Are renewables profitable in 2030 and do they reduce carbon emissions effectively? A comparison across Europe

Bertsch, Valentin and Di Cosmo, Valeria

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Bertsch, V. *†   Di Cosmo, V.‡

Abstract

The European Union has set ambitious targets for expanding renewable energy to meet emission reduction goals. After a period of subsidy-driven investments, the costs of renewables decreased strongly and renewable support schemes shift towards more market-based approaches. We therefore analyse the market-based profitability of wind onshore and offshore and solar PV across Europe to determine where it is optimal to invest and understand which factors drive the profitability of investments. We use a power systems model to simulate the whole European electricity market in 2030. Using the renewables' revenues determined by the model, we calculate the profitability of each technology in each country. We also analyse how effective renewables are in terms of emission reduction. Investments are found not to be homogeneously profitable across Europe, i.e. cooperation between European countries can be expected to achieve the overall targets at lower costs than nationally-driven approaches. We also find that in many countries, wind onshore and solar PV are profitable by 2030 in absence of any financial support, whereas wind offshore does never seem profitable without support. Finally, RES expansion alone will not guarantee an effective reduction of CO_2 emissions.

Keywords: Renewable Energy; Renewable Energy Target; Renewable Electricity Target; EU Electricity Market; Profitability; Emission Reduction; Carbon Price; Carbon Price Floor

Highlights:

*Corresponding author. Email: valentin.bertsch@ee.rub.de, Chair of Energy Systems and Energy Economics, Ruhr-University Bochum, Germany

†Economic and Social Research Institute (ESRI), Whitaker Square, Sir John Rogerson's Quay, Dublin 2, Ireland.

‡Department of Economics and Statistics "Cognetti de Martiis", University of Turin, Lungo Dora Siena, 100 A, 10153 Torino TO, Italy.

- Profitability of solar PV, wind onshore and wind offshore compared across Europe
- Power systems optimisation model used to simulate whole European electricity market
- Wind onshore and PV profitable by 2030 without financial support in many countries
- Wind offshore not profitable without financial support
- RES deployment does not automatically guarantee effective reduction of emissions

Table 1: Nomenclature

Symbol	Explanation	Unit
Objective		
Γ	total generation costs	€
Parameters		
$\gamma_{g,f}$	generation costs of generator g using fuel f	€$/MWh_{el}$
ϕ_f	fuel price of fuel f	€$/GJ$
ϵ	CO_2 emission price	€$/t\ CO_2$
η_g	heat rate of generator g	GJ_{fuel}/MWh_{el}
σ_f	specific CO_2 content of fuel f	$t\ CO_2/GJ$
α_g	other variable operation costs of generator g	€$/MWh_{el}$
μ_g	max power output of generator g	MWh_{el}/h
χ	loss of load costs	€$/MWh_{el}$
ψ	surplus costs	€$/MWh_{el}$
$\delta_{c,t}$	power demand for country c at time step t	MWh_{el}/h
$\rho_{c,t}$	renewable power generation for country c at time step t	MWh_{el}/h
Variables		
$\Pi_{g,t}$	power output of generator g at time step t	MWh_{el}/h
$\Lambda_{c,t}$	system loss of load for country c at time step t	MWh_{el}/h
$\Xi_{c,t}$	system surplus for country c at time step t	MWh_{el}/h
Γ_g	total generation costs of generator g	€
X	total loss of load costs	€
Ψ	total surplus costs	€
Indices		
c	country index	-
f	fuel type index	-
g	generator index	-
t	time step index	-

1 Introduction

The European Commission (EC) and the European Council set ambitious targets for 2030 to reduce greenhouse gas (GHG) emissions from the energy sector and secure clean and efficient energy in the European Union (EU).[1] In 2014, EU countries agreed that by 2030, the share of renewables should be 27% of total energy consumption in order to achieve

[1]See EC Directive 2009/28, [1] and [2].

the overall target of 40% GHG emission reduction [3]. This target holds at the EU level, so all countries should work together either by reducing the energy demand or increasing generation from renewable energy sources (RES), to achieve the overall goals.

Electricity generation is one of the sectors affected by the EU targets together with transport, agriculture and industry, as it is one of the major sectors responsible for total emissions [4]. Following the track started with the 2020 targets on emission reductions, renewable electricity generation (RES-E) should increase to 49% of total electricity demand by 2030 in order to be consistent with the overall target on total energy demand, as noted by the Commission [3] in their own impact assessment analysis. In 2018, these targets were made more ambitious, as the target share of renewables on total energy consumption in 2030 has been increased to 32% of total energy consumption [5], setting the ground for the 2050 European carbon neutrality target.

The installed capacity in renewable energy has increased strongly during the last decade, when every EU country set up different incentives to promote the investment in renewable generation. There are several studies that focus on the costs and the regulatory changes needed to promote the investments in renewable energy. All these studies highlight that subsidies given to renewables are positively correlated with the investment in this type of generation in all EU countries. Papaefthymiou and Dragoon [6] and Held et al. [7] analyse the impact of increasing RES-E penetration in the EU system and focus on the associated distribution network costs. Other studies [8, 9, 10, 11, 12] analyse how regulation and subsidies are necessary to encourage the investment in renewable energy.

During the same decade, however, renewable power generation technologies have matured strongly. Until 2030, investment costs associated with renewables are expected to decrease further, making the investment in renewable energy more attractive to market participants [13]. As a result, renewable support schemes have begun to shift towards more market-based approaches in recent years [14]. A careful analysis of the market-based profitability of investments in renewable technologies therefore becomes more and more relevant. In the absence of subsidies, it is expected that natural resource conditions, including the availability of wind and solar irradiation with respect to which European countries differ quite strongly, become increasingly important as part of this analysis. Moreover, financial market conditions differ significantly between countries, which is expected to play an important role.

This work therefore focuses on addressing the following two overarching research questions:

- How profitable are renewables in the market across Europe and what are the major drivers of their profitability?
- How effective are renewables in reducing CO_2 emissions across Europe?

Despite the importance of the subject, there are not many studies focusing on the profitability or effectiveness of renewable technologies in 2030 or beyond, in particular when it comes to comparing countries across Europe. A review of methods adopted to optimally locate investments in renewables is provided by Tan et al. [15]. Duscha et al. [16] combined short and long term simulations to find the optimal technological and economical pattern to meet the emission targets up to 2050. The authors examine the impact of different RES targets on the EU economy and find that the Commission's overall renewable energy target should be a minimum target rather than the maximum level of RES. The authors show that a RES penetration going beyond the overall EU target results in higher economic benefits for the Union. As the investment costs of RES decrease over time, the authors highlight that new investments rely on convenient cost of capital, and the regulation should then focus on reducing that in the next years. Finally, the authors point out that offshore wind and tidal energy are not economically efficient, so subsidies would need to be provided in order to incentivise investments in these technologies if desired. Safarzyńska and van den Bergh [17] focus on the financial stability associated with the investment in renewables and find that investments in gas fired plants instead of renewable technologies would be beneficial in countries in which coal plants are still active and play a major role in generation. Finally, Knopf et al. [18] find that the cost-efficient share of RES-E to meet the European targets in 2030 ranges from 43% to 56%, raising the question about the profitability of new investments above the initial threshold of 49% identified by the Commission. However, no specific focus is given to the profitability of specific technologies.

In addition, several works focus on costs linked to RES projects and use the Levelised Cost of Electricity (LCOE) to assess the feasibility of renewable-driven electrified systems.[2] However, while being commonly applied, the use of LCOE in such a context is discussed controversially in literature. For instance, [22] as well as [23] emphasise that LCOE as a metric to assess the viability of investments focuses on the cost side only but is not able to capture effects such as the market value of different (renewable) generation technologies.

[2] See, among others [19],[20] [21].

Moreover, [24] highlights the limitations of approaches, such as the LCOE, which are based on uniform cost of capital assumptions across projects and countries.

In this work we therefore investigate whether the investment in specific renewable technologies is profitable across Europe. We focus on solar PV, wind onshore and wind offshore investments, as significant investments in additional hydro capacity are rather unlikely and limitations to the feedstock potential are found to limit the expansion of biomass for electricity only generation [25]. In particular, we compare several scenarios to determine under which conditions investment in renewables would be profitable in each country without additional financial support. For this purpose, we use a power systems model to simulate the market-based revenues of different renewable technologies across Europe. We then use the revenues and costs to calculate two different measures of profitability: the internal rate of return (IRR), which takes into account the (natural) resource-driven profitability of the investment in renewables and the net present value (NPV), which incorporates the cost of capital of the projects, which may vary across countries and technologies.

In a first step, we focus on the (natural) resource-driven aspects of profitability, i.e. we calculate the IRR without considering and comparing financing conditions and their impact on costs of capital between the countries [26, 27]. Although the importance of providing favourable conditions to credit access for green projects has recently been highlighted by [28], quantifying the cost of capital for several technologies in different countries is not easy, given the limited amount of information available [27]. While the cost of capital is available for almost all countries in Europe for wind onshore ([27], [29]), cost of capital for solar PV and wind offshore is available for much fewer countries only. In the absence of cost of capital information across Europe, the IRR therefore seems like the natural choice to compare the (natural resource-driven) profitability of RES investments across Europe - acknowledging that the IRR does not consider any information about financial market conditions.

In a second step, we then use the information provided by [27] to calculate the NPVs of the investments for those technologies and countries, where cost of capital data is available. The differing weighted average cost of capital (WACC) assumptions between technologies and countries account for the fact that investments in renewables incorporate technology-specific risks (such as learning experience - [30] and [27]) as well as country-specific risks and the international conditions of credit access ([26],[27]).

Finally, we use the power systems model's output to analyse and compare RES shares and emissions by country and discuss the determinants of CO_2 emissions as well as the effectiveness of renewables on reducing same.

The remainder of this paper is organised as follows. Section 2 describes the methodology and data used. Section 3 presents our results, which we discuss in section 4. Section 5 concludes.

2 Methodology and data

2.1 Methodology

We use the Artelys Crystal Super Grid power systems optimisation model to simulate the European electricity market in 2030 (EU28 plus Switzerland and Norway).[3] The objective function (eq. 1) of the model is the minimisation of the total generation costs Γ_g of all generators g (eqs. 2+3), loss of load costs X (eq. 4) and surplus costs Ψ (eq. 5) across the EU to meet demand $\delta_{c,t}$ in each country c at an hourly resolution t and subject to technical constraints of generators and interconnectors. Table 1 provides an overview of the nomenclature used within this paper.

$$min \quad \Gamma = \sum_g \Gamma_g + X + \Psi \tag{1}$$

$$\Gamma_g = \sum_t \Pi_{g,t} \cdot \gamma_{g,f} \tag{2}$$

$$\gamma_{g,f} = (\phi_f + \epsilon \cdot \sigma_f) \cdot \eta_g + \alpha_g \tag{3}$$

$$X = \sum_c \sum_t \Lambda_{c,t} \cdot \chi \tag{4}$$

$$\Psi = \sum_c \sum_t \Xi_{c,t} \cdot \psi \tag{5}$$

The model optimises the power outputs $\Pi_{g,t} \leq \mu_g$ of each generator g at each time step t considering a number of constraints for each generator such as μ constraints or ramping constraints, as well as interconnection constraints and using load $\delta_{c,t}$ and renewable gener-

[3] See: `https://www.artelys.com`. We thank Artelys for the provision of the software and their support.

ation $\rho_{c,t}$ time series data as exogenous input. The main decision variables are the power outputs $\Pi_{g,t}$ as well as the system loss of load $\Lambda_{c,t}$ and the system surplus $\Xi_{c,t}$ for each country c at each time step t. For further information on the model, please see Bossavy et al. [31].

In these simulations a competitive market is assumed across the EU (i.e. no market power and power plants bid their short run marginal cost) and we assume perfect foresight, whereby the model has full knowledge of all input variables such as demand and variable renewable generation output. This hypothesis does not allow us to investigate the potential beneficial effects of competition in mitigating anti-competitive behaviour in different markets, as noted by Neuhoff et al. [32]. The resulting market price is calculated as the marginal price at member state level and does not include any extra revenues from potential balancing, reserve or capacity markets or costs such as grid infrastructure cost, capital costs or taxes.

For the economic assessment, we first calculate the internal rate of return (IRR) for solar PV, wind onshore and wind offshore at member state level. We use the IRR to compare the (natural) resource-related profitability of investments across Europe and deemed the IRR to be most appropriate for this purpose.

The IRR is the interest rate i that leads to an NPV or annuity of €0 including the cash flows CF_t (revenues and expenses, including investments CF_0) over all time periods $t \in \{0, ..., T\}$ of an investment project, where T is the project's lifetime (see equation (6)).

$$NPV = \sum_{t=0}^{T} \frac{1}{(1+i)^t} CF_t \equiv 0 \tag{6}$$

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Second, where available, we use the WACC data provided by [27] to calculate NPVs (where the WACCs are inserted as i in equation 6) associated with the different renewable technologies. As noted previously, the WACC data provided reflects technology-specific as well as country-specific risks associated with renewable power projects.

As shown in Section 3.5, we consider different lifetimes of the projects (with our baseline being 20 years). Artelys calculates annual revenues based on the hourly generation by technology and country and hourly prices by country assuming marginal costs of zero for the considered technologies. Capital and fixed operational expenditures are considered ex-post and, together with the revenues calculated by Artelys, provide input to our IRR calculations according to equation (6). We consider the year 2030 as a 'snapshot' and assume that each technology (solar PV, wind onshore and wind offshore) in each country has the same revenue for each year of its lifetime. We acknowledge that this is a limitation. However, given that the main focus of our analysis is the comparison between countries across Europe, we expect that the impact of this simplification is limited.

2.2 Data

The input data for our analysis can be structured into three main categories: *a)* supply and demand data for modelling the European power system, *b)* fuel and carbon prices, and *c)* capital and fixed operational expenditures of the considered RES-E technologies.

a) Supply and demand data

The supply and demand input data to Artelys are largely based on Deane et al. [33]. This includes data on the generation portfolio and demand for the 28 European member states from the 2016 European Commission modelling of a Reference Scenario (PRIMES) of the future European Energy system.[4] The Reference Scenario is one vision of the European power system in 2030 based on business-as-usual assumptions, including full implementation of European climate and energy policies adopted by December 2014 to achieve a renewable electricity penetration of 49% in 2030 up from 27.5% in 2014.[5] Note that the 2030 portfolio in the PRIMES 2016 scenario does not exactly match the recent EU target to achieve 32% of renewables in final energy consumption by 2030 (see [34]). The projections used here are designed to meet a 49% target for renewable electricity.

[4]PRIMES is a partial equilibrium model that provides projections of detailed energy balances, both for demand and supply, CO_2 emissions, investment in demand and supply, energy technology penetration, prices and costs". The projections are set up in order to meet the EU 2016 targets on emissions for 2030 (see `http://ec.europa.eu/environment/archives/air/models/primes.htm`.

[5]The generation mixes of Switzerland and Norway are not included in the PRIMES scenario. Swiss data was developed based on data available from the Federal Department of the Environment, Transport, Energy and Communications (DETEC). Norwegian data was developed based on data available from the Norwegian government (see: `https://www.regjeringen.no`) for thermal power plants and the Norwegian water resources and energy directorate (NVE, see: `https://www.nve.no`) for renewables including hydro power.

Table 2: Installed RES capacity, MW, by country, 2030

Country	Wind Onshore	Wind Offshore	Solar	Hydro	Other Renewables
AT	4,545	0	2,821	13,756	815
BE	3,557	3,350	3,818	1,484	820
BG	2,122	0	2,572	2,338	101
CH	834	0	5,272	16,587	0
CY	229	0	529	0	11
CZ	488	0	2,391	1,109	274
DE	57,796	9,418	63,959	13,102	7,065
DK	4,134	2,318	838	10	2,870
EE	445	0	1	8	154
ES	29,824	64	24,564	16,795	1,923
FI	2,763	152	19	3,461	3,330
FR	23,717	7,055	25,382	28,803	4,350
GR	6,038	0	5,616	3,579	232
HR	682	0	686	2,190	29
HU	477	0	106	57	409
IE	4,003	131	19	587	208
IT	15,574	3	24,562	18,939	6,182
LT	467	0	74	116	139
LU	302	0	131	1,345	35
LV	238	48	2	1,589	108
MT	0	0	198	0	2
NI	1,525	500	4	0	133
NL	6,975	3,121	5,586	37	2,308
NO	1,000	0	15	30,495	155
PL	9,442	897	99	1,039	2,105
PT	6,275	28	2,172	9,971	693
RO	6,017	0	2,223	6,645	157
SE	9,013	0	88	16,742	3,161
SI	242	0	779	1,284	118
SK	19	0	680	1,725	332
UK	18,550	12,846	11,040	4,624	17,233
Total	217,292	39,930	186,243	198,416	55,451

In addition to the data of the PRIMES Reference Scenario, hourly wind power generation for each Member State was taken from Aparicio et al. [35]. Hourly solar profiles for each Member State were developed using NREL's PVWatts® Calculator web application, which determines the electricity production of photovoltaic systems based on system location and basic system design parameters. Wind and solar profiles on the one hand as well as demand profiles on the other hand are taken from the same meteorological year (2012) so as to account for the weather-related correlations between these profiles and ensure consistent model input. Installed capacity and hourly generation profiles are considered at a country level, so our model does not take into account the location of different generators within each country. Capacity factors and generation profiles are assumed to be representative of an 'average location' for each country and technology (solar PV, wind onshore and wind offshore). We acknowledge that this assumption is simplistic and that capacity factors typically decrease over time because of (i) wear and tear and (ii) reduced 'quality' of locations with increasing penetration as the 'best' locations are exploited first. At the same time, however, technological advances and repowering lead to increasing capacity factors. We assume that these competing effects even out and the overall generation for each country and technology is in line with the PRIMES scenario. Finally, our model includes the network interconnection capacities between EU countries, as described in ENTSOE [36] for 2030.

The installed RES capacities by country, which are taken from PRIMES, are summarised in Table 2.[6] In this paper, RES capacities include hydro and thermal RES, where the latter is the sum of biomass, geothermal and other renewables. Table 2 reveals that the installed renewable capacity is not distributed homogeneously across Europe. Countries in the South, such as Spain and Portugal, have a higher proportion of solar generation than countries like Belgium or Ireland. Northern countries are rich in wind generation, and Central European countries have a variable proportion of both resources.

b) Fuel and carbon prices

The fuel prices used in our analysis are taken from DECC [37] and summarised in Table 3. The generators' costs are based on fuel costs, emission costs and heat rates.[7]

Table 3: Fuel price assumptions, (€2010)

€/GJ	Nuclear	Coal	Gas (CCGT, OCGT, derived gas)	Oil	**Carbon**
Low	2.00	2.40	5.70	10.00	20.00
Baseline	2.00	2.90	8.50	14.80	37.00
High	2.00	3.70	12.30	21.50	40.00

Data source: DECC [37]. Exchange rate €/GBP=0.858

c) RES capital and fixed operational expenditures

As in Slednev et al. [38], capital and fixed operational expenditures are taken from Taylor et al. [39]. For 2015, their assumptions are 1,810 US$/kW for solar PV, 1,560

[6] Data on installed capacity for conventional generation are also taken from PRIMES and are summarised in the Appendix

[7] Production costs for power plant type i, inclusive of CO_2, are calculated as:

$$ProdCost_i = FuelPrice_i * HeatRate_i + ETS * (HeatRate_i * CO_2EmissRate_i) \tag{7}$$

The assumed CO_2 emission rates are 93.6 kg/GJ for coal, 55.9 kg/GJ for gas and 77 kg/GJ for oil.

US$/kW for wind onshore and 4,650 US$/kW for wind offshore translating into 1,629 €/kW for solar PV, 1,404 €/kW for wind onshore and 4,185 €/kW for wind offshore assuming an exchange rate of 1 US$= 0.90 €. For 2025, Taylor et al. [39] assume technology costs of 790 US$/kW for solar PV, 1,370 US$/kW for wind onshore and 3,950 US$/kW for wind offshore translating into 711 €/kW for solar PV, 1,233 €/kW for wind onshore and 3,555 €/kW for wind offshore. Given that our study focuses on 2030, we will use the assumptions for 2025 as baseline technology costs. However, we have also carried out the analysis using the higher 2015 cost values as a robustness check. Moreover, these assumptions will be varied in a number of additional sensitivity analyses the results of which are presented in section 3.4. In terms of fixed operating and maintenance costs, we assume 1% of the specific investment costs per year for solar PV and 2% for wind onshore and wind offshore. The lifetime of the investment is assumed to be 20 years for all considered technologies. Again, we will vary this assumption (see section 3.5) to explore the impact of longer/shorter lifetimes.

3 Results

We now present the results of our analysis. Section 3.1 provides an overview of the achieved RES-E shares by country and technology in 2030, whereas section 3.2 provides insights into the different technologies' profitability in each country. Subsequently, sections 3.3-3.5 illustrate the impact on the IRR when varying the assumptions in relation to fuel prices, technology costs and lifetime respectively. Finally, section 3.6 provides insights into the relation between RES shares and emissions.

3.1 RES-E shares

First, we calculate the renewable penetration using the model results. With our assumptions including the demand and generation portfolio from PRIMES, the share of renewable electricity generation (hydro, solar, wind, biomass and other renewables) is 49% of the total European electricity demand. This is in line with the recommendation by EU Commission Staff [40] to meet the EU 2030 target in relation to total energy demand.

Figure 1 examines the proportion between RES-E generation and demand for each EU country (plus Switzerland and Norway). Figure 1 shows that Switzerland and countries in Scandinavia, e.g., Denmark and Norway, have the highest RES-E over demand proportion. These countries are followed by Austria (driven by their hydro power capacities, similar to Norway and Switzerland), the UK and a couple of Southern-European countries such as Portugal (79%), Greece (66%) and Spain (57%). Figure 1 also shows that countries with a very high overall RES-E share but without significant hydro capacities (e.g., Denmark and the UK) have rather high shares of other (thermal) RES-E. Moreover, it shows that with very few exceptions, the wind onshore shares are higher than the solar power shares. Overall, Figure 1 reveals that the expected RES shares in 2030 differ significantly across Europe. Because of differing RES-E capacity factors (mainly influenced by the geographical and meteorological conditions) and wholesale electricity market price levels and structures, we also expect the profitability of RES investments to differ strongly between countries. As for all models of this kind, electricity prices in our model are largely determined by the fuel and carbon prices assumed so they change accordingly with our assumptions in the different scenarios we considered. We assume that interconnection capacities between the countries have been realised according to the 10 year network development plan (TYNDP). As a result, electricity may flow between the EU countries, leading to price convergence across the states. Thus, for our baseline assumptions, electricity prices range between 60 and 70 €/MWh for all countries, with the exception of France (where prices are lower - mainly because of nuclear power) and Poland (where prices are higher - mainly because of old coal power).

In the following subsections, we therefore analyse the profitability of solar PV, wind onshore and wind offshore according to the PRIMES model based on their economic performance in 2030 for each member state aimed at understanding which countries have favourable conditions for which technologies.

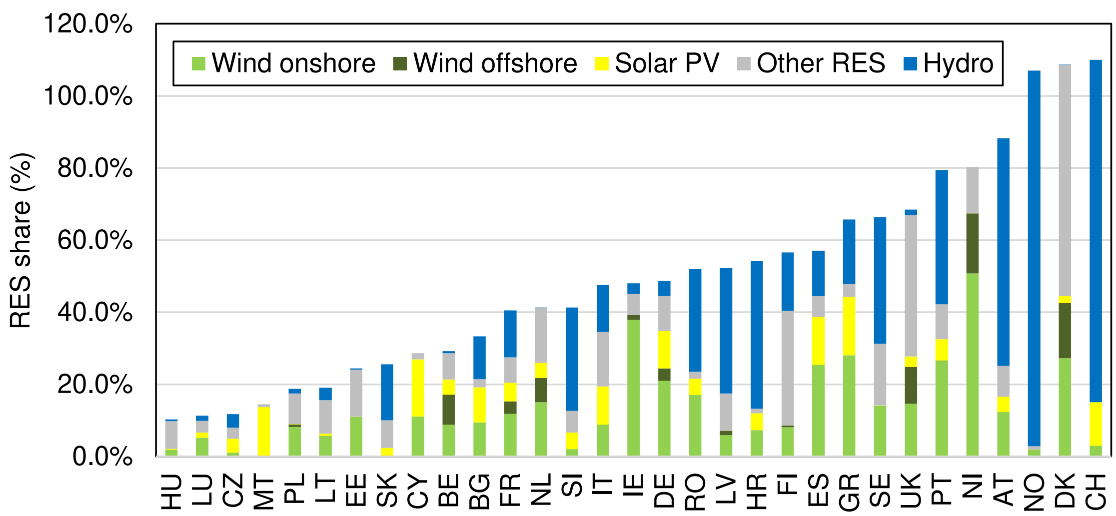


Figure 1: Proportion of RES generation on total demand, 2030

3.2 Profitability of investment in RES-E

Figure 2 provides an overview of the profitability of the three considered RES-E technologies across Europe on the basis of both the IRR and the NPVs. The IRR of wind onshore investments increases from the left to the right. For the baseline fuel price and technology cost assumptions, investments in wind onshore have a higher IRR than those in solar PV for half of the countries, while solar PV has a higher IRR for the other half. The IRR of wind offshore is negative throughout.

Broadly speaking, four categories of countries can be identified. First, there are a number of countries (e.g., in Scandinavia and other parts of Northern or Western Europe) where wind onshore is rather profitable, whereas the profitability of solar PV is low. Second, there is a group of countries in the South-Eastern part of Central Europe where solar PV is rather profitable, whereas wind onshore investments reach their lowest IRRs (e.g., the Czech Republic, Slovakia, Hungary and Bulgaria). Third, there are some countries in Central Europe where the profitability of both solar PV and wind onshore is rather low (e.g., Luxembourg, Lithuania and Slovenia). Fourth, there are a few countries in Southern Europe with coastal access where the profitability of both technologies is rather high (e.g., Portugal, Greece and Cyprus).

Looking at the investment in solar power, Italy, with a large capacity of solar PV installed, has the highest IRR for this technology, followed by other countries in Southern Europe (Malta, Greece, Cyprus and Portugal). Looking at the investment in wind onshore, the Netherlands, Cyprus and Greece achieve the highest IRRs, followed by a number of Scandinavian countries (Finland, Denmark, Sweden) and the UK. The situation is structurally similar for wind offshore investments. This technology achieves the relatively highest IRR in the Netherlands, followed by Finland, Denmark and the UK. However, for the baseline technology cost assumptions, this relatively highest IRR in the Netherlands is still negative.

When assuming today's (2015) technology costs as a robustness check without a decrease over time, it is interesting that wind onshore investments are more profitable than solar PV investments for all considered countries. In terms of the achieved IRRs, there is a step change in terms of the IRR levels of solar PV investments, whereas the IRR of wind onshore investments only decreases by around 2%. This is mainly driven by the much stronger cost reduction assumptions until 2025 in the case of solar PV as compared to wind onshore. This underlines the importance of reducing PV technology costs from today's levels in order to ensure sufficiently high IRRs for this technology across Europe.

It is interesting to observe that the rank order (between countries) for the NPV compared to the IRR differs strongly, e.g., for wind onshore where there is cost of capital data available almost across all of Europe. There is a group of five countries (Germany, Belgium, Denmark, Finland and the Netherlands) that stand out in terms of the wind onshore NPVs. While there are places in Southern Europe, such as Greece or Cyprus, which range among the areas with the highest IRRs, the NPVs are around zero because of much higher country-specific capital risks (lower financial stability).

Overall, investments in wind onshore seem generally profitable in several Northern European countries, where both meteorological and financial conditions are beneficial for this technology. Wind onshore also achieves a high IRR in some countries on the Mediterranean or Atlantic coast, the latter having favourable resource conditions for both solar PV and wind onshore. However, the financial conditions are much less stable for most of these countries leading to higher costs of capital and lower NPVs. Finally, a number of countries in Central and Eastern Europe neither have favourable conditions for PV nor wind - neither from a resource perspective nor from a cost of capital perspective. This raises the question if the import of renewable energy (certificates) from EU countries with more favourable conditions could be a viable option for these countries. Whether such an approach would really lead to meeting the RES targets at reduced costs, however, depends on many factors. For instance, shifting RES investments to countries with more favourable RES conditions may challenge the power grid and require grid reinforcements, which may lead to higher costs than a more balanced distribution of RES investments across EU countries. This question should therefore be part of future research.

In the next sections we stress our hypothesis by changing the fuel prices, technology costs and the lifetimes of the investments. In the absence of cost of capital data across technologies and countries, the sensitivity analysis presented in the following sections will focus on comparing the natural resource-driven aspects of profitability across Europe by means of the IRR.

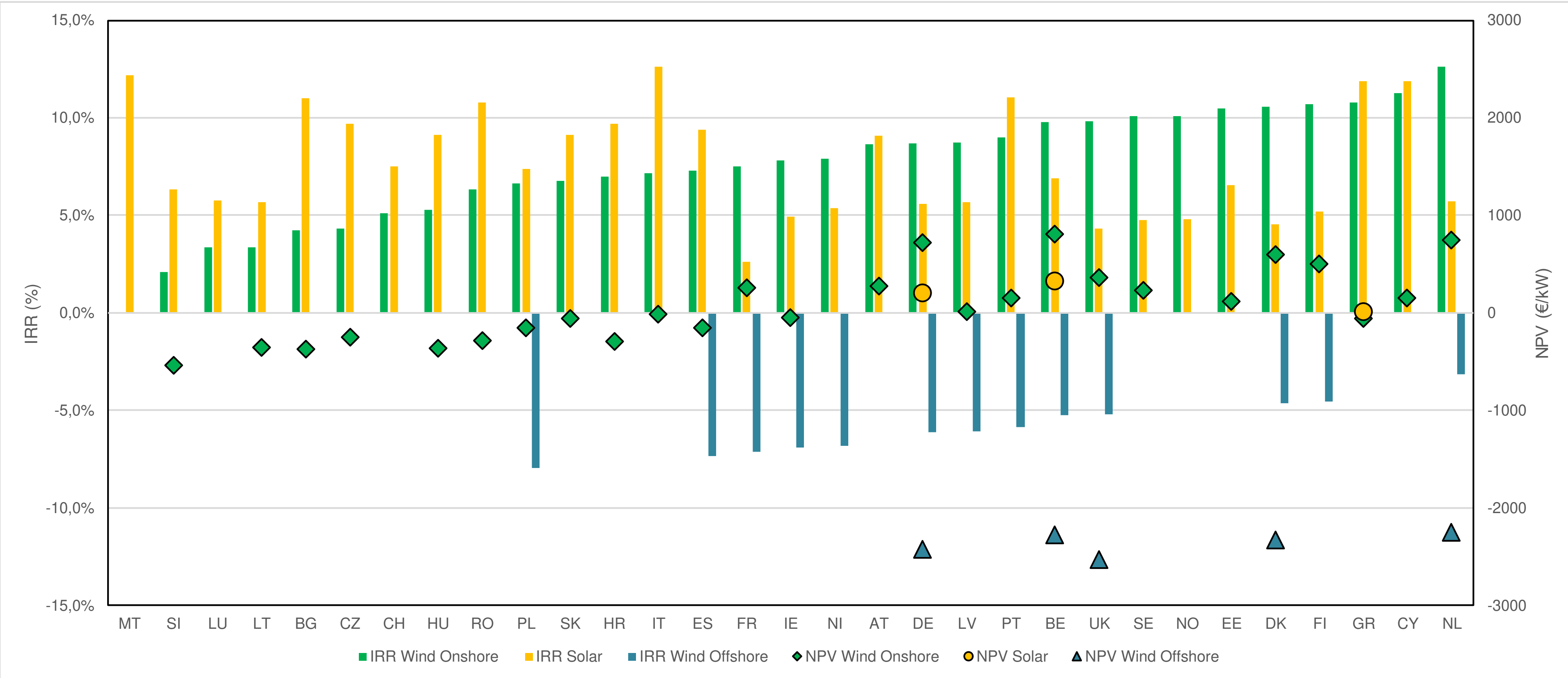


Figure 2: Overview of resulting IRRs and NPVs across countries and technologies

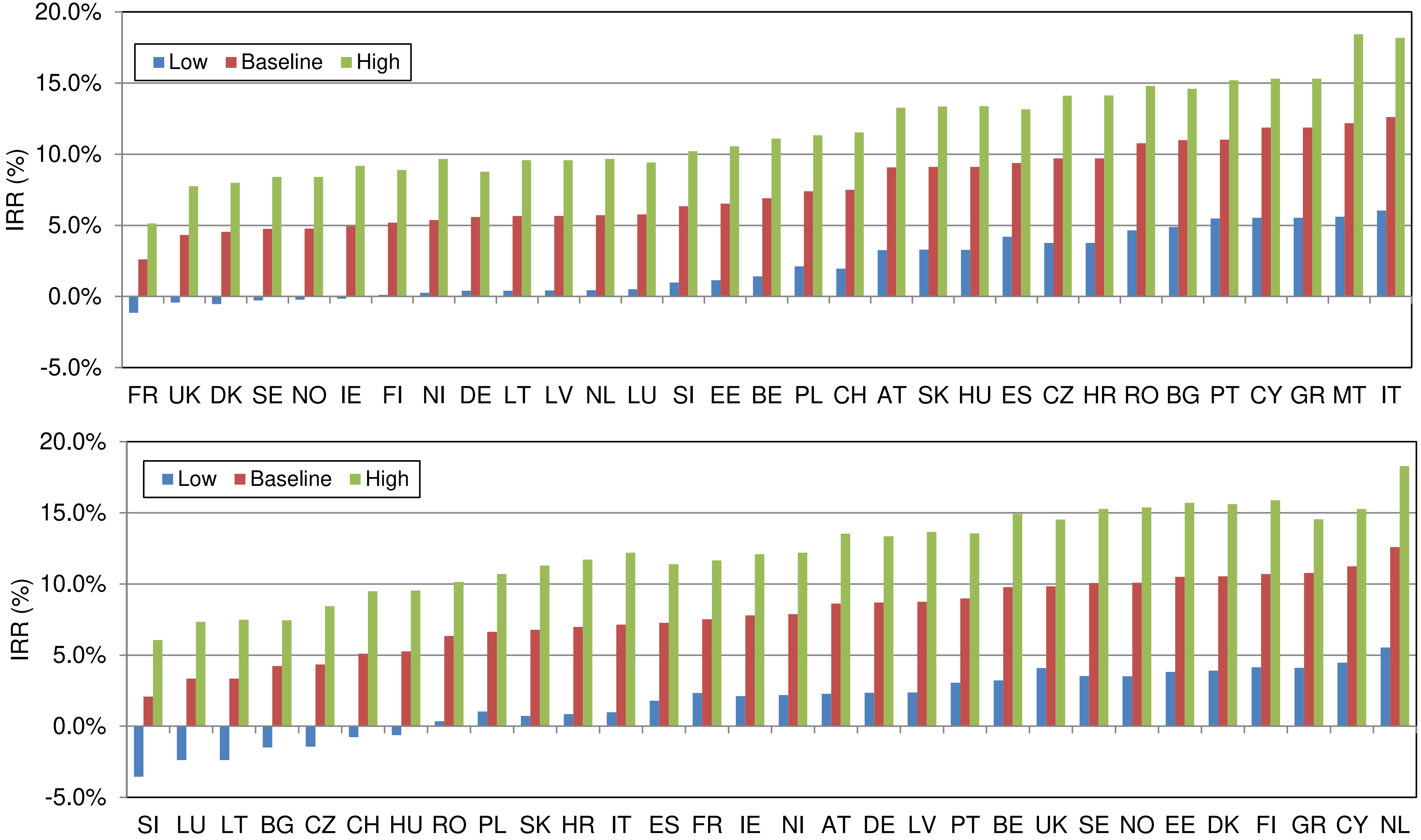
3.3 Impact of fuel price variations on the profitability of RES-E investments

Figures 3 and 4 show how the IRRs of the different RES-E investments change when fuel prices (and hence electricity prices) are higher or lower than the baseline assumptions (see Table 3 for the corresponding assumptions in the High and Low scenarios), while the technology costs are not changed. As expected, higher fuel prices increase the profitability of solar PV (see Figure 3a). Italy and Malta still achieve the highest IRRs for solar investments, now exceeding 18%. However, a number of countries in which the IRR was below 5% for the baseline assumptions now achieve an IRR of 8-9% (e.g., Scandinavia, the UK or Ireland). On average, the IRR increases by around 4% in the High fuel price scenario compared to the baseline fuel price scenario. In contrast, lower fuel prices result in IRRs around or below zero for solar investments for some countries (e.g., France, the UK, Ireland and Scandinavia). On average, the IRRs are around 5.5% lower in this scenario than for the baseline assumptions.

Figure 3b shows similar effects for wind onshore. On average, the IRRs are around 4.5% higher in the High fuel price scenario compared to the baseline scenario. Lower fuel prices result in IRRs that are around 6.1% lower on average than in the baseline scenario for this technology. This means that the IRRs for wind onshore investments are negative for some countries, including Slovenia, Luxembourg, Lithuania, Bulgaria and the Czech Republic, while Hungary and Romania yield IRRs of around zero under these fuel prices.

Figure 4 shows how wind offshore investments are affected by the different fuel price scenarios. In the scenario with high fuel prices, the IRRs are around 3.5% higher on average than under the baseline assumptions. While in the baseline scenario the IRRs for wind offshore were negative across Europe, the IRR is slighty positive under high fuel prices in the Netherlands (around 0.5%), followed by Finland and Denmark. Under low fuel prices, the IRRs of wind onshore would be strictly negative across Europe (around 6.4% lower on average than for the baseline assumptions), whereby the order between the countries remains largely unchanged.

Overall it is interesting to note that the fuel price variations do not have the exact same impact on all countries. For instance, Figure 3b shows that for wind onshore, the order between the countries would be slightly different under the High scenario than under the Baseline scenario. This can be explained by different power systems and generation portfolios, which are affected by the fuel price variations in different ways.



(a) *Solar PV*

(b) *Wind onshore*

Figure 3: Impact of fuel price variations on the IRR of solar and wind onshore investments across Europe, 2030

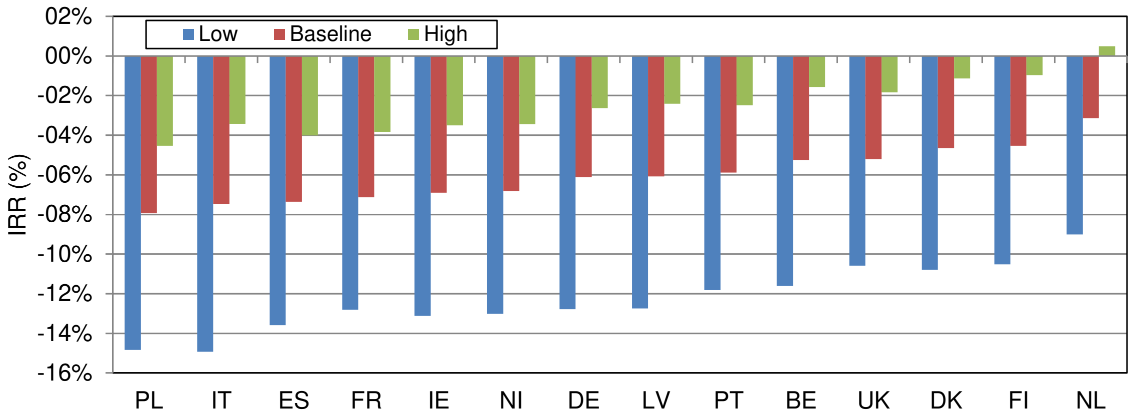


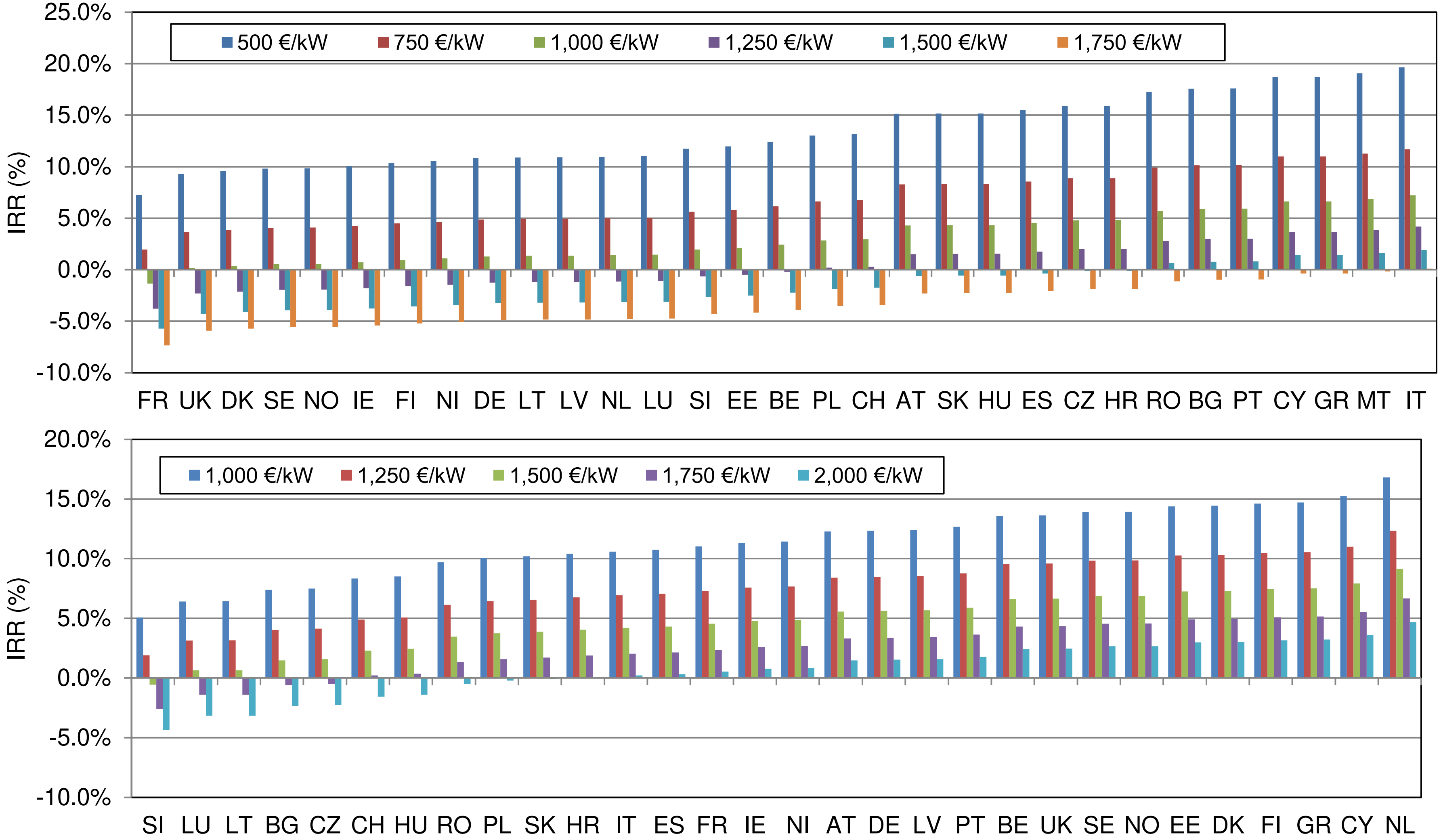
Figure 4: Impact of fuel price variations on the IRR of wind offshore investments across Europe, 2030

3.4 Impact of technology cost variations on the profitability of RES-E investments

For the considered technologies, the study by Taylor et al. [39] suggests that there will be huge reductions of investment-related costs by 2025. However, there is obviously also a very high uncertainty related to these reductions, which is yet higher in our case given that our analysis is based on 2030. A thorough sensitivity analysis of the impact of changes in technology costs on the profitability of RES-E investments is therefore very important. We shall do this using fuel price assumptions of the baseline scenario.

Figure 5a shows how the IRR of solar PV investments changes across Europe when the specific investment costs of solar PV vary between 500 €/kW and 1,750 €/kW (where Taylor et al. [39] expect 711 €/kW by 2025). It becomes obvious that such cost reductions lead to a step change in profitability of PV across Europe. Already a slightly less ambitious reduction to 1,000 €/kW would result in positive IRRs for the vast majority of countries in Europe and in IRRs around or above 5% for a third of the member states.

Figure 5b shows how specific investment costs of wind onshore varying between 1,000 €/kW and 2,000 €/kW affect the IRR of wind onshore across Europe (where Taylor et al. [39] expect 1,233 €/kW by 2025). If technology costs of wind onshore remained unchanged or increased slightly, the IRRs would still be positive in most countries. However, if the specific investment costs fell to around 1,000 €/kW, the IRRs would exceed 5% across Europe, while for two thirds of the countries they would exceed 10%.



(a) *Solar PV*

(b) *Wind onshore*

Figure 5: Impact of technology cost variations on the IRR of solar and wind onshore investments across Europe, 2030

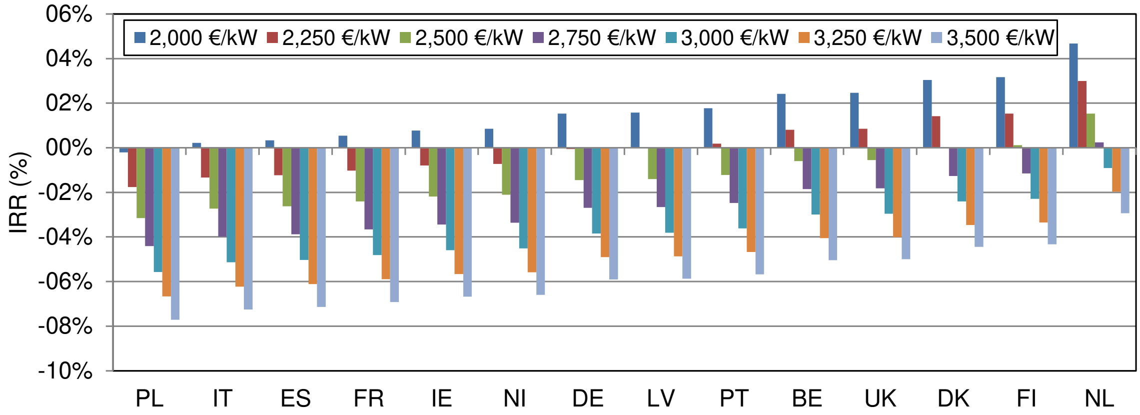


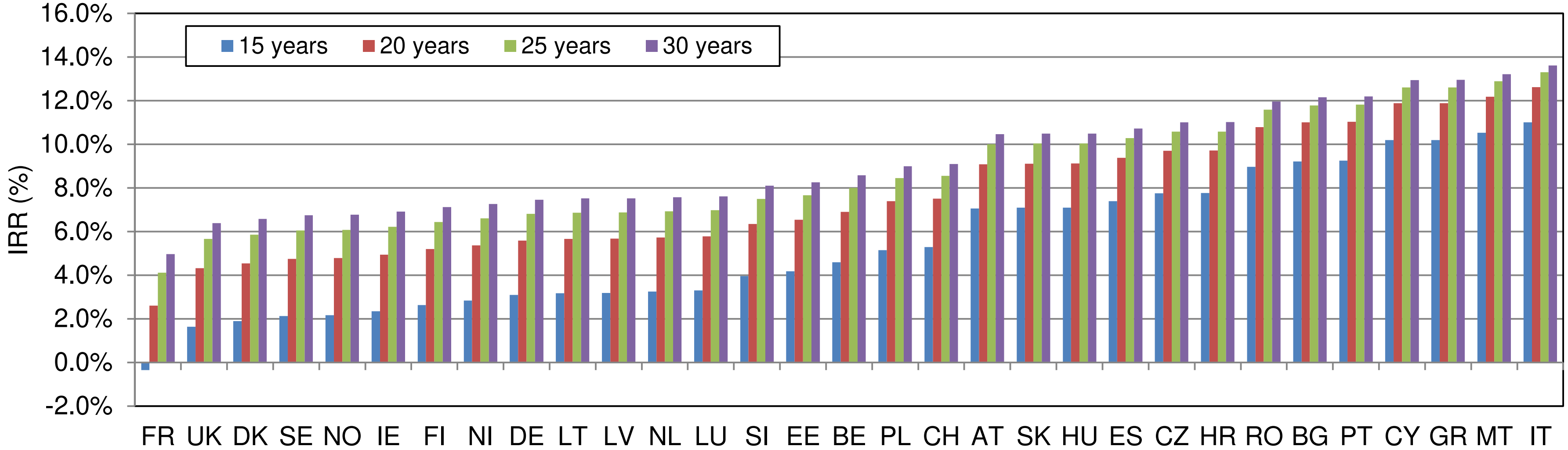
Figure 6: Impact of technology cost variations on the IRR of wind offshore investments across Europe, 2030

Figure 6 shows how technology cost variations between 2,000 €/kW and 3,500 €/kW would affect wind offshore investments. While Taylor et al. [39] expect 3,555 €/kW by 2025, Figure 6 shows that reductions to 2,000 €/kW would be necessary to achieve a positive IRR in most countries with wind offshore potential. However, even for such significant cost reductions, the IRR would not exceed 5% in any of the countries, which may not be sufficient to make this a viable investment given the scale of offshore projects.

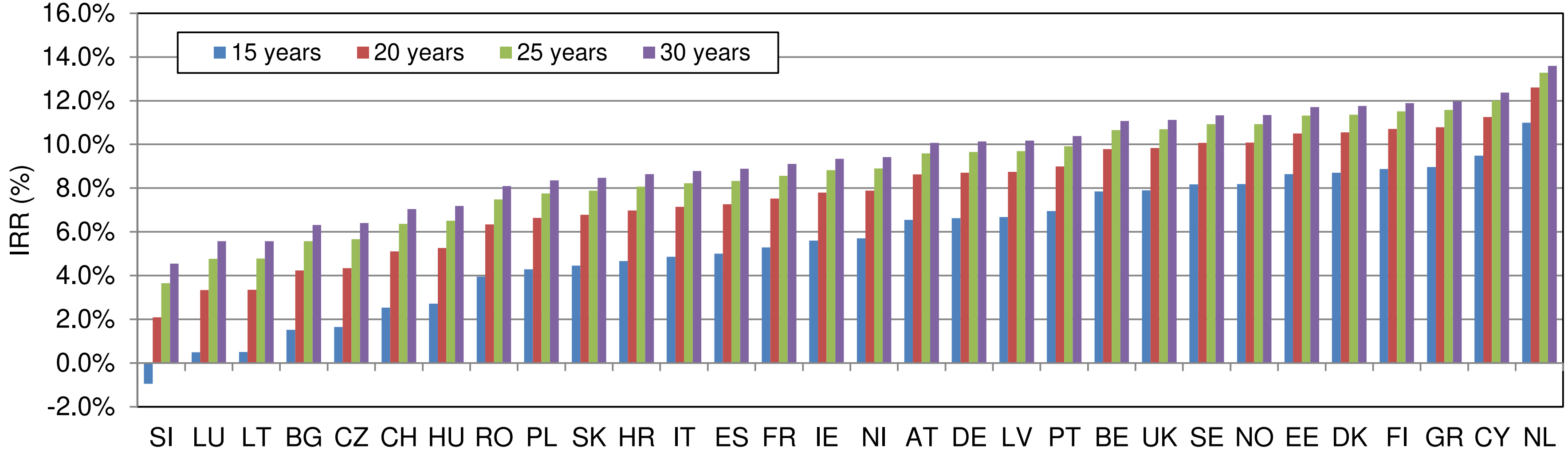
3.5 Impact of lifetime variations on RES-E investments

We now explore how changes in the expected lifetime of solar and wind projects affect their profitability, where our baseline assumption is 20 years (see section 2.2). Figure 7 shows that for both solar PV and wind onshore, decreasing the lifetime expectation to 15 years would result in IRRs that are around 2% lower on average. An increase in the lifetime of the projects would have a slightly lower positive effect. The IRRs for both technologies would be around 1% higher for a lifetime of 25 years (compared to 20 years), while the IRRs would increase by another 0.5% for a lifetime of 30 years (compared to 25 years).

Furthermore, Figure 7a shows for solar PV investments that a lifetime reduction to 15 years would lead to an IRR of below 4% in almost 50% of the countries. An increased lifetime of 25 years, however, would ensure an IRR of at least 6% in almost all countries. For wind onshore, Figure 7b shows that the IRR would fall below 6% if the lifetime was reduced to 15 years. A lifetime increase to 25 years, would ensure an IRR of at least 8% for two thirds of the countries. However, countries in Northern Europe (Estonia, Finland, Sweden and Norway) and Western Europe (Belgium, UK, Netherlands) as well as Cyprus and Greece achieve IRRs of around or higher than 8% for all considered lifetime scenarios.



(a) *Solar PV*



(b) *Wind onshore*

Figure 7: Impact of lifetime variations on the IRR of solar and wind onshore investments across Europe, 2030

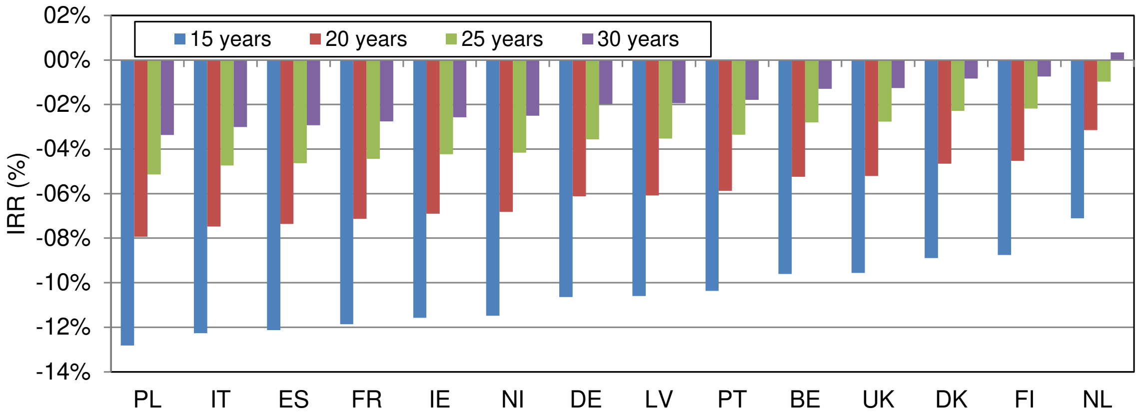


Figure 8: Impact of lifetime variations on the IRR of wind offshore investments across Europe, 2030

Figure 8 shows that the IRR of wind offshore investments is yet more sensitive to lifetime variations than the IRR of wind onshore or PV. A lifetime reduction of offshore projects to 15 years would come along with IRRs that are around 4.5% lower on average. A lifetime increase to 25 years would lead to IRRs that are around 2.5% higher on average (compared to 20 years), while the IRRs would increase by another 1.5% for a lifetime of 30 years (compared to 25 years). However, with the exception of an assumed lifetime of 30 years in the Netherlands the IRRs remain negative under all lifetime scenarios for the baseline technology cost and fuel price assumptions.

3.6 Relation between RES shares and CO_2 emissions

Figure 9 shows the relative RES shares and specific CO_2 emissions for each of the considered countries. This comparison is highly relevant since RES expansion is one of the main pillars of EU policy to achieve the overall target of 40% GHG emission reduction [3, 5]. As expected, Figure 9 shows that countries with very high RES shares, such as Austria, Switzerland or Norway have very low specific CO_2 emissions, whereas countries with very low RES shares in 2030, such as Poland, have much higher specific CO_2 emissions. It is interesting to observe, however, that countries with moderate and very similar RES shares, such as Italy, Ireland and Germany, differ significantly in terms of their specific CO_2 emissions, where Germany is found to have the second-highest specific emissions in Europe. This can be explained by the different power system structures. While the three countries are similar in terms of their RES shares, they differ with respect to their conventional power generation technologies. Italy and Ireland have a gas-dominated conventional power generation system, whereas Germany's conventional power generation is

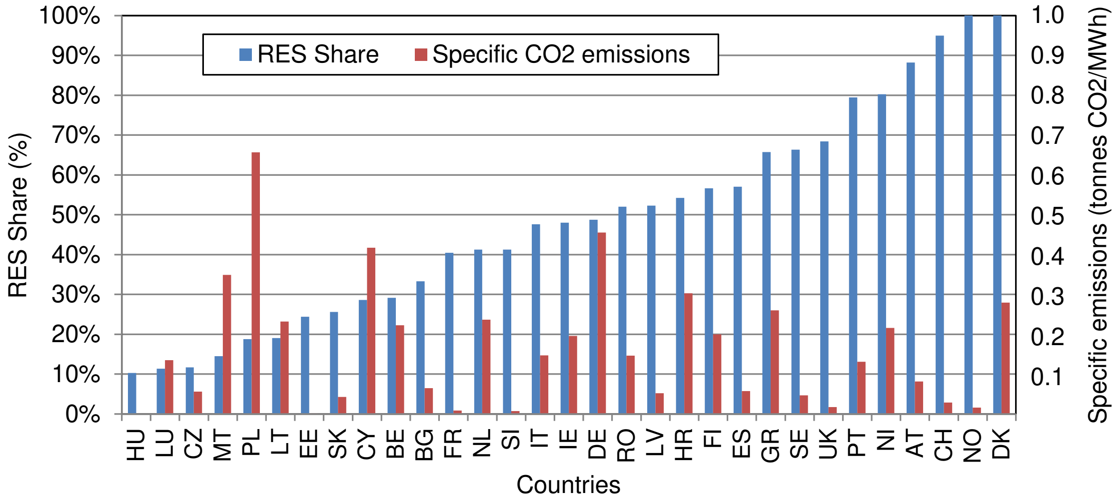


Figure 9: RES shares and specific CO_2 emissions across Europe, 2030

still dominated by coal-fired power plants. In the absence of any relevant carbon price (floor), this results in (less carbon-intensive but more expensive) gas-fired generation being pushed out of the market in Germany, whereas the (more carbon-intensive and cheaper) coal-fired generation remains in the market. This finding also holds for other countries with a relevant share of coal capacities, such as Poland or the Netherlands but it is most relevant for Germany in the light of its high total demand resulting in the highest absolute CO_2 emissions in Europe, followed by Poland. To summarise, Figure 9 shows that the effectiveness of RES in terms of reducing CO_2 emissions depends to a large degree on the power system structure and the carbon pricing policy.

4 Discussion

The results in the previous section highlight that the market-based profitability of RES-E investments differs substantially across Europe. While some technologies are profitable in some countries without any additional subsidies, the same or other technologies are not profitable in other countries. Consequently, if all countries, for whatever reason, sought to deploy all RES technologies within their own jurisdiction, additional incentives would need to be provided to investors, which would ultimately be borne by the consumers. In theory this suggests that, as long as interconnection capacities between countries are sufficiently high, it would be more efficient to export renewable generation from countries in which natural and financial conditions incentivise the development of renewable generation to other countries in which these conditions are less favourable. However, the issue of trading so-called Renewable Energy Certificates (RECs) or Guarantees of Origin (GOs) is debated controversially. While those in favour of an approach for cross-border trading of renewables [e.g., 41] would broadly follow the same arguments outlined above, those against such an approach [e.g., 42] would typically highlight the administrative barriers and increasing risk for investors ultimately turning into increased costs to consumers. In contrast, Green et al. [43] propose a market design aimed at facilitating long-distance trading of renewable energy, hence mitigating existing barriers. Altogether, it should be noted that our analysis across the EU focusses on 2030 and shows that the considered RES technologies can be profitable in quite a few countries without any subsidies, largely driven by cost reductions of RES technologies. This suggests that spikes of REC prices as anticipated by Haas et al. [44] for trading-based RES support systems within individual countries should not be expected, at least not to the same extent.

In this paper, we present IRRs and NPVs for different RES-E technologies across Europe. For an adequate interpretation, it is important to note that these have been calculated using wholesale electricity prices and a uniform payback period of 20 years. We acknowledge, however, that in reality there are different investors with different expectations and considerations. Energy companies or investment funds are likely investors in wind onshore capacities [45], which suggests that the use of wholesale electricity prices is adequate. In the case of solar PV, on the other hand, and indeed some wind onshore projects, likely investors also include non-energy companies [46], whose investment considerations would be based on industrial tariffs rather than wholesale prices. In addition, the perception of regulatory or technology-related risks are important determinants of (energy as well as non-energy) firms' investment behaviour [47]. Finally, residential households are very likely investors for small-scale solar PV assets. Their investment considerations are usually based on residential retail tariffs as well as a number of non-economic aspects, such as investing in green technologies or achieving a certain level of autonomy [48, 49, 50, 51, 52, 53]). For the latter two (investments by non-energy companies and residential households), the IRR estimates based on wholesale prices should therefore be understood as lower boundaries as the wholesale prices are only one component of the total industrial and residential retail tariffs. Moreover, costs of capital will vary between investors (e.g., between household-level and utility-scale PV investments), which will have a major impact on NPV calculations.

Overall, the rates of return required to undertake an investment in RES technologies vary significantly between different types of investors [54] and may also vary across countries. For instance, our results (see Figure 2) show that the IRR of solar PV investments is below 7% for around half of the countries, which may not be enough to incentivise utilities to invest in this technology [55]. For residential households, studies show that these face a market interest rate between 1% and 3% [56, 57] and may consider 15 years as a reasonable payback period for their investment. At the household level, the investment in solar PV may therefore be undertaken in most of the countries by 2030 (see Figure 7a).

As for wind offshore, it is interesting to observe that this technology is almost never profitable in our analysis, which concurs with findings by Green and Vasilakos [58] and Duscha et al. [16]. However, in recent auctions held in Germany for instance, investors submitted bids for wind offshore projects without any financial support.[8] One possible reason could be that the investors expect strong reductions in investment costs associated with this technology [59]. However, our analysis on the impact of technology cost variations (see Figure 6) shows that even for a reduction of wind offshore investment costs to 2,000 €/kW (i.e. a reduction to around 50% of today's costs), the IRR does not exceed 5% in any of the countries and does not exceed 3% in most countries. In order to understand under which conditions wind offshore may become profitable, we carried out an additional sensitivity analysis on the corresponding capacity factors. For this purpose, we increased the capacity factors of wind offshore in all countries proportionally reflecting technological improvements. With a capacity factor between 40 and 50% for all the countries with wind offshore potential, however, we still find that capital costs above 2,500 €/kW result in IRRs below 6% for all countries. This suggests that there may be other considerations behind these wind offshore bids. Either, the investors expect lower technology costs in combination with high fuel prices and/or longer lifetimes or they may evaluate the importance of entering in this market as a strategic option and may re-evaluate their investment decisions over time, e.g., as information about new support schemes (to be put in place by 2030) becomes available [60]. However, such 'wait-and-see' strategies have been proven to be detrimental [61]. We acknowledge that all these factors are crucial to understand the strategy of the investors in wind offshore but they cannot be included within the scope of this paper.

While the focus of this paper is the assessment of the economic viability of different renewable technologies across Europe on the basis of the IRR and (partly) NPV, there are

[8] https://www.cleanenergywire.org/news/support-free-bids-again-germanys-second-offshore-wind-auction

non-economic considerations which are important, in particular for policy makers, in the context of RES-E deployment. Above, we already mentioned non-economic determinants of investments such as the willingness to pay for 'green investments' or autonomy. Another crucial aspect for the successful and timely deployment of renewables is the public acceptance of these investments, i.e. not the acceptance by those investing but by those who are affected by the investments [e.g., 62, 63]. Acceptance of renewable technologies usually depends on the technology type (e.g., solar vs. wind), the size of the investment and the geographical distance between the built capacity and the people affected [64, 65, 66]. For instance, studies show that (i) the social acceptance of renewable projects is inversely related to the geographical proximity to residential dwellings and (ii) that the acceptance of solar PV is much higher than that of wind onshore even at very low distances to people's homes [e.g., 62, 66, 67]. Moreover, existing research has found that in some regions the public acceptance of wind offshore is higher than that of wind onshore [68]. This is important to understand for both policy makers and investors as such considerations of public acceptance may counterbalance the economic advantages of wind onshore to some extent. While policy makers might give preference to solar PV or even wind offshore instead of wind onshore with the objective of ensuring a timely achievement of the European renewable energy targets, investors might give preference to solar PV hoping to avoid project delays. Overall, this underlines the importance of understanding the investment economics and public acceptance of different RES-E technologies as well as the tradeoffs people make and their willingness to pay for the second-cheapest or even third-cheapest RES-E technologies if their acceptance levels are higher. The analysis presented in this paper is one contribution to resolving this conundrum.

Finally, the analysis in the previous section has highlighted that renewable deployment alone does not guarantee an effective reduction of CO_2 emissions. Depending on the power system structure and carbon price levels, renewables may push gas-fired generation out of the market rather than coal-fired generation, which has a limited effect on emission reduction. As a result, we have identified Germany as the country with the second-highest specific and highest absolute CO_2 emissions in Europe, which shows the limitations of Germany's "Energiewende" policy to date. It is important to note though that Germany has recently decided to phase out coal-fired power generation through a regulatory mechanism. Given the time line of the planned coal phaseout (last unit is planned to be decommissioned in 2038), however, the assumption that Germany has "solved" the problem would be misleading. Since it is not merely relevant to reduce emissions until a certain target year but the cumulative emissions should not exceed a certain carbon budget, Germany's power generation sector should still be a matter of concern. A regulatory plan to phase out coal-fired power generation will do little to the emissions of each coal-fired power station until the final shut-down. Instead, an appropriate carbon price floor should be introduced, which ensures a fuel switch from coal to gas. This would be a helpful instrument, complementing both RES deployment and coal phase-out, since it would increase the effectiveness of RES in terms of emission reduction. This recommendation is in line with previous work by Kalkuhl et al. [69] and Huntington et al. [14], who both suggest that it is usually most efficient to price externalities directly.

As for all quantitative studies, the analysis and results presented in this paper come along with some limitations and therefore need to be interpreted with caution. For countries and technologies, where cost of capital data is available (e.g., wind onshore for most countries), we calculate the internal rate of return (IRR) as well as the net present value (NPV). While the NPVs include aspects of financial market conditions by considering country-specific and technology-specific costs of capital, the IRRs only focus on the (natural) resource-driven aspects of profitability. Consequently, conclusions about the financial feasibility of projects can only be drawn for wind onshore projects in most countries, whereas for the other two technologies considered, such conclusions are not possible for most countries in the absence of the required cost of capital information. This is important to bear in mind when interpreting the results since the rank orders according to the IRR as compared to the NPV may vary significantly between countries (see Figure 2 as well as [26, 27]). Moreover, Ceseña et al. [70] as well as Santos et al. [71] highlight that a real option analysis would be better suited than the IRR methodology, in particular when investors face uncertainty and may postpone their investment decision. However, in the framework in this paper, we consider only one year (2030) and we acknowledge the simplifying assumption that the projects have constant annual cash flows over their lifetime. Nevertheless, the IRRs and NPVs assessed here, give a sound estimate of the profitability of each project, and (in our specific case) is also a good measure to compare projects between different countries. Moreover, in order to calculate the costs associated with the investment in renewable generation, we assume that the costs of solar and wind technologies are the same across Europe. We acknowledge that this is a simplifying hypothesis that may be changed in future work. Finally, our analysis is based on the PRIMES 2016 scenario for 2030, which does not exactly match the recent EU target to achieve 32% of renewables in final energy consumption by 2030 (see [34]). For some countries, we can already see that the PRIMES scenario used here has underestimated the dynamics of RES developments. Assuming that the actual RES shares in some countries are higher than assumed in the scenarios, we can expect that – ceteris paribus – the power prices would be slightly lower reducing the profitability of RES investments. At the same time, however, a faster RES expansion may be accompanied by stronger technology cost reductions and possibly WACC reductions (because of reduced perceived risk), which in turn would be positive for the profitability of renewables. The extent to which these competing effects balance out is impossible to anticipate but it is important to be aware of this uncertainty when interpreting the results of the analysis.

5 Conclusions

This work has estimated the market-based profitablity calculating IRRs and NPVs for different renewable technology investments across Europe, i.e. no financial support for renewables outside the market is assumed. The analysis focuses on solar PV as well as wind power (onshore as well as offshore) and uses both the net present value (NPV) and the internal rate of return (IRR) as indicators to compare the profitability between technologies and countries.

We show that investments in the considered technologies are not homogeneously profitable across Europe. Our results reveal four categories of countries. The first category includes a number of countries in Scandinavia and other parts of Northern or Western Europe where wind onshore has a rather high IRR, while the IRR of solar PV is low. The second category consists of a group of countries in the South-Eastern part of Central Europe (e.g., the Czech Republic, Slovakia, Hungary and Bulgaria) where solar PV has a rather high IRR, whereas wind onshore investments achieve very low IRRs. The third category includes countries in Central Europe (e.g., Luxembourg, Lithuania and Slovenia) where neither solar PV nor wind onshore achieve particularly high IRRs. Finally, the fourth category consists of countries in Southern Europe with coastal access (e.g., Portugal, Greece and Cyprus) where the IRRs of both solar PV and wind onshore are rather high. Wind offshore is not found to be profitable under our baseline assumptions.

Country-specific risks also play a role in determining the profitability of the investments through the cost of capital. The NPVs calculated for wind onshore projects (the only technology for which data on the cost of capital are available for most of the countries) highlight that the profitability of investments is strongly linked to each country's financial market conditions. As a result, several countries in Southern and Eastern Europe with IRRs for wind onshore in the upper half (above 6%) only have a marginally positive (or even negative) NPV.

We also carried out a number of sensitivity analyses to explore the impact of varying key factors, such as the fuel prices, technology costs and technology lifetimes. Our analysis shows that a reduction in the lifetime of the projects, increased technology costs / less than anticipated technology cost reductions by 2030 and lower fuel prices significantly reduce the profitability of wind and solar investments. More specifically, we observe that the downside risks and the upside potentials of the investments are distributed asymmetrically, i.e. the downside risk of lower fuel prices and shorter technology lifetimes is larger than the corresponding upside potential of higher fuel prices and longer lifetimes. In contrast, the upside potential of decreased technology costs is larger than the downside risk of increased costs. All these factors need to be taken into account when assessing if investments in renewables will meet the 2030 targets in the absence of any financial supports by Member States or what form and level of support may be required in different countries.

There are a number of messages that policy-makers can take away from this research. *First*, our analysis shows that allowing for some form of trading renewable generation between countries or providing some other mechanism for joint target achievement / co-operation between European countries (as opposed to national targets that have to be met nationally only) can be expected to achieve the overall targets at lower costs. Comparing the 2030 target shares (Figure 1) and profitabilities (Figure 2) reveals that some countries have high RES-E targets while the profitability is rather moderate or low and vice versa. This suggests that either financial support payments will be required (ultimately leading to higher costs to consumers) to meet the targets in these countries or the targets may not be met. Trading of renewable generation between countries can resolve both problems. Should countries, for whatever reason, wish to achieve certain technology-specific national targets, our analysis provides quantitative support in determining which technologies need support in which countries. Moreover, our analysis shows that in most countries at least one technology (wind onshore or solar PV) achieve reasonable IRRs by 2030 even in absence of any financial support payments. *Second*, our analyses provide insights for policy makers as to how sensitive a successful RES deployment and target achievement are to uncertainties related to different factors. For technology developers, these analyses can be used to derive targets in relation to technology cost reductions and lifetimes. *Third*, our results show that in quite a few countries, wind onshore achieves higher IRRs than solar PV, and definitively higher than those of wind offshore. Beyond these economic considerations, however, the public acceptance of energy infrastructure investments is a prerequisite for a successful deployment of renewables, which has been shown to be higher for solar PV and wind offshore compared to wind onshore in many cases as discussed in section 4. It is therefore crucial for policy makers to have an open and transparent discourse about the tradeoff people make between consumer costs (depending, amongst others, on the profitability of investments) and acceptance related to different renewable technologies. The analyses presented in this paper provide an important contribution to understanding the investment economic side of this tradeoff. Fourth, RES deployment alone will not guarantee an effective reduction of CO_2 emissions. If accompanied by an appropriate carbon price (floor), however, renewables would unfold their full power in mitigating carbon emissions.

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Appendix

Table 4: Conventional capacities installed (2030)

	CCGT fleet	Coal fleet	Nuclear fleet	OCGT fleet	Oil fleet
AT	2338	778	0	260	423
BE	9298	16	0	1033	215
BG	938	3391	1920	104	2
CH	636	0	1200	144	0
CY	462	0	0	51	930
CZ	1526	8797	4006	170	64
DE	22560	36775	0	2507	1248
DK	899	1472	0	100	217
EE	214	1408	0	24	0
ES	25106	3968	7399	2790	2952
FI	2818	1844	3398	313	607
FR	7000	0	59493	778	1679
GR	4264	2845	0	474	733
HR	1050	658	0	117	107
HU	2226	396	4482	247	5
IE	2848	842	0	316	173
IT	37497	5098	0	4166	2332
LT	1215	0	1117	135	0
LU	614	0	0	68	4
LV	982	21	0	109	15
MT	641	0	0	71	144
NI	875	0	0	97	307
NL	10562	4429	485	1174	66
NO	700	0	0	215	45
PL	4494	20704	0	499	155
PT	3931	0	0	437	691
RO	3559	1909	2828	395	676
SE	2840	128	6949	316	510
SI	364	632	700	40	16
SK	901	483	4020	100	84
UK	30470	501	13107	3386	860

Data are from PRIMES Reference Scenario, 2016