

Costs or benefits? Assessing the economy-wide effects of the electricity sector's low carbon transition – The role of capital costs, divergent risk perceptions and premiums

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ABSTRACT

To mitigate climate change, societies strive to transform the energy sector towards greenhouse gas emission neutrality, a move which assessment studies often indicate incurs large macroeconomic costs. In this context the weighted average costs of capital (WACC) are especially important, as renewables are highly capital intensive. In particular, investors' perceptions and expectations of risks are fundamental determinants of WACC and thus strongly influence the macroeconomic outcome of transition analyses. For the case of Europe's electricity sector transition, we analyze this sensitivity by choosing different WACC settings, driven also by different policy settings redirecting expectations. First, we find that when differentiating WACC across regions and technologies more accurately than usually done in the literature, immediate and substantial macroeconomic benefits from the transition emerge. We thereby reveal a systematic overestimation of low-carbon transition costs in the literature. Second, we find that when pricing-in increasing trust in renewables, these benefits get significantly larger, outweighing possible negative macroeconomic effects from the risk of stranding of fossil-based assets. We also demonstrate that in developed regions such as Europe, de-risking renewables is an effective lever for reaching climate targets, which indicates the relevance of green macroprudential regulation.

1. Introduction

The target of limiting global temperature rise “well below 2 °C” [1] requires a fundamental transformation of the global economic system towards carbon neutrality, with the energy sector – currently a core emitter – playing a key role [2]. From a policy-makers' perspective it is crucial to understand the macroeconomic effects of such a transformation, including indirect effects to other sectors or the labor market and eventually implications on economic growth and economy-wide welfare. For assessing such effects a rich spectrum of integrated or “hybrid” energy-economic models has been developed in recent decades [3]. These models typically use information from detailed bottom-up (BU) energy sector models (such as the well-known TIMES model [4]) and feed it into top-down (TD) macroeconomic models (such as EPPA [5]). This allows for making use of the strengths of both model types [6], enabling researchers to study the macroeconomic effects of interventions in the energy system. In many cases the link from BU to TD is unidirectional (see e.g. [7]), however stronger integration is also possible (e.g. via iteration [8], or via full integration [9,10]).

Irrespective of how BU and TD models are combined, the results of such integrated BU-TD assessments are very sensitive to the underlying assumptions on technology costs and their development over time. One parameter that is particularly relevant in energy transition analysis is capital cost, due to the high cost share of capital in energy technologies in general and an even higher one in renewables in particular. More explicitly, it is the weighted average costs of capital (WACC) parameter and its development over time that strongly drives results [11,12]. Yet, with respect to capital cost assumptions we identify three major shortcomings in the literature, which we address in this paper.

The first shortcoming is that WACC parameters are typically chosen without much differentiation across technologies and regions, even though it has been shown that there are substantial differences [13–15]. While it is uncontroversial that technologies with high capital intensities (and large upfront investment costs) benefit stronger from lower interest rates than less capital intensive technologies [12], most empirical work still applies uniform interest rates, not just across technologies, but also across regions and other domains of risks (for an overview see Table A 1 and references thereof). Interest rates are

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usually set between 5% and 10% and are mostly not further motivated. For instance, Pfenninger and Keirstead [16, p.307] indicate “*an interest rate of 10% is assumed for [technologies], so no assumptions about different investment attractiveness or project financing models are made.*” Most representative TD policy evaluation studies do not even mention the underlying interest rate explicitly, adding substantial uncertainty to the validity of the qualitative insight of results. Although some BU and TD assessments discuss sensitivities regarding uniform interest rate assumptions, only few distinguish interest rates by technology. For instance, Pleßmann and Blechinger [17] attach an interest rate of 6% to mature technologies (e.g. gas fired electricity generation or hydro-power) and 7% to (in these authors' perception) riskier technologies (e.g. photovoltaics (PV) or wind power). However, the values are chosen arbitrarily and without further motivation, and differentiation across regions is not taken into account. The most comprehensive study to our knowledge is by García-Gusano et al. [18], who deploy technology-specific interest rates¹ for 17 different electricity generation technologies, with changes over time motivated by a decreasing implicit technological risk. While their results demonstrate the importance of using differentiated interest rates, they do not go beyond the energy sector's domain and only give aggregated results for the whole of Europe. To account for a such required differentiation across electricity generation technologies and regions in a transparent and consistent way, we build upon the empirical analysis of Steffen [19] who identifies differences in financing schemes as main drivers of WACC differences.

The second gap we identify concerns WACC reduction for renewables via “de-risking”. Besides civil society initiatives such as the “Divestment” movement [20], the greening of finance is also on the agenda of corporate initiatives such as “Climate Action in Financial Institutions”, a global collaboration amongst various public and private banks.² While de-risking and greening is discussed in the literature, it focuses on developing regions, most notably Africa and the MENA region (see e.g. refs [14,21–23]) and on the role of development banks [24]. However, de-risking could also be an effective leverage point for climate change mitigation policy in developed regions [25]. Moreover, it has been shown that the stand-alone risk³ of variable renewables decreases with higher market shares [26] and that project risk for PV and wind has fallen in the recent years [27]. Yet, for Europe and its regions an economy-wide modeling study on the potential effects of de-risking of renewables is still missing (with the notable exception of first estimates by [28]).

The third shortcoming is that there is a strong focus on the WACC of renewables only (see e.g. refs [12,25]), as these technologies seem to be more risky and offer de-risking potentials [21,29]. In contrast, the assumptions on WACC for fossil fuels are left unattended and fixed to historic or arbitrary “standard” values from the literature. This is problematic, as there is a substantial technological-change-driven risk that fossil fuel assets become less competitive or even stranded due to the rapid cost decline for renewables, especially for PV panels and batteries – a decline both already observed and expected to continue – even without any further climate policy [30]. Moreover, current and future (climate) policy signals add another uncertainty dimension to this technological-change-driven risk [31]. Even though governments declare targets (or pathways), these are typically of long-term character and thus might simply not materialize in a world dominated by short-term political cycles. The associated possible adjustment of targets on short notice can be either an increase in the speed and/or stringency of climate policy (e.g. by the “ratcheting-up”-mechanism [32]) or,

conversely, even a reduction of stringency (as exemplified by the US). Investors thus face a risk from climate policy instability. These fossil-fuel-related risks are connected to the literature of the so called “carbon bubble” [33,34]: if humanity wants to meet the 2°C-target, large fractions of currently known fossil reserves need to remain in the ground [10] and reserves, as well as infrastructure, could end up as stranded assets [35]. If markets do not adequately price in this risk of stranding, a bubble might emerge due to overvaluation of fossil fuel assets. Recent studies indicate that this risk is already materializing on stock [36] and on capital markets [35,36] as a fossil fuel risk premium. However, as policy has only declared a temperature target, but no explicit emission trajectory to reach this target,⁴ whether as well as when this risk will materialize (and to which degree) remains unknown.

In addressing the three gaps identified, we contribute to a more robust and adequate basis of information for the decision-making process in climate change policy. Due to the first gap (no differentiation of WACC across regions and technologies) the economy-wide costs of mitigation might be substantially over- or underestimated for specific regions, depending on the regional characteristics (such as political stability, distortions, capital scarcity and factors from other risk domains [39]). Possibly of more importance, the presence of the latter two shortcomings in the literature (neglecting the potential of de-risking renewables in developed regions as well as neglecting the risk of stranding of fossil fuel-oriented assets) implies that the change in risk perceptions has so far been overlooked in the analysis of low carbon transition pathways. Consequently, the costs of mitigation from a shift to renewables might have been (possibly even substantially) overestimated. We thus argue for explicit accounting of such changes in risk (perceptions) and corresponding risk premiums in economy-wide numerical analysis and simulations. This will allow for gaining insights into magnitudes and ranges of effects, acknowledging these refinements of fundamental parameters. We propose to do so in two ways: First, the “reference” pathways, to which transition pathways are usually compared, need to include at least the technological-change-driven risk for fossil fuel investments, as technological change happens independently of climate policy. Second, the mitigation scenario, e.g. a low carbon transition pathway, should include different WACC settings. On the one hand, the mitigation scenario should include a lower risk premium (WACC) for renewables than in the reference, due to strengthened trust in renewables via the policy(-signal) itself. On the other hand, the mitigation scenario should also include a higher WACC for fossil-fueled technologies than the reference scenario, due to investors' perception of likely further increases in the speed/stringency of climate policy (i.e. “ratcheting up”); on top of what has been already declared by governments. In our analysis, we include these different risks by refining WACC assumptions in a stepwise manner. This allows us to analytically isolate the respective effects occurring simultaneously in the real world.

This logic of including different risk premiums (due to divergent risk perceptions and expectations) in different narratives has so far not been carried over into numerical model analysis and we believe we are the first to do so. In general, the peer-reviewed literature on the de-risking of renewables and stranded fossil fuel assets is relatively⁵ scarce, even more so from an economy-wide perspective. Also, in the domain of the finance literature there is only very little peer-reviewed literature on climate change mitigation issues [40], making it even harder to estimate economy-wide effects. Nevertheless, the topic of stranded fossil fuel assets is analyzed from an economy-wide perspective in some studies. Mercure et al. [30] analyze the macroeconomic implications of stranded fossil fuel assets from a demand perspective (globally, using the demand constrained model E3ME coupled with an energy sector

¹ They denote them as being “hurdle” rates.

² <https://www.mainstreamingclimate.org/>.

³ Stand-alone risk means that an asset is considered in isolation, resembling a project finance structure. Alternatively, a portfolio approach would assume that the asset is part of a larger corporate structure, resembling a corporate finance structure.

⁴ Note that many different emission trajectories can lead to the same level of greenhouse gas concentrations (and respectively of global warming).

⁵ Compared to the vast literature on the economics of climate change mitigation.

model) and demonstrate that even without additional climate policy, the risk of stranding is substantial. They also show severe GDP effects for countries that do not comply with international climate policy agreements. Further, Bauer et al. [41] investigate the opposing effects on greenhouse gas emissions coming from the “green paradox” effect (i.e. selling-out fossil fuels as long as they are still profitable to avoid assets becoming stranded) and the divestment effect (i.e. reducing investments in fossil fuel projects due to uncertain profitability). The authors make use of the intertemporal optimization (perfect foresight) model REMIND and use a globally binding CO₂ price as policy instrument to stimulate an “announcement effect.” They conclude that the divestment effect dominates CO₂ emission changes (with net reductions), because divestment in coal is relatively strong. Similarly, but in an analytical model, Rozenberg et al. [42] also demonstrate that private costs of stranding are significant when choosing an optimal CO₂ price as policy instrument.

In the present contribution, we add to this literature but follow a different approach and demonstrate its relevance for the European electricity sector's low carbon transition. As compared to other state-of-the-art analyses, we do not focus on an optimal (and often unrealistically high and globally uniform) CO₂ price as policy instrument, but rather assume a top-down second-best policy in the form of renewable portfolio standards (RPS). This approach is closer to reality as most countries across the world already have such standards in place [43] and RPS are increasingly gaining popularity [44]. In addition, RPS can be introduced unilaterally and is thus compatible with the post-Paris climate policy architecture, with Nationally Determined Contributions (NDCs) at its heart. Another difference to existing studies is that we refrain from assuming perfect foresight, an assumption which in our view is problematic when it comes to uncertainty and risk analysis. Instead, we assume myopic behavior, however with changing risk-perceptions (via different interest rate assumptions – risk premiums fractions – in the “present”). The innovation of the analysis presented here lies in the implementation of changes in risk perceptions, which are assumed to be triggered by the introduction of such binding RPS, interpreted by investors as a strong policy signal. As pointed out by Schmidt [25], a credible policy framework – and even more so the resulting signaling – is pivotal to increase trust in renewables, thereby decreasing their capital costs via lower risk-premiums. However, such policy comes at a cost, which in our case is the deviation from a baseline pathway to a (at least from a BU perspective) costlier but renewable energy pathway.

We address the stated shortcomings for the case of a transition scenario to an (almost) 100% renewable electricity system in Europe. Our results demonstrate the importance of WACC differentiation in macro-economic modelling per se and the importance of possible diverging risk perceptions. On a European scale, no such analysis is currently available. We fill this gap and give a first quantification of ranges and magnitudes.

2. Model description, calibration and scenario framework

2.1. General model description and calibration

For the economy-wide assessment of a large-scale renewable electricity expansion under different risk perceptions we use the WEGDYN model [45,46]. WEGDYN is a global multi-region, multi-sector, recursive-dynamic computable general equilibrium (CGE) model, which solves in five-year steps, starting in 2011. From a macroeconomic modelling perspective WEGDYN is supply-side constrained, meaning that capacities (capital, labor⁶ and resource endowments) are fully utilized, constraining macroeconomic expansion through scarcity

(referring to a long-run macroeconomic state). We assume a fixed savings rate, meaning that a fixed part of regional income is spent for investment, which accumulates over time to build up the generic capital stock. Labor supply follows (working-age) population growth. Regarding the general socio-economic development, we follow the shared socio-economic pathway (SSP) framework [78] and use SSP2.

The sectoral resolution in the model distinguishes between sixteen economic sectors. The “Electricity” sector distinguishes eight different generation technologies, implemented as separate sub-sectors with Leontief-type production technologies,⁷ and a remainder representing “Collection and Distribution” (CAD). A Leontief-nested electricity mix aggregate (together with CAD) then eventually supplies electricity to the market. For the spatial resolution, WEGDYN differentiates between sixteen regional aggregates.⁸ We focus on EU-28 member states (plus Norway, Liechtenstein and Iceland) represented by four regional aggregates: Eastern Europe (EEU), Northern Europe (NEU), Southern Europe (SEU) and Western Europe (WEU). Additionally, we keep Austria (AUT) and Greece (GRC) as separate model regions. We do so, because Austria and Greece serve as examples with very different initial conditions for the transition and thus are expected to react differently. Compared to other regions, Austria is characterized by low interest rates (on debt; reflecting low risks from regional characteristics), high return on equity and a high share of renewable electricity in its mix, however with only moderate capacity factors for wind and PV. With respect to these factors, Greece is very different, facing higher interest rates (on debt) than other regions, lower returns on equity and a relatively high share of fossil electricity, but promising capacity factors for wind and PV (many shorelines and high insolation). For more details on the structure of WEGDYN, the associated closure rules and background assumptions we refer to [Appendix A2](#), and refs. [45,50].

2.2. Electricity sector pathway implementation

Regarding the development of the electricity sector, we follow a RPS approach. As discussed in section 1, this second-best-approach fits well into the current post-Paris climate policy architecture. We do so by exogenously setting a region-specific electricity generation mix, specified for each 5-year step of the model, that meets the given electricity demand.

In WEGDYN the dynamics in supply of electricity is modelled as follows. Each electricity generation technology is represented by a sub-sector of the electricity sector aggregate, or in other words by a technology's power plant stock (e.g. the PV power plant stock of a region). Each power plant stock develops over time since there are power plant additions and shutdowns (given plant lifetime and the RPS over time). To account for changing investment costs over time, we differentiate by annual vintages and only then aggregate to a technology power plant stock. Particularly, we take care of the changing capital costs (CAPEX) of each power plant, since additional investments for capacity upscaling lead to additional annuities at the aggregate level. Since the production of a kWh has different unit-costs across technologies, we combine physical target quantities (kWh) and technology specific generation costs (i.e. levelized costs of electricity, LCOE), to derive cost mark-up factors to account for the differences in unit-costs (as for example done in [7]). For further details on the implementation the electricity sector pathway see [Appendices A3 and A4](#).

⁷ The benchmark monetary output levels of the electricity supply sector (including power generation and collection/distribution) in 2011 are based on GTAPv9 data [47]. For its disaggregation by generation technology we use physical generation from 2011 ([Table A 1](#)) and benchmark LCOE provided by [48,49].

⁸ [Table A 6](#) gives details on country-wise aggregation.

⁶ Note that we model “classical” unemployment via a minimum wage. Details on WEGDYN labor market modelling are given in [45].

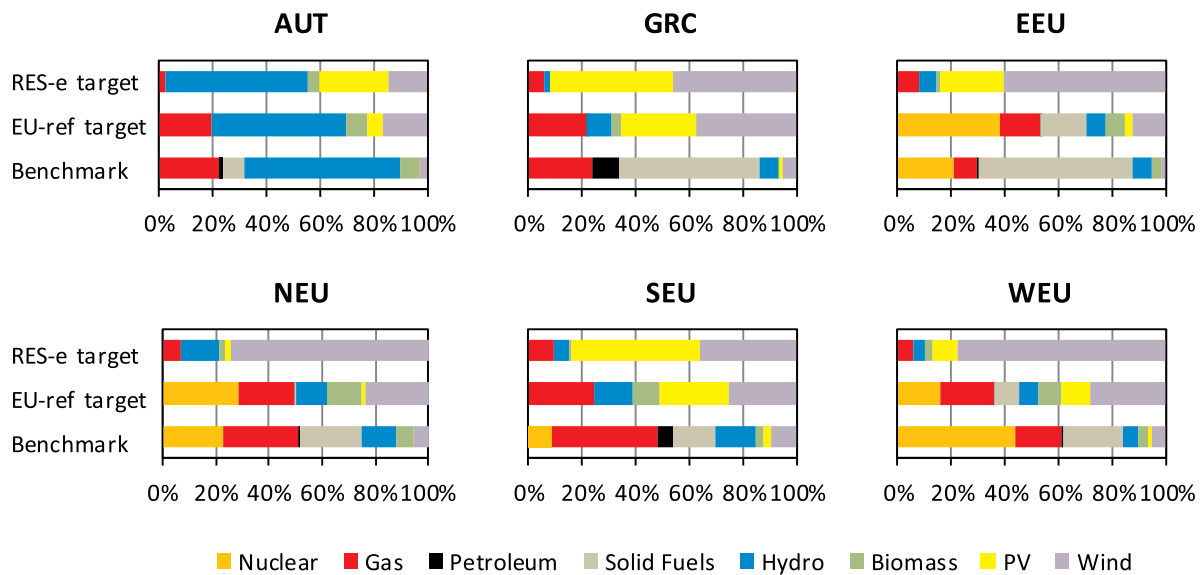


Fig. 1. Benchmark electricity mix (2011) across EU regions and mixes for 2050 for the reference scenarios (EU-ref) and for the large-scale expansion of renewables scenarios (RES-e).

2.3. Scenario framework

In general, we compare two simulation runs, or scenarios. First, for the baseline simulation run we choose the regional shares of renewable electricity generation from the “EU Reference Scenario” (EU-ref, [51]). EU-ref depicts a moderate expansion of renewable electricity, which is imposed exogenously. Second, we carry out a simulation run with a large-scale expansion of renewable electricity, which reaches an almost 100% renewables share by 2050, called “Renewable Energy Sources for Electricity Scenario” (RES-e), based on generation shares from [17]. The RES-e scenario is imposed exogenously as a binding RPS, but as compared to the EU-ref is much more ambitious in terms of renewables shares. Note that even though this RPS materializes in the model, agents are not perfectly informed in reality (approached here with myopic foresight). Hence, they might still have doubts about future climate policy stability and the materialization of the RPS. The results of the two simulation runs (EU-ref and RES-e) are then compared to each other to isolate the effect of enforcing the RPS. This comparison is done several times, but each time we change the underlying WACC parameters to increase accuracy and/or reflect different risk perception.

In both simulation runs (EU-ref and RES-e) we use the same total electricity demand trajectories until 2050, based on [17,52], which is assumed to increase linearly, with the total electricity demand in Europe being about 37% higher in 2050 (compared to 2011), amounting 4,448 TWh. Until 2050, for the whole EU-28plus3 policy region the share of renewable electricity generation (biomass, wind, PV, hydro) increases from 22% (2011) to 57% in the EU-ref simulation and to 93% in the RES-e simulation (with gas accounting for the remaining share). Note that generation from solid fuels (coal), nuclear and petroleum is fully phased out in the RES-e simulation. In Fig. 1 the regional electricity mixes are shown for the benchmark year (2011) as well as for 2050, respectively for the EU-ref and the RES-e scenarios. In RES-e additional investments in the electricity system accrue from grid expansion and the implementation of batteries and power to gas facilities to the system (taken from [17]). See Appendix A5 for details on the investment modelling.

3. The weighted average cost of capital and scenario settings

3.1. WACC revisited

crucial determinant of model results and recommendations for policy designs. In general, the weighted average costs of capital is defined as the sum of the cost of equity and the cost of debt [53]:

$$WACC = i_{RoE} * E / (E + D) + i_{RoD} * D / (E + D) \quad (1)$$

with i_{RoE} being the return on equity, i_{RoD} the return on debt, E the equity part of the investment (in absolute terms) and D the debt part of the investment (in absolute terms). It is thus the return rates themselves as well as the respective shares of debt and equity that determine WACC.

The extant literature usually uses commonly accepted WACC values uniformly across the board (usually in the range of 5%–10%; cf. Table A 1), i.e. without differentiation across technologies and regions. However, capital costs differ strongly across regions, depending on factors such as political stability or the business cycle. Also, it is rather plausible that technological characteristics are at the core of assessing the expected return of an investment and – the other side of the coin – evaluating the respective riskiness. Hence, the simplification of a uniform WACC across regions and technologies strongly distorts relative costs and benefit evaluations of any policy.

We also ascertain that in the literature there is a strong focus on the WACC of renewables for two reasons: First, because they are more capital intensive than fossil technologies, and second because they are considered through a risk lens. This risk perspective led to a consensus that renewable technologies are subject to higher WACC than fossils fired technologies, because they are considered riskier.⁹ This partial view is problematic, however, because projects in the fossil industry are also risky undertakings [54], facing even some of the same risks, e.g. from the business cycle or political stability. Moreover, it is important to note that a high WACC does not necessarily reflect a high risk, but rather high profitability in general, i.e. high returns on investment [55], which are higher in economically strong regions.

Only recently has academia started to call for more attention for WACC settings and its meaning. Schmidt [25] stresses the need for a global database on financing costs and Polzin et al. [55] argue for not only looking at risks, but also at differences in returns. Egli et al. [27] collected project micro data from Germany and use both WACC determinants (return rates and financing shares) to deduce WACC for PV and Wind. For 2017, they find WACC of 1.6% for solar PV and 1.9% for

⁹ For instance, and as noted above, Pleßmann and Blechinger [17] assume WACC rates of 6% for conventional and 7% for renewable technologies.

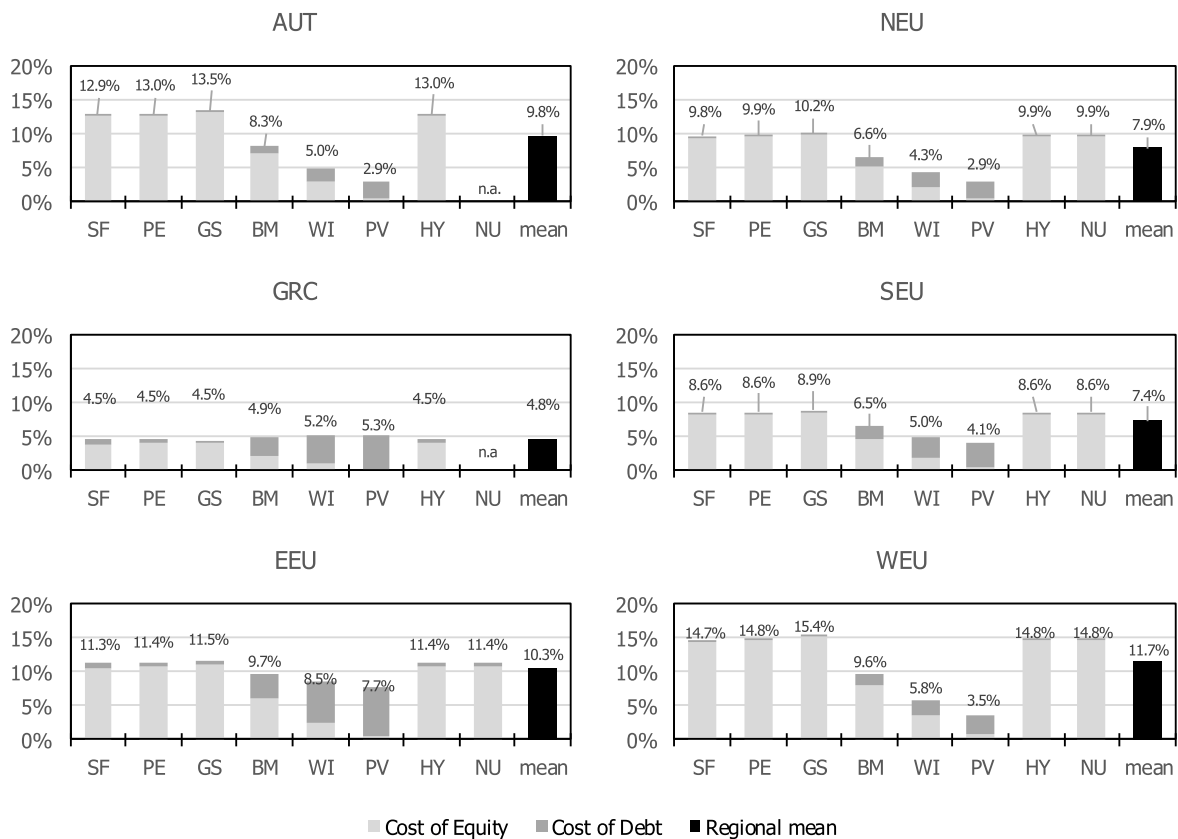


Fig. 2. WACC rates across regions and technologies of the MAIN setting. (SF = Solid Fossil Fuels (coal); PE = Petrol (oil); GS = Gas; BM = Biomass, WI = Wind, PV = Photovoltaics; HY = Hydropower; NU = Nuclear).

wind power plants (5.1% and 4.5% on average between 2000 and 2005, respectively). These are unprecedented low values, driven by high debt shares in combination with the current low return on debt rates; a beneficial financing structure that is also highlighted in [25]. Steffen [19] isolates the main drivers of this mechanism, revealing that mostly (groups of) individuals and (local) initiatives have used primarily debt money for financing renewables projects.

Taking up these recent findings, we explore the relevance of using detailed costs of capital data, considering regional and technological peculiarities. Following [56], we calculate WACC rates according to Eq. (1), which are replicable with publicly available data and are consistently determined. We use return on equity data from IMF [57], and return on debt data from World Bank [58] and ECB [59] (summarized in Figure A 4).¹⁰ The economic strength of regions like WEU and countries like Austria show up in relatively high returns on equity. In contrast, weaker economies, such as SEU and countries like GRC, face lower returns on equity. Regarding debt, low values of return on debt reflect low lending risks. We observe that north-western regions and Austria are confronted with lower rates as opposed to south-eastern regions and Greece. Interestingly, the regional means across regions are 11% for return on equity and 4% for return on debt, which correspond roughly to the upper and lower bound of the cost of capital range that is used in the literature (cf. Table A 1). To account for technological differentiation, we make use of the findings of [19] of different financing shares (debt or equity) for different technologies (summarized in

Figure A 5). This enables us to construct a technology- and region-specific WACC.¹¹

3.2. WACC settings for scenario simulations

In order to reflect the recent empirical findings regarding different financing structures, returns as well as risk (perception) in the electricity sector, we change/update the underlying WACC in different simulation runs in a stepwise manner. More specifically, we carry out the two simulation runs (EU-ref and RES-e) under different WACC assumptions, or settings, and investigate how these differences in WACC assumptions alter the macroeconomic effects of taking the RES-e instead of the EU-ref pathway.

As a point of departure (and to connect to the state-of-the-art literature) we adopt a uniform WACC rate of 8% across regions and technologies (setting UNI). In a second setting, which we will refer to as the “Main Setting” (MAIN), we deviate from this uniform WACC assumption and apply the calculated technology- and region-specific WACC. The calculated WACC are shown in Fig. 2, with values for wind ranging between 4.3% and 8.5% (average: 5.6%) and for PV between

¹⁰ To account for the currently exceptional situation in the aftermath of the 2007/2008 financial and economic crises, we take for each measure a medium-term median (2003–2017) of country-specific values instead of current values and aggregate individual country values using respective gross domestic product weights.

¹¹ One may argue whether these observed type-of-finance ratios for German projects are applicable for other regions and that this share could change over time (e.g. equity shares for renewables may increase if also large utility firms strive towards decarbonizing their portfolios). However, we deem these assumptions reasonable for at least two reasons. First, they are at most equally incorrect as assuming uniform WACC rates. Quite the contrary, they highlight the implications of assumptions that are inconsistent with observations. Second, the main objective here is gaining insight and not uncontested numbers. We investigate orders of magnitude effects and the sign of implications, not the exact value of costs and benefits related to the implementation of RPS.

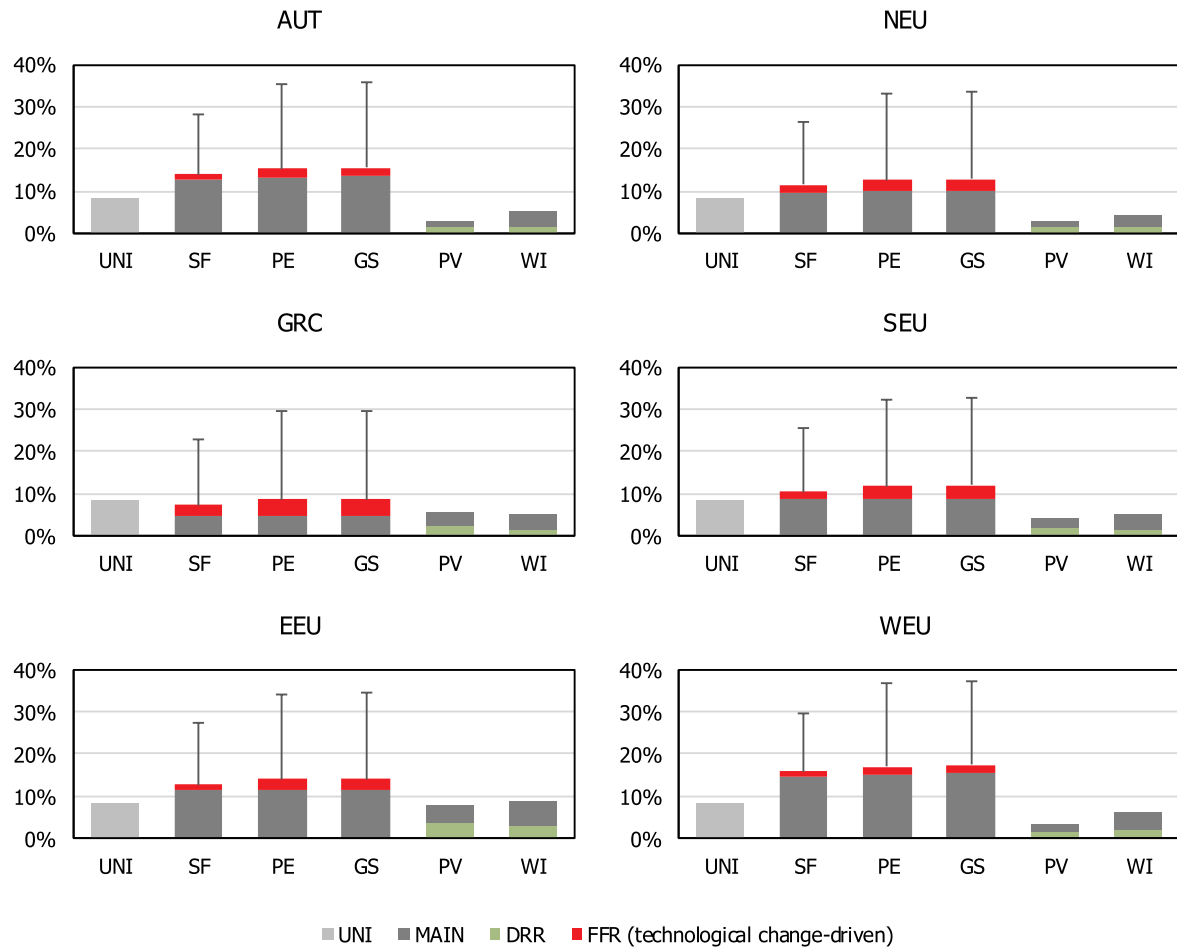


Fig. 3. WACC rates across regions and technologies of the Uniform (UNI), Main (MAIN), Fossil Fuel Risk (FFR) and De-risking Renewables (DRR) settings. Whiskers show the maximum of assumed WACC increase from climate policy instability risk. (UNI = Uniform WACC across all regions and technologies; SF = Solid Fossil Fuels (coal); PE = Petrol (oil); GS = Gas; PV = Photovoltaics; WI = Wind).

Table 1
Overview of WACC settings. (* = additional settings for sensitivity analysis).

Settings	Simulation run	WACC setting
UNI	EU-ref	Uniform
	RES-e	Uniform
MAIN	EU-ref	Main Setting
	RES-e	Main Setting
DRR	EU-ref	Main Setting
	RES-e	De-Risking Renewables
FFR	EU-ref	Fossil Fuel Risk (technology driven: 1/2 of lifetime)
	RES-e	Fossil Fuel Risk (technology and policy stability driven: 1/8 of lifetime)
COMB	EU-ref	Fossil Fuel Risk (technology driven: 1/2 of lifetime)
	RES-e	De-Risking Renewables and Fossil Fuel Risk (combined technology and policy stability driven: 1/8 of lifetime)
FFR_med*	EU-ref	Fossil Fuel Risk (1/2 of lifetime)
	RES-e	Fossil Fuel Risk (1/4 of lifetime)
FFR_low*	EU-ref	Fossil Fuel Risk (1/2 of lifetime)
	RES-e	Fossil Fuel Risk (1/2 of lifetime)

2.9% and 7.7% (average: 4.4%). The average across all technologies and regions is 8%, which lies in the middle of the range of usually used uniform WACC assumptions. Fig. 2 also clearly indicates the different financing structures of fossil and renewables.

In a third setting, called “De-risking Renewables” (DRR) we take into account that the perceived policy signal (i.e. an ambitious RPS), elevates investors’ trust in renewables, which reduces risk premiums

and thus WACC for renewables. We assume that WACC rates of renewables can be reduced to the rate as observed in the recent years in Germany [27] (1.6% and 1.9% for solar PV and wind, respectively).¹² Note that the policy signal from the ambitious RPS only exists in the RES-e scenario. We thus implement this assumption of lower WACC for renewables only in the RES-e simulation run.

In a fourth setting, “Fossil Fuel Risk” (FFR), we take into account that investors price in carbon-content-related risks for new investments, i.e. the risk of assets becoming stranded before their economic lifetime ends (with the exact point in time being uncertain, though).¹³ In the EU-ref simulation run, as a first approximation, we assume a halving of the expected lifetime for gas, coal and petroleum fired technologies (similar as done by [41]), which is assumed to be driven by technological change alone. In the RES-e simulation run, we account for an even higher risk and assume a lifetime reduction for fossil fired technologies to 1/8 of the respective economic lifetime. This is driven by technological change and in addition by the risk from climate policy instability, since a credible RPS might come along with the investor’s suspicion that policy could even speed up the transition, relative to what is signaled by the RPS (“ratcheting-up”).

¹² Compared to MAIN. The WACC of the other technologies remain as in the MAIN setting.

¹³ The reader can find an explanation of our approach in Appendix A6. Note that we keep WACC of PV, wind power, hydropower, biomass and nuclear power as in the main setting.

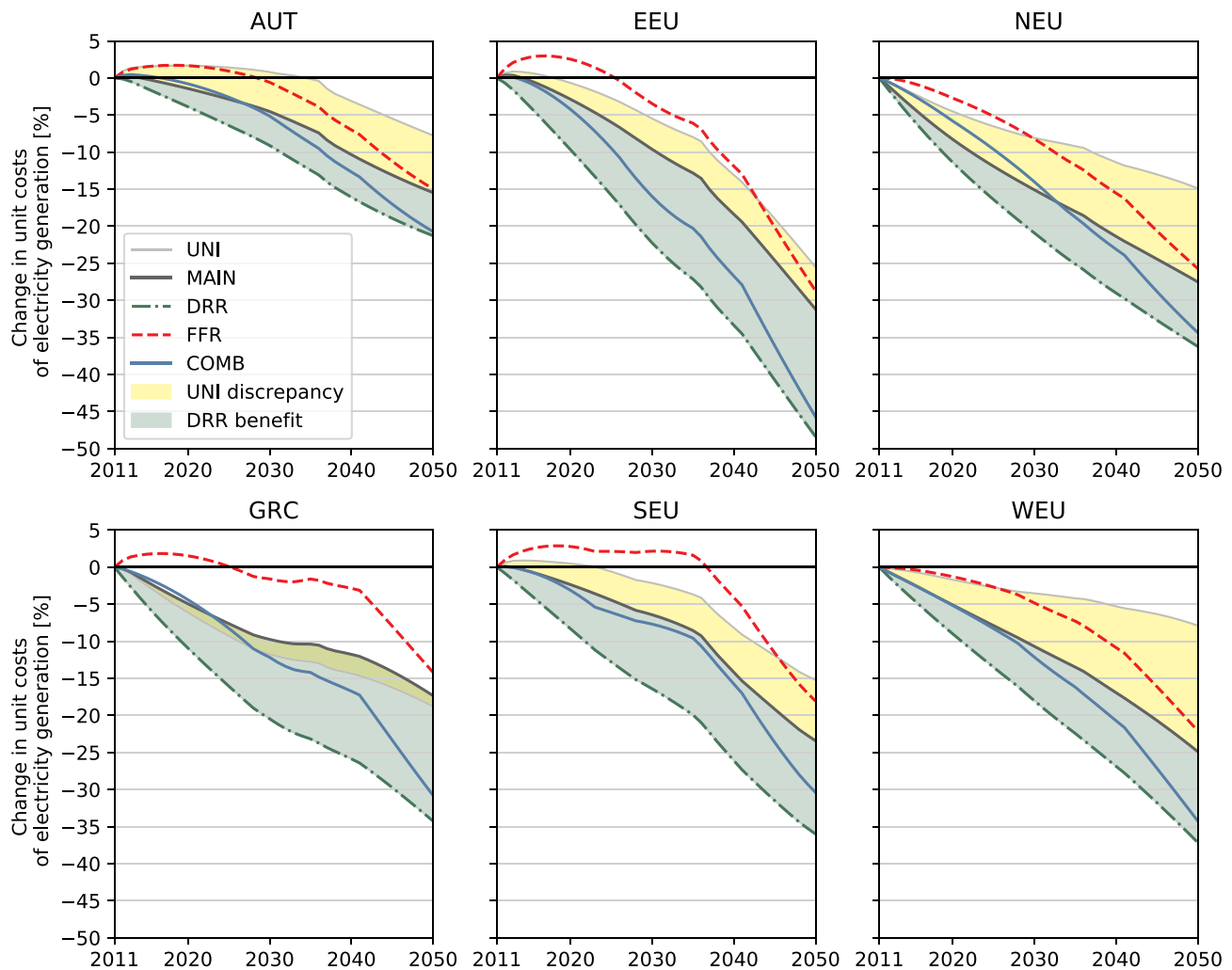


Fig. 4. Change in bottom-up derived unit-costs (RES-e versus EU-ref).

A last setting combines the isolated effects of DRR and FFR, denoted “Combination” (COMB). The five described settings are summarized in Fig. 3 and Table 1. All of the resulting WACC rates are shown in Table A 7.

4. Results

4.1. Direct economic effects

Fig. 4 shows the change in average unit costs of electricity (EUR/kWh), when comparing the RES-e to the EU-ref simulation under the different WACC settings as presented in Table 1.¹⁴ We observe one common pattern across all model regions: In the long run the average unit costs are lower in the RES-e simulation run compared to the EU-ref, irrespective of the chosen WACC setting. This reflects the recently observed, and further expected, decline in investment costs of renewables, particularly of PV and wind power. However, there are important differences in the short run and also between the different WACC settings.

First, we find that the uniform WACC assumption (UNI) leads to substantial discrepancies when compared to the more differentiated MAIN scenario setting (discrepancies shown as yellow shaded area). For some regions (Austria, EEU and SEU), this discrepancy even changes

the results qualitatively, with higher unit costs in the first years of the transition. Hence, the UNI setting substantially overestimates the direct (and consequentially also indirect) costs of the transition.¹⁵ Using the MAIN WACC setting, generation costs of the RES-e pathway are far below the EU-ref pathway, reaching cost reductions between −15% (AUT) and −30% (in EEU) by 2050. Second, we find strong cost-reducing effects from the assumed de-risking of renewables (DRR). A credibly designed RPS may increase trust in renewables, driving down risk perception and risk premiums for renewables. Due to the capital-intensive nature of renewables, this lever turns out to be very effective. The green area in Fig. 4 shows the possible benefit of such a de-risking (relative to the MAIN setting without de-risking). Thereby cost reduction can reach magnitudes between −20% (in AUT) and −45% (in EEU) below the EU-ref. This rather low WACC level under the DRR scenario setting should be regarded as lower bound, though.¹⁶ Third, we find interesting effects from including carbon-content related fossil fuel risks (FFR). In the first phase of the transition (RES-e), additional gas capacities are required to bridge the phase out of coal and oil-fired

¹⁵ The only exception is Greece, where we find a slight underestimation of direct costs, however less pertinent due to similar levels of return on debt and return on equity.

¹⁶ Note that the WACC development in Germany is not directly related to risk-reduction, but we choose these values as a possible lower bound of how low WACC can get in reality.

¹⁴ Note that this BU measure is net of any fiscal effects (e.g. a CO₂ price) and also does not acknowledge any macroeconomic feedbacks, yet.

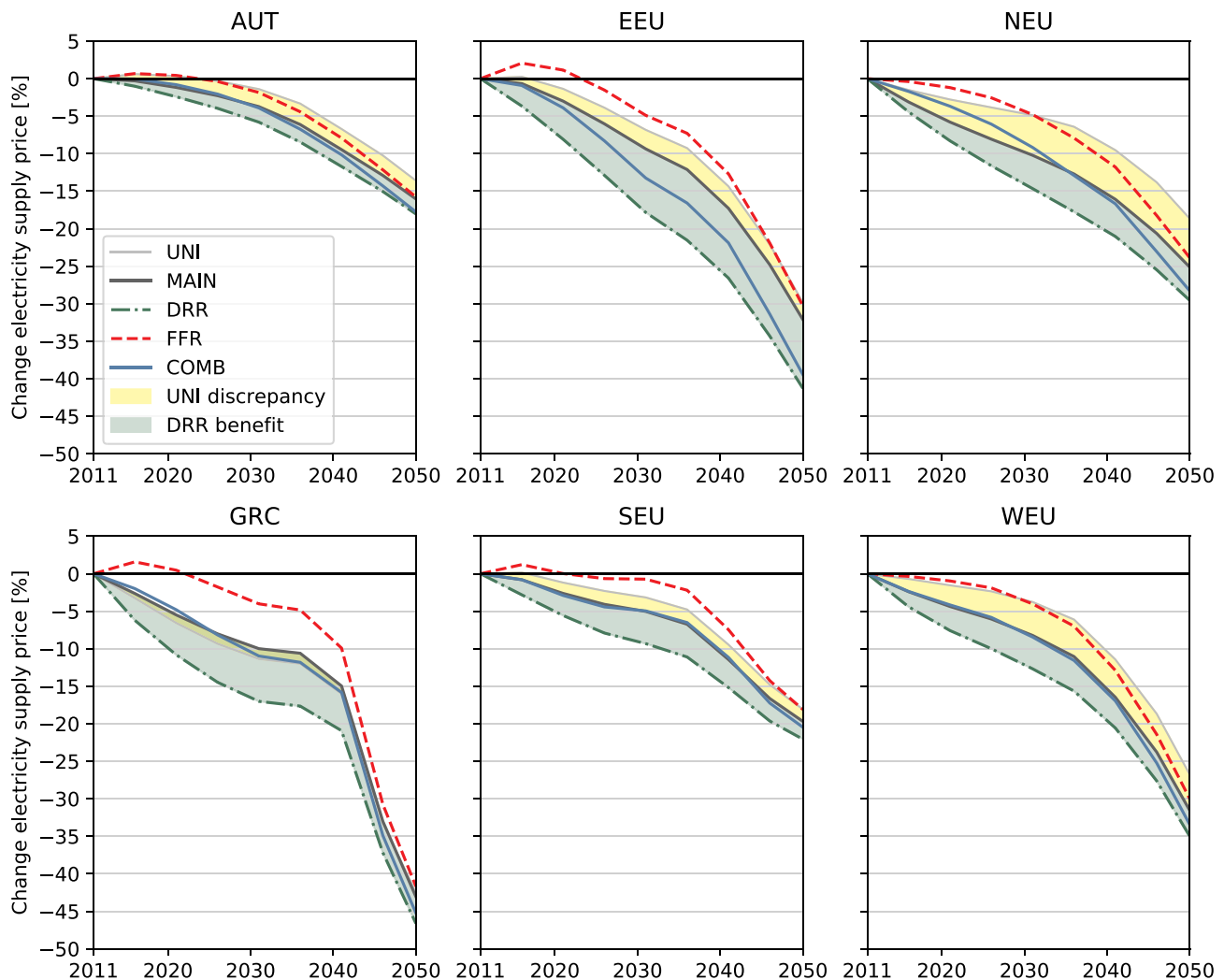


Fig. 5. Change in electricity supply price (RES-e versus EU-ref).

capacities. Factoring in fossil fuel related risk¹⁷ implies higher financing costs of these additional gas-fired capacities (as compared to the settings where this risk is not included) and thus of overall unit costs of electricity supply. In isolation, in some regions (Austria, Greece, EEU and SEU) this effect leads to unit-costs of the total supply of electricity that are even higher than in EU-ref. However, in the long term they converge back to the low values as under the MAIN setting. Finally, combining the isolated effects of DRR and FFR (COMB) reveals further interesting dynamics. Although long-term unit-costs are substantially below the EU-ref case, (here driven by the expected decline in investment costs of renewables as shown with UNI and MAIN) and policy could lower the long-term unit-costs even further, policy makers should be aware of fossil-fuel-related risk – which they can partly influence via stability signaling – on bridging technologies like gas-fired power plants. (The magnitude of the FFR is however subject to large uncertainty and we thus carry out further sensitivity analysis on this influential parameter in section 4.3).

4.2. Economy-wide feedback effects

In the following sections we present the economy-wide effects from integrating the direct effects into WEGDYN. We are now acknowledging

CO₂ pricing, investment costs for storage, macroeconomic and inter-sectoral feedbacks as well as cumulative capital stock effects over time.

4.2.1. Sector level

The large-scale renewable electricity expansion (RES-e) in Europe leads to changes in the market price of electricity relative to the EU-ref baseline, as shown in Fig. 5. Generally, the pattern of unit cost effects (Fig. 4) recurs in price changes, however with steeper reductions in the second half of the modeling period due to an increasing CO₂ price that supplements the transition. This effect is particularly strong for Greece, where in the EU-ref pathway coal fired power plants are phased out only by 2050, whereas in the RES-e pathway coal is phased out by 2035. This leads to a strong price advantage from 2035 onwards in the RES-e case. For Austria we see that the differentiation of WACC is less important, since Austria's electricity mix already has a relatively high share of renewables in the benchmark year (2011) as well as in the EU-ref scenario. This means that a de-risking of renewables has a weaker effect (lower WACC only apply for *additional* capacities), while simultaneously the country is less exposed to fossil fuel related risks. In general, we find that even without de-risking (i.e. MAIN) immediate price declines emerge in all regions. Only under a setting where there would be a fossil fuel risk (FFR), but no de-risking of renewables at all, electricity supply prices would be slightly higher in the first years of the transition (in Austria, Greece, EEU and SEU), but then converge towards the MAIN level in the long-run.

¹⁷ Driven by both technological change and possible climate policy instability (i.e. “ratcheting up”).

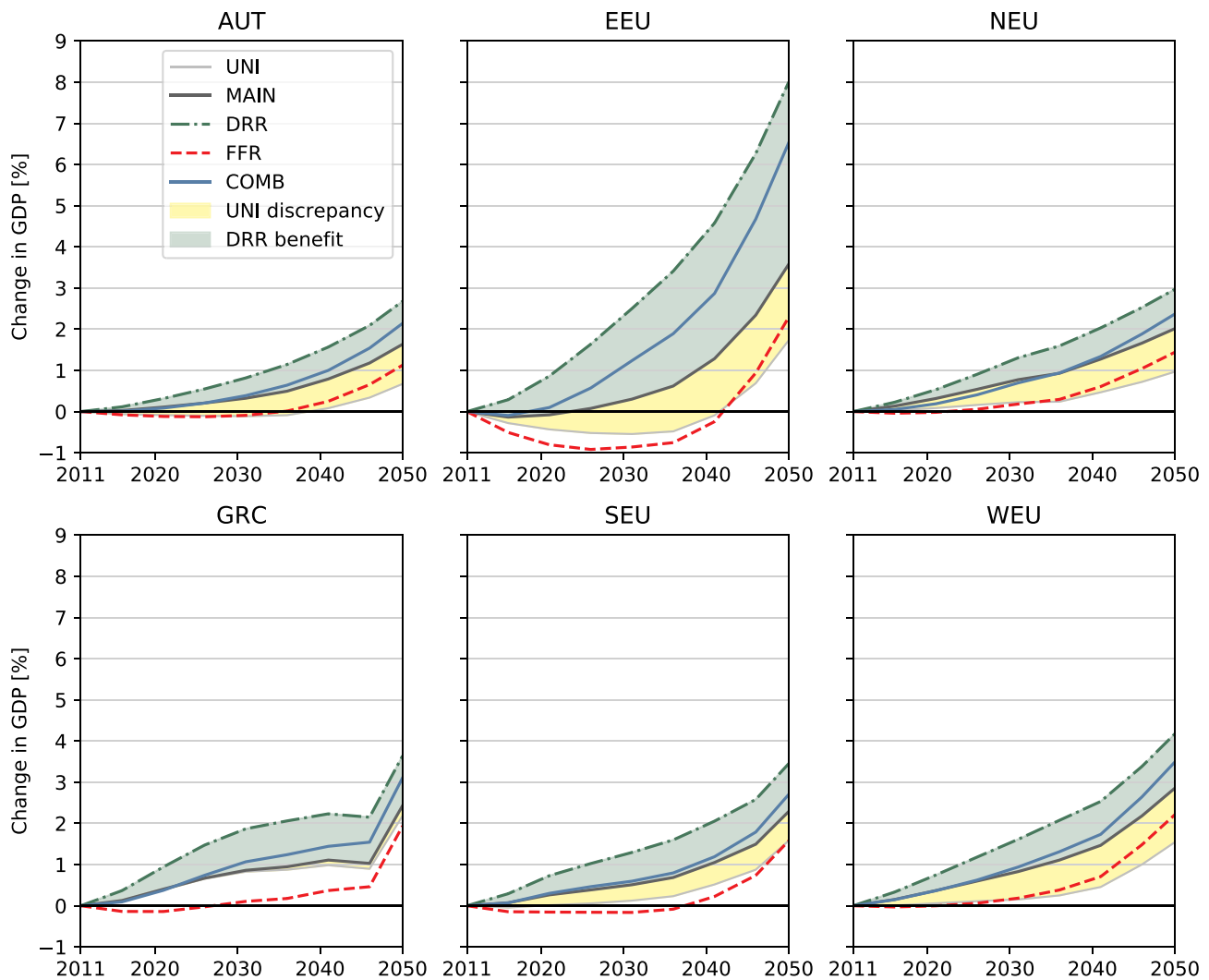


Fig. 6. Change in gross domestic product (RES-e versus EU-ref).

4.2.2. Macroeconomic level

Fig. 6 shows regional GDP effects. Under the MAIN WACC setting, long-term GDP implications are positive in all regions compared to EU-ref. This is due to the previously shown lower generation costs and market prices for electricity that lead to higher economy-wide productivity and thus GDP. In 2050 GDP is higher by +1.5% (Austria) to +3% (WEU) under the MAIN settings. Again, we find that a uniform WACC assumption would substantially bias the effects to the negative (yellow areas), potentially blocking the initiation of the transition due to the fear of lower productivity and GDP growth rates. When assuming de-risking of renewables (DRR) we find that the positive GDP effects from MAIN become even stronger (green areas show the benefits of de-risking), especially for regions in which large fossil fractions of the electricity mix are replaced by renewables (EEU and Greece). When also including a fossil fuel risk premium, these benefits of the transition are getting smaller, though (COMB). This is because of the “bridging-effect” as explained.

Contrary to GDP, for welfare the RES-e transition induces some unfavorable short-term effects as soon as large investments for storage become necessary (see Figure A 7, showing consumption possibilities of the regional household). This effect is particularly strong for Greece, where additional necessary investments are relatively large (see Figure A 10), requiring savings to be sharply increased, crowding out consumption accordingly. This leads to a negative welfare effect (−2% in 2046 in Greece), however only temporarily, since these investments

build up the capital stock, which becomes highly effective and generates capital income in the following years (which is also reflected in the steep increase in GDP in 2050 in Greece).

4.2.3. Labor market effects

Since renewables are much more capital intensive than fossil fuel-based technologies, the regional electricity mixes in the RES-e simulations are characterized by higher capital intensities and capital rents (Figure A 11). Thus, less labor is required which temporarily leads to higher unemployment rates¹⁸ (see Figures A 8 and A 9). However, our results show that in the long-term, positive effects on employment levels emerge in all regions, as the higher economy-wide productivity leads also to higher employment in non-electricity sectors. These results hold for all WACC settings, however, we find that an additional fossil fuel risk premium weakens this positive employment effect. Also, note that the uniform WACC assumption would again bias the results towards negative (or less beneficial) macroeconomic, in this case employment, effects.

¹⁸ Provided that economies are characterized by full capacity utilization, i.e. there is no output gap.

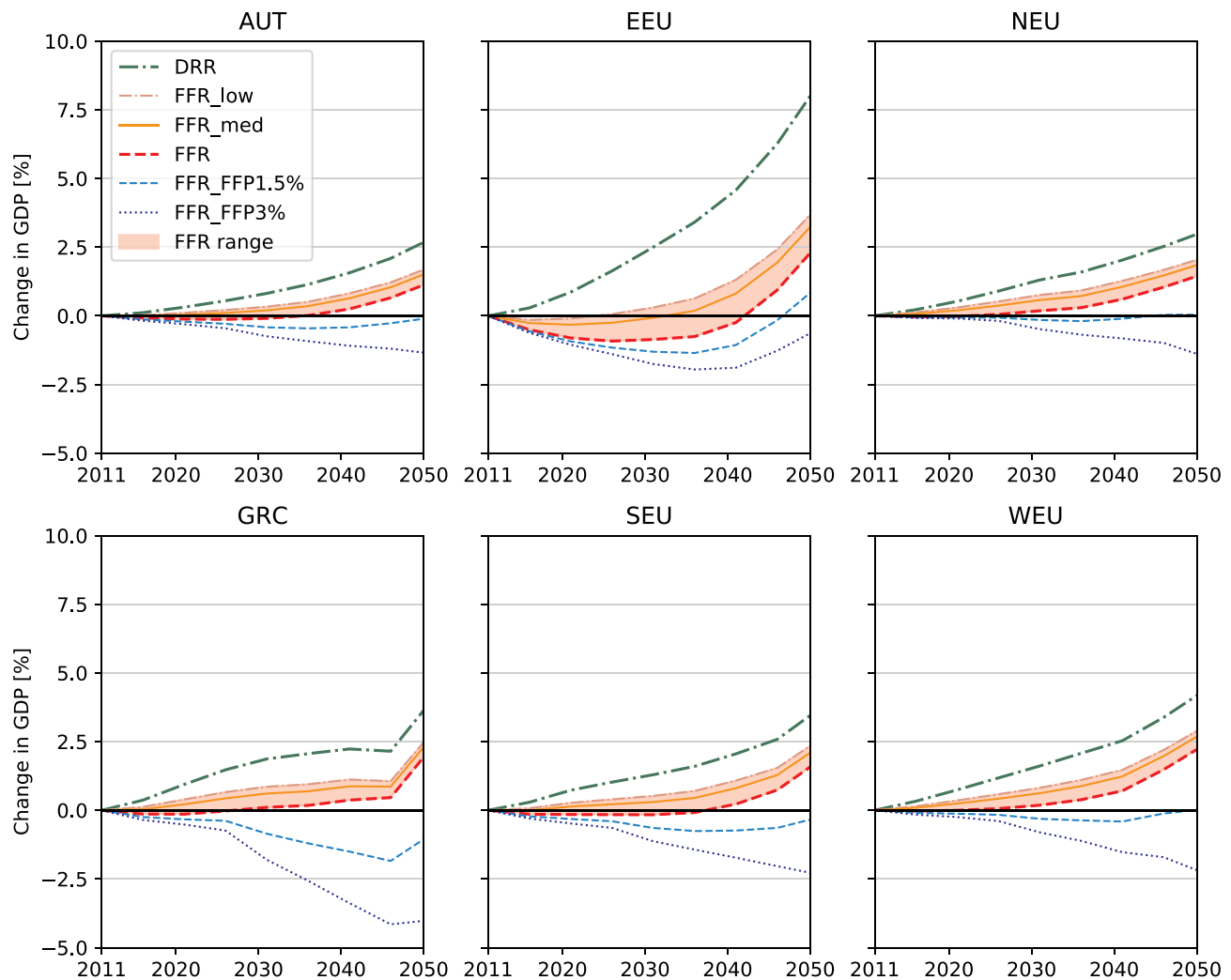


Fig. 7. Sensitivity analysis on changes in gross domestic product (RES-e versus EU-ref).

4.3. Sensitivity analysis

In the previous sections we have shown that the “best-case” setting (in terms of lowest transition costs) would be the DRR setting, i.e. a relatively strong de-risking of renewables but without any consideration of fossil fuel related risk. This DRR should be thus regarded as an upper bound for positive effects of de-risking. The setting that leads to the “worst-case” is when we only consider fossil fuel related risks, i.e. the FFR setting, which is associated with a fossil fuel risk premium that we approximated by a reduction to 1/8th of economic lifetime. This assumption is, however, highly uncertain and might be overestimating the additional risk premium from climate policy instability. Thus, we carry out sensitivity analyses in the FFR scenario setting, where we reduce lifetime to only 1/4 (i.e. FFR_med) and 1/2 (i.e. FFR_low) in the RES-e simulation run (instead of 1/8, cf. Table 1).¹⁹ The red shaded corridors in Fig. 7 show the range resulting from changing the lifetime reduction-assumptions. We find that when lowering the fossil fuel risk (i.e. going from FFR to FFR_med and FFR_low), GDP effects are shifted upwards, however only weakly, when compared to the effect of DRR.

Since climate policy in the electricity sector might also lead to changing risk perceptions and risk premiums in the fossil fuel extraction

sectors, we carry out further simulation runs where we – additionally to the standard FFR scenario setting – increase the global fossil fuel prices such that they are increased by 1.5% (FFR_FFP1.5%) and 3% (FFR_FFP3%) in 2050, as compared to the default model assumption. This increase is however only implemented in the RES-e simulation run, as the strong policy signal and respective fossil fuel risk only occur in this case. This would lead to relatively strong negative effects from following the RES-e pathway, as the whole economy would suffer from higher fossil fuel prices, particularly the gas-fired capacities which are needed for the bridging-phase of the transition. However, this effect should be interpreted with care, as we do not model any further decarbonization options in the non-electricity energy sectors (e.g. mobility, heating). This means that the economy cannot easily switch to cleaner technologies as they simply do not exist in the modelled world.

5. Discussion & limitations

In this article we shed light on the significant bias from uniform WACC assumptions, which also has far-reaching implications for economy-wide assessments. In state-of-the-art climate change mitigation assessments, be it via bottom-up or in integrated modelling exercises, WACC are typically not differentiated across technologies and regions but set to “standard” values. For the case of Europe's electricity sector, we show that this assumption systematically overestimates the direct costs of a low carbon transition and that also important policy-relevant macroeconomic indicators (e.g. GDP effects) follow this trend.

¹⁹ Note that FFR_low means that the fossil fuel risk premium only includes technological change-driven risk, but no additional risk from climate policy instability.

In some cases, this bias is so strong that anticipated costs even change to benefits when using a more differentiated approach for setting WACC parameters. The main reason for this bias is the difference in financing structures between conventional (fossil) energy and renewable energy technologies. Whereas financing of the former more strongly depends on equity, the latter depends much more on debt. This bias might lead to too cautious climate policy measures, and may even postpone or prevent measures. Further, we demonstrate in this article that there is a huge potential for economy-wide benefits, employment and stronger economic growth from de-risking renewable electricity technologies. This effect is significant for all modelled European regions, but particularly strong for those regions that currently face large fractions of fossil fuels in their electricity mix. Finally, we reveal interesting dynamics coming from the need of bridging the phase-out of coal and oil-fired electricity generation by using additional gas-fired capacities. As there are many reasons for expecting increasing risk premiums for fossil fuel investments (coming from both technological change but also climate policy instability) these additional capacities might be confronted with higher capital costs, which in turn might reduce the benefits of the low carbon transition. In total, however, we show that the potential benefits of an extreme de-risking scenario by far outweigh the potential negative effects from an extreme fossil fuel risk scenario.

As a limitation, we have to note here, that the equity shares in the financing structure of renewables might increase in the future, if large energy suppliers increase their portfolio shares of renewable energy. In a more decentralized energy system this might not be the case, though. Further limitations of the analysis relate to both the level as well as comprehensiveness of carbon-content-related risk (and corresponding risk premiums). Regarding the level, we choose a simple approach for a first approximation of changing capital costs, by reducing the economic lifetime in the calculation for annuities. To that end more sophisticated methods and research are needed. Endogenizing risk-perception based on market shares could be one way to approach this. Regarding comprehensiveness, we note that in the analysis presented we focus on power plant investment risk but not on possible investment risk for extraction facilities (e.g. offshore oil or gas platforms). However, first sensitivity analyses indicate that also acknowledging the existence of risks in the fossil fuel extraction sector might have additional strong effects.

A further limitation is the uncertainty regarding investments requirements and the here-imposed assumption of full capacity utilization [60]. These issues should be explored in more depth in future assessments. Welfare measures, in terms of consumption possibilities, are especially sensitive to this assumption, as more investments at the cost of higher savings (and thus less consumption) might lead to less beneficial (or negative) welfare effects.

Appendix. A1: Literature review on the current handling of interest rates in energy modelling

A2: Underlying model and shared socio-economic pathway assumptions

We use SSP2 growth rates for GDP and population to calibrate the model. SSP2 represents a middle-of-the road scenario [78]. It is implemented through exogenous parameters for regional effective labor force growth (capturing population growth), multi-factor productivity growth, autonomous energy efficiency improvements, and capital depreciation rates, such that region-specific GDP growth rates are met. Additionally, a moderate CO₂ tax is included, starting with 5 EUR/tCO₂ in 2011 and reaching 46 EUR/tCO₂ in 2050. This reflects the IEA [79] “New policies scenario” (given for EU, but implemented globally to mimic nationally determined contributions as a weak price signal).

A3: Electricity generation technology data

In 2011, the installed capacity for each electricity generation technology is shown in Table A 4. Assumptions on technology-specific investment costs and economic lifetime are given in Table A 5. For the former, we apply the values from [17] for the benchmark year 2011. Technological progress in PV and wind power technologies is highly dynamic. We therefore use detailed observations for the benchmark year 2011 and the latest available information at times of modelling: 1,000 EUR/kW in 2014 for a representative PV system (i.e. module, inverter and components for system balancing) given in [80] (Fig. 40) and [81] (Fig. ES-1) and 2,050 EUR/kW in 2017 for a representative wind power plant (assuming 75% onshore) given in [82] (Fig. 5.3 and 5.10). Expected investment costs in 2050 for PV and wind power are taken from [80,83]. Note that we linearly interpolate

6. Conclusions

Our findings indicate that immediate positive effects emerge at macroeconomic scales when using more accurate data on capital costs and more up-to-date data on investment costs of renewable electricity technologies. Consequently, weighted average costs of capital (WACC) assumed for both fossil-based and renewable technologies, need to be handled with care, communicated transparently and differentiated. Uniform WACC assumptions (across technologies and regions) imply a significant bias in results, which by now can be avoided relatively easily. A more accurate modelling framework adds important robustness to techno-economic modelling and possibly even a more ambitious climate policy.

De-risking renewables further improves the effects of renewable electricity transition across all regions, particularly in eastern and southern Europe, where electricity is produced relatively CO₂-intensive in the reference scenario. The positive effects do not involve any need for technology costs to become cheaper, but the credible long-term framework conditions turn out to be most important. Setting up such conditions does not necessarily involve large direct costs and can also be implemented unilaterally.

We also conclude that the bridging-phase needs special attention. If gas capacities are used in the beginning of the transition for phasing-out coal and oil, conflicting goals may emerge, as policy makers are on the one hand interested in fostering the transition, but by sending signals to eliminate fossil fuel use the transition actually might get more expensive. However, we show that the potential benefits of an extreme de-risking renewables setting outweigh the potential negative effects of an extreme fossil fuel risk setting.

By considering the fact that transitions towards renewables are particularly capital-intensive, the analysis exceedingly emphasizes that investors' risk perceptions of renewables are of higher relevance than those of fossils. Thus, the role of expectations from investors and associated financial policies and macroprudential financial regulations should be given a more prominent role, going beyond carbon pricing, as discussed by [61]. De-risking renewables provides decision makers with an additional game-changing option for staying within long-term climate policy objectives. The results clearly show the value of more reliable financing cost parameters: they are of utmost epistemic importance.

Acknowledgements

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investment costs until 2050 for all technologies. Economic lifetime assumptions are based on [83].

The reference LCOE for each region is calculated taking the generation-weighted average of technology-specific LCOE in the benchmark (based on data from [84], cf. Table A 6). This results in reference LCOE of 0.06 EUR/kWh for AUT, of 0.08 EUR/kWh for GRC, NEU and SEU, of 0.09 EUR/kWh for WEU and of 0.10 EUR/kWh for EEU.

A4: Linking electricity sector investment-cycle model with the top-down CGE model

Based on the benchmark electricity generation quantities in 2011 [kWh] (Table A 4) and target shares in 2050 by technology (Fig. 1), we calculate technology-specific demand in a spreadsheet module as follows. For PV and wind, we take the benchmark and target quantities and assume logistic break-through. For all remaining technologies except gas, we linearly interpolate between 2011 and 2050. The resulting residual load is filled with generation from gas power plants based on the assumption that it represents the most flexible technology in terms of “dispatchability.”

The resulting technology-specific “demand” trajectories (measured in [kWh]), which represent the exogenously imposed RPS, are then compared to potential output (based on existing capacities) determining whether additional capacities have to be built up. If so, the required investments are converted to vintage-differentiated annuities, ultimately increasing capital expenditures (CAPEX) in the respective periods of repayment (which is assumed to coincide with the economic lifetime of the technology). The derivation of annuity payments A follows the common specification

$$A = S \frac{(1+i)^t i}{(1+i)^t - 1}, \quad (A1)$$

with S being the loan amount, i being the interest rate and t being the financing term.

Based on the specific capacity development of each technology also the development of the operating expenditures (OPEX) can be evaluated applying unit-OPEX of the benchmark to actual generation throughout 2050.

The bottom-up calculated development of OPEX and CAPEX (which differ for the EU-ref and the RES-e scenario since target shares in 2050 are different) flows into the macroeconomic top-down assessment in the following way. First we rescale the benchmark inputs of each technology-specific production function (measured in [EUR]) for a given year in order to reflect the changing input structure over time. For this purpose we use each input i to electricity generation $ELY(i)$ classified as OPEX (i.e. excluding capital input) to calculate the benchmark share of operating expenditures $ox_sh_bench(i)$ (measured in [%]) in order to update the over time changing OPEX (measured in [EUR])²⁰:

$$ox_sh_bench(i) = \frac{ELY(i)}{\sum_i ELY(i)}. \quad (A2)$$

Accordingly, vector $A(i, t)$ consists of all updated OPEX multiplying the benchmark share of operating expenditures with the actual OPEX in period t , and we extend this vector with an entry for technology-specific CAPEX in the respective period which gives us vector $A^*(i^*, t)$ with i^* being all inputs to electricity generation including capital. Vector $A^*(i^*, t)$ is then used to calculate a dimensionless factor Q which is weighted with the inverted input share of the benchmark and subsequently multiplied with the benchmark inputs of the production function for each electricity generation in the macroeconomic model (measured in [EUR]):

$$A(i, t) = ox_sh_bench(i) * OPEX(i, t), \quad (A3)$$

$$Q(i, t) = \frac{A^*(i^*, t)}{\sum_{i^*} A^*(i^*, t)} \frac{\sum_{i^*} ELY(i^*)}{ELY(i^*)} \quad (A4)$$

Note that the updated cost structures for each electricity generation technology still represent unit-cost functions. Those are combined to give an electricity mix. To account for the changing technology-specific unit-costs we use a cost mark-up cmr which gives the ratio of the technology-specific updated unit-costs UC and the reference levelized costs of electricity²¹ $LCOE_{ref}$ for each technology tec in period t :²²

$$cmr(t, tec) = \frac{UC(t, tec)}{LCOE_{ref}}. \quad (A5)$$

This cost mark-up ratio is then weighted with the inverted technology-specific benchmark generation $BG(tec)$ (measured in [EUR]) and the technology-specific physical generation target $PG(tec)$ of each period t (measured in [kWh]) representing a dimensionless cost mark-up factor cmf which is used for scaling the unit costs in the electricity mix:

$$cmf(t, tec) = \frac{\sum_{tec} BG(tec)}{BG(tec)} * \frac{PG(t, tec)}{\sum_{tec} PG(t, tec)} * cmr(t, tec). \quad (A6)$$

This approach warrants the vintage-based integration of the OPEX and CAPEX development in the dynamic-recursive CGE model.

A5: Handling of investments for grids and storage infrastructure

Total system investment costs are composed of three parts: 1) power plants, 2) grids and 3) batteries and P2G facilities. Regarding 1) and 2) we assume crowding out of other generic investments, meaning that total investment volume does not change between EU-ref and RES-e. On the contrary, for 3) we account for *additional* investments for batteries and P2G facilities (only necessary in RES-e), which are modelled explicitly as additional investments, financed via higher savings and thus a reduction in consumption. The corresponding annuities materialize as additional annual capital costs of the electricity sector. Figure A 3 shows these additional investments costs by region for the modelled annual time slices (before 2036 no storage investments are necessary).

²⁰ For convenience, we drop indices for model regions and electricity generation technologies.

²¹ The region-specific reference unit-costs represent the average LCOE of each technology weighted with the benchmark share of generation.

²² Note that we here drop only region indices.

A6: Additional material and explanations for WACC calculation

We use a typical specification of the annuity factor AF of an investment project as the point of departure for assessing the relationship between a project's lifetime t and its WACC i (Eq. (A1)). The initial settings are $i = 10\%$ and $t = 40$ years. In a first step we reduce the underlying economic lifetime (e.g. halving it to 20 years) to calculate a new annuity factor. In the second step we then set the lifetime back to its original value (i.e. 40 years) and solve for the interest rate that reaches the same new annuity factor as determined in the first step. As the AF formula is not invertible, we solve numerically.

For very large reductions in the economic lifetime of a project, the WACC can get prohibitively high. If the project can exploit only 18% of its usual lifetime (ca. 7 years instead of 40) the WACC doubles for the given numerical example. Figure A 6 shows the relationship between the lifetime reduction and the corresponding WACC, according to the described method.

A7: Additional results

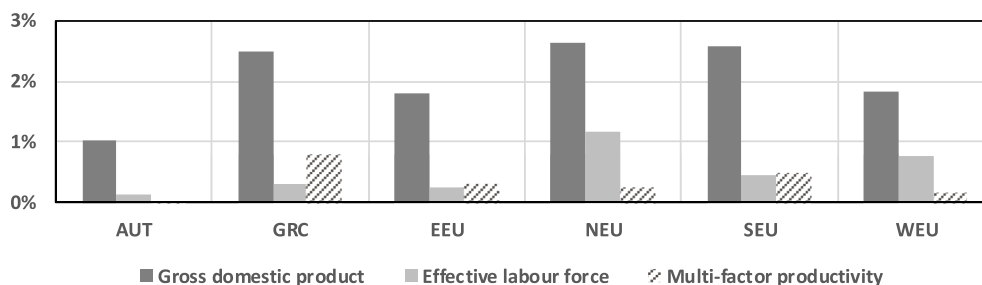


Fig. A1. Regional economic growth rate, effective labor force growth rate and multi-factor productivity growth per anno for SSP2.1

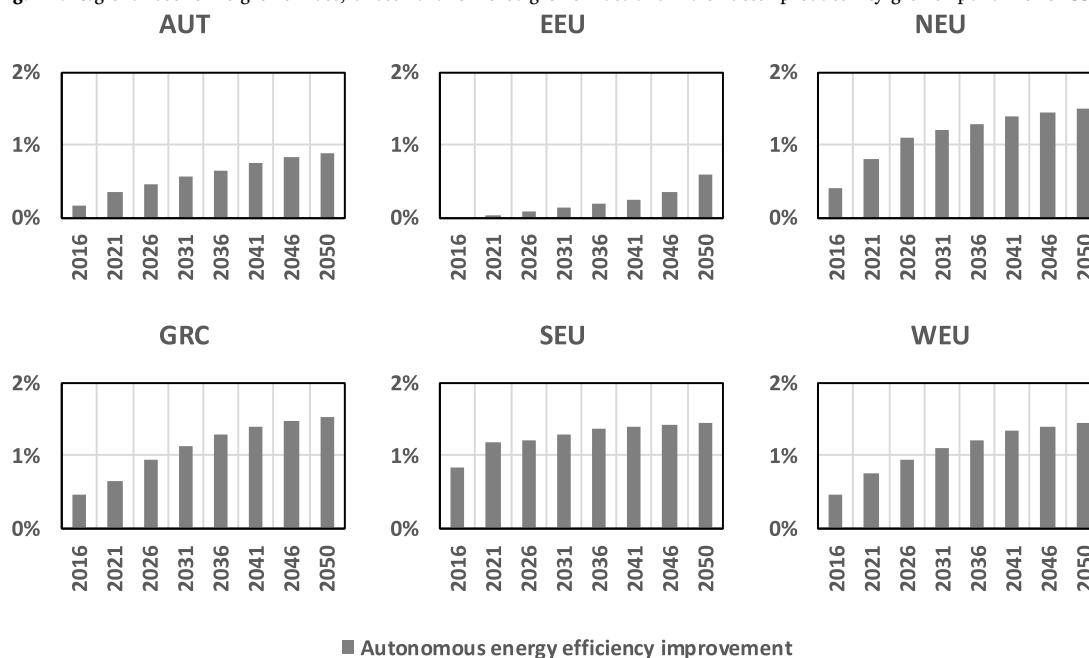


Fig. A2. Assumptions on annual autonomous energy efficiency improvement per policy region.2

Storage total investment costs [Bn. EUR]

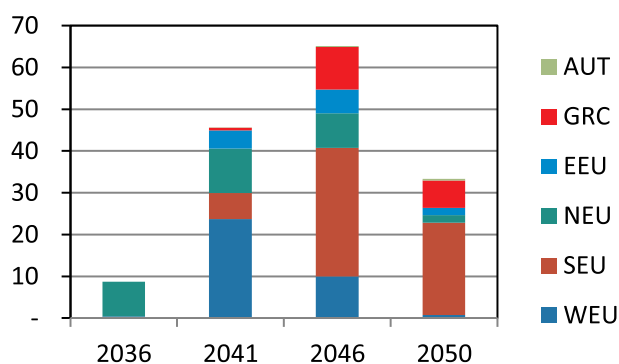


Fig. A3. Annual storage investment costs in billion EUR by region for the modelled time slices (based on [17]).3

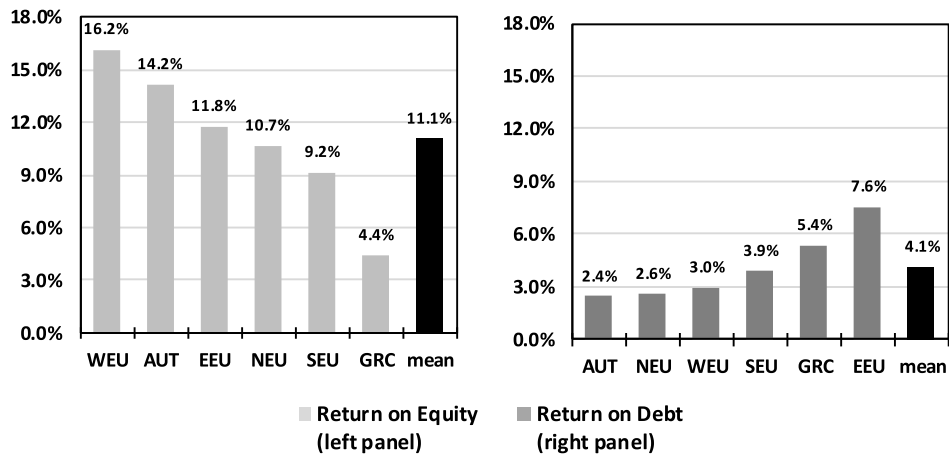


Fig. A4. Regional return on equity and return on debt rates, based on long-term country data on equity (IMF, 2019) and debt (ECB, 2019; World Bank, 2019) for non-financial corporations.⁴

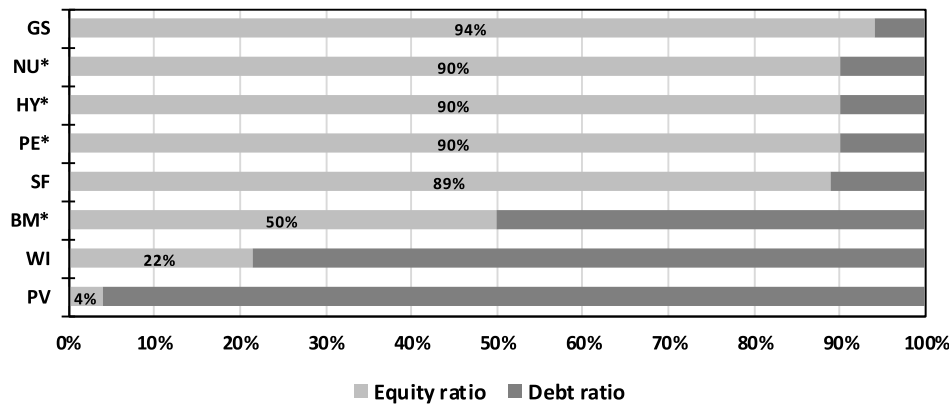


Fig. A5. Type of financing by electricity generation technologies based on Steffen (2018, Fig. 4). We assume an offshore share of 25% for wind power (WI) across Europe. *Author's assumption for other (conventional) technologies, which are not depicted in Steffen (2018).⁵

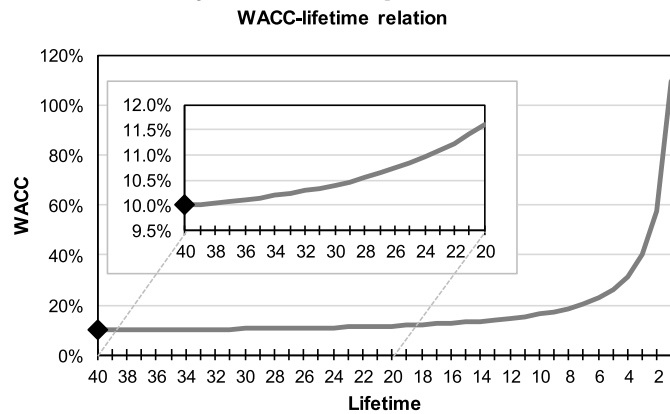


Fig. A6. Relationship between WACC and lifetime of a representative investment project. The marker indicates the initial setting.⁶

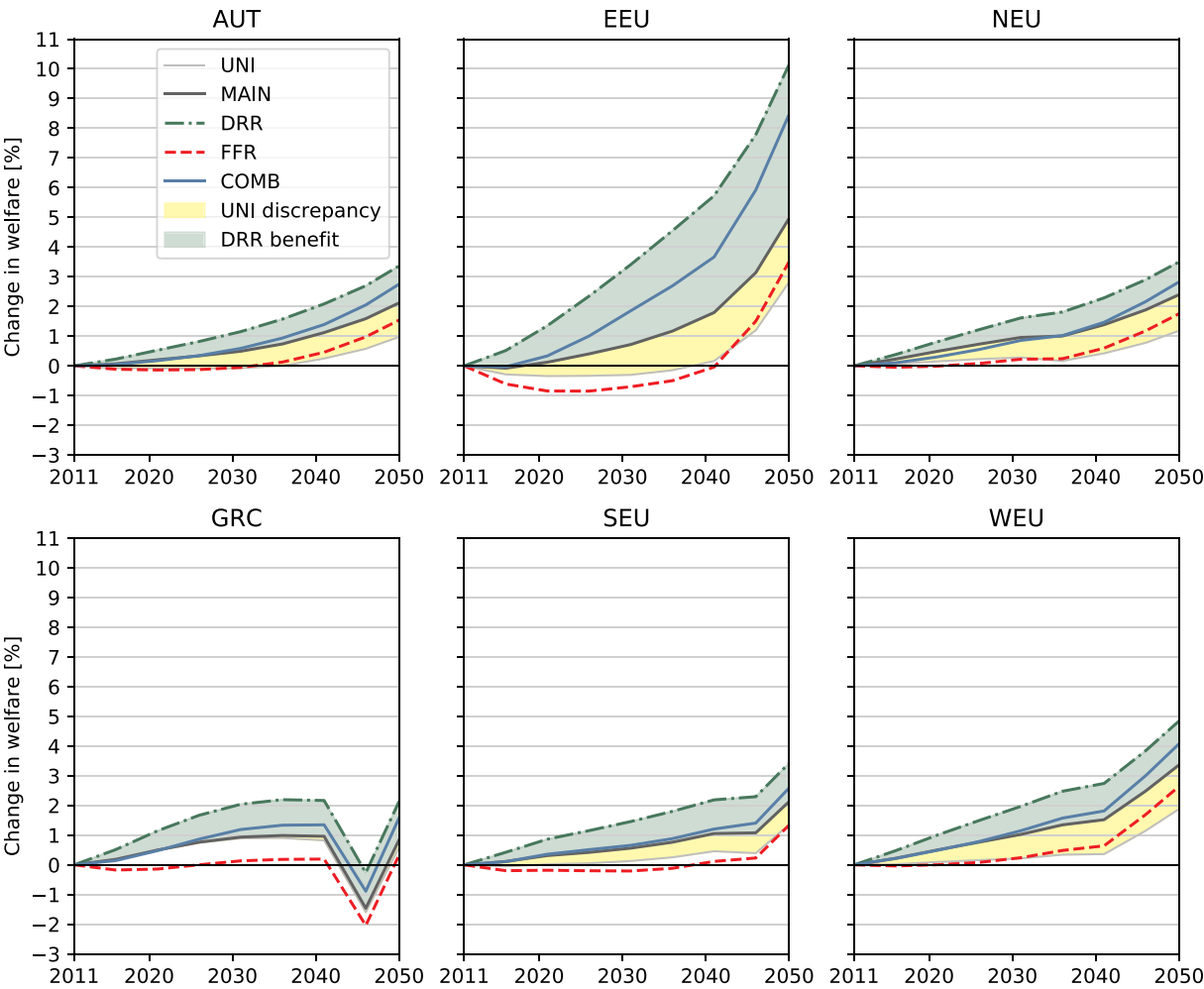


Fig. A7. Change in welfare (RES-e versus EU-ref).

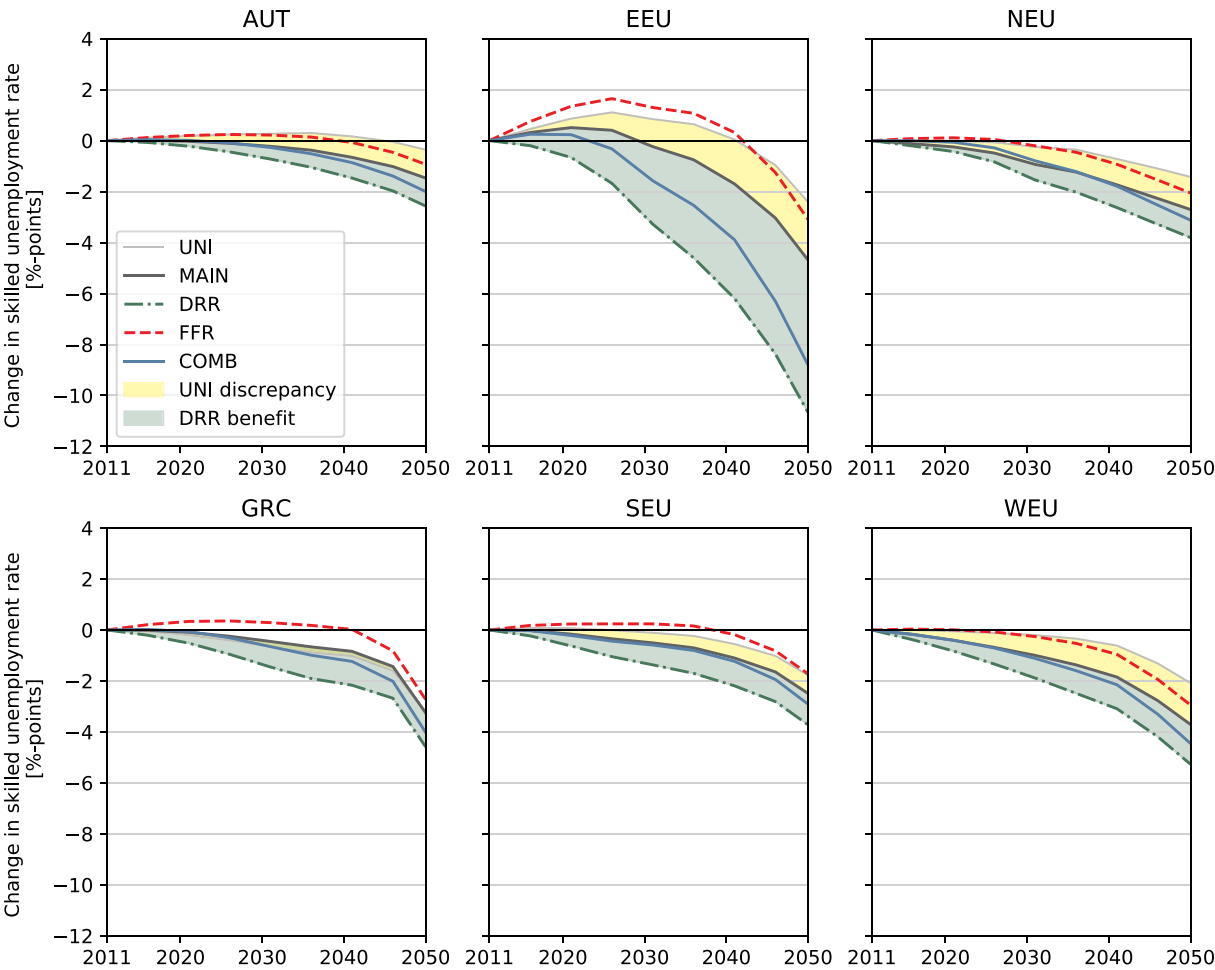


Fig. A8. Change in unemployment rate of skilled labor (RES-e versus EU-ref).

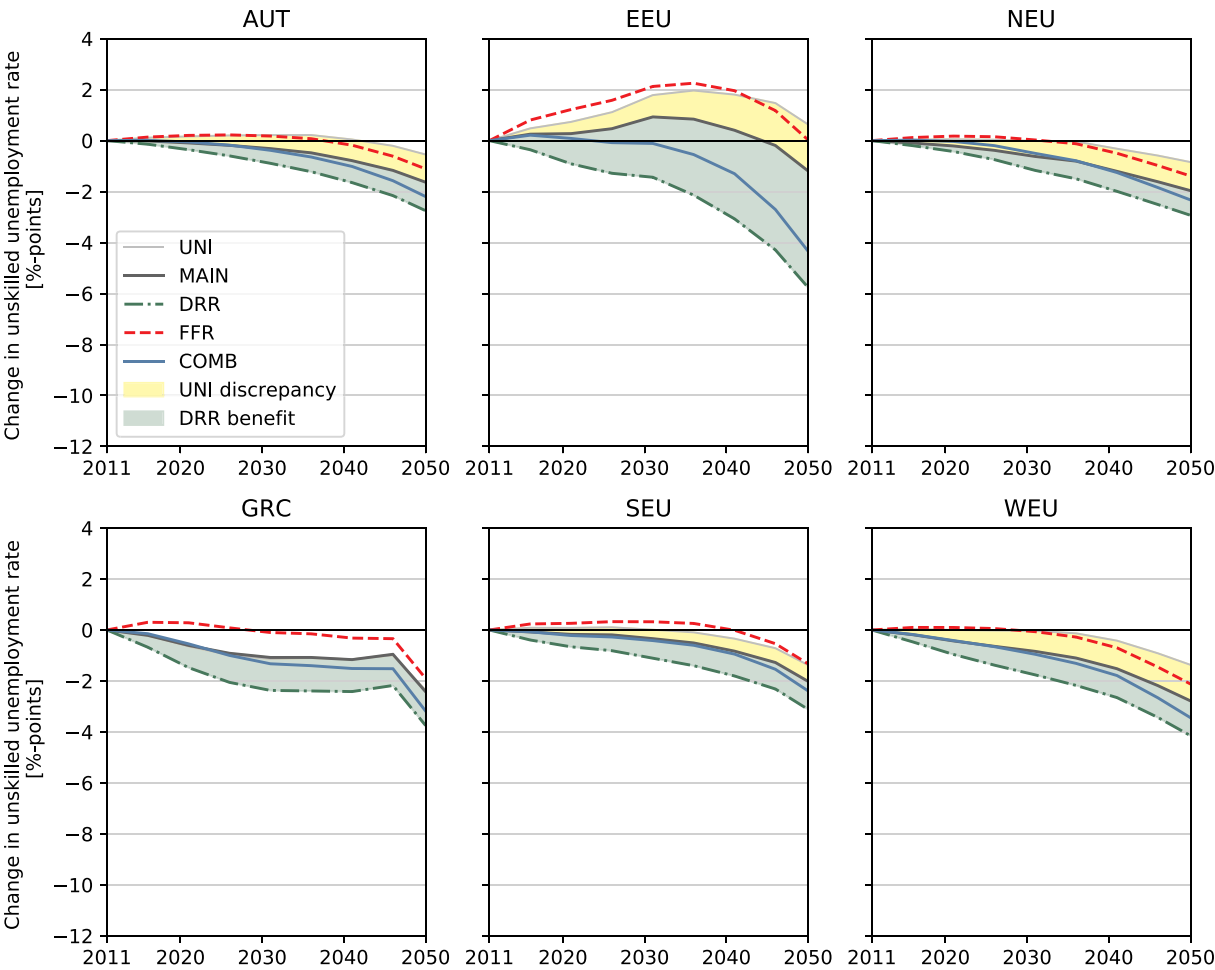


Fig. A9. Change in unemployment rate of unskilled labor (RES-e versus EU-ref).

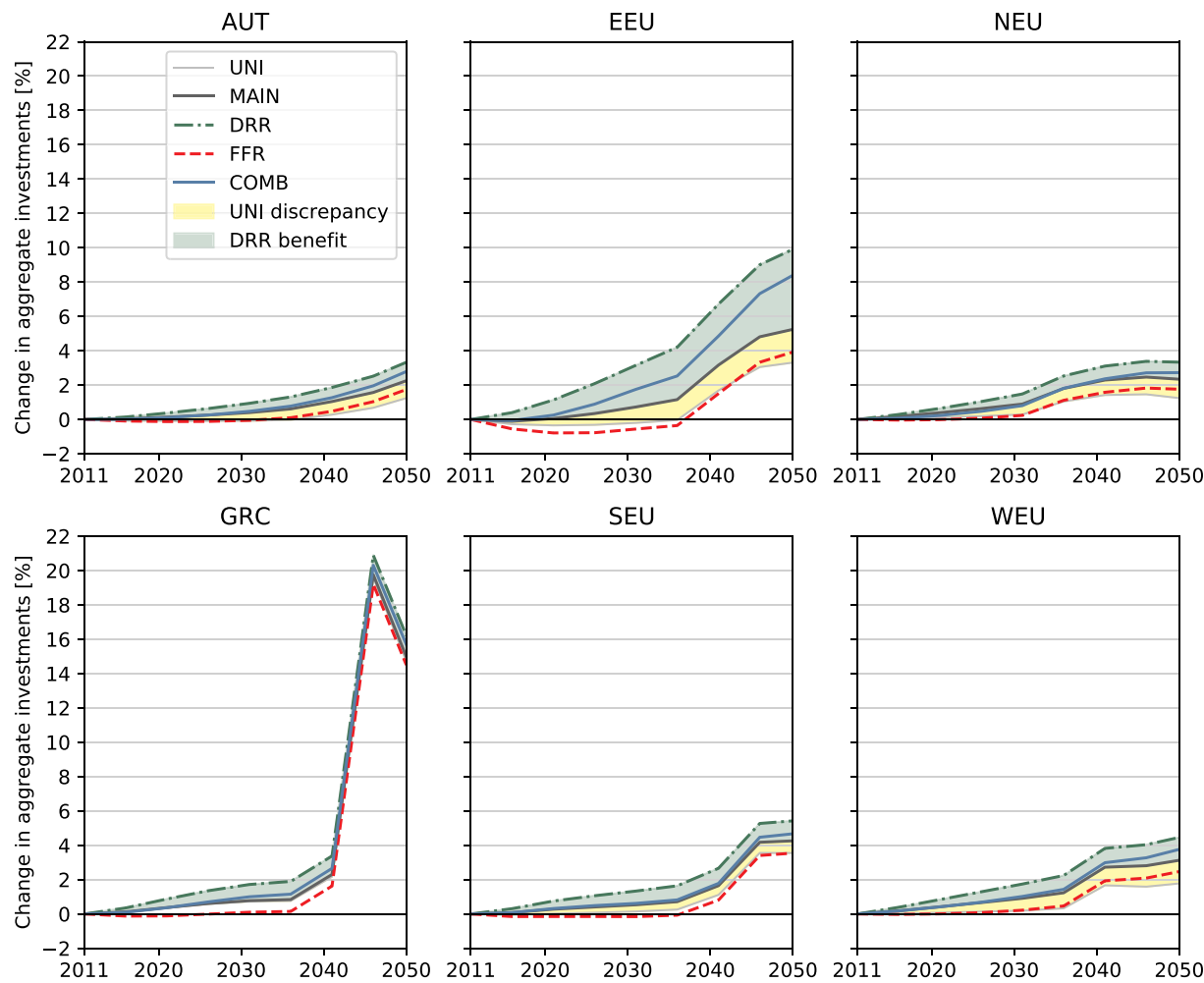


Fig. A10. Change in total investment (RES-e versus EU-ref).

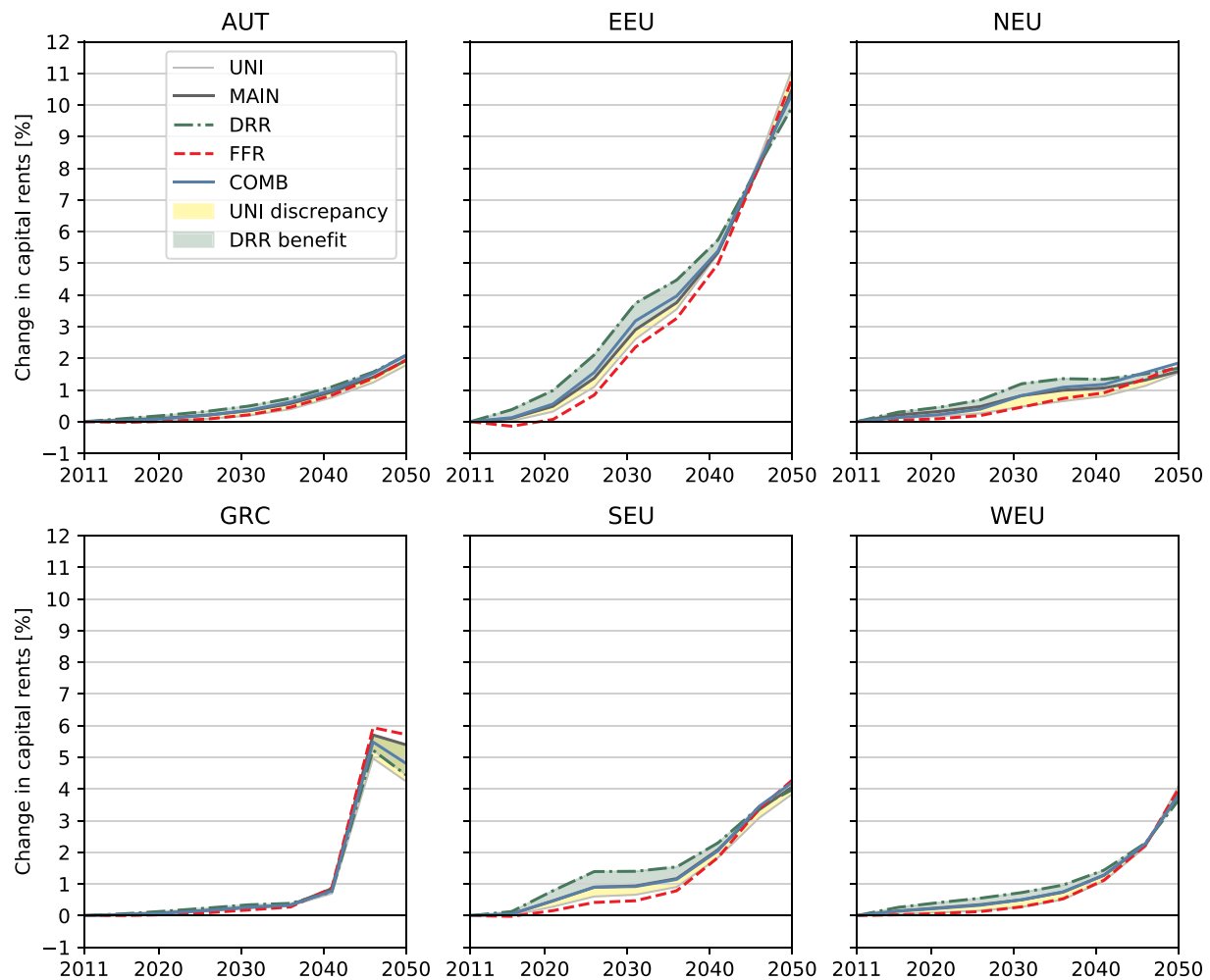


Fig. A11. Change in capital rents (RES-e versus EU-ref).

Table A1

Interest rate assumptions of various models used for policy evaluation in the energy-economy-environment context. BU = bottom-up; TD = top-down; (N)LP = (Non) Linear Programming; PE = Partial Equilibrium; CGE = Computable General Equilibrium; n.s. = not specified; *Evolutionary bottom-up simulation of technology diffusion & top-down macro-econometrics. #Technology-specific hurdle rates.

Model class	Model acronym	Method	Interest rate assumption	Sensitivity analysis	References
BU	elesplan-m		6%-7%	No	[17]
BU	Calliope	LP	10%	yes	[16]
BU	DIETER	LP	n.s.	no	[62]
BU	EMMA	LP	7%	no	[63]
BU	ETSAP/TIAM	LP	5%	yes	[64]
BU	ETSAP/TIAM & TIMES-Norway	LP	5% [#]	yes	[18]
BU	REMIND/TIAM	NLP	5%	yes	[65]
BU	IMAGE	PE	10%	no	[66,67]
Hybrid	FTT-E3ME	*	10%	yes	[30]
Hybrid	MESSAGE-MACRO	LP/CGE	n.s.	yes	[8,68]
Hybrid	PRIMES/GEM-E3	PE/CGE	8%	no	[69,70]
TD	AIM/CGE	CGE	n.s.	no	[71]
TD	-	CGE	n.s.	no	[72]
TD	EPPA	CGE	n.s.	no	[73–75]
TD	GEM-E3	CGE	n.s.	no	[76,77]

Table A 2
Aggregate sectors and regions of the WEGDYN CGE model.

Model sector code	Aggregated Sectors	Model country code	Region Name
AGRI	Agriculture	AUT	Austria
COA	Coal	GRC	Greece
CRP	Chemical, rubber, plastic products	EEU [#]	Eastern Europe
ELY*	Electricity	NEU [#]	Northern Europe
EXT	Extraction	SEU [#]	Southern Europe
FTI	Food and textile industries	WEU [#]	Western Europe
GAS	Gas	AFR	Africa
I_S	Iron & Steel: basic production and casting	CAN	Canada
NMM	Mineral products	CHN	China
OIL	Oil	ECO	Emerging economies
P_C	Petroleum, coke products	IND	India
PPP	Paper, pulp and paper products	LAM	Latin America
SERV	Other services and utilities	OIGA	Oil and gas exporting countries
TEC	Tech industries	RASI	Rest of South & East Asia
TRN	Transport	REU	Rest of Europe
CGDS	Capital goods	USA	United States

Notes: *Represented by eight generation technologies (Solid fuels, Petroleum, Gas, Nuclear, Hydropower, Biomass, PV, Wind) and one subsector for Collection and Distribution. [#]EEU includes: Bulgaria, Czech Republic, Hungary, Poland, Romania, Slovakia, and Slovenia. NEU includes: Estonia, Lithuania, Latvia, Denmark, Finland, United Kingdom, Ireland, Norway, and Sweden. SEU includes: Croatia, Cyprus, Spain, Italy, Malta, and Portugal. WEU includes: Belgium, Germany, France, Liechtenstein, Iceland, Luxembourg, and the Netherlands.

Table A3
Regional aggregates of the WEGDYN model.

Model code	Aggregate name	Aggregated countries
AUT	Austria	Austria
GRC	Greece	Greece
EEU	Eastern Europe	Bulgaria, Czech Republic, Hungary, Poland, Romania, Slovakia, Slovenia
NEU	Northern Europe	Estonia, Lithuania, Latvia, Denmark, Finland, United Kingdom, Ireland, Norway, Sweden
SEU	Southern Europe	Croatia, Cyprus, Spain, Italy, Malta, Portugal
WEU	Western Europe	Belgium, Germany, France, Liechtenstein, Iceland, Luxembourg, Netherlands
CHN	China	China
IND	India	India
CAN	Canada	Canada
USA	USA	USA
REU	Rest of Europe	Albania, Switzerland, Bosnia-Herzegovina, Makedonia, Serbia, Moldavia
ROI	Rest of industrialised countries	Australia, New Zealand, Japan
ECO	Emerging economies	South Africa, Hong Kong, Armenia, Azerbaijan, Georgia, Kazakhstan, Kyrgyzstan, Russian Federation, Tajikistan, Turkmenistan, Ukraine, Uzbekistan, Brazil, Mexico, Indonesia, Republic of Korea, Pakistan, Belgium, Turkey
LAM	Latin America	Argentina, Belize, Bolivia, Chile, Costa Rica, Dominican Republic, Guatemala, Honduras, Jamaica, Nicaragua, Panama, Peru, Paraguay, El Salvador, Trinidad and Tobago, Uruguay, Puerto Rico, Bahamas, Barbados, Cuba, Guyana, Haiti, Suriname
OIGA	Oil and gas exporting countries	Angola, Democratic Republic of the Congo, Nigeria, Ecuador, Venezuela, United Arab Emirates, Bahrain, Algeria, Egypt, Iran, Iraq, Israel, Jordan, Kuwait, Lebanon, Libya, Morocco, Oman, Occupied Palestinian Territory, Qatar, Saudi Arabia, Syrian Arab Republic, Tunisia, Yemen
RASI	Rest of South & South East Asia	Cambodia, People's Democratic Republic Lao, Macao Special Administrative Region China, Vietnam, Brunei Darussalam, Malaysia, Philippines, Singapore, Thailand, Bangladesh, Sri Lanka, Nepal, Fiji, New Caledonia, Papua New Guinea, French Polynesia, Solomon Islands, Vanuatu, Samoa, Afghanistan, Bhutan, Maldives, Myanmar, Timor-Leste
AFR	Africa	Benin, Benin, Burkina Faso, Botswana, Côte d'Ivoire, Cameroon, Ethiopia, Ghana, Guinea, Kenya, Madagascar, Mozambique, Mauritius, Malawi, Namibia, Rwanda, Senegal, Togo, United Republic of Tanzania, Uganda, Zambia, Zimbabwe, Mongolia, Burundi, Central African Republic, Congo, Comoros, Cape Verde, Djibouti, Eritrea, Gabon, Gambia, Guinea-Bissau, Equatorial Guinea, Liberia, Lesotho, Mali, Mauritania, Niger, Sierra Leone, Somalia, Swaziland, Chad

Table A4
Installed base year capacity and benchmark generation 2011 based on [48].

		Solid Fuels	Petroleum	Gas	Nuclear	Hydro	Biomass	PV	Wind
AUT	GW	1,262	1,105	4,425	-	12,795	648	298	1,267
	GWh	5,431	1,014	14,343	-	37,782	4,517	174	1,936
GRC	GW	4,235	2,499	4,363	-	3,250	55	683	1,469
	GWh	31,063	5,915	13,938	-	4,275	207	610	3,315
EEU	GW	53,300	2,548	13,488	11,776	13,455	1,133	2,640	3,874
	GWh	254,540	4,204	37,130	93,655	32,136	13,492	2,747	6,482

(continued on next page)

Table A4 (continued)

		Solid Fuels	Petroleum	Gas	Nuclear	Hydro	Biomass	PV	Wind
NEU	GW	37,000	15,672	46,669	22,155	23,353	10,915	2,241	16,241
	GWh	156,059	5,140	187,271	152,642	92,283	41,504	276	37,279
SEU	GW	21,925	28,403	87,690	7,756	41,597	4,641	11,676	31,884
	GWh	101,136	38,013	254,152	57,718	97,945	18,422	20,476	62,136
WEU	GW	61,678	15,825	59,679	88,558	29,383	6,359	25,769	42,143
	GWh	302,436	12,282	228,677	602,729	75,986	54,456	22,976	68,411

Table A5

OPEX, investment costs (2011 and 2050) and economic lifetime of electricity generation technologies [80,83].

	Investment costs [EUR/kW]		Economic lifetime [years]	Operating expenditures [EUR/kWh]					
	2011	2050		AUT	GRC	EEU	NEU	SEU	WEU
Solid Fuels	1,523	1,523	40	118	78	95	79	73	94
Petroleum	400	400	30	309	168	329	397	312	197
Gas	653	653	30	87	95	126	75	86	82
Nuclear	6,528	6,528	40	-	-	89	84	81	102
Hydro	3,263	3,263	100	2	3	3	2	2	3
Biomass	2,485	1,951	30	26	11	82	38	16	28
PV	3,800	445	25	4	2	3	4	2	4
Wind	2,563	1,330	25	35	24	29	36	29	38

Table A6

Technology-specific LCOE 2011 in EUR/kWh [48,84].

LCOE 2011 [EUR/kWh]	AUT	GRC	NEU	WEU	EEU	SEU
Solid Fuels	0.11	0.07	0.08	0.08	0.10	0.06
Petroleum	0.27	0.15	0.36	0.17	0.30	0.29
Gas	0.08	0.09	0.07	0.07	0.12	0.08
Nuclear	-	-	0.10	0.10	0.10	0.09
Hydro	0.03	0.04	0.04	0.05	0.04	0.03
Wind	0.09	0.09	0.10	0.09	0.09	0.09
Biomass	0.10	0.04	0.07	0.09	0.08	0.03
Solar	0.13	0.09	0.15	0.12	0.13	0.09

Table A7

Detailed overview of WACC settings

		Solid fuels	Petroleum	Gas	Nuclear	Hydro	Biomass	PV	Wind
Uniform	AUT	8.0%	8.0%	8.0%	8.0%	8.0%	8.0%	8.0%	8.0%
	GRC	8.0%	8.0%	8.0%	8.0%	8.0%	8.0%	8.0%	8.0%
	EEU	8.0%	8.0%	8.0%	8.0%	8.0%	8.0%	8.0%	8.0%
	NEU	8.0%	8.0%	8.0%	8.0%	8.0%	8.0%	8.0%	8.0%
	SEU	8.0%	8.0%	8.0%	8.0%	8.0%	8.0%	8.0%	8.0%
	WEU	8.0%	8.0%	8.0%	8.0%	8.0%	8.0%	8.0%	8.0%
MAIN	AUT	12.9%	13.0%	13.5%	"n.a."	13.0%	8.3%	2.9%	5.0%
	GRC	4.5%	4.5%	4.5%	"n.a."	4.5%	4.9%	5.3%	5.2%
	EEU	11.3%	11.4%	11.5%	11.4%	11.4%	9.7%	7.7%	8.5%
	NEU	9.8%	9.9%	10.2%	9.9%	9.9%	6.6%	2.9%	4.3%
	SEU	8.6%	8.6%	8.9%	8.6%	8.6%	6.5%	4.1%	5.0%
	WEU	14.7%	14.8%	15.4%	14.8%	14.8%	9.6%	3.5%	5.8%
DRR	AUT	12.9%	13.0%	13.5%	"n.a."	13.0%	8.3%	1.3%	1.6%
	GRC	4.5%	4.5%	4.5%	"n.a."	4.5%	4.9%	2.4%	1.7%
	EEU	11.3%	11.4%	11.5%	11.4%	11.4%	9.7%	3.5%	2.8%
	NEU	9.8%	9.9%	10.2%	9.9%	9.9%	6.6%	1.3%	1.4%
	SEU	8.6%	8.6%	8.9%	8.6%	8.6%	6.5%	1.9%	1.6%
	WEU	14.7%	14.8%	15.4%	14.8%	14.8%	9.6%	1.6%	1.9%
FFR	AUT	28.3%	35.3%	35.7%	"n.a."	13.0%	8.3%	2.9%	5.0%
	GRC	22.8%	29.6%	29.6%	"n.a."	4.5%	4.9%	5.3%	5.2%
	EEU	27.3%	34.2%	34.3%	11.4%	11.4%	9.7%	7.7%	8.5%
	NEU	26.2%	33.2%	33.4%	9.9%	9.9%	6.6%	2.9%	4.3%
	SEU	25.4%	32.3%	32.5%	8.6%	8.6%	6.5%	4.1%	5.0%
	WEU	29.6%	36.7%	37.0%	14.8%	14.8%	9.6%	3.5%	5.8%

(continued on next page)

Table A7 (continued)

		Solid fuels	Petroleum	Gas	Nuclear	Hydro	Biomass	PV	Wind
COMB	AUT	28.3%	35.3%	35.7%	"n.a."	13.0%	8.3%	1.3%	1.6%
	GRC	22.8%	29.6%	29.6%	"n.a."	4.5%	4.9%	2.4%	1.7%
	EEU	27.3%	34.2%	34.3%	11.4%	11.4%	9.7%	3.5%	2.8%
	NEU	26.2%	33.2%	33.4%	9.9%	9.9%	6.6%	1.3%	1.4%
	SEU	25.4%	32.3%	32.5%	8.6%	8.6%	6.5%	1.9%	1.6%
FFR_low 1/2 lifetime	WEU	29.6%	36.7%	37.0%	14.8%	14.8%	9.6%	1.6%	1.9%
	AUT	14.1%	15.2%	15.6%	"n.a."	13.0%	8.3%	2.9%	5.0%
	GRC	7.2%	8.5%	8.5%	"n.a."	4.5%	4.9%	5.3%	5.2%
	EEU	12.7%	13.9%	14.0%	11.4%	11.4%	9.7%	7.7%	8.5%
	NEU	11.4%	12.7%	12.9%	9.9%	9.9%	6.6%	2.9%	4.3%
FFR_med 1/4 lifetime	SEU	10.4%	11.7%	11.9%	8.6%	8.6%	6.5%	4.1%	5.0%
	WEU	15.7%	16.8%	17.3%	14.8%	14.8%	9.6%	3.5%	5.8%
	AUT	18.3%	21.6%	21.9%	"n.a."	13.0%	8.3%	2.9%	5.0%
	GRC	12.5%	15.8%	15.8%	"n.a."	4.5%	4.9%	5.3%	5.2%
	EEU	17.2%	20.4%	20.6%	11.4%	11.4%	9.7%	7.7%	8.5%
	NEU	16.1%	19.4%	19.6%	9.9%	9.9%	6.6%	2.9%	4.3%
	SEU	15.2%	18.6%	18.7%	8.6%	8.6%	6.5%	4.1%	5.0%
	WEU	19.7%	22.9%	23.3%	14.8%	14.8%	9.6%	3.5%	5.8%

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