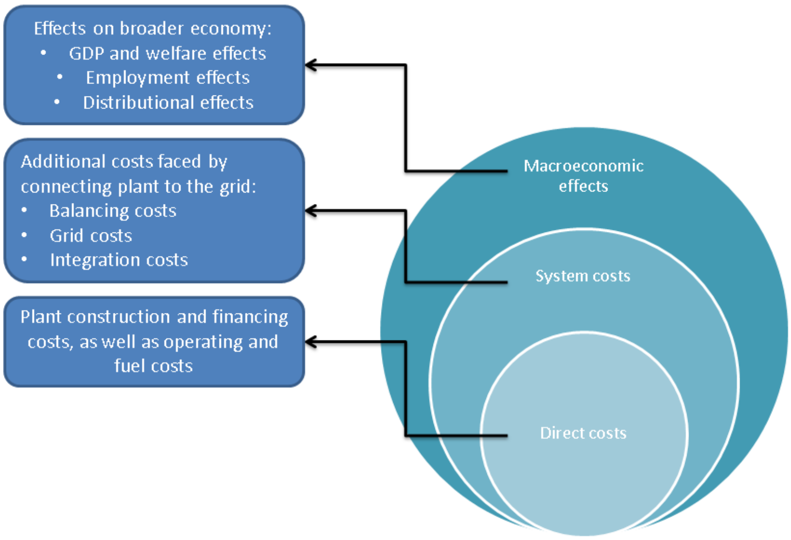

Figure 1. Different dimensions of costs for renewables as addressed in this work

Moving beyond direct costs, we address the problem of system costs and go beyond the state-of-the-art by introducing these costs explicitly as additional cost components to the different parts of the electricity system. To the authors' best knowledge there are no other macroeconomic studies where this is done, except for the recently published article by Hannum et al. (2017). However, this analysis only takes into account a part of system costs, which is, according to Hirth et al. (2015a), very small. In contrast, in our analyses we include the most important integration cost components, which are believed to be more important in terms of cost impact (Hirth 2013, Hirth, 2015). These include (i) "grid-related" costs, namely the additional costs due to geographical reasons, transmission constraints and losses as well as (ii) "profile costs" due to increased ramping and cycling of conventional plants and due to a reduced utilization of thermal plants (Hirth et al., 2015a). Our analysis shows that the inclusion of integration costs significantly alters the estimated macroeconomic effects, which in some cases even change sign, going from positive to negative. Note, however, that we do not consider energy storage costs, which would potentially mitigate such profile costs, as such technologies are complex and site specific, requiring optimization based on wind power forecasting error, technical constraints, market rules and energy prices (Zhao et al, 2015), and are beyond the scope of this research. However, as renewables increase in the share of total generation, and as storage becomes cheaper, it may play a significant role in reducing profile costs, and merit further research in the future.

This report therefore analyzes the possible economy-wide implications (e.g. wages and capital rents, welfare) of a large-scale expansion of wind and photovoltaics (PV) – two promising climate change mitigation technologies – in the European Union. To estimate the economy-wide effects, we use the latest version of the GTAP model, a multi-regional multi-sectoral computable general equilibrium (CGE) model, described in Section 4.

The remainder of the report paper is structured as follows. Section 2 discusses direct cost calculations and the state of current technology. A discussion of system costs follows in Section 3. The macroeconomic assessment of wind and solar PV costs is discussed in Sections 4 and 5 respectively, with Section 6 presenting the results of our analysis, discussing the economy-wide effects and highlighting the critical aspects of our approach.

2. Current state of technology

As discussed in Section 1, understanding the challenges faced by the electricity sector due to climate change mitigation, entails moving beyond direct costs to comprehend broader macroeconomic effects. This calls for a broader system perspective.

However, direct costs constitute the basis on which these broader cost categories should be calculated. As such, a discussion on current costs and trends for the technology under consideration is warranted. In the following section (2.1), we provide an overview of the components of the Levelized Cost of Electricity (LCOE), a commonly used metric to perform cross-comparisons between different electricity technologies. Section 2.2 discusses how LCOE vary over time and location, related to these underlying components of LCOE.

2.1. Direct costs: LCOE

While LCOE have long been seen as commonly-used metric to compare the costs of electricity from different energy sources (Ueckerdt et al., 2013), an overview of the factors accounted for in LCOE calculations is useful in setting the stage for our further analysis and understanding the driving forces behind differences in LCOE across technologies and regions over time.

2.1.1. Calculating LCOE

Put simply, LCOE is an estimate of the price at which a unit of electricity would need to be sold in order for the plant to recover expenses and pay investors. It is represented by the following equation:

$$LCOE = \frac{Capital\ Cost * CRF * (1-TD)}{8760 * Capacity\ Factor * (1-T)} + \frac{fixed\ O\&M\ costs}{8760 * Capacity\ Factor} + \frac{variable\ O\&M}{1{,}000\,\frac{kWh}{MWh}} + \frac{Fuel\ price * heat\ rate}{1{,}000{,}000\,\frac{BTU}{mmBTU}}$$

where *N* indicates plant lifetime, *T* represents taxes, *D* denotes depreciation, *Capacity Factor* the percentage of the year at which the plant operates at full capacity, and *O&M* representing operations and maintenance costs.

CRF, an abbreviation for Capital Recovery Factor, calculated as follows:

$$CRF = \frac{R_D\,(1+R_D)^N}{(1+R_D)^N - 1}$$

where R_D represents discount rate and *N* plant lifetime.

The LCOE is therefore the combination of amortized initial capital costs to build the plant, with yearly payments depending on discount rate, plant lifetime, expected rate of return for financing, taxes, depreciation, and capacity factor, plus fixed O&M costs (again varying by capacity factor), plus variable O&M costs (which change based on plant output) and finally the costs of fuel (OpenEI, 2016). The result is the total cost of producing one unit of electricity, usually stated in Currency per Megawatt-hour or per kilowatt-hour.

LCOEs enable a degree of comparison between different types of generation technologies because they represent an initial calculation of the cost to produce a single unit of electricity incorporating all factors which may affect costs over time.

However, it is apparent that LCOEs do not take into account a variety of factors which have an impact on the eventual cost of electricity to consumers. Referring back to **Fehler! Verweisquelle konnte nicht gefunden werden.**, LCOEs embody the direct cost of electricity, from the buying and using of equipment and fuel to generate power (NEA, 2012). This does not include, for example, the costs associated with policy interventions such as government subsidies or the costs charged for emitting CO_2 faced by fossil-based generation technologies. It also does not take into account additional costs which may be faced by certain renewable technologies, such as system costs, as further discussed in Section 3.

LCOEs vary widely by technology, region, and over time, and are discussed in the next sections.

2.2. LCOE by technology

LCOE estimates are extremely place- and context-specific, and depend on various technological and economic considerations such as estimated full load hours, costs of capital, operations and maintenance, borrowing costs and internal rates of return (IRR) indicating perceived riskiness of investment, fuel costs (for conventional generation) etc. Such temporal and context specificity leads to an inability to generalize LCOE estimates with a high degree of precision for future projects, however it suffices for broader, national- or regional- scale assessments.

For the modelling part of this deliverable, a set of country-specific LCOEs were derived from the work of Alberici et al (2014) and an attempt was made to validate the estimates thus obtained by comparing them to other existing estimates for both the EU and other developed regions[1]. The result was a collection of LCOE estimates from a range of studies

[1] . Where necessary, costs were converted from the base currency (e.g. GBP and USD) to constant 2011 EUR. In cases where prices were in a different currency, estimates were deflated to 2011

carried out between 2009 and 2015. These were used to calculate the range of likely LCOEs for each fuel type, with the values from Alberici et al. (2014) for individual EU countries added as point values (Figure 2). Most costs from Alberici fall within the range of estimates found in other studies, with the exception of small- and large-scale PV, which is appreciably lower than in other data sources. This peculiarity of the PV LCOE will be revisited in Section 2.3, but Figure 2 more generally serves to illustrate the large variation in LCOE estimates, even within a single technology. This results from variations in the estimates of the factors that make up LCOE. For instance, natural gas combustion turbines (NGCC) exhibit such a broad range of LCOEs due to their design purpose; often, NGCC plants are used as "peak-load" plants, being brought online to handle unexpected loads on the energy system, as they are dispatchable and can be brought online to generate power rapidly, in comparison to other conventional sources such as coal and nuclear, which serve baseload power needs, but have long lag times when being brought into operation. Thus a peak-load NGCC plant may be estimated to have a high LCOE due to a low capacity factor, compared to a similar plant which operates at a baseload level (Stacy and Taylor, 2015).

A major difference emerging from Figure 2 relates to conventional and renewable sources of electricity. Fuel costs account for a large contribution to the overall LCOE for conventional technologies. Logically, these costs aren't incurred on most forms of renewables, with the exception of bioenergy, which on the other hand bears costs which are closer to those characterizing conventional technologies.

Hydropower LCOE estimates derived from Alberici et al. are consistently lower than the averages found in the literature. However, these are still mostly within the 2nd quartile of previous estimates, and not as drastically different from observations as in the case of PV estimates.

The values of LCOE from Alberici et al. for all remaining technologies (i.e. all conventional technologies, wind, hydro and biomass) seem to fall within the ranges found in other literature, and can be seen as moderately robust for estimating regional LCOEs for Europe, given the inherent uncertainty in such estimates due to their contextual nature discussed above.

values, and converted into 2011 EUR. For EUR in constant values other than year 2011, prices were deflated based on inflation estimates for the energy sector from Statistik Austria (2016)

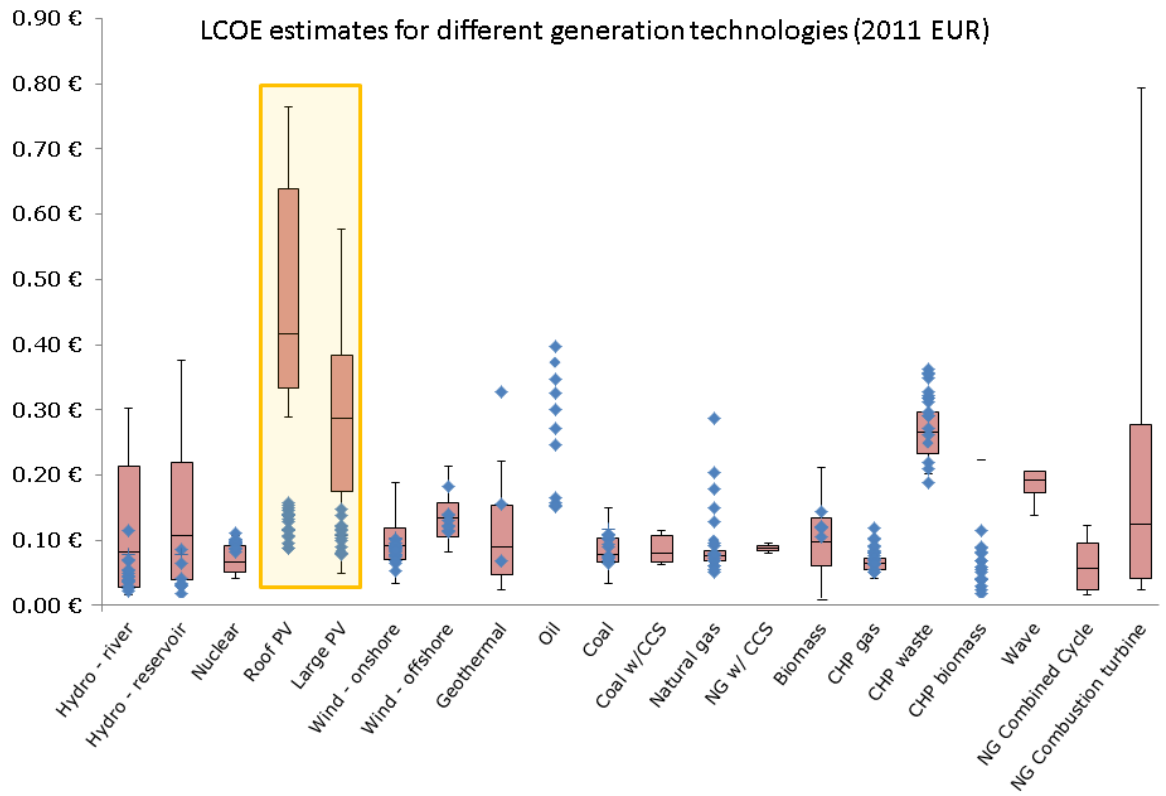

Figure 2. LCOE estimates for various electricity generation technologies from the years 2009-2014, based on data from DECC (2012), Held et al (2015), IEA, NEA, OECD (2010), OpenEI (2016), and World Energy Council (2013), compared to estimates from Alberici et al. (2014). Compiled literature estimates are provided as box-and-whisker indicating quartiles with a line indicating median value, and country estimates from Alberici are indicated as point values. Roof and large-scale PV is highlighted to emphasize the aberration in values between literature and estimates used in the CARISMA project.

2.3. LCOE – variations over time

A portion of the variation in the estimates presented in Figure 2 is due to changes over time, especially for renewables, which have experienced tremendous growth in the past 10 years and longer. Wind power in Europe has consistently experienced yearly growth rates of 25%, slowing slightly over the past five years to around 15% (IRENA, 2015a). Over the same period of time, the global installed capacity of solar PV has increased from under 40 GW to over 220 GW in 2015 (averaging approximately 19% year-on-year growth) (IEA, 2016), with simultaneous increases in efficiency (IRENA, 2014) . Such gains in installed capacity are believed to lead to lower costs thanks to technological learning rates. The learning curve literature suggests that every doubling of capacity is associated with significant cost decrease. These differ by technology; in the case of certain PV modules, for instance, IRENA (2014) estimates learning rates as high as 22%.

This, plus increased efficiency, are believed to lower LCOEs, as shown in Figure 3 below. This provides partial explanation for the wide range of costs for PV, as the LCOE for PV has dropped precipitously in the past ~5 years, with a reduction in average LCOE observed in the literature of almost 50% from 2009 to 2014, from $0.34 to $0.16 (OpenEI, 2016). This 2014 median price is in fact much closer to the estimated values from Alberici et al. Additionally, the relative popularity of solar PV in the EU may be contributing to lower perceived riskiness of investment, and thus may be associated with lower IRR and borrowing costs. This clearly would further lower the LCOE.

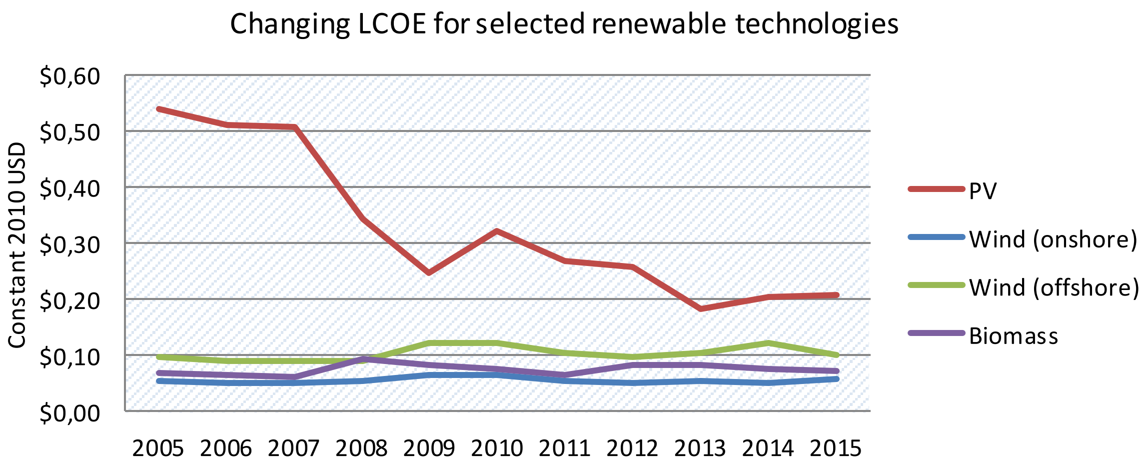

Figure 3. Worldwide median LCOE over time for wind - both on and offshore - PV, and biomass generation technologies, based on modeled and observed values from OpenEI (2016).

However, capacity and efficiency gains do not always lead to reductions of LCOE (see, for example Grubler's (2010) analysis of the rising specific cost of nuclear in France, despite an increase in experience), and here wind serves as an example of how such changes may not be reflected in LCOE. As per chart above, over same time period, wind stayed relatively constant. Cumulative new installed capacity kept increasing at a rate of about 25% per year, with a slight reduction in later periods as previously discussed. However, due to increased capital expenditure costs – mainly due to rise in prices of commodities e.g. steel and copper which are heavily used in the capital intensive technology – the cost of turbines fluctuated markedly in the same period that PV LCOEs declined. (IRENA, 2015b)

2.4. LCOE – regional variation

LCOEs also vary for a given technology across world regions. Such variations are due to financial situations (e.g. different financing rates in certain countries over others, IRR reflecting riskiness of investment), but also changing capacity factors. For PV, northern latitudes are subject to less solar insolation generally, and thus expected capacity factor

and LCOE will differ by location (Huld et al, 2014). This north-south gradient can be seen to some degree in Figure 4 below, although solar insolation is not the only factor affecting regional or national LCOEs differences.

The weighted average cost of capital (WACC) as used in calculation of the capital cost, also gives rise to national differences in eventual LCOE. WACC is comprised of the costs of debt and equity, the latter of which is based on the theoretical risk-free rate of return of an investment, expected market premium, and policy and technology risk premiums. Policy risk premiums can be either positive or negative, and indicate the changes to risk based on policies and support measures effecting specific technologies. Due to varying market risk premiums found in member states (e.g. a low of 5.5% in Denmark, and high of 9.6% in Greece) (Fernandez et al, 2012) and policy risk premiums, WACC can vary widely by country, thus contributing further to the variation seen in the charts below.

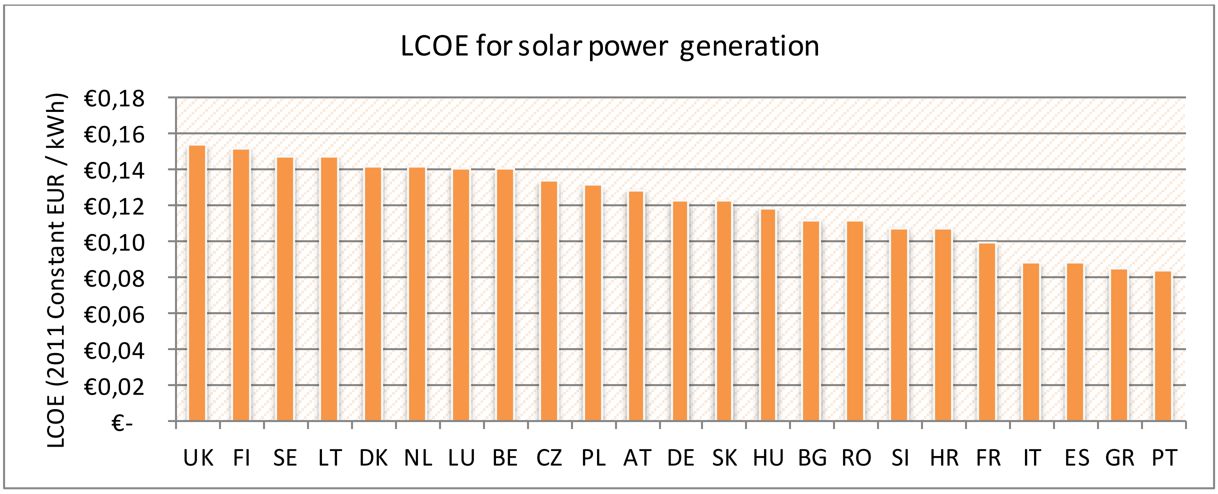

Figure 4. National LCOEs for solar PV in EU member states for 2014, as used in this work's modelling of the macroeconomic effects of renewables, based on estimates from Alberici et al. (2014).

It should be noted that "policy risk premium" takes into account the perceived effect of policies on costs of investment into technologies, but policies which address the costs of electricity explicitly, e.g. subsidies and feed-in tariffs, are not reflected in LCOE estimates, including those presented here.

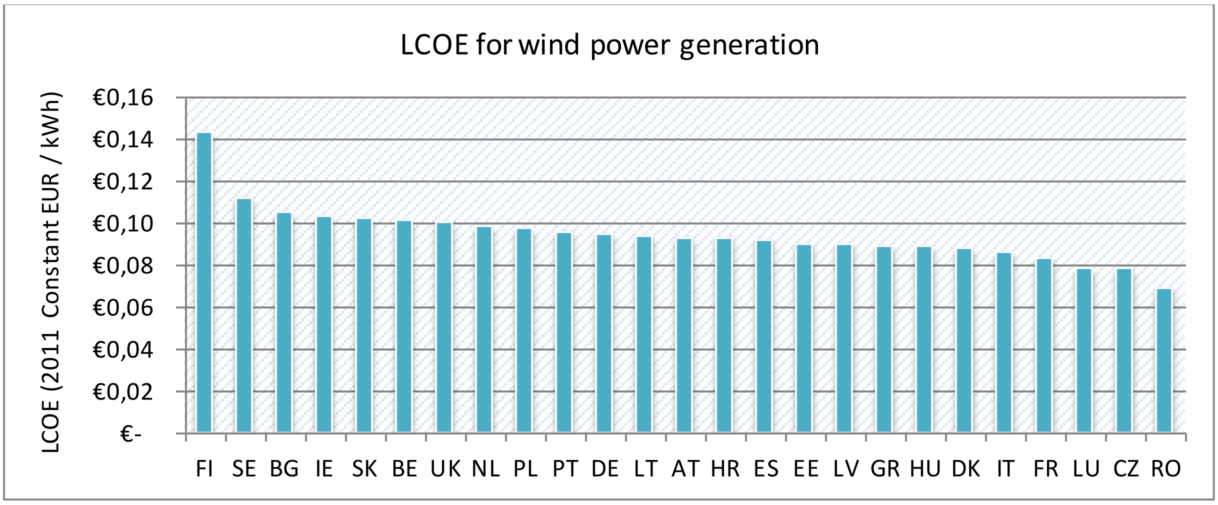

Figure 5. National LCOEs for on and offshore wind power in EU member states for 2014, as used in this work's modelling of the macroeconomic effects of renewables, based on estimates from Alberici et al. (2014).

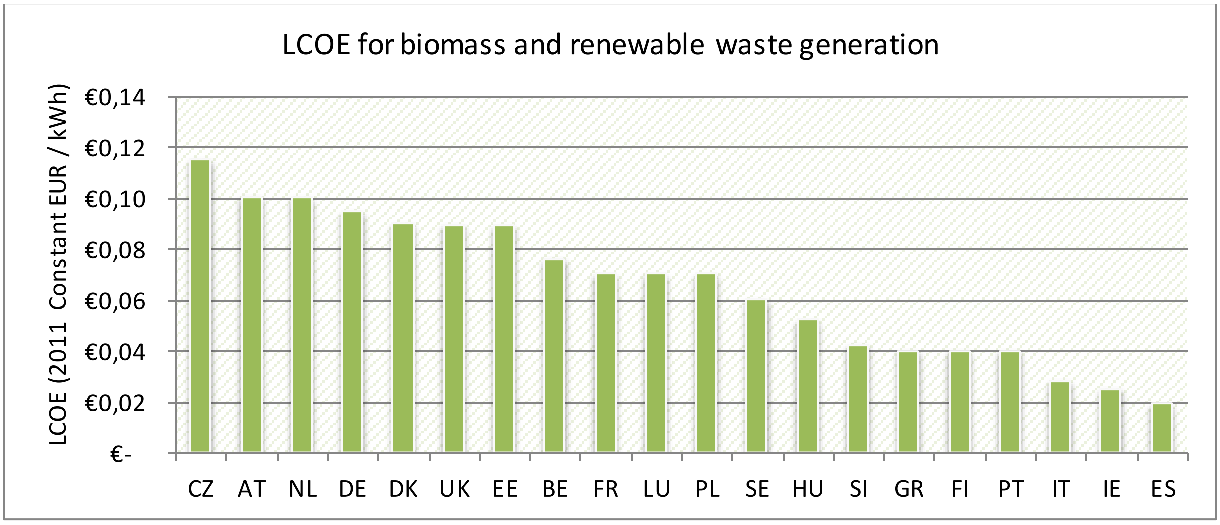

Figure 6. National LCOEs for biomass power in EU member states for 2014, as used in this work's modelling of the macroeconomic effects of renewables, based on estimates from Alberici et al. (2014).

2.5. Limitations of LCOE

As noted previously, LCOEs have been criticized for the inability to provide adequate comparisons of the costs of technologies, especially when comparing intermittent renewables (Steininger et al, 2016). Indeed, as argued above, there are a number of factors which are not incorporated in current LCOEs calculations. These costs can occur at any point of the value chain, starting from the direct costs of producing a unit of

power and ending with the final prices of electricity. In terms of actual plant investment decisions, factors other than LCOE must be considered in the decision-making process. These include, for instance, projected utilization rates, which are based on the load curve and existing generation mix, and capacity values, namely the ability of a plant to reliably meet demand, Regulations and policy may also have an effect on overall costs which are not reflected in LCOE, e.g. taxes, changing allotments of EU ETS credits, or country-specific feed-in tariffs. Another factor which likely impacts LCOE estimates of renewables e.g. wind and solar, more than those of traditional fossil based are system costs. Essentially these are the costs embodied in connecting renewable generation sources to the larger energy grid, and are discussed more in depth in the following section.

3. Overview of system integration costs

System integration costs arise after production of electricity at a generation site, when that power is supplied to the larger grid. Simply put, grid operators need to constantly balance energy with demand. Variable renewable energy (VRE), e.g. wind and solar, present three unique issues which lead to higher costs associated with their integration in the grid:

1. VRE is, by definition, variable*,* i.e. determined by weather conditions, and output cannot be controlled (i.e. non-dispatchable) in a similar manner to conventional generation;
2. VRE is uncertain until it is produced; normally, decisions on power plant production are made far in advance of their delivery and use. Any deviations between the predicted VRE generation and actual production have to be balanced on short notice;
3. VRE cannot be easily transported similarly to fuel-derived energy, e.g. fossil fuels, and frequently good locations for VRE do not correspond with locations with high demand for energy.

These factors lead to system integration costs, which have had varying definitions in literature; we clarify their meaning below.

Balancing costs

Balancing costs are the marginal costs which accrue due to deviation from day-ahead planned generation schedules, due to e.g. forecasting errors. These costs appear as the net costs of intraday trading and imbalance costs, and are exhibited in the difference between the day-ahead and real-time prices. They reflect the marginal cost of balancing those deviations. In some countries such as Germany, balancing costs have declined over the last seven years: improvements on the balancing market have outweighed the impact of increasing renewables.

Grid-related costs

Grid-related costs are the reduction in market value due to the location of generation in the power grid, essentially, the marginal costs of transmission losses or limitations. For wind, we take the example of Hirth et al. (2013) and define them as the spread between the load-weighted and the wind-weighted electricity price across all bidding areas of a market, following a similar approach for solar. They reflect the marginal value of electricity at different sites and the opportunity costs of transmitting electricity on power grids from VRE generators to consumers.

Profile costs

Profile costs (or "utilization costs") arise due to the impact of timing of generation on the market value. Adding new wind and PV or new baseload to a power system has a different impact on the residual generation, and its costs. Even disregarding grid and balancing costs, e.g. assuming production can be perfectly forecast, and no transmission costs are incurred, increasing VRE capacity will incur profile costs, because their production profile does not perfectly match demand profiles.

Put simply, there is a low limit to the amount of generation capacity which can be replaced with VRE, as there are times when VRE does not produce and load must be handled by dispatchable plants. However, the full load hours of these plants are reduced for the majority of the time, resulting in higher LCOEs for these plants. Finally, at the other end of the spectrum there will be times when VRE supply exceeds demand, and there is an oversupply of electricity (Hirth et al., 2015a).

For wind power, profile costs can be defined as the spread between the load-weighted and the wind-weighted electricity price *over all time steps during one year* (Hirth et al., 2013), differing from the definition of grid-related costs as this factor includes a temporal dimension. They reflect the marginal value of electricity at different moments in time and the opportunity costs of matching VRE generation and load profiles through storage. Adding new wind and PV or new baseload to a power system has a different impact on the residual generation, and its costs.

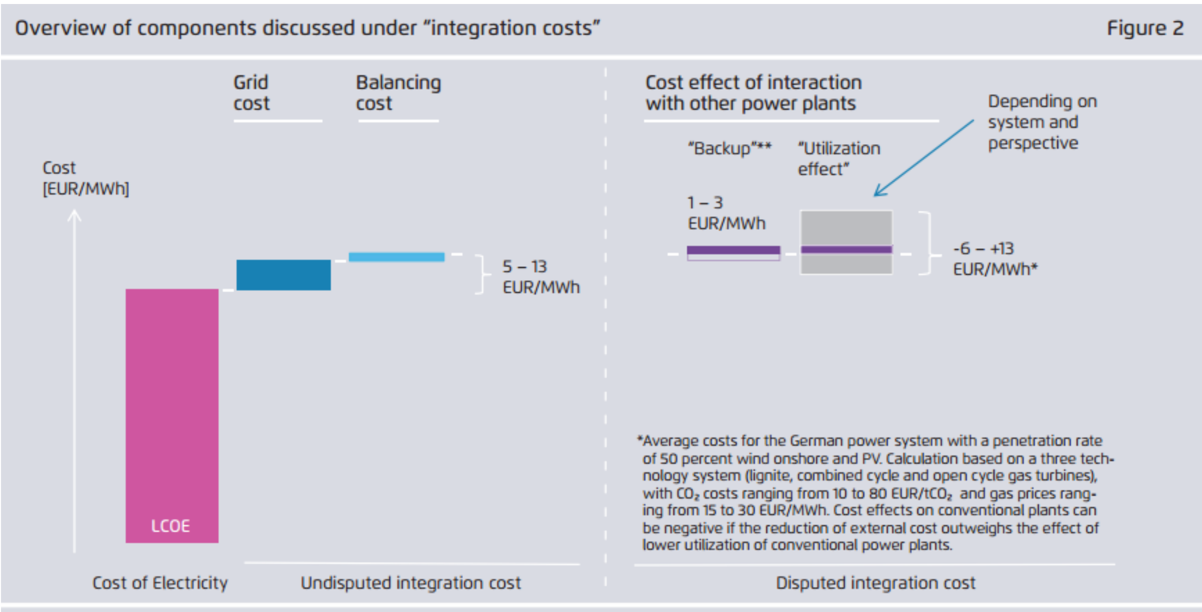

Figure 7. Overview of the components of integration cost. Our analysis focuses on grid costs and utilization effects, as described in Chapter 4. Source: Agora Energiewende (2015)

Interviews with, economists, energy system researchers, and other stakeholders via the CARISMA project have shown that there is no clear understanding yet whether integration cost will decrease over the coming years, as the energy system is switching form highly centralized to increasingly decentralized structures, and an integration of renewables into the wholesale markets may not be so important anymore. Micro grids, an emerging technology, may involve the integration of demand-side management (DMS) with supply-side management (SMS) including electric and thermal storage. On the other hand new technologies used in decentralized systems such as batteries may be expensive the short an midterm and depending on the technologies use still back-up capacities may be needed form the grid. The upshot of all this is that a number of pathways are available for future technological development, which will likely have an effect on integration costs, but the effects are as of yet too uncertain to quantify in our modeling approach.

However, the comparison of integration costs for centralized and for decentralized solutions may be too narrow a view according to stakeholders we consulted, as they depend on the system boundaries defined. Sometimes it may be not straightforward to estimate which costs can be attributed to which technologies. It would be better to compare entire energy systems – including the infrastructure needed and the portfolio of technologies, as well as possible links to markets for the case of decentralized solutions – and to carry out such comparisons for different time horizons.

4. Macroeconomic analysis part I: Expanding wind power

4.1. Introduction

The following sections analyze the economy-wide implications of the introduction or expansion of two climate mitigation technologies in the European Union. The analyzed technologies are wind power and electricity from photovoltaics (PV).. Our aim is to reveal the effects which are not visible in narrow and partial technology specific bottom-up analyses. Such consequences can be of different directions and divergent across different indicators, such as GDP or measurements of social welfare. Introducing PV at a large scale may result in conventional electricity suppliers losing market shares and closing down, but other sectors, e.g. suppliers for construction of PV panels, might benefit. Households too would see winners and losers, depending on their particular endowments and skills. Foreign trade may also be affected, due to the introduction or expansion of mitigation technologies. Eventually, the combination of all these indirect effects leads to changes of macroeconomic indicators such as regional GDP, welfare, or employment due to a combination of an increase in renewables and the inclusion of system-costs.

4.1. The Method

To assess the economy-wide effects of the three mitigation technologies wind, PV and bio-CCS, we deploy a global multi-regional multi-sectoral computable general equilibrium (CGE) model (based on Bednar-Friedl et al., 2012; Schinko et al., 2014) updated to the GTAP9 database (base year 2011). The model comprises 17 regions, thereof 7 European regions and 10 further regional aggregates for the rest of the world (see Table 1). Concerning the European regions, they are separated into northern (NEU), eastern (EEU), southern (SEU) and western (WEU) Europe.

We make the methodological choice of keeping Greece (GRC) and Austria (AUT) as separate from the more aggregated EU regions, because these two countries represent cases with very different preconditions for a transition towards a carbon-free economy concerning economic performance and the electricity mix and therefore illustrate extreme cases.[2] GRC is currently a weak economy, facing high interest rates and is characterized by a high share of fossil fuels (>80%) in its electricity mix. In contrast, AUT represents a relatively strong economy, facing low interest rates, with a high share of renewables (>60%) in its electricity mix (EC, 2016).

The general functioning of the model is as follows. In each region, one representative household provides production factors (skilled labor, unskilled labor and capital) and

[2] We focus on the electricity mix, since the electrification of the economy seems to be a promising first option for switching to a pathway towards a low-carbon economy.

collects taxes. There are 15 production sectors (see Table 2), using inputs from each other (intermediate demand) in combination with production factors to create output. Factor and tax income is used to maximize final demand, implemented as nested constant elasticity of substitution (CES) functions, separately for private and public consumption. The production sectors use intermediate inputs and production factors in order to create output and maximize profits, also subject to nested CES production functions. Foreign trade is depicted via bilateral trade flows. Domestically produced commodities can either be exported or supplied to domestic markets. Imported commodities can substitute for domestically produced commodities, but only to a certain extent (following Armington, 1969). Hence, all economic agents (i.e. producers and households) are interlinked via domestic and international markets, making it possible to reveal economy-wide effects of a large scale expansion of renewable electricity.

A comparative-static CGE model[3] is used, and is calibrated to the monetary flows across producers and consumers for the year 2011, which represents the "benchmark" equilibrium. In the simulation scenario, this benchmark equilibrium is "shocked" exogenously (in our case by the introduction and employment of large-scale wind or solar power technology in the energy sector), leading to endogenous responses of producers and consumers in the sense that they maximize profits and consumption utility, respectively, under new circumstances. This leads to changes in demanded quantities and relative prices, until a new (long-term) equilibrium emerges. This new equilibrium is compared to the benchmark equilibrium, which reveals the long-term economy-wide consequences of the "shock" (the employment of large additional amounts of renewables). Note, that we do *not* compare two development pathways over time (e.g. baseline versus mitigation-scenario). Instead the analysis remains in the base year (2011), meaning that we compare two states of the economy to each other: One equilibrium representing the current status of the economy *without* an expansion/implementation of any new electricity technologies and another representing the economy if a new (more cost efficient) technology had been expanded/implemented early enough such that the new equilibrium were able to emerge by the base year. This approach is extensively used in the literature (see e.g., Ciscar et al., 2011; Halsnæs et al., 2007) and has the advantage of not requiring assumptions about the future development of economies, which would otherwise strongly influence results. Such an approach reduces the number of assumptions, uncertainties and possible inconsistency problems. Results are thus presented with respect to the year 2011. To be policy relevant, we use technological and cost characteristics of the new technologies as they are expected to develop by 2030.

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[3] Modeling the effects of a change in the economy (in this case, introduction of additional wind or solar generation, with/without system costs) for only one point in time

The new electricity generation technologies are implemented in the tradition of Böhringer (1998) and Böhringer and Rutherford (2008) via additional production sectors of a Leontief production function type, meaning that input component combinations are predetermined. Since each production input reflects a generation cost component, we calculate the levelized costs of electricity (LCOE) for each new electricity technology we want to implement and use the structure of the LCOE as unit cost structure of the new technologies in the CGE model (mapping the different cost components of the LCOE calculation to the model's commodities and factors). The LCOE are calculated as defined in eq (1),

$$LCOE = \left(\sum_{t=1}^{n} \frac{I_t + M_t}{(1+r)^t}\right) / \left(\sum_{t=1}^{n} \frac{E_t}{(1+r)^t}\right) \qquad (1)$$

with I_t denoting investment expenditures in year t (including financing costs), M_t operation and maintenance costs, E_t electricity generation, r the weighted average costs of capital (WACC) and n the lifetime of the system.

In the analyzed scenarios, we assume that new renewable electricity replaces a certain share of conventional electricity (given exogenously by scenario target share assumptions). Since the model calculates in monetary terms, the physical 1:1 replacement (kWh) is not equivalent to the replacement in monetary units (in this case, €) whenever generation costs per physical unit between the new and the conventional technology differ. In other words, depending on whether the new technology is more or less expensive than the conventional technology, replacing one kWh might increase or decrease the monetary value of electricity to be produced. Thus, we calculate the *value* shares of the new and the conventional electricity for the final electricity production mix (combining conventional and new renewable electricity). as follows.[4] Concerning investments, we assume that new investments in renewables crowd out other

[4] The monetary value (V) of the newly introduced electricity (w for "wind") is given as $V_w = T * LCOE_w$ with T being the target amount of electricity to be replaced by the new technology in physical units (kWh). Equivalently the monetary value of conventional (c) electricity to be replaced is $V_c = T * LCOE_w * 1/r$ with $r = LCOE_w/LCOE_c$ being the generation cost ratio between the new and the conventional technology. Defining $\bar{Y}$ as the total electricity output value in the benchmark equilibrium (which is assumed to be generated by technology c), the value share for the new technology is calculated as $\theta_w = V_w/\bar{Y}$ and the value share for the conventional technology as $\theta_c = (\bar{Y} - V_c)/\bar{Y} = 1 - (V_c/\bar{Y})$. Whenever $r > 1$, the new technology has higher generation costs, meaning that $\theta_n + \theta_c > 1$, implying that overall generation costs increase, and thus also the final market price of electricity. Whenever $r < 1$, the opposite is the case. The new and conventional electricity outputs are combined into a single wholesale market electricity commodity of value $Y = \bar{Y}(\theta_n + \theta_c)$.

investments[5], meaning that the economy-wide total investment volume stays constant, but has a different composition. The alternative would be to cut consumption (and thus welfare) during the investment phase for financing purposes. However, we might also argue that when replacing conventional power plants with PV or wind plants, less investment is necessary in the residual system, meaning that overall investment volume might not change as substantially as assumed.

In addition to the implementation of new electricity technologies, we go beyond the state-of-the-art by explicitly including integration costs in the macroeconomic model. According to Hirth et al. (2015a) balancing costs and the costs of the "flexibility effect" (as a part of "profile costs") are both quite low, and as a result, we do not incorporate them. The single most important component of integration costs is the "utilization effect" (another part of "profile costs") but "grid-related costs" are also significant, thus we include these two components in the macroeconomic analysis. Since we follow a cost perspective in modelling the economy-wide effects, we burden the residual electricity system with costs from the "utilization effect". This is implemented in the CGE model explicitly as capital cost markups (cf. Carrara and Marangoni, 2016), resulting in a lower capital efficiency of generation of conventional electricity. In other words, more capital input per unit of output is necessary, or equivalently, less output can be generated when holding capital input constant, which translates into a higher price. "Grid-related costs" are modelled explicitly as higher investment costs, adding to the capital costs of new installations.

[5] Uniformly, sectoral investment demands are weighted by their share in the benchmark investment structure.

Table 1 Regions

Region label	Region	GTAP country code
NEU	Northern Europe	dnk, est, fin, lva, ltu, swe, irl, gbr, nor
WEU	Western Europe	bel, fra, deu, lux, nld, xef
AUT	Austria*	Aut
EEU	Eastern Europe	bgr, cze, hun, pol, rou, svk, svn
SEU	Southern Europe	hrv, cyp, ita, mlt, prt, esp
GRC	Greece**	Grc
REU	Rest of Europe	alb, che, xtw, xer, xee
CHN	China	Chn
IND	India	Ind
CAN	Canada	Can
USA	United States of America	usa, xna
ROI	Rest of Industrialized countries	aus, nzl, jpn
ECO	Emerging economies	blr, rus, ukr, kaz, kgz, xsu, arm, aze, geo, hkg, pak, bra, mex, zaf, kor, twn, tur, idn
LAM	Latin America	arg, bol, chl, col, slv, hnd, pry, per, ury, xsm, cri, gtm, nic, pan, xca, dom, jam, pri, tto, xcb
OIGA	Oil and Gas exporting countries	bhr, irn, isa, kwt, jor, oma, qat, sau, are, xws, egy, mar, tun, xnf, nga, xac, ecu, ven
RASI	Rest of South- and Southeast-Asia	xea, brn, khm, lao, mys, phl, sgp, tha, vnm, xse, bgd, lka, xsa, xoc, npl
AFR	Africa	cmr, civ, gha, ken, mng, nam, ben, bfa, gin, tgo, rwa, sen, xwf, xcf, eth, mdg, mus, moz, mwi, tza, uga, zmb, zwe, xec, bwa, xsc

**representing a relatively strong economic region with a high share of renewables in electricity generation (>60%); **representing a currently weak economy, facing high interest rates, with a high share of fossil fuels in the electricity mix (>80%)*

Table 2 Production sectors

Sector label	Sector description
P_C	Refined oil and coal products, processing of nuclear fuel
ELY	Production, collection and distribution of electricity
I_S	Manufacture of basic iron and steel, Casting of iron and steel
NMM	Manufacture of other non-metallic mineral products
PPP	Manufacture of paper and paper products, Publishing and printing
CRP	Manufacture of basic chemicals, other chemical products and rubber and plastic products
TEC	Tech industries
FTI	Food and textile industries
SERV	Other services and utilities
TRN	Transport services
EXT	Other mining, forestry and fishery
COA	Mining and agglomeration of hard coal, lignite and peat
OIL	Extraction of crude petroleum
GAS	Extraction of natural gas
AGRI	Agriculture

4.2. Expanding wind power

4.2.1. Framework and scenario setting

EU energy and climate policy is characterized by higher target shares of renewables in national energy mixes. Wind power is expected to play an important role to reach these targets, with different potentials in different European regions. For our economy-wide analysis we follow the "Wind Energy Scenarios for 2030" (EWEA, 2015). In the EWEA's "central" scenario wind power capacities in the EU are expanded such that 24.4% of the EU's electricity demand is covered by wind power by 2030 (EWEA, 2015). We thus model a replacement of current conventional electricity by wind power to reach this target in the EU.[6]

The EWEA scenario has been used here for its breakdown of projected wind generation capacities to national levels. Other scenarios, such as the OECD/IEA's "New policies" or "450 ppm scenario" (OECD/IEA, 2013), or those of the Global Wind Energy Outlook (GWEC, 2014) do not go so far as to specify a national-level breakdown of new generation capacity, thus limiting their use for our study. The "central" EWEA scenario was selected due to its projections of total European installed capacity in 2020 and 2030, which closely correspond to the 450 ppm scenario, which limits emissions globally to stabilize CO_2 levels at 450 ppm. The scenario does not assume any introduction of new technologies, and current technology is forecasted to realize cost reductions and efficiency gains comparable to what is currently observed. The OECD/IEA scenario projects total installed wind capacity in 2020 to be 195 GW, rising to 314 GW by 2030, which closely corresponds to the EWEA's projected capacities of 192 and 320 GW in 2020 and 2030 respectively. With this in mind, we utilize the EWEA's projections, which is more optimistic than others regarding assumptions of an implementation of high carbon prices[7] or new policies beyond what is already planned. However, we acknowledge that the closely related OECD/IEA scenarios also seems feasible from a technological and policy standpoint.

The (2011 share of wind power (2011 is the models base year) of overall electricity demand in the EU is 5.4% (EC, 2016), meaning that a gap of 19% needs to be closed to reach the target of 24.4%. In our scenario this means an additional supply of 634 TWh wind power, replacing the same amount of conventional electricity.[8]

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[6] Note, that we deploy a portfolio approach, meaning that the regional targets are imposed exogenously and are not dependent on the choice of policy instrument for their implementation.
[7] carbon prices rise to a significant level only after 2035 in this scenario, which is beyond the time horizon of the underlying analysis. This potential inconsistency can therefore be neglected.
[8] Note, that conventional electricity (represented as the current regional electricity mix) is replaced by a new, wind power technology. The current EU average capacity factor of wind is 25%, whereas in 2030 it is assumed to be 28%, with factors of up to 30% in Northern and Western Europe (EWEA, 2012 and EWEA, 2015).

The absolute regional contributions to this expansion by 2030 are calculated on the basis of EWEA's (2015) central scenario national expansion targets and are given in Table 3 (both in absolute terms and as a share of regional electricity generation in 2030). The given wind targets are most ambitious for Greece (35% of generation) and NEU (27%), but also for Austria and WEU (20% and 19% respectively). Table 3 also gives the regional capacity factors as well as the resulting necessary additional capacities.

Table 3 Regional contributions of wind power expansion [%], additional TWh supplied, regional capacity factors and additional necessary capacity [GW] until 2030 (source: EWEA, 2015 and own calculations)

	NEU	WEU	AUT	EEU	SEU	GRC
Regional contributions to expansion	29%	42%	2%	8%	15%	3%
Capacity factor	30%	29%	24%	25%	24%	24%
Additional capacity [GW]	69.09	105.44	6.29	24.48	45.60	9.83
Additional wind electricity supply targets [TWh]	184.27	266.26	13.22	53.74	95.90	20.67
Wind power share in electricity generation	27%	19%	20%	12%	15%	35%

4.2.2. Technology costs

Investment costs

Following IRENA, (2016), investment costs for wind power are assumed to be € 960 per kW in 2030, with a lifetime of 25 years, which represents a middle range of estimates for the region.[9] Total regional investment volumes are calculated by multiplying the required additional capacities with the assumed investment costs per kW. Since we are interested in the long term effects, the costs are divided by the lifetime (reflecting only the annual depreciation). The resulting annual long-run regional (re-)investment volumes are given in Table 4. Within the CGE model new investments are crowding out other investments[10], meaning that the economy-wide total investment volume stays constant, but has a different composition.

Generation costs

Generation costs, calculated as the LCOE, consist of two components: Operation and maintenance (O&M) costs as well as capital costs. O&M costs are assumed to be € 50 per

[9] In this work we limit our assessment to onshore wind power plants, since this technology is less costly than offshore wind.
[10] Uniformly, sectoral investment demands weighted by their share in the benchmark investment structure.

kW (IRENA, 2016). We assume that 40% of O&M are material costs and 60% are labor costs. To transform O&M costs into generation costs in €/kWh, we use the regional capacity factors given in Table 3.

For the calculation of capital costs we use the total necessary regional investment volume together with the weighted average costs of capital (WACC) by region based on Angelopoulos et al. (2016). The regional WACC are given in Table 4 for a high WACC case (as it currently prevails) as well as for a low WACC case, reflecting a potential de-risking by reaching the currently prevailing WACC in WEU. The WACC are relatively high for Greece (12%), EEU and SEU (both 9%), whereas for NEU, WEU and Austria the WACC range between 5%-7%.

Table 4 Assumptions for the calculation of regional generation costs of wind power

	NEU	WEU	AUT	EEU	SEU	GRC
WACC high (Angelopoulous et al. 2016)	6.83%	5.23%	6.50%	9.00%	9.00%	12.00%
WACC low	5.23%	5.23%	5.23%	5.23%	5.23%	5.23%
Total investment volume including grid-related costs **[Bn. €]**	76.68	117.04	6.98	27.17	50.62	10.91
Operation and maintenance [€/kW]	50	50	50	50	50	50

In addition, we include integration costs into the model, which can be split up into three components (cf. Hirth et al., 2015a). As discussed in the literature, *balancing costs* emerge due to uncertainty and forecasting errors, leading to deviations from planned generation schedules. Second, *grid-related costs* emerge due to geographical reasons, transmission constraints and losses. Third, *profile costs* emerge due to increased ramping and cycling of thermal power plants (the "flexibility effect") and due to a reduced utilization of thermal plants (the "utilization effect"). According to Hirth et al. (2015a) balancing costs and the costs of the flexibility effect are very small, thus we disregard these two parts. The single most important component of integration costs is the "utilization effect" and also the grid-related costs are significant. We thus include these two components in the macroeconomic analysis, as described below.

Following Hirth et al. (2015a) and Hirth (2015, 2013) who estimate the utilization effect between €15-20 for each MWh of generated variable renewable electricity (VRE) for penetration rates <40%, we assume €15/MWh of additional costs.[11] Since we follow a cost perspective in the modelling of the economy-wide effects, we burden the residual electricity system with these costs, implemented in the CGE model as lower capital efficiency in the generation of conventional electricity. In other words, more capital input per unit of output is necessary, or equivalently less output can be generated when

[11] Since the thermal capacity mix is expected to adjust until 2030, we use the lower bound here.

holding capital input constant. This effect translates into a higher price for conventional electricity.

Grid-related costs are estimated in the literature to be between €50-200/kW (taken from Hirth, 2013, 2015; Hirth et al., 2015a; Holttinen et al., 2011). We thus assume €150/kW are added to the previously stated €940/kW investment costs, leading to total investment costs of €1,110/kW.

When conventional electricity is replaced by wind power, relative generation costs between those two types of electricity are important. Figure 8 shows the comparison across the current (2011) electricity mix to be replaced (based on EC (2016); ECOFYS (2014)) and the wind power generation costs for 2030 with different combinations of assumptions for WACC and whether integration costs (component grid-related costs) are included.[12] We clearly see that, future wind generation will be competitive in most regions (NEU, WEU, EEU, SEU) with generation costs between €0.05-0.08/kWh, however the combination of high WACC and including integration costs can also lead to cases where wind is not competitive (Austria and Greece). When lowering the WACC sufficiently – by a potential de-risking of investment (discussed in Section 6) – generation costs drop to competitive levels also in these cases.

The highest generation costs emerge in Greece (0.09€/kWh), the lowest in NEU and WEU (0.05€/kWh). Generation costs in NEU and WEU are not only lower because of lower WACC, but also due to higher capacity factors (capacities can be used more efficiently, meaning that the cost for one kWh are lower). Capital cost shares estimated with our methodology range between 60%-75%, which is relatively high compared to current conventional electricity generation, with capital costs shares between 20%-40% (Aguiar et al., 2016).

[12] Note that costs from the utilization effect are not shown here, but would increase the costs of the current mix (conventional)

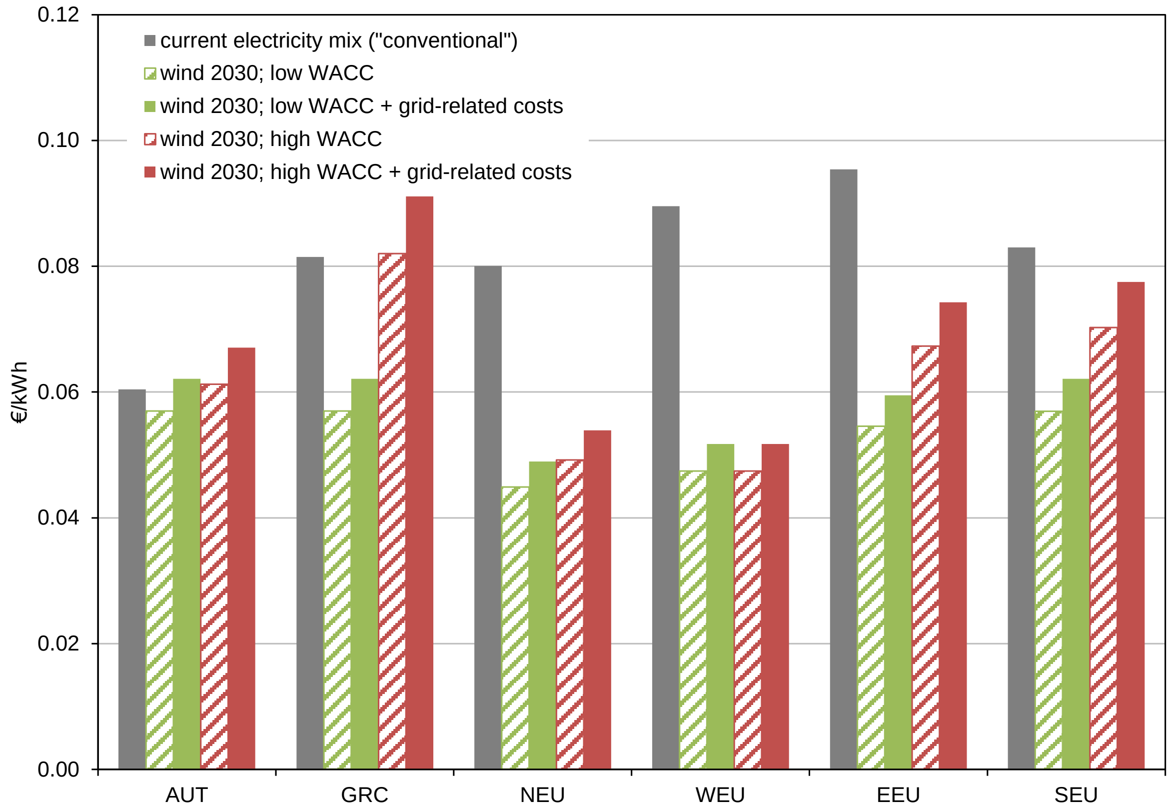

Figure 8 Comparison of LCOE between current electricity mix (2011) and wind power in 2030 with low and high WACC as well as with and without grid-related costs.

5. Expanding photovoltaics

5.1. Framework and scenario setting

We follow the same EU-wide target as in the wind-expansion scenario but apply it to PV (as the EWEA does not specify a similar scenario for solar PV), in order to make the analyses of wind versus PV-expansion comparable. We thus assume that the share of PV of EU's electricity demand is 24.4% by 2030.

The current[13] (2011) share of solar power of overall electricity demand is 1.4% (EC, 2016), meaning that a gap of 23% needs to be closed to reach the target. In our scenario this means an additional supply of 766 TWh from PV, replacing the same amount of conventional electricity.[14] The necessary regional PV capacity expansion is based on calculations from a PV-insolation optimization model (based on Grossmann et al., 2013).

Table 5 summarizes the data used for this part of the analysis. The highest contribution to the expansion of PV capacity makes SEU (due to higher insolation and due to size) but also considerable shares are located in NEU, EEU and WEU (also due to a scale effect). PV capacity factors vary between 11% (northern regions) and 18% (southern regions) and are thus lower than for wind (mainly due to the fact that PV is inactive during night). The additional generation in terms of TWh leads to PV generation shares of up to 91% (in Greece).

Table 5 Regional contributions of PV expansion [%], additional TWh supplied, regional capacity factors and additional necessary capacity [GW] until 2030 (source: own calculations)

	NEU	WEU	AUT	EEU	SEU	GRC
Regional contributions to expansion	19%	12%	3%	16%	42%	7%
Capacity factor (Grossmann et al., 2013)	11%	13%	13%	13%	18%	17%
Additional capacity [GW]	144.77	82.52	21.71	108.39	202.79	36.40
Additional PV electricity supply targets [TWh]	141.81	94.43	25.03	126.46	324.67	54.06
PV share in electricity generation in 2030	21%	7%	38%	28%	49%	91%

[13] Since the CGE model's base year is 2011, we take 2011 to describe the "current" state.
[14] Note, that conventional electricity (represented as the current regional electricity mix) is replaced by a new PV technology.

5.2. Technology costs

Investment costs

For 2030 we assume PV full installation costs of €740/kW by 2030 which is the upper bound of possible future cost estimates by IRENA (2016). Alternatively, we could follow a learning curve approach, assuming a 20% cost reduction every 2 year (assumed by Liebreich (2016)), which would lead to €270/kW by 2030, however, as we are not sure if such learning curves will persist into the future under such expansion, we use the value from IRENA (2016) of €740/kW. The resulting total investment volumes are given in Table 6. Economic lifetime is assumed to be 25 years (as in the discussion on cost assumptions in Section 4).

Total regional investment volumes are calculated by multiplying the required additional capacities with the assumed investment costs per kW. Since we are interested in the long term effects, the costs are divided by the lifetime (reflecting only the annual depreciation). The resulting annual long-run regional (re-)investment volumes are given in Table 6. Within the CGE model new investments are crowding out other investments, meaning that the economy-wide total investment volume stays constant, but has a different composition.

Generation costs

Generation costs, calculated as the LCOE, consist of two components: Operation and maintenance (O&M) costs and capital costs. Following IRENA (2016), O&M costs are assumed to be €5/kW, with 20% of O&M assumed to be material costs and 80% labor costs. To transform O&M costs into generation costs in €/kWh, we use the regional capacity factors given in Table 5.

For the calculation of capital costs we use the total necessary regional investment volume together with the weighted average costs of capital (WACC) by region. Concerning WACC, we follow two scenarios: In the high-WACC scenario we assume the currently prevailing WACC for wind (Angelopoulos et al., 2016), but lower it by 20% because of the lower development, technical, and yield risks of PV projects (Ecofys, 2017), while national policy and economic risks remain. The WACC for the high scenario are slightly lower than current WACC (see e.g. Ecofys 2017), which also reflect the effects of the current economic crisis. In the low WACC scenario we assume a potential economic de-risking, leading to the currently prevailing WACC of WEU in all regions. Table 6 shows the WACC used for the two scenarios.

Table 6 Assumptions for the calculation of regional generation costs of PV

	NEU	WEU	AUT	EEU	SEU	GRC
WACC high	5.47%	4.19%	5.20%	7.20%	7.20%	9.60%
WACC low	4.19%	4.19%	4.19%	4.19%	4.19%	4.19%
Total investment volume [Bn. €]	119.27	208.23	9.84	65.72	71.08	6.90
Operation and maintenance [€/kW]	5.0	5.0	5.0	5.0	5.0	5.0
LCOE using high WACC [€/kWh]	0.06	0.05	0.05	0.06	0.04	0.06
LCOE using low WACC [€/kWh]	0.05	0.05	0.05	0.05	0.03	0.04

Also in the analysis for PV we include the most important components of integration costs (see section 4.2.2 for details). Regarding the "utilization effect" we assume €15 for each MWh generated by PV, which accrue to the residual conventional electricity system (Hirth 2013, 2015). For grid-related costs we assume €150/kW, which are added directly to the previously stated €740/kW investment costs, leading to total investment costs of €890/kW (Hirth 2015, 2013, Hirth et al 2015a, Holttinen et al. 2011)

Figure 9 shows the comparison across the current (2011) electricity mix to be replaced (based on EC (2016); ECOFYS (2014)) and the PV electricity generation costs for 2030 with different combinations of assumptions for WACC and whether integration costs (component grid-related costs) are included.

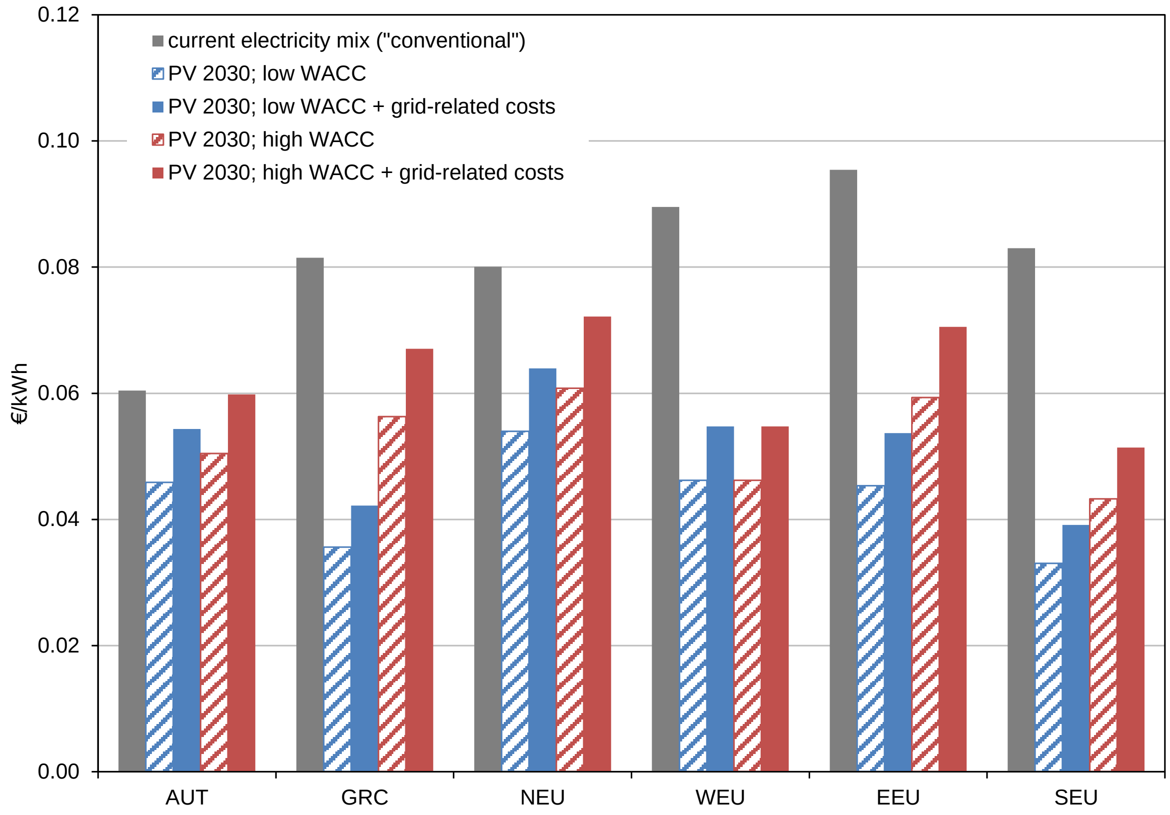

Figure 9 Comparison of LCOE between current electricity mix (2011) and PV electricity in 2030 with low and high WACC as well as with and without grid-related costs.

We clearly see that future PV electricity will be competitive in all regions. Even when integration costs are included and high WACC are assumed, LCOE range between €0.05-0.07/kWh.

The highest generation costs emerge in NEU (0.07€/kWh), the lowest in SEU and WEU (0.05€/kWh). The relatively high costs in NEU can be explained by the prevailing low capacity factor, while the low costs in SEU are a result of the prevailing high capacity factor overcompensating possibly higher WACC, whereas the low WEU costs are a result of the combination of moderate capacity factor and low WACC. Capital cost shares range between 90%-95%, which is relatively high compared to current conventional electricity generation, with capital costs shares between 20%-40% (Aguiar et al., 2016), and also much higher compared to wind, with shares between 60%-75%.

Note that in all cases, PV is less costly than the current mix using costs of €740/kWp and lifetime of 25 years. Alternatively, we could follow the learning curve estimates of Liebreich (2016), leading to only €270/kW by 2030.

6. Economy-wide effects from wind and PV

6.1. Effects on the electricity price

There are two major driving forces determining the direction of macroeconomic effects. First, it is the *relative capital intensity* of renewable electricity generation, compared to the conventional electricity which is replaced. In all regions, PV, just like wind electricity generation, is more capital intensive than the conventional electricity generation. Thus, due to capital scarcity, capital rents (i.e. the price of capital) increase, making renewable electricity generation actually more expensive than in the technology cost descriptions of sections 4.3.2 and 5.2. The second driving force is the *relative generation cost* between the renewable technology in question and conventional electricity (as shown Figure 8 and Figure 9). The actual electricity which is supplied at the market is a combination of the new renewables and the benchmark mix (which is itself a combination of conventional electricity and previously-installed renewables in the GTAP model's base year of 2011). Hence, whenever renewable electricity generation is cheaper than the previous mix of electricity generation, the modeled effect on would be a lower market price for electricity, and vice versa (when renewable electricity generation is more expensive, the market price for electricity would be higher). Note that additional integration costs also increase the generation costs of conventional electricity (and therefore its price) due to the utilization effect, which in turn increases the final market price of electricity. In addition, the *level of penetration* of renewable electricity (expressed as share of the total electricity mix) co-determines the strength of the effect.

When integrating the region-specific renewable electricity generation costs and targets into the CGE model, these driving forces (*relative capital intensity*, *relative generation costs* but also the *utilization effect* and the *level of penetration*) interact and lead to different outcomes in different regions.

Figure 10 shows the effects emerging on the electricity market for the analyzed wind (a) and PV (b) expansions under the high-WACC assumption and including integration costs. In the benchmark equilibrium (i.e. without additional renewable electricity) the electricity price was calibrated to unity; hence the deviations from unity show percent-changes in relative prices after having expanded renewable electricity generation. Figure 10 thus shows the new equilibrium prices of conventional electricity, the respective renewable electricity and the eventual market price arising from the combination of both. In the following sections, we discuss relevant conclusions from both wind and solar in turn.

When wind is expanded, the market price in Austria and Greece is pushed up, since the LCOE are higher compared to the LCOE of the conventional regional mix (see Figure 10) , but the reasons why prices in these two regions are higher are very different. In Austria, the LCOE of the current mix is initially rather low in absolute terms (€0.06/kWh) due to a high share of hydropower, making it difficult for wind to compete (as it faces an

unfavorable cost ratio wind/conventional of 1.11 as a result), whereas in Greece, renewables are hindered by a high WACC, leading to high LCOE and to a generation cost disadvantage (a cost ratio wind/conventional of 1.12).[15] Interestingly, the market price in SEU also increases slightly, despite the clear cost advantage of wind. This effect is explained by the utilization effect, which drives up costs for conventional electricity, and thus the final market price.

In the case of PV expansion the eventual market price is below unity in all regions, except for Austria and NEU. In Austria it is due to the same reasons as in the wind expansion case, whereas in NEU it is the utilization effect, which drives up prices such that the new equilibrium market price is eventually higher as before the expansion, despite the cost advantage of PV compared to conventional electricity.

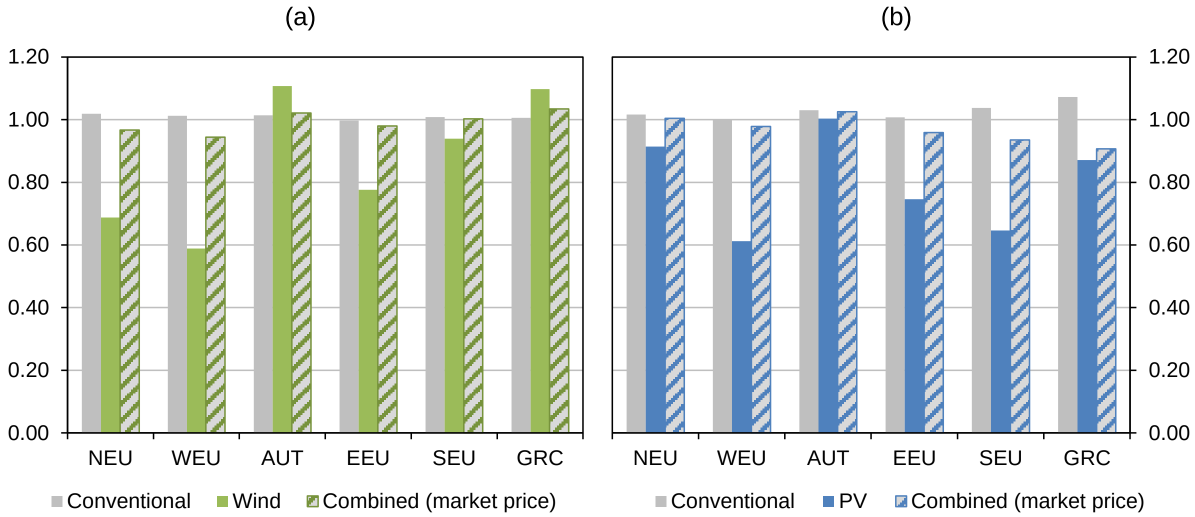

Figure 10 Relative electricity prices after the expansion of wind (a) and PV (b) in the high-WACC scenario, including integration cost (after economy-wide feedback effects)

6.2. Macroeconomic effects and de-risking

We now elaborate as to how the effects electricity market effects influence the rest of the economy. Figure 11 shows the price effects on the production factors skilled labor, unskilled labor and capital (for the high-WACC scenario, now with and without integration costs; see Figure 12 for the low-WACC scenario). With the expansion of wind/PV, the

[15] Note that in the CGE model the conventional electricity sector is incorporated as an average technology, representing the current electricity mix. In the underlying analysis we replace this average electricity technology with a new renewable generation technology. This means that relatively cheap renewables are also partly replaced by new renewables, meaning that we might underestimate the competitiveness of the new technology, as its LCOE should be compared to the technology with the highest LCOE.

demand for capital increases and since factors are scarce, relative prices rise. Conversely, the relative price for labor decreases, as there is less demand. Hence, we observe higher capital rents and lower wages after having expanded wind/PV, since these technologies are relatively more capital-intensive than other renewables and conventional technologies (Al-Riffai et al. 2015).

When comparing across regions, the strongest effects emerge in Greece, with up to +9% capital rent increases and reductions in wages for unskilled labor of up to -7%. The relatively strong magnitude of effects in Greece is because of a higher capital cost share (due to high WACC) and due to ambitious penetration targets. When comparing across technologies, we see that PV triggers stronger effects since it is even more capital intensive than wind. In the PV expansion case capital rents increase by up to +9% and wages decline by up to -7%, whereas in the wind expansion case the maximum increase in capital rent is +3% and the strongest decline in wage is -3%. We also observe that when integration costs are included, the effects on factor prices are slightly stronger, since the utilization effect additionally drives up capital prices. Also grid-related costs are associated with higher capital demand and thus higher prices.

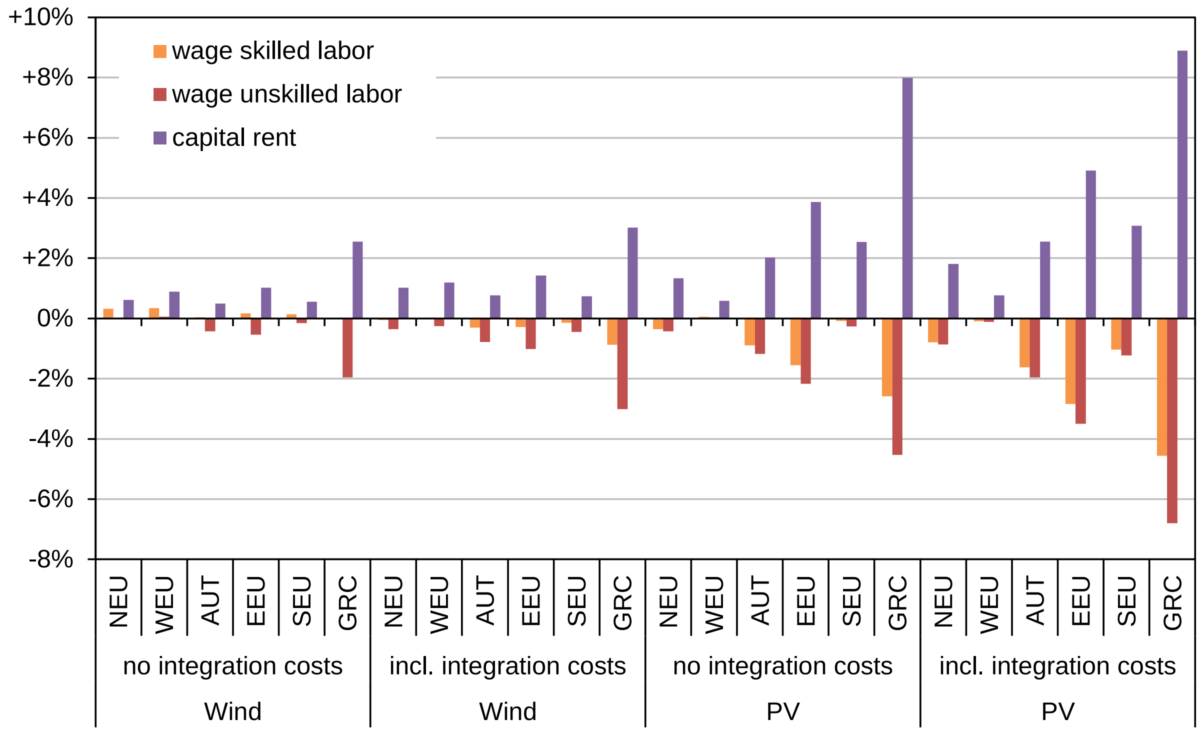

Figure 11 Changes of factor prices after the expansion of wind and PV (high-WACC scenario)

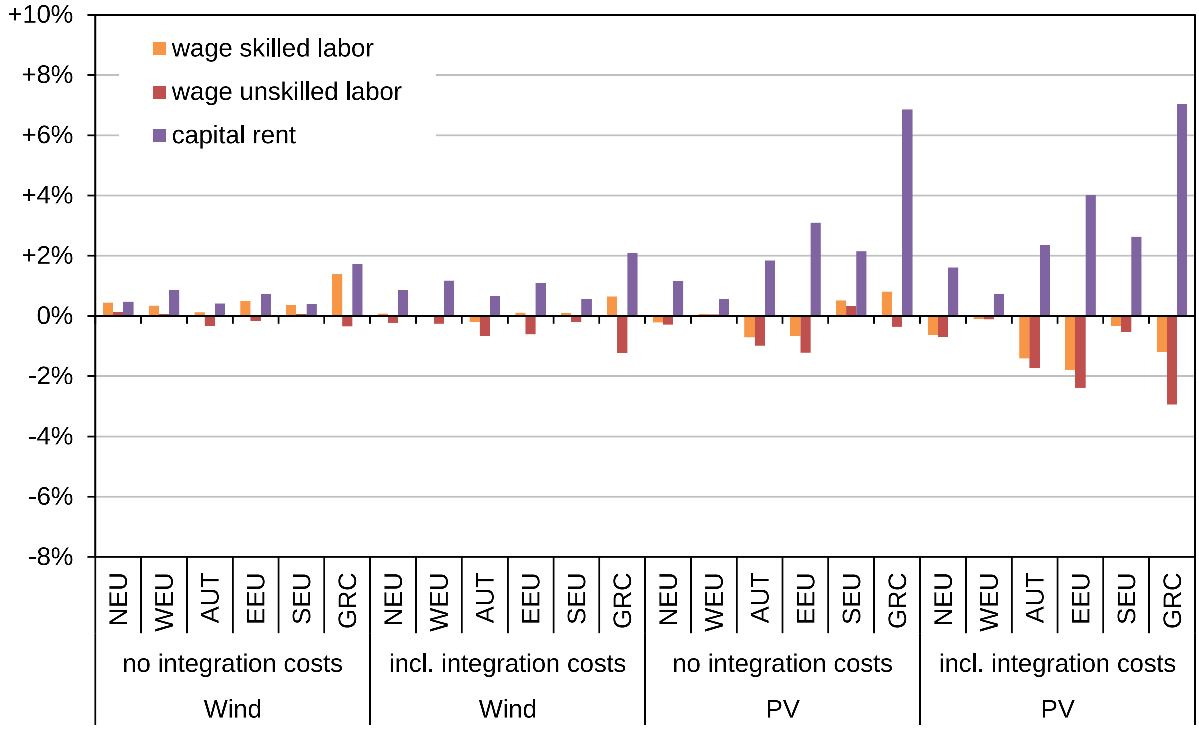

Figure 12 Changes of factor prices after the expansion of wind and PV (low-WACC scenario)

The effects on GDP are positive in all regions for both technologies and under both the low and the high-WACC scenario. However, welfare (measured as the Hicksian Equivalent Variation[16]) is only higher in regions where electricity can be supplied at lower prices compared to the case prior to the expansion of renewable electricity. In those regions where electricity is supplied at higher prices, welfare declines. Note that the different signs between GDP and welfare effects are crucial. GDP effects also include price increases meaning that in "real" terms GDP does not necessarily increase, but even declines in some cases. We therefor do not focus on GDP effects but rather on welfare, since this indicator "corrects" for price effects and represents the change in utility out of changed consumption quantities under new circumstances (prices).

Figure 13 shows the regional welfare effects for wind and PV expansion with and without integration cots under the high-WACC scenario. First, we see that welfare effects are mostly positive, except for those cases, where the electricity market price is increasing due to an expansion (compare Figure 10). Second, we observe that the positive welfare effects are much stronger when expanding PV, especially in those regions where PV has the highest potential and penetration (Greece and SEU), but also in EEU where

[16] Defined as "the change in income which, if it took place at [p0] prices, would have the same effect on satisfactions as is produced by the change in prices from [p0] to [p1]" (Hicks, 1942)

consumption is relatively fossil fuel intensive and since fossil fuels are getting cheaper (since there is less demand for it for the generation of electricity) free income can be spent on other consumption goods and services which in turn increases welfare. Third, we see that when including integration costs, the possible welfare gains are much lower and might even turn negative (e.g. for PV in NEU and Austria or for wind in Greece and SEU).

When looking at the low-WACC scenario (Figure 14), we see that a potential de-risking can have substantial additional positive welfare effects. The strongest effects can be seen in Greece (wind: +0.3%-points higher welfare, PV: +0.9%-points), since the spread between the low and the high WACC is the largest. However, there are still cases in which neither wind nor PV can compete with the conventional mix (Austria).

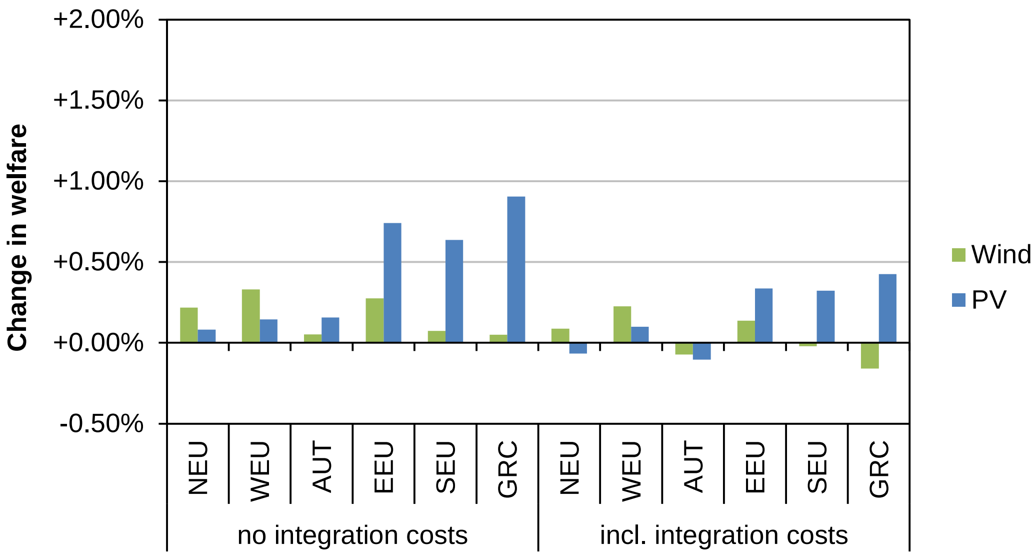

Figure 13 Welfare effects after the expansion of wind and PV (high WACC scenario)

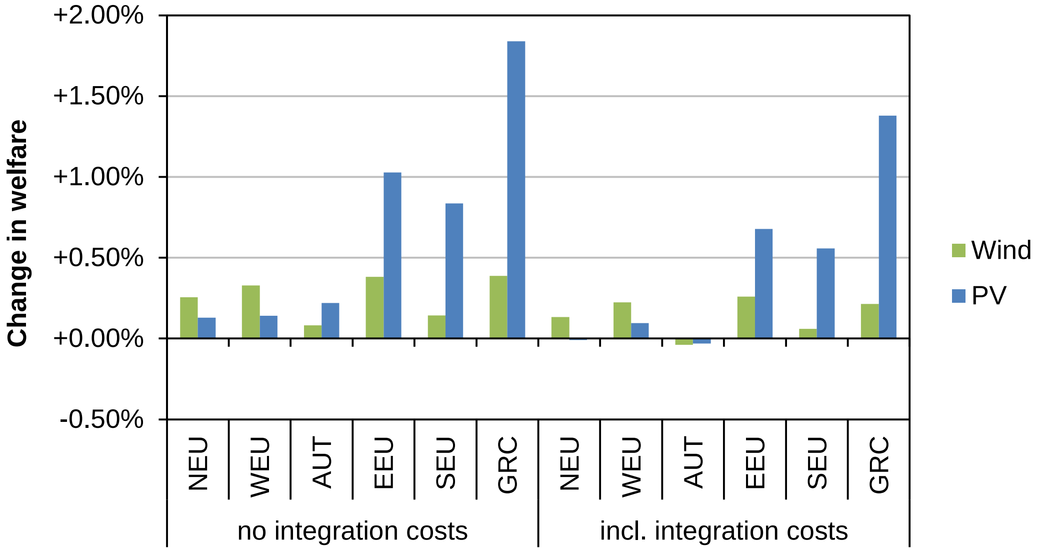

Figure 14 Welfare effects after the expansion of wind and PV (low WACC scenario)

6.3. Sensitivity analysis

For now we have analyzed the economy-wide effects under full employment of factors (labor and capital), which can be interpreted to be the relevant perspective in phases of an economic boom; this is the standard assumption in CGE models. However, since the economy-wide effects of the expansion of renewable electricity are strongly determined by relative price effects of capital, we carry out additional sensitivity analyses. Instead of assuming full factor employment, we assume that the economy is in a phase of recession (there is an "output gap"), where capital is idle. This means that in the case of an expansion of capital intensive renewable electricity generation, previously idle capital can now be used effectively. This relaxes the strict scarcity assumption, meaning that additional capital is available, and thus capital prices do not rise that strong than is the boom-case. In other words, new renewable investment no longer fully crowds out other investment, but the policy actually increases the overall capital stock of the economy over time, creating an additional production factor supply. Figure 15 shows the ranges of possible welfare effects, spanned by the combination of "boom and high-WACC" (minima) and "recession and low-WACC" (maxima); including integration costs. We see that when renewables are expanded during a recession, the possible positive welfare effects are stronger and that in those cases where negative welfare effects emerged, now also positive effects become possible.

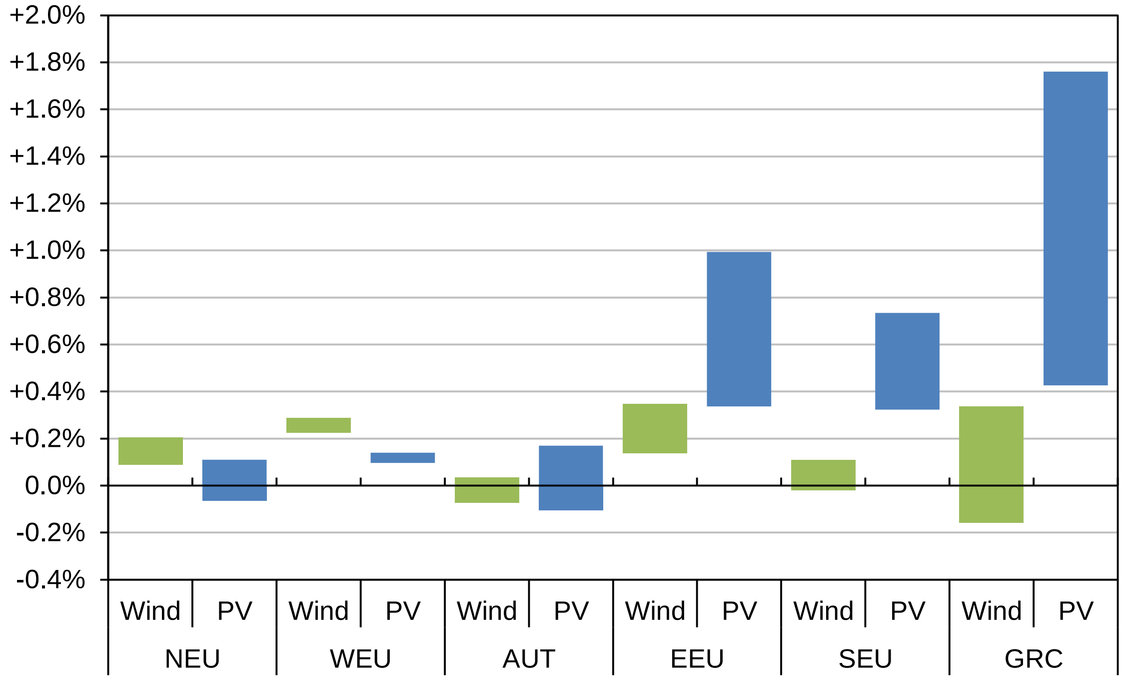

Figure 15 Ranges of possible welfare effects spanned by combinations of high/low-WACC and boom/recession-assumption (including integration costs). Lower ranges show the effects of "boom and high WACC" combinations, while upper bounds show the effects of a "recession and low WACC" combination.

6.4. Discussion and conclusions

This paper went beyond classical LCOE assessments of renewable energy expansion and showed the critical importance of incorporating macroeconomic effects and feedbacks for policy evaluation and design. Macroeconomic effects for scenarios of either wind or PV penetration targets of 24.4% of EU's total electricity generation have been analyzed by means of a global multi-regional multi-sectoral computable general equilibrium (CGE) model. We found that the direction of regional welfare effects (measured as Hicksian Equivalent Variation) depend on (i) relative costs of electricity generation technologies, (ii) relative capital intensity of generation technologies, and quite considerably on (iii) integration costs. In addition, the targeted regional penetration rates co-determine the magnitude of the effect.

When carrying out the analysis without integration costs, societal welfare effects are positive in all regions and for both technologies (+0.1% to +0.3% for wind expansion and +0.1% to +0.7% for PV expansion, even when assuming currently prevailing average costs of capital). We then considered two components of integration costs, grid- and profile-related costs, with the latter being governed by the utilization effect in the residual electricity system (i.e. lower rate of use of other existing generation capacity,

still required as a back-up). Upon inclusion of integration costs, the welfare effects are much smaller and in some cases even become negative (-0.2% to +0.2% for wind and -0.1% to +0.3% for PV). For PV expansion, this occurs in both northern Europe (NEU) and Austria. In these two regions, both generation technologies seem to be competitive from a bottom-up (LCOE) perspective, even when grid-related integration costs are accounted for, e.g. in the form of additional capital costs (see Figure 9). However, the macroeconomic welfare effect turns out to be negative (see Figure 13), due to two effects. First, additional costs as a result of the utilization effect drive up generation costs for the residual system (conventional power plants) consequently increasing the price of electricity. Second, due to the relatively high capital intensity of the new technologies (and PV in particular), capital prices also increase, leading to higher generation costs than anticipated from a bottom-up perspective. In other words, at high penetration rates of renewables the macroeconomic feedback effects can considerably increase generation costs. This is a crucial implication of renewable expansion which needs to be acknowledged in climate and energy policy evaluation and design.

We have also shown that when weighted average costs of capital (WACC) can be reduced in all regions to levels which we currently observe in Western Europe (WEU, about 5%), the LCOE of renewable electricity can be lowered to levels, where negative effects nearly disappear. De-risking of investments in renewable energies for example by more stable policy frameworks should thus be on energy policy agendas.

When comparing across the two technologies, wind and PV, we see differences in many ways. First, wind has a higher welfare improving potential in Western, Northern and Eastern Europe than in Southern Europe. PV on the other hand has higher potential in Southern and Eastern Europe than in Northern and Western parts. For the case of Austria, neither wind nor PV is welfare increasing, since these technologies compete with already relatively low generation costs (due to a high share of hydropower). Second, we have shown that, despite the higher absolute investment requirements of PV, possible positive welfare effects are much stronger for PV. Third, we found that the WACC plays a smaller role for PV than for wind, as PV is expected to get competitive even with relatively high WACC (which in the long run might increase trust in PV and thus reduce WACC).

Another crucial aspect of a possible large-scale expansion of renewable electricity is the resulting distributional effects within regions or countries. We observed an increase of income from capital whilst income from labor decreases; with stronger reductions for unskilled labor. This means that the positive welfare effects may be distributed very unevenly across the domestic population. Since PV is more capital intensive than wind, this distorting effect is stronger in the PV-expansion case. Policy makers thus have to think about ways to distribute possible welfare gains and losses evenly. One way could be the de-risking of investment (reducing WACC), which relieves pressure from the capital market and thus partly closes the gap between capital rents and wages.

Some points of the analysis need critical reflection. To begin with, the current version of the model represents the electricity sector as a single average generation technology, meaning that new wind and PV technologies compete with this average technology, and not the most expensive technology at the margin. As a result, we may underestimate the possible positive welfare effects of the expansion. One example is the case of Austria, where new technologies compete with relatively low average generation costs of conventional electricity due to the large share of hydropower in the current generation mix.

Secondly, future PV cost estimates are highly uncertain. The question of whether or not we can expect learning rates to continue at historically-observed levels (a 22% cost reduction with each global doubling of installed capacity; IRENA, 2016) is open. The costs of €740/kWp applied here are at the upper bound of numbers from the literature (IRENA, 2016), and it is still well above a learning curve-based estimation which would lead to less than €200/kWp in 2030 (derived from Liebreich, 2016).

An additional caveat is that there is no capital mobility across regions, meaning that in each region a separate capital market leads to region specific capital prices. However, additional sensitivity analysis showed that when there is perfect mobility on capital markets across the European regions, the effects are similar in magnitude, but slightly more positive in terms of welfare. Thus the results presented indicate lower bounds for welfare implications, i.e. in cases where positive welfare effects occur they tend to be larger when we allow for at least some capital mobility, or, respectively, negative welfare effects tend to be smaller.

Lastly, the modelling of investment is crucial. In the analysis we assumed that only the composition of investment changes, but the total investment volume stays constant ("crowding out"). This assumption might be questionable. The alternative would be to cut consumption (and thus welfare) during the investment phase for financing. However, we might also argue that when replacing conventional power plants with PV or wind plants, less investments becomes necessary in the old system, meaning that overall investment volume might not change substantially.

A very general point of discussion is the issue of decentralized versus centralized energy systems. In our analyses we implicitly assumed that there will be a wholesale market also in the future. However, the role of integration costs may decrease over the next years, if the energy system shifts form highly centralized to increasingly decentralized structures, and an integration of renewables into the wholesale markets may not be so important anymore. However also decentralized energy system may cause integration cost depending on the mix of technologies used (eg whether storage is included) and the resulting need for back-up capacities. The impacts on integration costs therefore need to be carefully assessed if decentralized solutions should not lead to business economic but also macroeconomic and societal benefits.

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