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Policy brief on the Future of RES auctions in a changing electricity system

Key insights on the model-based analysis on a possible phase-out of RES support in future as conducted in the course of the AURES II project

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Authors: Gustav Resch, Jasper Geipel, Lukas Liebmann, Albert Hiesl, Florian Hasengst, Franziska Schöniger (TU Wien),

Reviewed by: Vasilios Anatolitis (Fraunhofer ISI)
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Content

Executive summary 5

1 Introduction 8

1.1 Scope and structure of this analysis 8

1.2 Policy context 8

2 Approach and assumptions 10

2.1 The applied modelling system 10

2.2 Scenario definition 12

2.3 Key input parameters and assumptions 14

2.3.1 Decarbonisation ambition 14

2.3.2 Electricity demand 14

2.3.3 (Fossil) Fuel price trends 15

2.3.4 Grid expansion 16

2.3.5 Technology cost trends 16

2.3.6 Final remarks and Data availability 17

3 Results 18

3.1 Results from the power system analysis – assessing distinct long-term trends of a changing electricity system 18

3.1.1 Installed capacities and electricity supply 18

3.1.2 Cross-border electricity exchange 23

3.1.3 Hourly dispatch 24

3.1.4 Power system flexibility needs – a closer look at residual load and the impact on wholesale prices 26

3.2 Results from the RES policy analysis – assessing the future need for dedicated RES support in a changing electricity system 29

3.2.1 RES uptake within the European Union until 2050 29

3.2.2 The impact of long-term electricity market trends on total remuneration of RES technologies 32

3.2.3 Sensitivity analysis on the impact of RES policy design 35

3.2.4 Sensitivity analysis on the impact of high fossil fuel prices 37

3.2.5 Future price trends for green gas – a key determinant on the need for dedicated RES support 38
4 Conclusions 42
5 References 43

Executive summary

This model-based analysis complemented the narrative scenarios describing plausible visions of EU electricity markets and networks in the period up to 2050. Scenarios were derived using TU Wien's Green-X model, a specialised energy system model with a sound incorporation of various RES policy approaches, closely linked to the open-source energy system model Balmorel, allowing to shed further light on the interplay between supply, demand and storage thanks to a high temporal resolution.

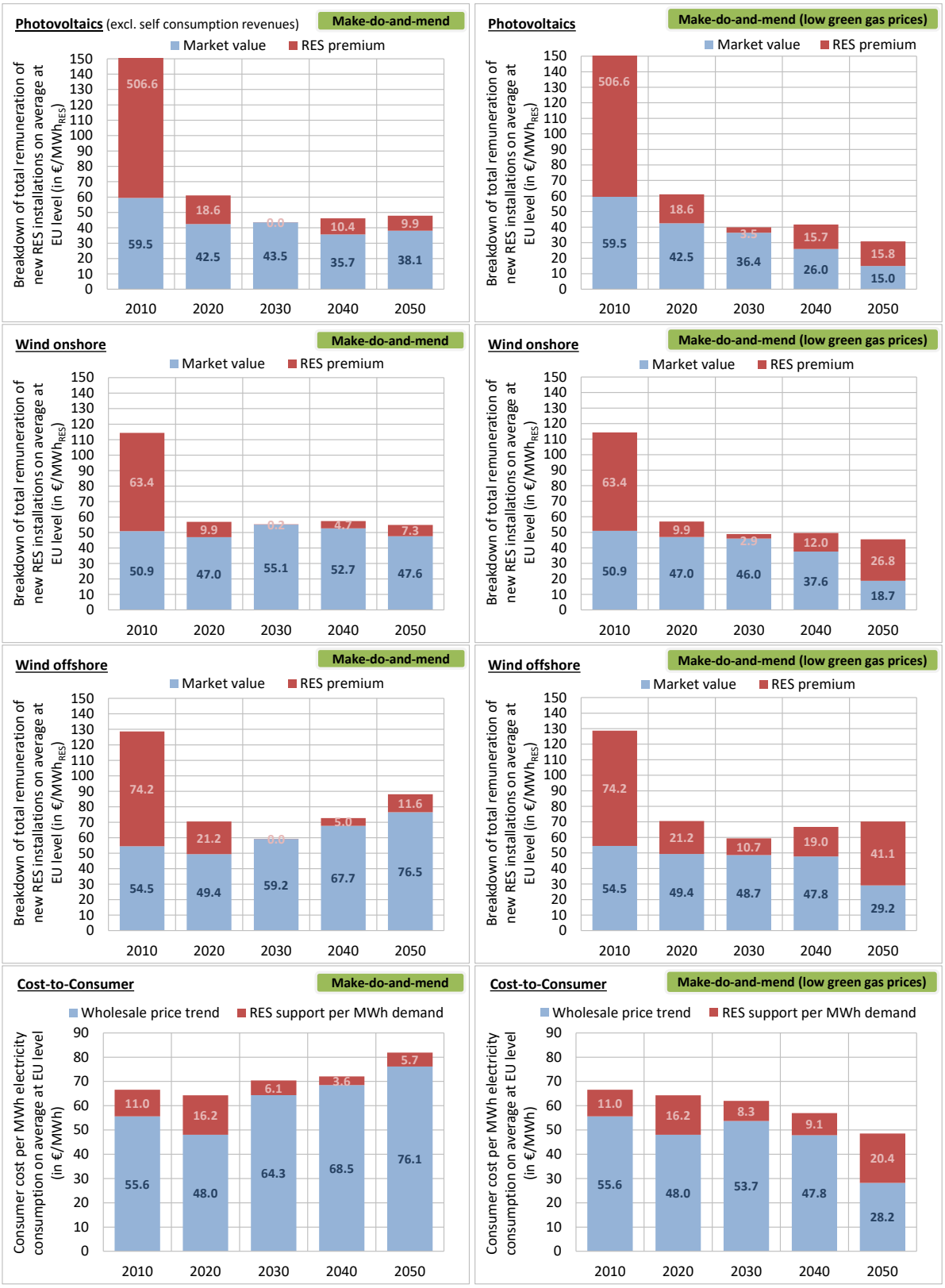
Key assumptions were to presume the Green Deal ambition for 2030, imposing an increase of the overall RES share to (at least) 40% in gross final energy demand by 2030, and a carbon-free electricity system by 2050, implying that RES and nuclear serve to provide the electricity supply in the entire EU by that point in time. Moreover, the assumed full decarbonization of the whole EU economy by 2050 leads to more than a doubling of electricity demand and implies a strong RES uptake in forthcoming years. In accordance with the qualitative scenario narratives, two key aspects stood originally in focus of the modelling: the level of *power system flexibility* provided in future years, indicating the ability of the power system to react on changes in supply and/or demand, and the degree of *decentralisation*, specifically concerning RES supply thanks to a continuation or phase-out of dedicated incentives for small-scale decentral RES systems. Other aspects like future energy price trends or details on RES policy design were analysed by means of sensitivity analyses.

The outcomes of the modelling have shown that a high degree of system flexibility and decentralisation can act as enabler, and even be a prerequisite for a successful RES market integration. The key parameter to determine whether or not only low (or almost zero) subsidies will be required to accommodate the future RES uptake is however the future price level on the wholesale electricity market. These prices are, in turn, determined by the future prices at which key flexibility options on the supply side like biogas or green hydrogen (subsequently named as "green gas" as synonym for both) will be available. For green gas two distinct price trends were assessed: a high and a low price scenario.[1] With high prices for green gas, modelling indicates also high prices on the European wholesale electricity market and vice versa. The impacts of these distinct price trends on total remuneration of key RES technologies (i.e. PV, on- and offshore wind) and on RES-related cost-to-consumer at EU level in the period up to 2050 are shown in Figure A.

In overall terms, total remuneration of key RES technologies like onshore wind and PV is generally expected to decline in future years compared to 2020 levels. There are however strong differences between both price trends for green gas. In the case of high prices for green gas one can observe a decline in total remuneration in the near future, i.e. by 2030. In subsequent years up to 2050, according to modelling total remuneration is projected to increase again – but total remuneration for both technologies will remain below 2020 levels. In contrast to the above, under the scenario of low green gas prices one can observe a (more or less) continuous decline of total remuneration over the whole period up to 2050. For offshore wind, the third key pillar for future electricity supply, total remuneration is expected to decline until 2030 but, later on, an increase in total remuneration can be expected under both price trends. The increase is however stronger in the case of high prices for green gas.

[1] In the high price scenario it was assumed that the price for green gases takes orientation on the price of natural gas plus the cost for related CO_2 emission allowances under the EU Emission Trading Scheme. In the low price scenario former bottom-up price projections for biogas fed into the gas grid served as basis. By 2050, the difference between both price trends is significant: In the (default) high price scenario green gas was assumed to be available at around 155 €/MWh by 2050 whereas in the low price scenario less than a third of that was assumed (i.e. ca. 50 €/MWh).

Figure A. Development of total remuneration of key RES technologies (i.e. PV, on- and offshore wind) as well as cost-to-consumer of the RES uptake at EU level in the period up to 2050 according to selected electricity system trend scenarios – with default (high) (left) or low prices for green gas (right). (Source: Green-X modelling)



Since Figure A informs also on the decomposition of total remuneration, i.e. on the market-driven income (cf. the pale blue bars named as "market value") and on the support-driven income (cf. the red bars named as "RES premium"), we can elaborate on the need for dedicated RES support in forthcoming years below. By 2030, even under low prices for green gases and, in consequence, low wholesale price levels, low or even zero-subsidy auctions can be expected for all key RES technologies. By 2040 and beyond, RES support is required to fill the remuneration gap, despite declining remuneration levels for onshore wind and PV in the case of low green gas prices. Reason is generally the decline of market values driven by self-cannibalism – as a consequence of the required strong RES uptake in accordance with decarbonization needs. According to modelling, similar trends are applicable for wind on- and offshore, although market values are higher compared to PV. Similar to total remuneration, there is also a strong difference in RES support between both price trends for green gas. The need for and height of dedicated RES support is significantly higher in the case of low green gas prices due to lower market-driven revenues feasible under these wholesale price developments.

The graphs at the bottom of Figure A indicate the impacts electricity consumers may face, showing the average yearly consumer cost in specific terms (per MWh electricity consumption). The cost elements taken up in that latter comparison comprise the wholesale electricity price and the RES-related support.[2] Here again a strong difference between both "gas price worlds" is observable. In the case of (default) high prices for green gas (cf. Figure A, left) consumer cost per MWh of electricity consumed are expected to increase steadily over the whole period up to 2050, with a peak value of 81.9 €/MWh at that point in time. In the case of low green gas prices the opposite trend can be expected: Consumer cost per unit of electricity consumption are expected to decline until 2050, reaching a minimum value of 48.5 €/MWh by 2050 – almost half the price compared to the case of high prices for green gas.

Summing up, the assessment allowed for identifying key parameter that determine the need for and the height of dedicated RES support in forthcoming years. The key parameter to determine whether or not only low (or almost zero) subsidies will be required to accommodate the future RES uptake is the future price level on the wholesale electricity market. These prices are, in turn, determined by the future prices at which key zero-carbon flexibility options on the supply side like biogas or green hydrogen will be available. In general, with massive amounts of high vRES infeed there are many times during a day and year when prices are well below current wholesale price levels. During times of low solar radiation or low wind, hydrogen, green gas, batteries and other flexibility options have to contribute to meet the given demand. If these flexibility options are available at low cost/prices, the need for dedicated support increases but consumer cost are expected to decline and vice versa.

[2] Our comparison of cost impacts on electricity consumer does however not provide the "full picture" since network charges as well as energy-related or general taxes are not taken into consideration. This would however not add value to the scope of our analysis where we aim to assess impacts from electricity market developments and RES-related support requirements, and the overall consequences of these from a consumer perspective.

1 Introduction

1.1 Scope and structure of this analysis

It is still uncertain whether the current trend of a market-based RES expansion will continue and whether zero-subsidy auctions and/or PPAs will make a significant contribution to the RES increase needed to meet future European RES targets. One critical factor opposing this trend is the limited ability of the electricity system to integrate variable RES leading to a reduction in market values and thus a reduction in incentives for market-based expansion. The model-based analysis of long-term trends in Europe's changing electricity system as presented in this report aimed for shedding light on the above, informing on the need for dedicated RES support in forthcoming years. In practical terms, the quantitative analysis builds on qualitative scenario developments on the future of RES auctions in a changing electricity system (cf. Woodman and Fitch-Roy, 2020), prescribing different electricity market trends related to the future of auctions carried out within AURES II and the accompanying modelling activities as presented in further detail below.

The forward-looking model-based analysis on the need for dedicated RES support also acknowledges recent energy and policy developments, incorporating currently observable high energy prices as a sensitivity analysis to the default modelling that was built using price trends from the latest EU reference scenario as basis. Additionally, the assessment reflects the uncertainty related to the future cost of key options for meeting system flexibility needs, done by modelling wholesale price impacts of high or low prices for green gas in future. Another sensitivity assessment is conducted on the design of RES support and how that may affect RES-related support expenditures and consumer cost.

In terms of structure we start after a brief recap of the policy context with a description of the approach taken, the scenarios defined and key assumptions applied. Results are then presented for the two complementary elements of the assessment: the power system analysis reflecting predefined long-term trends in a changing electricity system, done by use of the open-source energy system model Balmorel, and the RES policy analysis, done by use of TU Wien's Green-X model. This policy brief concludes with a recap of the lessons learned and the recommendations on the way forward.

1.2 Policy context

In the last few years, auctions have become the predominant policy instrument for securing and managing RES deployment in Europe. Auctions simultaneously address a number of market failures, including wholesale electricity remuneration rates that are often lower than production costs and prohibitive risk premia associated with volatile wholesale electricity markets. Auctions also protect society from the immediate costs of over-rewarding renewable generators and system costs of uncontrolled RES expansion.

However, the role played by RES technologies is determined by the broader context in which they are embedded, which is likely to change in the coming decades. The value that renewable generators can realise through participating in markets will influence whether RES auctions are appropriate and, if they are, the most suitable design. The value of RES output and therefore the role of auctions may be subject to significant change between today and 2030 and beyond.

In particular, evolutions in market design and network regulation will have a profound effect on the cost of producing and integrating renewable electricity in the future electricity system. The 'routes to market' available to producers of renewable electricity will be determined by the products that can be exchanged and by how costs are allocated among generators, network operators, consumers, taxpayers and others.

For example, the future status of issues such as degree of market liberalisation, grid congestion and constrained output, balancing charges and trading arrangements, as well as the system value of renewables generation, will together define whether or not renewable electricity production can be conducted profitably. The future condition of markets and networks is therefore central to the issue of whether subsidies awarded through auctions (or otherwise) can or should be removed, changed or reduced over time.

At all levels of policymaking discussions about future developments such as the emergence of more local energy markets and a more active management of low-voltage distribution networks have started throughout last years. A newly designed electricity market of the future could be more supportive of renewable technologies than the current, more centralised model, reducing overall system costs and reshaping routes to market for renewable energy. As a result, there are many uncertainties about how future electricity systems may look, and many possible trajectories for the co-evolution of markets, networks and renewable technologies. This task has generated qualitative scenarios described in Woodman and Fitch-Roy (2020) as a way of thinking about the future using these drivers to think about future electricity system development. The aim was to inform debates about what the implications of market and network design and operation might be for the future viability of renewables, and therefore how auctions might evolve over time.

Moreover, a look at this year's (2022) and last year's economic and political developments shows that price increases or price turbulence can currently (as of Spring 2022) be observed worldwide in raw material and energy markets, affecting the energy sector and the whole economy significantly, specifically within Europe. Under current high energy prices, even in the absence of dedicated RES support, investments in RES technologies appear cost-competitive and highly attractive for investors despite of the increase of investment cost triggered by the above. The question remains however how long the period of high energy prices may last and how the trend will continue in forthcoming years. The Russian invasion of the Ukraine and the political, economic and societal crisis driven by that is currently triggering policy debates related to the energy sector at various angles.

- Europe's energy supply vulnerability is seen as a major concern given the strong dependency on energy imports, in particular of natural gas and oil from Russia;
- A social and economic crisis driven by the tremendous increase of energy prices, in particular in gas markets and in the electricity sector, is emerging, triggering policy debates also on aspects like the price setting mechanism in the wholesale power market.

As a consequence of the above, at EU level an increase of the overall RES ambition towards 2030 appears likely, cf. EC (2022), given that renewables together with energy efficiency are key for combating climate change as well as for safeguarding supply security in future. Thus, an increase in the RES ambition may, in turn, affect the need for dedicated RES support, since RES potentials that can be mobilized at short notice appear generally limited.

2 Approach and assumptions

2.1 The applied modelling system

This analysis builds on modelling works undertaken by the use of TU Wien's Green-X model, a specialised energy system model with a sound incorporation of various RES policy approaches, closely linked to the complementary power system models and the open-source model Balmorel. A brief characterisation of both models is provided in Box 1 below.

More precisely, Green-X delivers a first picture of future RES developments under distinct energy policy trends and cost assumptions, indicating details on technology trends (investments, installed capacities and generation) and the geographical distribution of RES deployment as well as related costs (generation cost) and expenditures (capital, operation and support expenditures). For assessing the interplay between RES and the future electricity market, Green-X was complemented by its power-system companion, i.e. the model Balmorel. Thanks to a higher intertemporal resolution than in the RES investment model Green-X, Balmorel enables a deeper analysis of the merit order effect and related market values of the produced electricity of variable and dispatchable renewables and, therefore, can shed further light on the interplay between supply, demand and storage in the electricity sector.

Box 2-1. Brief characterisation of the applied modelling system (Green-X in combination with Balmorel)

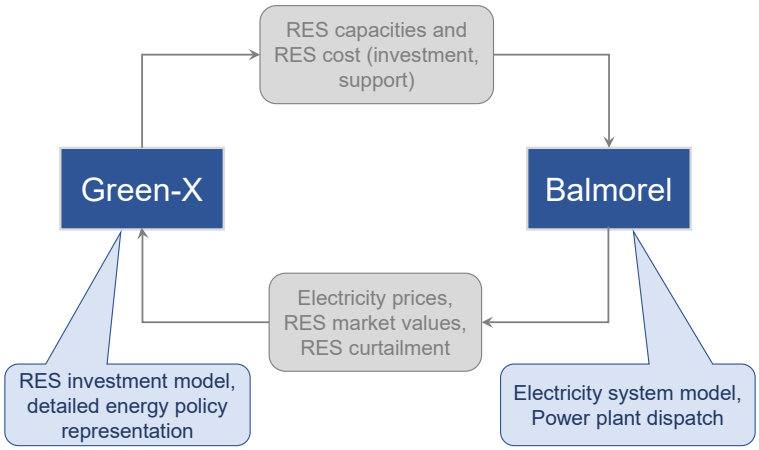
Green-X is an energy system model, developed by TU Wien, that offers a detailed representation of the potentials and the related technologies of various renewable energy sources (RES) in Europe and in neighbouring countries, including all EU Member States and all Contracting Parties of the Energy Community. It aims at indicating consequences of RES policy choices in a real-world energy policy context. The model simulates technology-specific RES deployment by country on a yearly basis, in the time span up to 2050, taking into account the impact of dedicated support schemes as well as economic and non-economic framework conditions (e.g. regulatory and societal constraints). Moreover, the model allows for an appropriate representation of financing conditions and of the related impact on investor's risk. This, in turn, allows conducting in-depth analyses of future RES deployment and corresponding costs, expenditures and benefits arising from the preconditioned policy choices on country, sector and technology level.

Balmorel (the BALtic Model for Regional Electricity Liberalisation) is an open-source partial equilibrium model, analysing the electricity and combined heat and power sector on various geographic levels. The analysis of further sectors via sector coupling (e.g. e-mobility, individual heating) is also possible via model add-ons. The model was originally developed by DTU and is now used and further developed by a wide range of institutions within Europe and worldwide, including TU Wien who is conducting also recent extensions in the course of this project. Balmorel is a deterministic bottom-up energy system model that is able to co-optimize energy dispatch and investments via linear (and for some applications mixed-integer) programming. For this, equations on electricity and district heat balance, capacity and energy constraints, production of dispatchable and non-dispatchable units, operational constraints, storage operation, transmission constraints, emission caps, and several more are considered. As a result, the model delivers energy conversion characteristics, fuel consumption, electricity exports and imports, emissions, investments in plants and transmission lines, prices on traded energy, and total system costs.

Figure 2-1 gives an overview on the interplay of both types of models. All models are operated with the same set of general input parameters, however in different spatial and temporal resolution. Green-X delivers a first picture of renewables deployment and related costs, expenditures and benefits by country on a yearly basis (2030 to 2050). The output of Green-X in terms of country- and technology-specific RES capacities and generation in the electricity sector for selected years (2030, 2040, 2050) serves as input for the power-system analysis done with Balmorel. Subsequently, the applied power system model analyses the interplay between supply, demand, and storage in the electricity sector on an hourly basis for the given years. The output of the power system model Balmorel is then fed back into the RES investment model Green-X. In particular, the feedback comprises the amount of RES that can be integrated into the grids, the electricity prices, and corresponding market revenues (i.e. market values of the electricity produced by variable and dispatchable RES-E) of all assessed RES-E technologies for each assessed country. This feedback loop

constitutes the soft model linking between Balmorel and Green X and enables us to combine the strengths of both models: Obtaining RES deployment values that respect existing European and national energy policies, specifically dedicated RES support instruments, as well as the optimization of the dispatch of generation technologies and available flexibilities.

Figure 2-1. Model coupling between Green-X (energy policy analysis) and Balmorel (power system analysis) for an assessment of RES developments in the electricity sector. (Source: own development)



The feedback loop sketched above is run until the results of both models converge. For the calculations of the scenarios carried out in this task, each model run had to undergo two successive iterations of the combined modelling framework.

In its default configuration and described in (Ravn et al., 2001) the partial equilibrium model Balmorel incorporates the power sectors and its interplay with the district heating sector. However, for forward looking scenario analysis of the power sector until 2050, other forms of sector coupling and flexibility options to integrate volatile renewable energy sources will become relevant. Three major trends are expected to rise in prominence until 2050 and are incorporated in our modelling framework via the inclusions of the following Add-Ons:

- Electric vehicles (EV) add-on: Gunkel et al. (2020) It enables to depict the interactions of the power sector with the growing fleet of electric vehicles. Different degrees of flexibility can be provided by the batteries in the EVs via different charging patterns. Under the regime of '*dumb charging*', the EVs simply constitute an additional electricity consumer with a static load profile. With *'smart charging'*, the battery of electric vehicle is charged in times of low electricity prices. Under the *'vehicle to grid'* regime, the batteries can additionally feed in electricity back into the grid in times of low supply.
- Demand Response (DR) add-on: Helistö et al. (2018). It enables to depict the interactions between the power sector and consumers that are able to react flexibly towards times of high and low prices and to shift or curtail their demand accordingly. The two type of consumers that can provide this flexibility and that are incorporated in our scenario assessments are industrial consumers as well as operators of large scale heat pumps for district heating.
- Hydrogen (H2) Add-on: Bermúdez et al. (2021) Given a load profile for hydrogen demand, this add-on enables the optimal investment and dispatch of electrolysis capacities and hydrogen storage facilities. By shifting hydrogen production in times of low electricity prices, the coupling of the power sector with the hydrogen and the derived synthetic fuel market allows for a greater integration of variable renewable energy. The add-on also enables the storage of energy via the intermedium of hydrogen and the consequent recovery of the electric energy via the fuel cell technology.

The specific extent to which these flexibility options are actually deployed, varies in the modelled scenarios as described in section 5.3.2.

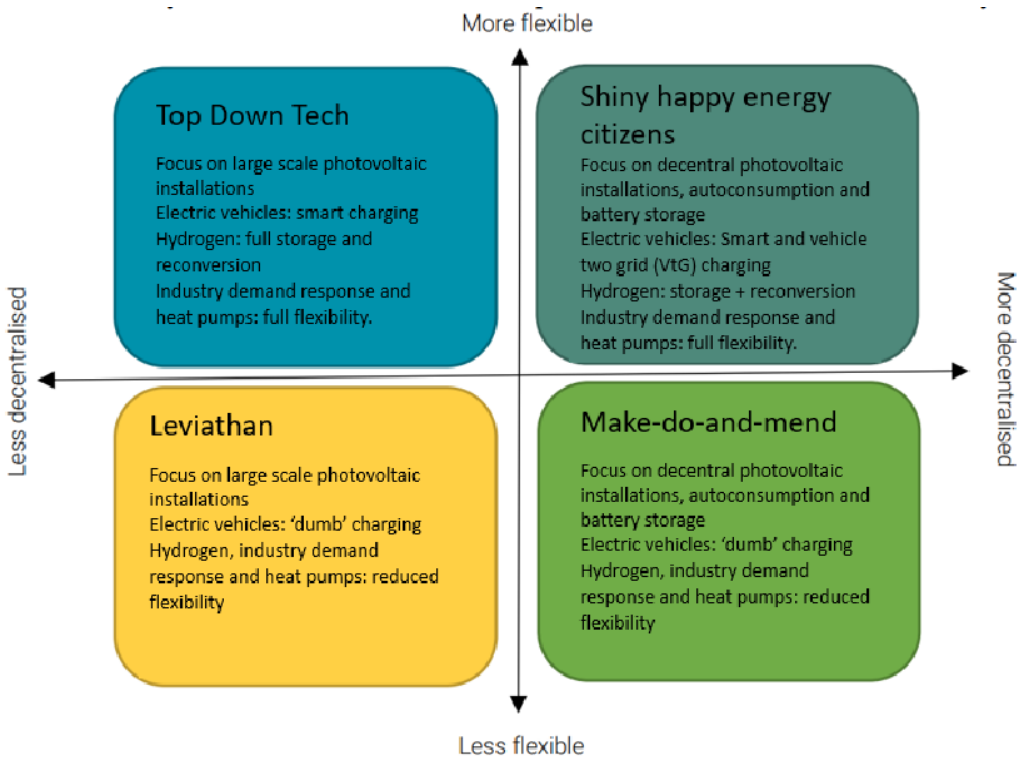
2.2 Scenario definition

As mentioned above, this quantitative analysis builds on qualitative scenario developments on the future of renewable energy auctions in a changing electricity system – in particular on the qualitative scenarios and pathways derived by Woodman and Fitch-Roy (2020).

Those qualitative scenarios developed describe plausible visions of EU electricity markets and networks in the period 2030 to 2050 based on the variation of two key trend parameters, i.e., the level of flexibility available in the system as well as the level of decentralization. In the course of this analysis, the possible future socio-economic and –political conditions from the four qualitative scenarios, namely "Top Down Tech", "Shiny happy energy citizens", "Leviathan" and "Make-do-and-mend", were translated into quantifiable scenarios characterized by specific assumptions and technical parameters. This enables us to assess in a consistent manner long-term trends in a changing electricity system and related impacts on the need for dedicated RES support, specifically the role of auctions for RES.

The outcomes of our translation of the qualitative scenarios derived by Woodman and Fitch-Roy (2020) into quantifiable ones to be incorporated into our modelling are illustrated in Figure and described below.

Figure 2-2. Scenarios of a changing electricity system across Europe. (Source: own development based on Woodman and Fitch-Roy (2020))



"Top Down Tech": The narrative for this scenario contains "*the top-down planning at the national and European levels allows significant flexibility through sector coupling, e-mobility and electrification of heat services. Smart consumer appliance technology and advanced data analytics allows significant demand-side response and large-scale markets are able to accurately value a range of system services*" (**Woodman and Fitch-Roy, (2020)**). **We translated this narrative by setting a strong emphasis on large-scale photovoltaic installations. This is done by limiting the self-consumption privilege that some decentralised and small-scale PV producers currently benefit from. Electric vehicles are able to charge their batteries in times of low electricity prices yet do not feed electricity back into the grid. For the hydrogen market, industrial demand response and heat pumps, we enable our model to optimise in the full range of the derived potentials.**

Shiny happy energy citizens: The narrative for this scenario contains that "*technological innovation is accompanied by a shift in governance as participation by consumers and citizens increases towards the*

ideals of 'energy democracy'. The boundaries between the supply-side and the demand-side of the electricity market are blurred by the rise of widespread prosumerism, with domestic participation across storage, transport, heat and generation." (**Woodman and Fitch-Roy, (2020)**). **We translated this narrative by setting a strong emphasis on prosumage and thereby on decentralised PV. This is done by expanding the self-consumption privilege for small scale PV installations to all EU countries. Prosumers thus see a much higher value of their self-produced electricity, e.g. the retail price instead the wholesale price. Furthermore, the expanded deployment of decentral photovoltaic is coupled with an equivalent amount of electric storage capacity. This reflects the current trend that more and more prosumers combine their PV installation with a battery storage, not only to increase the share of auto-consumption but also in a spirit of autarky to increase their independence from the large suppliers. Analogical to the "Top Down Tech" scenario, electric vehicles are able to charge their batteries in times of low electricity prices. However, here they can also feed electricity back into the grid. For the hydrogen market, industrial demand response and heat pumps, we enable our model to optimise in the full range of the derived potentials.**

"Leviathan"*: The narrative for this scenario contains that "**contemporary trends towards energy system decentralisation and greater flexibility stall or are reversed. Governance of (and participation in) the electricity system is dominated by central public and private actors, most likely at the scale of the nation-state."** (**Woodman and Fitch-Roy, (2020)**). **We translated this narrative by setting a strong emphasis on large scale photovoltaic installations. This is done by limiting the self-consumption privilege that some decentralised and small-scale PV producers currently benefit from. The amount of system flexibility is strongly reduced: Electric vehicles users proceed in 'dumb charging' by simply following a static load profile independent of the actual wholesale price. For the hydrogen market, industrial demand response and heat pumps, the available flexibility is also reduced and we enable our model to optimise only up to 25% of the derived potentials for heat pumps and only up to 10% for industrial demand.**

"Make-do-and-mend"*: The narrative for this scenario contains that "**there is a strong divergence between stuttering technical innovation and very active social innovation. Failure to commercialise key flexibility technologies in the heat, transport and large-scale battery storage sectors, and wide-spread rejection of in-home technologies for enhanced energy management due to concerns about privacy and autonomy constrains the degree of technical system flexibility."** (**Woodman and Fitch-Roy, (2020)**). **We translated this narrative by setting a strong emphasis on prosumage and thereby on decentralised PV. This is done by expanding the self-consumption privilege for small scale PV installations to all EU countries. Prosumers thus see a much higher value of their self-produced electricity, e.g. the retail price instead the wholesale price. Analogously to the "Shiny happy energy citizens" scenario and in order to emphasise the decentral character, the expansion of decentral PV is hard coupled to a battery storage expansion. That implies the availability of small-scale battery storages as an option to store solar energy. Those battery storages are however not optimized from a system perspective but instead from the point of view of the prosumer. For the sake of this modelling activity we assumed that the prosumers are subject to real time pricing electricity tariffs and that therefore those perspectives align. On the other hand the amount of centralised system flexibility is strongly reduced: Electric vehicles users proceed in 'dumb charging' by simply following a static load profile independent of the actual wholesale price. For the hydrogen market, industrial demand response and large-pumps, the available flexibility is also reduced and we enable our model our model to optimise only up to 25% of the derived potentials for heat pumps and only up to 10% for industrial demand.**

Additionally, we quantified the models' sensitivities towards increasing gas prices and in order to assess their potential impact on the development of the future electricity system. This is currently of particular importance given the discussions on the requirement to limit the imports of Russian natural gas. Other aspects like the uncertainty concerning future cost/price of carbon-free power system flexibility provision, exemplified by green gas (as representative for green hydrogen or biogas) or details on RES policy design were also analysed by means of sensitivity analyses.

2.3 Key input parameters and assumptions

This section provides an overview on key input parameters and assumptions that are common to all scenarios as well as the underlying data.

Before digging into details, we start we a brief recap of these: Key assumptions were to presume the EU Green Deal ambition for 2030, imposing an increase of the overall RES share to (at least) 40% in gross final energy demand by 2030, and a carbon-free electricity system by 2050, implying that RES and nuclear serve to provide the electricity supply in the entire EU by that point in time. Moreover, the assumed full decarbonization of the whole EU economy by 2050 leads to more than a doubling of electricity demand and implies a strong RES uptake in forthcoming years.

In accordance with the qualitative scenario narratives, two key aspects stood originally in focus of the modelling: the level of *power system flexibility* provided in future years, indicating the ability of the power system to react on changes in supply and/or demand, and the degree of *decentralisation*, specifically concerning RES supply thanks to a continuation or phase-out of dedicated incentives for small-scale decentral RES systems.

For the Balmorel model that implied an update of the entire underlying database and expansion for the EU. While the scenarios differ along the flexibility and decentralization axes – and therefore in many indicators – to enable comparison, we assume the following fundamental outcomes and trends are common to all four:

2.3.1 Decarbonisation ambition

The overall narrative concerning decarbonisation can be summarised as follows:

- The top-line EU targets for energy efficiency, renewable energy and decarbonization are met or exceeded for 2030
- In line with the EU's commitment to achieve 'climate neutrality' by 2050 and the terms of the Paris agreement, Member States' are assumed to collectively reduce greenhouse gas emission by at least 95% compared to 1990 levels by 2050;
- It is assumed that popular support for climate policy, including energy policy, is strong and growing between now and 2050 as the manifestations of climate change become increasingly apparent – as a consequence, 'political will' to enact climate policy is adequate to fulfil the goals above

As a consequence of the above, within all scenarios the assumption is taken that a full decarbonisation of the energy system – zero CO_2 emissions –, and in particular of the power system is achieved until 2050 at EU level. In general terms, this has strong implications on future technology choices (e.g. fossil CCS is no viable generation option in the power sector, as it is not fully zero-carbon) and on energy market developments.

To achieve the full decarbonisation within our stylised energy system representation, a strong increase in carbon prices is assumed in modelling (69, 212 and 529 $€_{2020}/tCO_2$ for the years 2030, 2040 and 2050).

2.3.2 Electricity demand

The assumed full decarbonization of the whole EU economy by 2050 leads to more than a doubling of electricity demand by 2050 compared to today. Due to a lack of cost-effective carbon-free alternatives sector coupling is predominant and strong electrification of heating, industry and transport acts as a driver for increased electricity demand. For our modelling, default future trends concerning electricity demand were taken from the "Electrification" scenario of the recently completed EC study concerning renewable space heating under the revised RED (cf. Kranzl et al., 2021). These consumption trends can be classified as being in accordance with former studies assessing the impacts of a deep decarbonisation of the whole EU economy, cf. EC (2018) or Crespo et al. (2020).

More precisely, a default final electricity demand per country was given as a restriction to Balmorel. This default final electricity demand comprises the total final electricity demand minus the electricity required for

sector coupling via heat supply, electromobility and the production of hydrogen. Electricity demand for the heat supply and electromobility are provided as input parameter to the respective Add-On described in 2.1. The part of the hydrogen demand that has to be produced in Europe via electrolysis induces an additional block of final electricity consumption that is however dependant on the electrolysis technology in use and therefore also varies from scenario to scenario.

In consequence the electricity demand resulting from the system optimization in Balmorel may be much higher than the default electricity demand even if one includes the two sector coupling roads via heat pumps and electromobility. Exemplarily for the year 2050, we set a default (final) electricity demand of 4300 TWh as exogeneous input parameter. Yet the modelled final electricity demand at EU27 level well exceeds the 5000 TWh due to the electrolysis of ~ 700 TWh of hydrogen. (with variance on the exact value across electricity system trend scenarios). As stated above, compared to today this implies more than a doubling of electricity demand.

2.3.3 (Fossil) Fuel price trends

Default fossil fuel price trends as illustrated in Table 2-1 are taken from the Global Energy and Climate Outlook 2019 (GECO (2019)). These fuel prices were also at the basis of the EC study mentioned above (cf. Kranzl et al., 2021) where our electricity demand assumptions stem from. Using those fuel price trends thus constitutes a coherent assumption.

While said trends reflect in principle a strong climate ambition on the global level, they might appear moderate in relation to current events on the global market. In consequence, and in addition to the default assumptions also a *high fossil fuel price case* was assessed for sensitivity purposes, cf. Table 2-2. Under that trend natural gas prices as well as prices for other fossil fuels are expected to decline compared to current price peaks but, later on, remain at – compared to default assumptions – higher price levels in the near and mid future. This is currently of particular importance given the discussions on the requirement to limit the imports of Russian natural gas.

Table 2-1. Default fossil fuel price trends (Source: GECO , 2020)

Fuel price trends in €$_{2020}$/MWh$_{th}$	Natural gas	Coal	Lignite	Oil	Nuclear
2030	10.9	2.8	1.1	13.0	1.0
2040	13.0	3.3	1.1	15.8	1.0
2050	13.9	3.6	1.1	19.2	1.0

Table 2-2. High fossil fuel price trends (used for sensitivity assessment of high fossil fuel prices) (Source: own assumptions based on GECO, 2020)

Fuel price trends (high fossil fuel price scenario) in €$_{2020}$/MWh$_{th}$	Natural gas	Coal	Lignite	Oil
2030	18.0	4.6	1.8	21.5
2040	20.6	5.1	1.7	25.0
2050	20.8	5.3	1.7	28.8

<u>High uncertainty on future cost/prices for green gas:</u> Please note that in accordance with the guiding principle to head towards carbon neutrality, natural gas is expected to be fully replaced by green gases of renewable origin, including green hydrogen, biogas or other synthetic carbon-neutral gases, by 2050. For this decarbonisation option, representing a key option for the provision of power system flexibility in future years, future cost/prices are highly uncertain. In order to reflect that in our modelling, two distinct price trends were assumed:

- In the (default) high price scenario it was assumed that the price for green gases takes orientation

on the price of natural gas plus the cost for related CO_2 emission allowances under the EU Emission Trading Scheme. That price trends reflects a high demand for green gas combined with limited supply options and in consequence limited competition on the supply side of the market.

- In the low price scenario former bottom-up price projections for biogas fed into the gas grid served as basis, reflecting first lessons learned from demo projects in the Netherlands and expert judgements concerning expected future progress.

As applicable in Table 2-3, by 2050, the difference between both price trends is significant: In the (default) high price scenario green gas was assumed to be available at around 155 €/MWh by 2050 whereas in the low price scenario less than a third of that was assumed (i.e. ca. 50 €/MWh).

Table 2-3. Distinct price trends for green gases (i.e. high and a low price scenario) (Source: own assumptions)

Fuel price trends for green gas in $€_{2020}/MWh_{th}$	High price scenario	Low price scenario
2030	68.9	55.2
2040	94.7	52.5
2050	155.3	49.8

2.3.4 Grid expansion

As default we presume a strong expansion of the power system infrastructure in future years, specifically of the transmission grid. The net transfer capacities, that are an exogeneous input parameter for our power system modelling with Balmorel stem from the ten year network development plan 2020 (TYNDP2020) from ENTSOE (2021). In order to ensure comparability between our scenarios that focus on the supply side of the power sector, for all four of our scenarios we rely on the NTCs derived from the Distributed Energy (DE) scenario. This scenario is compliant with the 1.5° C target of the Paris Agreement and that presents a decentralized approach to the energy transition. While it presents such a decentralized approach it also entails the largest expansion of NTCs of all the TYNDP scenarios and therefore does not pose restrictions to our scenarios on the less decentralized axis. The current TYNDP2020 includes NTCs for 2020, 2030 and 2040, however not yet for 2050. It is assumed that for 2050, the NTCs remain at their maximum potential. The full NTC data set that was used for our modelling can be found in our data repository (see below on data availability).

2.3.5 Technology cost trends

The general data source for technology cost trends in the energy sector was the ASSET study (cf. De Vita et al., 2018), reflecting assumptions used in the EC's own energy and climate modelling done by use of the PRIMES modelling system.

For RES technologies a different approach was used as described in Box 2-2 below.

Box 2-2. Approach used in Green-X on modelling technological learning of RES technologies

Thus, for most RES-E technologies, the future development of investment cost is based on technological learning. Two key parameters determine the development of investment cost of a certain RES technology: the deployment & the learning rate.

Assumptions on future RES deployment:

As learning is generally taking place on the international level (i.e. presuming a global learning system) the deployment of a technology on the global market must be considered. For the model runs, global RES deployment consists of the following components:

- Deployment within the EU27 Member States is endogenously determined, i.e. is derived from the model.

- Expected developments in the "rest of the world" are based on forecasts as presented in the IEA World Energy Outlook 2020 (IEA, 2020). For the analysis performed within AURES II we make use of the IEA Stated Policies scenario and the technology-specific global deployment indicated therein.

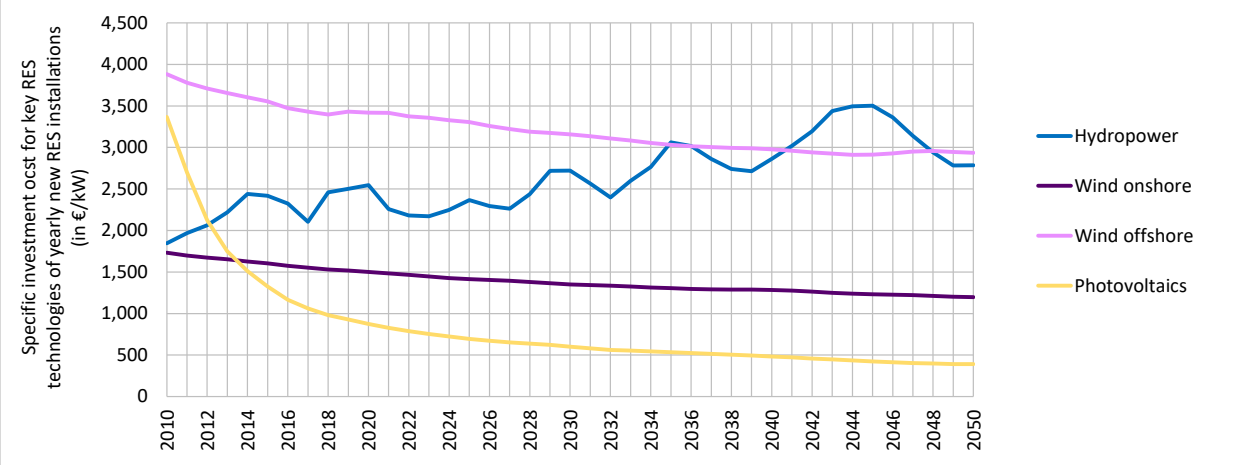
Assumptions on learning rates:

Complementary to future RES deployment, assumptions on future learning rates for key RES technologies (apart from CSP as discussed above) are taken from corresponding recent topical studies and are as follows:

- PV (central and decentral): 20% in the period up to 2025, declining to 17.5% post 2030
- Wind (on- and offshore): 7%
- Hydropower: zero – i.e. no future cost reductions are expected for this mature technology.

Figure 6-3 illustrates the outcomes of the approach taken for RES cost trends where expected cost developments for RES technologies stem from Green-X modelling. The exemplified trends in investment cost refer to a specific scenario (i.e. the "Make-do-and-mend" scenario in the case of (default) high green gas prices) and showcase the specific investment cost for a new RES installation on average at EU27 level in a given year. As applicable from this graph, moderate cost reductions are expected for key RES technologies like solar PV and wind on- and offshore. For hydropower the opposite trend is observable: on average at EU27 level specific investment cost are expected to increase in future years since the available future potential is comparatively limited, specifically for large-scale projects. Consequently, a tendency to invest in small-scale installations is presumed for this technology.

Figure 2-3. Development of specific investment cost of selected key RES technologies at EU27 level, exemplified for the "Make-do-and-mend" scenario in the case of (default) high green gas prices



2.3.6 Final remarks and Data availability

Please note that all cost data presented in this chapter are expressed in real terms, using $€_{2020}$.

For increasing transparency in the approach used and the underlying data and results, key modelling data is publicly available in the Zenodo repository "AURES II, WP8, Dataset Input Data" by Resch, Geipel, Hasengst. (2022)!

3 Results

This chapter is dedicated to inform on the outcomes of our analyses on the future of RES auctions in a changing electricity system. Results are presented for the two complementary elements of the assessment: the power system analysis reflecting predefined long-term trends in a changing electricity system, done by use of the open-source energy system model Balmorel, and the RES policy analysis, done by use of TU Wien's Green-X model.

3.1 Results from the power system analysis – assessing distinct long-term trends of a changing electricity system

This section presents the modelling results on the European electricity supply in the various scenarios introduced previously in section 2.2. These results were obtained with the open-source energy system model Balmorel, integrated in a modelling system with the RES policy model Green-X through multiple iterations.

Before discussing the results of the power system analysis in detail, it has to be noted that, as outlined under the modelling framework (cf. section 2.1), a large part of the renewable energy capacity is already determined by the Green-X model and is given as a restriction to the system optimization within the Balmorel model. This holds for the vast amount of RES electricity capacity at country level from the following technologies: wind (onshore and partly offshore), PV (decentral and utility scale) and CSP, hydro, geothermal, and certain fractions of biomass[3]. Furthermore, nuclear power generation is prescribed in order to depict the policy preferences and the corresponding pathways shown in section 2.2.

The electricity demand side is also largely determined by the general assumptions taken as prescribed in section 2.2. The total final electricity demand (including sector coupling, i.e., use of electricity for hydrogen production, heat supply, and electromobility) per country is given as a restriction to Balmorel. Nevertheless, the electricity demand resulting from the system optimization in Balmorel may be higher due to e.g. additional hydrogen production for re-electrification or other storage options, a different choice of technology for the heat supply in heat grids, higher curtailment, and transport losses (factors being subject to the system optimization).

This modelling approach means that there remains only a certain fraction of the total electricity supply that can be optimized within Balmorel. In the following, we will call this amount of electricity the "gap". This gap between the actual total electricity demand and the prescribed generation can be filled with electricity from fossil fuels (taking into regard the assumed CO_2 price), biogas and additional offshore wind. Because of its importance for the interpretation of the model results, we will discuss the gap together with the results.

The installed capacity of the technologies with prescribed generation follows directly from the underlying generation profiles in Balmorel, while for the other technologies it can be optimized by the model.

Before delving into the modelling results right below and in order to facilitate the interpretation of the results, here a quick recap on the modelled scenarios: "Top down" and "Shiny Happy Energy Community" are those scenarios with a high degree of system flexibility, while Leviathan and "Make Do and Mend" are those with only limited flexibility. On the decentralization axis, "Shiny Happy Energy Community" and "Make Do and Mend" represent a decentral approach towards the energy transition while "Leviathan" and "Top Down tech" represent a more centralized approach.

3.1.1 Installed capacities and electricity supply

First, we will look at the technology-specific power plant stock at EU level, that is the cumulated available generation capacity for all available conventional and renewable technologies. Figure 3-1 depicts those

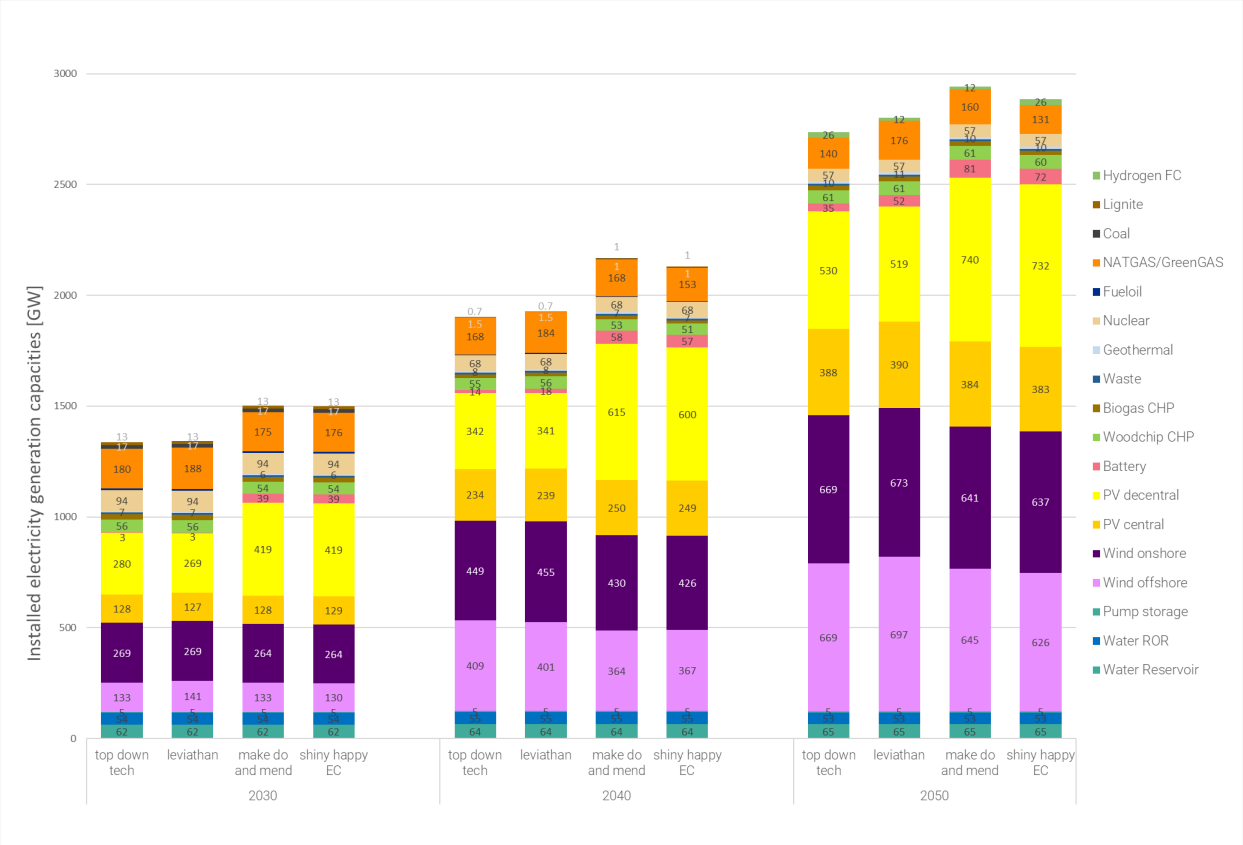
[3] In the case of biomass, only the amount of electricity generated from biowaste and solid biomass in the Green-X model was prescribed as biomass in Balmorel. This was because Balmorel had the option to freely optimize the capacity and use of gas power plants using a certain share of biogas (50% in 2030, 75% in 2040 and 100% in 2050).

capacities for all modelled years (2030, 2040, 2050) and for all four key scenarios.

Most importantly, we observe that capacities for bituminous coal and lignite are phased out rapidly. Already in 2030 only a fraction of currently available capacities remain in Europe. At this time coal constitutes only around 2% of the overall capacity in Europe, while in 2040 no coal power plant is required to dispatch the necessary electricity supply. The other conventional generation technology, namely gas only slightly decreases its total European fleet size in absolute terms. Exemplarily it falls from 175 GW in 2030 to 160 GW in 2050 in the "Make Do and Mend". The decrease is similar in the other scenarios. While the total gas capacity thus remains roughly at the same order of magnitude in absolute values, it diminishes significantly in relative terms. Furthermore, the plants themselves are subject to a progressive fuel switch from natural gas towards green synfuels to avoid the high cost for carbon allowances and to fulfill CO2 reduction targets. In total, this leads to a continuous phase out of fossil fuels and a fully decarbonized power sector by 2050!

Next, we observe a strong increase in the total electricity generation capacity following the increase in total electricity demand that is taken as exogeneous input parameter. The general trend for all scenarios contains a doubling of the power plant stock from 1500 GW in 2030 to 3000 GW in 2050. On the one hand this reflects the actual increase in total electricity demand due to electrification of other sectors yet it is also related to the lower amount of full load hours of volatile renewable energy sources compared to their dispatchable counterparts. Regarding the total capacity of dispatchable renewable energy sources, namely geothermal, biomass, biogas and hydro, one can observe that their aggregated value does not vary between the scenarios and that it remains roughly at their 2030 level, with only slight increases until 2050. This is due to the limited potential of those technologies making a stronger expansion unfeasible.

Figure 3-1. Comparison of the technology-specific power plant stock at EU level in all modelled years (2030, 2040, 2050) and for all four key scenarios (Source: Balmorel modelling)



The main increase in total electricity generation capacity is linked to the expansion of photovoltaic and wind power and to their respective sub-technologies decentral small-scale PV and utility size PV as well as onshore and offshore wind turbines. In aggregate terms, the total PV capacity roughly doubles from 2030 to 2050 across all scenarios while the total wind capacity nearly triples. However, while this general trend is

common to all four scenarios, it is in relation to the total deployment of solar and wind capacities that we observe the largest differences between the scenarios:

First and foremost, we constate a much larger capacity fleet of photovoltaics in the "Make Do and Mend" and "Shiny happy Energy Community" scenarios compared to the other two. In 2050, the two decentral scenarios contain a total of 1115-1124 GW decentral PV while in the less decentralized the capacity amounts to 909-918 GW. The difference is entirely related to the higher amount of decentral PV, meaning that the amount of utility scale PV is virtually identical across the scenarios. The different value attributed towards the prosumage of decentral PV (e.g. retail price vs wholesale price) as described in the scenario description actually lead to this preference of our models towards the decentralized PV technology. However, it is also noteworthy that the relation between the amount of decentralized PV compared to utility scale PV, changes over time. While in 2030 for each kilowatt peak of centralized PV three kilowatt peak of decentralized PV are installed, in 2050 this factor diminishes to the factor of two! We attribute this shift towards the increased deployment of utility scale PV in the later years to the progressive depletion of the potential for decentral roof top PV. The described higher PV capacity in the decentralized scenarios goes hand in hand with a lower total capacity of wind power in said scenarios. The reduction is thereby equally split between both wind power technologies. Yet due to the higher amount of full load hours of wind compared to PV, the reduction is not as large in absolute terms as the increase in PV capacity.

Another difference between the four scenarios that occurs the axis of centralization is the amount of added battery storage capacity. As described in the scenarios, the expansion of decentral PV was linked to the deployment of home storage options to increase auto-consumption values of prosumers. Consequently, their overall deployment is roughly doubled.

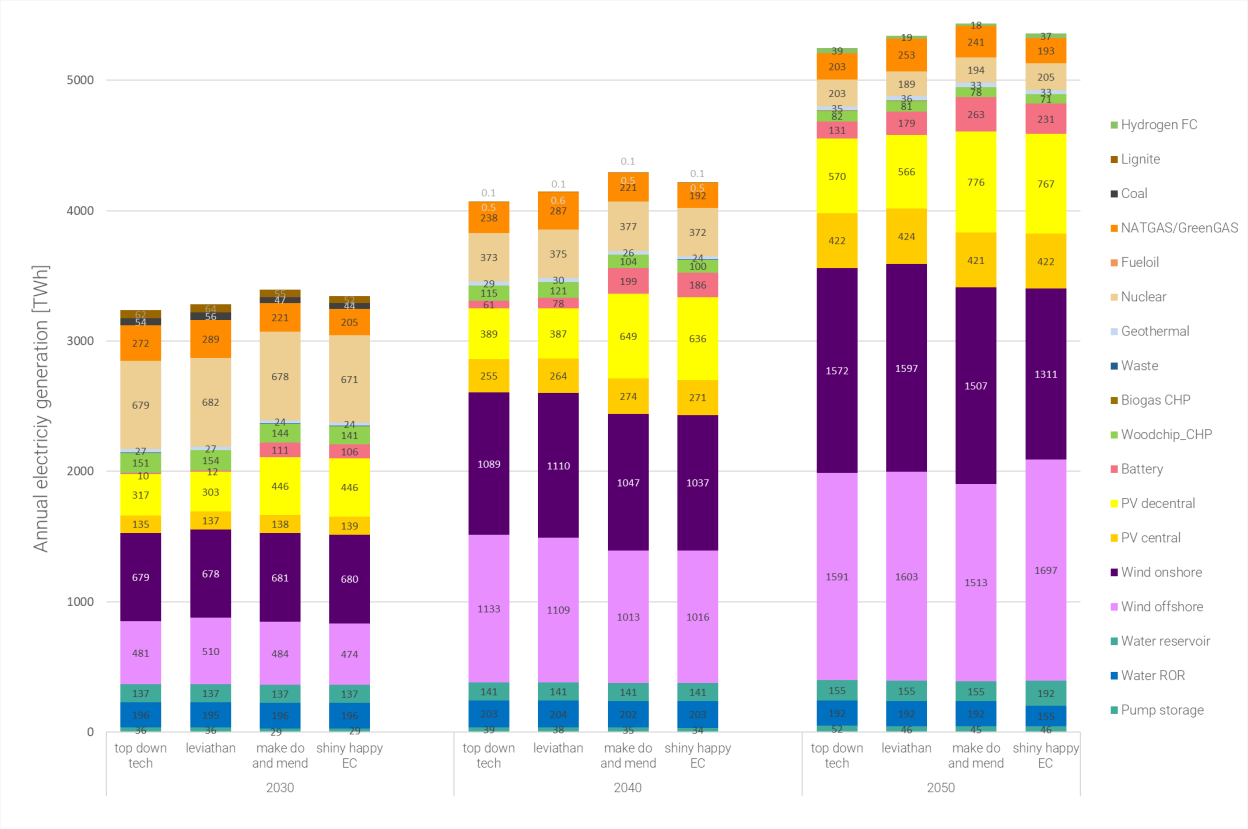
Along the flexibility axis, we observe that the flexible scenarios, e.g., "Shiny happy Energy Citizen" and "Top Down Tech" contain lower amounts of dispatchable gas capacity as well as lower amounts of battery storage compared to their respective counterpart on the same side of the centralization axis. The additional flexibility in these scenarios is characterized by the option to shift demand from time of high prices towards times of low prices, for example via smart charging of electric vehicles, industry demand response or residential heating shifting potentials through the usage of heat pumps. This allows to integrate larger amount of volatile renewable energy, thereby reducing the need for more expensive dispatchable power plants. Also, it can reduce the reliance on lossy electrical storage to level supply intermittencies of renewable energy sources. Lossless shifting of demand compared to the classical battery storage cycle entails a lower total consumption of electricity and thereby a reduced need for total generation capacity.

As for the storage option via the hydrogen road, e.g. electrolysis of hydrogen and reconversion into electricity in times of high demand, we can observe that our model does actually invests into hydrogen fuel cells but only to a very minor degree amounting to less than 1% of total installed capacity.

Next, we will look at Figure 3-2 depicting the amount of electricity that is actually generated with the power plant park discussed before. Provided that generation is directly linked to the available capacity fleet, the overall picture and trends are alike. However, there are some noteworthy specifics that can be derived from the generation figure.

Most importantly, we observe the prominence of wind power as a share of the total generation. While it cannot surprise given the capacities and the higher full load hours compared to photovoltaic generation, it is nevertheless striking that in 2050 roughly 60% of the total generation stems from on- and offshore wind power.

Figure 3-2. Comparison of yearly technology-specific electricity generation at EU level in all modelled years (2030, 2040, 2050) and all four key scenarios (Source: Balmorel modelling)

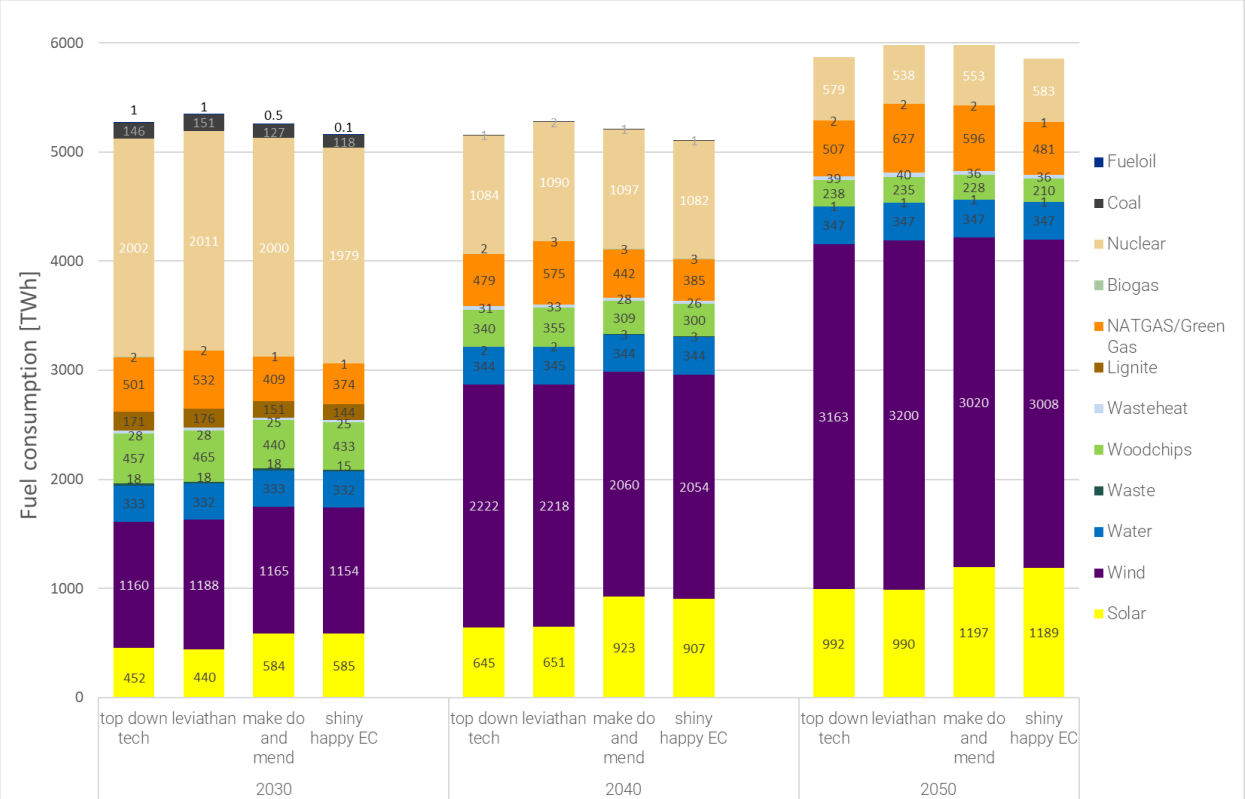


Furthermore, it is noticeable that the dispatchable generation technologies running on either renewable energy carriers such as biomass or (green) hydro carburants are dispatched only in very few hours of the year limiting the full load hours to not more than 2000 hours per year. This means, that our optimization model uses those capacities to fulfill the demand in times of very low renewable infeed and where other flexibility options are either not available or too costly. We constate that dispatchable generation technologies in 2050 will play only a minor role in terms of overall electricity generation yet a critical role as a flexibility provider for matching demand and supply in key hours. The historically used base load providers are no longer used, with the only exception being the remaining nuclear power plants.

One additional aspect that needs to be addressed is the difference in the overall total electricity generation across the scenarios, given that the final electricity demand was exogeneous input parameter identical to all four scenarios. Differences that occur are linked to different flexibility and storage uses that are more or less efficient. The scenario with the highest electricity generation is the "Make Do And Mend" scenario, being the scenario that comprises low system flexibility and as well as a decentralised approach to the transition. This can be explained by the scenario's strong reliance on electric battery storage to match supply and demand. On the one hand, the decentral character and the subsequent high prevalence of electric storage in prosumer households favors a high number of lossy battery storage cycles and on the other hand more efficient flexibility options that can shift demand without losses are not available.

Finally, as a part of this section about the electricity supply results, we look at the European fuel consumption in the four key scenarios and that is depicted in Figure 3-3. Here, only the original fuel, e.g. provenance of the electricity is presented and energy carriers and options that solely serve as an intermediate storage like electric batteries or hydrogen are not included.

Figure 3-3. Comparison of fuel consumption (excl. electricity) in the EU's power sector in all modelled years (2030, 2040, 2050) and for all four key scenarios (Source: Balmorel modelling)



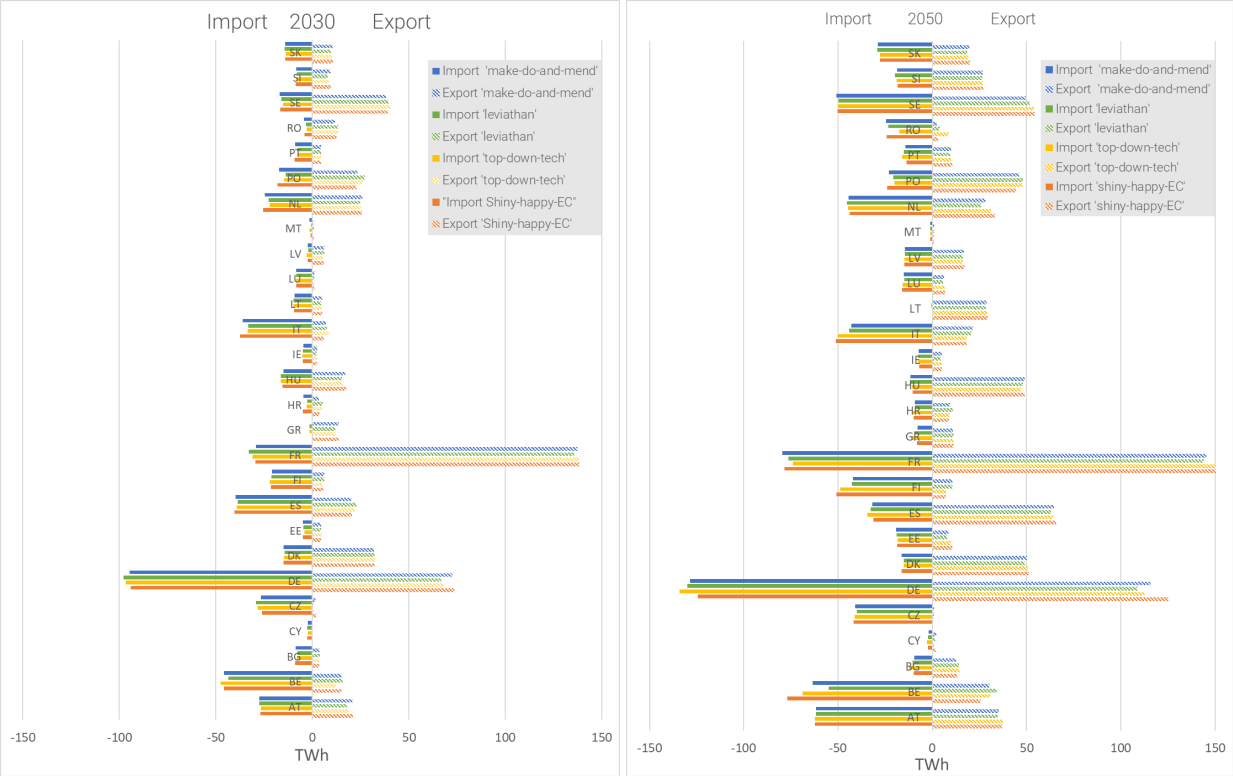
It is most striking that unlike the electricity generation and the capacity size of the European power plant fleet, the fuel consumption does only moderately increases between 2030 and 2050 and even decreases in the decade between 2030 and 2040. Of course, this is due to the progressive phase out of thermal power plants that have an electric efficiency in the range of 0.3 to 0.4 unlike intermittent renewables that are attributed a statistical efficiency of 1. However, it sets into relation the overall need for primary energy that remains surprisingly constant over time and that contradicts the popular narrative that our energy consumption in the power sector is increasing disproportionably quick.

Next, we note the prominent role that nuclear power still constitutes in 2030 and its steep decline in the years thereafter. It drops from a total share of 40% in 2030 to less than 10% in 2050. Then and in contrast to the capacity and generation charts presented above, we observe identical fuel consumption values for the non-dispatchable renewable energy sources and that the differences in fuel consumption between the four scenarios stem solely from differences regarding the dispatchable technologies.

3.1.2 Cross-border electricity exchange

In this section we look at one flexibility option that is critical for the integration of intermittent renewable sources, the levelling of the regionally varying renewable feed-in and load via the cross-border exchange of electricity. As described in the section on input parameters and key assumptions, the net transfer capacities between the European Member States were assumed to be identical across all scenarios. Figure 3-4 depicts the cross-border electricity exchange across EU Member States at a yearly balance.

Figure 3-4. Comparison of cross-border electricity change (in TWh) across EU Member States at a yearly balance in 2030 (left) and 2050 (right) for all four key scenarios (Source: Balmorel modelling)



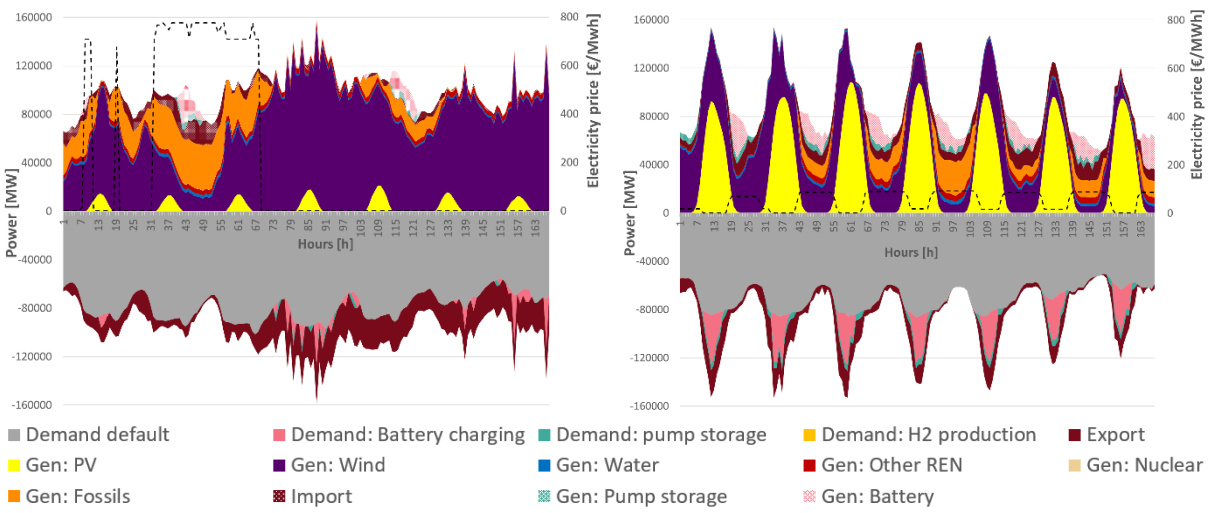
Given the identical NTC values across the scenarios, it is unsurprising that the energetic flows differ much less across scenarios than across the years. The small differences that are nevertheless occur can be explained by the varying degrees of system flexibility and storage options at the country level. In between 2030 and 2050 however, we can observe that for virtually all member States the total amount of exported and imported electricity significantly increases, thereby taking advantage of the increase in NTC capacities. For example, the electricity imports of Germany increase by more than 30% from 95 TWh in 2030 to 130 TWh in 2050. For most countries, while the absolute value of cross border electricity exchange increases, the relation of imports and exports mostly remains the same. Yet, there are some noteworthy exceptions: Most importantly France, that in 2030 exports significantly more electricity than it imports has a much more balanced relation, even if it still is a net exporter. Lithuania, a country that in 2030 still is a net importer constitutes a purely exporting country and the only one in 2050 that does not import any amounts electricity. This reflects their abundant potentials for dispatchable biomass and hydropower. All the other countries rely on cross border exchange as a tool to match national supply and demand. National unilateralism and potential restrictions on the usage of existing NTC capacities would therefore go to the detriment of an optimal European electricity dispatch and thus to the final electricity consumer.

3.1.3 Hourly dispatch

After having discussed results that were averaged over complete years, we will now look at the electricity dispatch on the hourly level for exemplary time periods. We selected one week in January and one week in June, for which the dispatch in the energy system of Germany and Spain (two of the largest European electricity markets) in the year 2030 and 2050 is shown in Figure 3-5 to Figure 3-8. The figures show the hourly dispatch for the "Make Do and Mend" scenario that can be interpreted as an intermediate scenario given while it does not have access to the full range of flexibility options regarding demand response, heat pumps and electric vehicles, its decentral character provides some level of flexibility via the prosumer electric battery storage installations. Besides the dispatch the chart additionally shows the electricity price in €/MWh on the secondary axis as well as the default and flexibility demand as negative power.

First, we look at the shown winter weeks (w4) for both countries: In Germany already in 2030, the electricity generation is dominated by a substantial amount of wind power feed in. Nearly half of the week, the wind feed in alone is sufficient to satisfy the demand. This supply of renewable electricity at very low marginal generation costs enables also significant amount of electricity exports and leads to wholesale prices of 0€/MWh in more than two thirds of the hours in this week. However, there is a period of time from hour 31 to 70 where we observe very low overall feed in of renewables. Considerable electricity imports as well as the dispatch of conventional fossil plants are required to meet the demand. Spiking prices reaching 600€/MWh are caused by the dispatch of fuel oil plants. Looking at this very week 20 years later with the same renewable generation profile, we observe a general scale up of the wind power production. Solar generation remains however limited even in limited and cannot contribute significantly to meet the demand. Instead, the residual demand in the hours 31 to 70 are covered by mix of electricity stemming from battery storage, hydro power, imports as well as synfuel generation. The usage of fuel oil plants is entirely phased out, leading to a reduced price peak compared to 2030. In 2050, the price is then set by the marginal costs of electricity generation with gas turbines running on green gas.

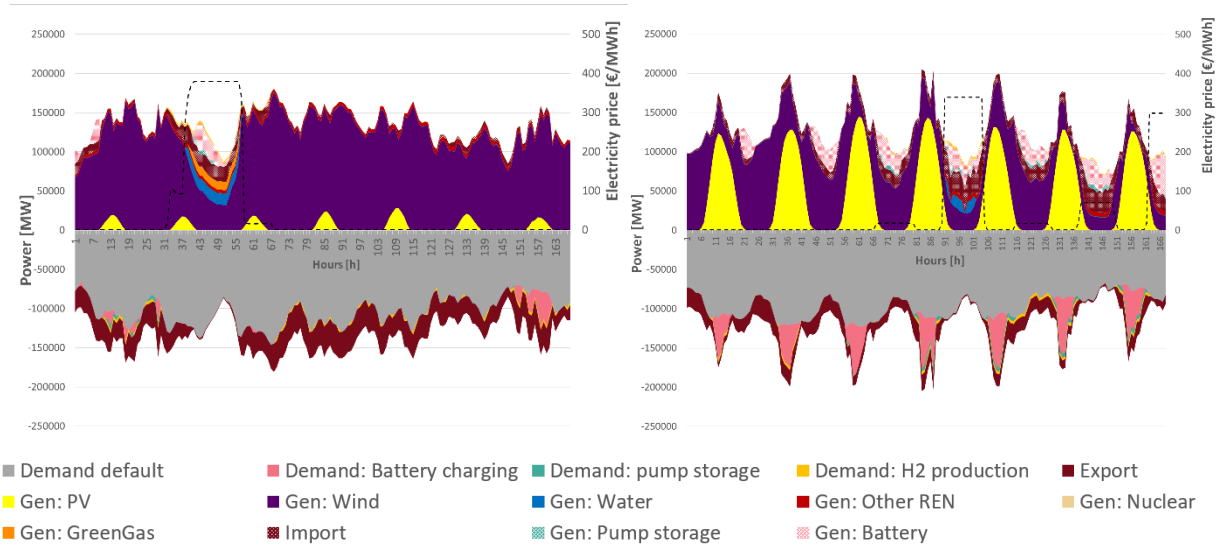
Figure 3-5. Weekly electricity generation in Germany in 2030; on the left week 4 (winter); on the right week 26 (summer) (Source: Balmorel modelling)



In the winter week of Spain in 2030 we observe already considerable amount of renewable feed-in consisting of both solar and wind power. Both technologies provide roughly two thirds of the overall electricity generation. However, wholesale prices never reach the marginal costs of wind and solar meaning that at no hour in this week, this renewable feed in is able to fully met the demand. The respective residual demand always requires the dispatch of some thermal power plants. With prices not exceeding and hovering around 90€/MWh we constate that coal power is the main fuel source for this thermal generation. Twenty years later, the solar generation during the day solar feed even in winter is that high that it enables to charge the electric battery storage systems. This is depicted by demand by the battery demand peaks exceeding the

default mand. During the night, the generation is dominated by wind power complemented with dispatchable generation from pump storage and batteries.

Figure 3-6. Weekly electricity generation in Germany in winter (week 4) and summer (week 26) week in 2050 (Source: Balmorel modelling)



Now we look at the shown summer weeks (w26) for both countries: For Germany in 2030 we constate that compared to the respective winter week in 2030, in summer the overall electricity generation is much more volatile, meaning that the difference in generation between day and night is more pronounced. Of course, this is caused by the characteristic solar generation profile. As solar is unavailable during the night, at those hours the residual demand is met by a mix of wind power, fossil fuels, dispatchable renewables as well as battery storage feed in. What is more striking is that on the demand side already in 2030, the solar peak generation exceeds the default demand and is stored mostly into electric battery systems. Accordingly, the wholesale price alternates between 0€/MWh during the day and 100€/MWh during the night. Looking at this same week, 20 years later with the same renewable generation profile we constate that the combined generation of solar and wind energy is sufficient to cover demand is most hours. The use of flexibility options in this week is therefore limited to a few hours of battery generation and some imports during the night. Dispatchable thermal power plants is entirely phased out.

In the summer week of Spain in 2030 we observe similarly to Germany a very volatile generation profile yet with an even stronger focus on solar generation. Once again, we observe demand peaks from the charging of electric batteries to integrate the generation from photovoltaic power plants. During the night, the renewable generation remains insufficient to cover the demand due to the comparatively low feed-in of wind power. Spain therefore relies on the dispatch of a wide range of dispatchable technologies as well as imports. Looking at the same week 20 years later, it is most noteworthy that unlike in 2030, the wind generation is entirely limited to hours during the night. This implies that the potential wind power generation during the day is entirely curtailed and cannot be shifted for use in other hours via flexibility measures.

Figure 3-7. Weekly generation in Spain in winter (week 4) (left) and summer (week 26) (right) in 2030 (Source: Balmorel modelling) (Source: Balmorel modelling)

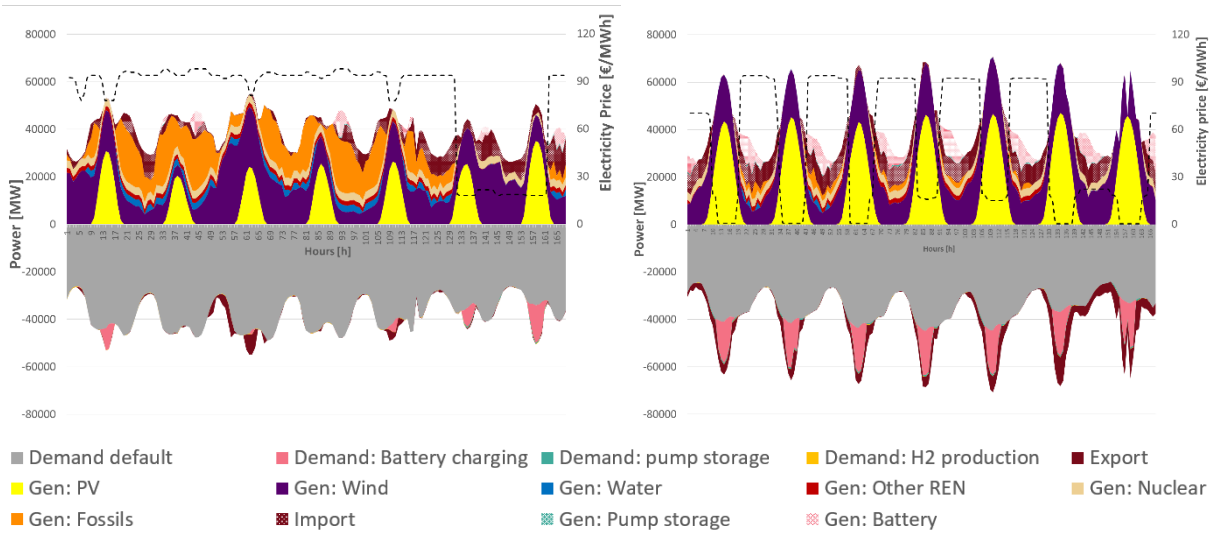
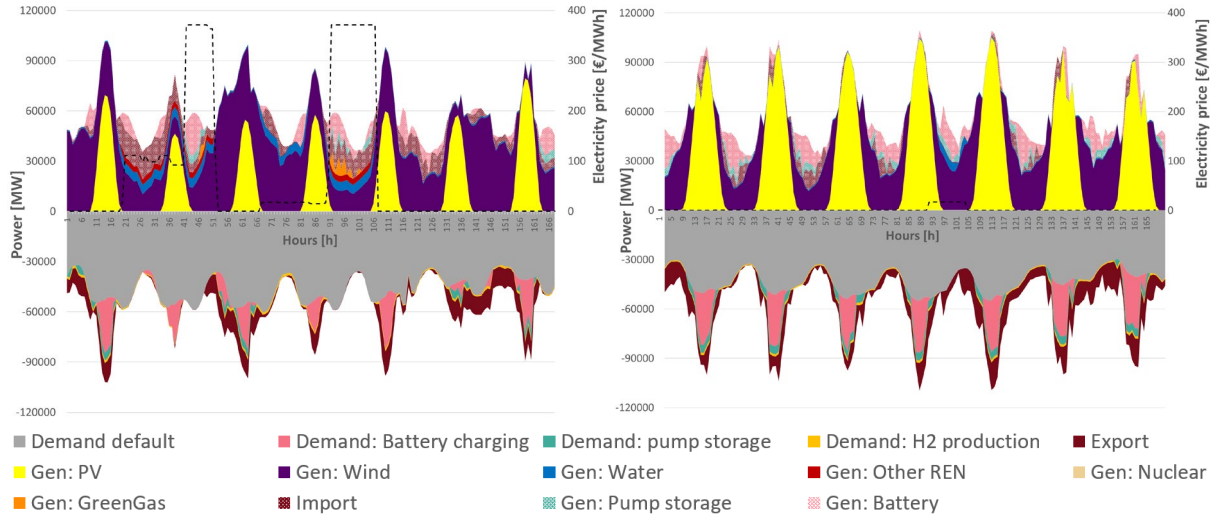


Figure 3-8. Weekly generation in Spain in winter (week 4) (left) and summer (week 26) (right) in 2050 (Source: Balmorel modelling)



3.1.4 Power system flexibility needs – a closer look at residual load and the impact on wholesale prices

As a part of the results section, we next take a closer look at the overall power system flexibility need. We define this need for power system flexibility as the residual or gap between the non-dispatchable feed in of renewable energy sources compared to the default electricity demand. The default electricity demand is the gross electricity demand before flexibility options are employed. This gap has to be filled by (a combination) of dispatchable electricity generation, demand shifting via storages, demand response or sector coupling or actual demand shedding.

Figure 3-9 to Figure 3-12 illustrate this gap for Germany and Spain and the years 2030 and 2050 respectively. Each figure shows the feed in of non-dispatchable renewable energy meaning solar, wind and run of river as well as the default electricity demand and the (averaged) electricity price. As a disclaimer it must be emphasized however that those charts present values that are averaged over a week, and therefore solely

present a reflection on the general trend and the season flexibility requirements. The total flexibility need of the power sector is thus underestimated, yet the general trend depicted in the charts below provides nevertheless some noteworthy insights.

The figures show that for both Germany and Spain in 2030 in nearly all weeks of there is a requirement for dispatchable energy supply or additional flexibility. The largest difference between the default demand and the non-dispatchable renewable supply occurs in week 47 for both countries. This gap goes hand in hand with the highest electricity prices of the year. As a general trend we can observe that the electricity price strongly correlates with the size of the gap, e.g. the absolute amount of required power system flexibility. The main difference between Germany and Spain in 2030 is that in Spain wind and solar energy are more complementary to each other entailing a lower weekly volatility of the RE generation. In consequence the price level in Germany is also slightly higher than in Spain (85€/MWh vs 65€/MWh)

Figure 3-9: Yearly RES generation, electricity demand and wholesale prices for Germany, 2030 (Source: Balmorel modelling)

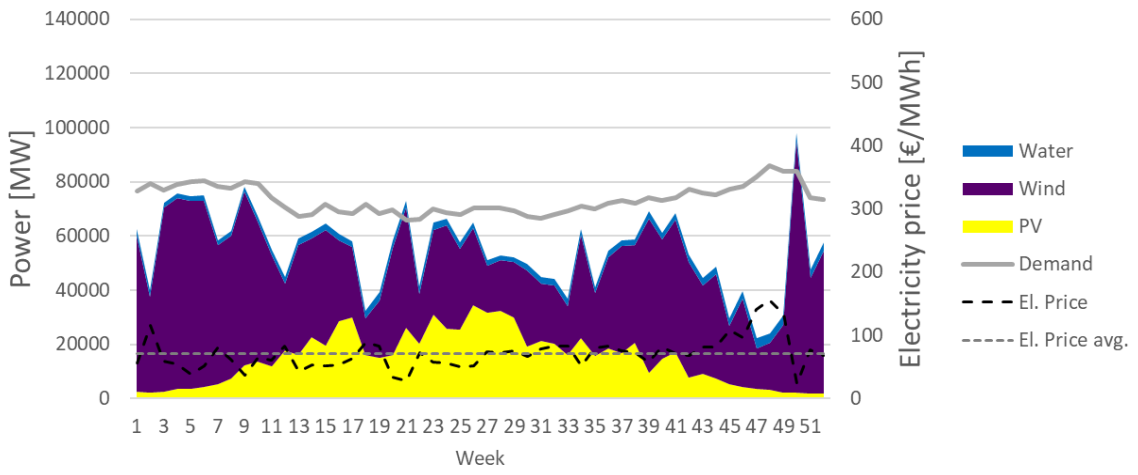
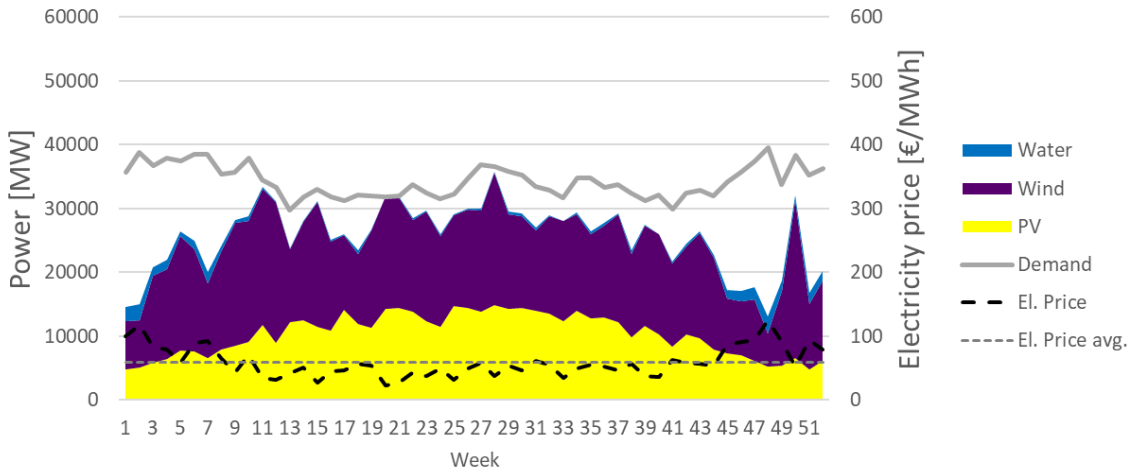


Figure 3-10: Yearly RES generation, electricity demand and wholesale prices for Spain, 2030 (Source: Balmorel modelling)



As for 2050, the figures show that for Germany the non-dispatchable RE generation covers the electricity demand in half of the total weeks of the year, while in Spain it actually exceeds the national demand in three quarters of the year. This makes Spain a net exporter of renewable electricity and leads to very low average electricity prices (50€/MWh). Analogously to 2030, the observed electricity price in both countries correlates with the need for intraseasonal power system flexibility leading to higher prices if the gap between RE

generation and default demand increases. In aggregate we observe that the intraseasonal flexibility requirement is much larger for Germany than for Spain explaining the formers higher average electricity prices.

Figure 3-11: Yearly RES generation, electricity demand and wholesale prices for Germany, 2050 (Source: Balmorel modelling)

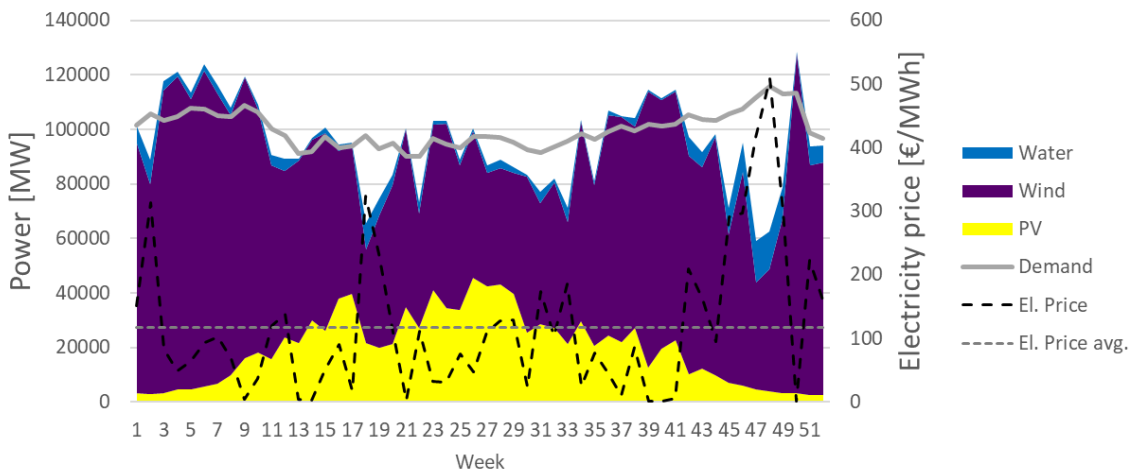
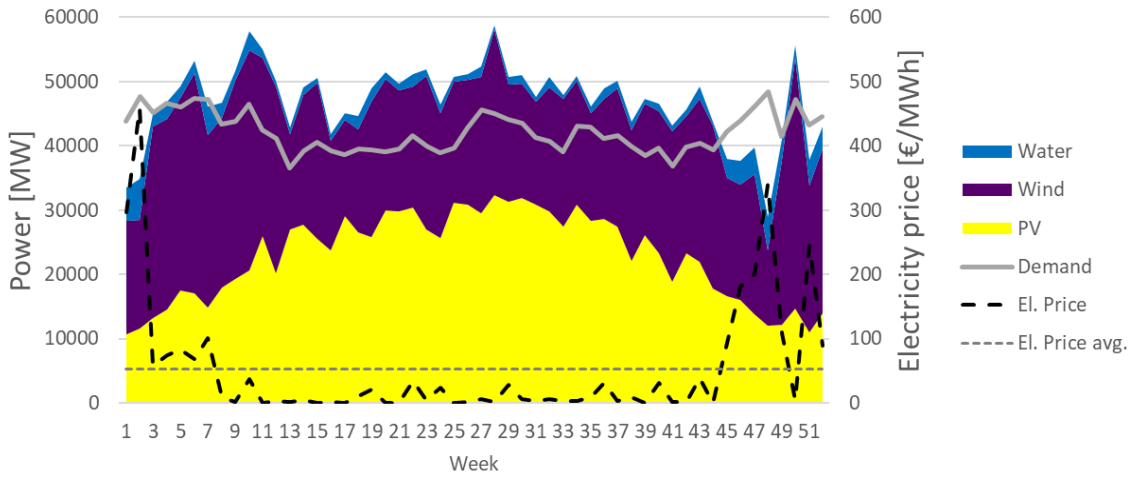


Figure 3-12: Yearly RES generation, electricity demand and wholesale prices for Spain, 2050 (Source: Balmorel modelling)



However, and most interestingly the mentioned correlation between prices and the requirement for system flexibility is less stringent in the case of Germany. There, while the general correlation still holds, we nevertheless observe a few weeks (e.g. W29 & W30) where the wholesale price is below average and close to zero, even though there is a significant gap. In Spain such circumstances do not occur in 2050. We therefore conclude that Germany disposes of a proportionally larger potential that enables it to fill the gap between non dispatchable RE generation and default demand with low marginal cost flexibility options.

3.2 Results from the RES policy analysis – assessing the future need for dedicated RES support in a changing electricity system

This section is dedicated to inform on results from the prospective energy policy analysis dedicated to RES, specifically on the impact of a changing electricity system on the need for dedicated RES support. The main tool used for that purpose is TU Wien's Green-X model, a specialised energy system model offering a sound coverage of support instruments for renewables as well as on the available resources and corresponding cost of individual RES technologies within Europe.

As outlined in section 2.1, within the integrated model-based analysis Green-X has been complemented by the Balmorel model, serving to analyse the interplay between demand, supply and storage in the power system of tomorrow. Balmorel has been used to identify the gap in system flexibility that needs to be covered by available flexibility options (incl. various storage technologies, flexible supply options including green gas or flexibility options on the demand side) for safeguarding supply security in future years when variable renewables like wind and solar PV times are the dominant generation assets and when fossil fuel based dispatchable generation assets are no longer viable options for doing so. For results on that part of the analysis we refer to the previous chapter.

Below we start with a brief recap on the role of renewables in Europe's electricity system of tomorrow. Complementary to the insights gained from the power system analysis, we take a closer look at the uptake of renewables over time, and on how that is spread across technologies. Subsequently we analyse how that may differ by scenario and which parameters are key influencer in this respect. A large part of the analysis is then dedicated to assess the energy policy needs and the corresponding impacts, informing on expected cost trends and on how large the financing gap may be that needs to be covered by dedicated support instrument for RES technologies. Here RES auctions may serve as predominant tool for providing public support. Subsequently we generally focus on the four trend scenarios concerning electricity system developments that have been identified in the corresponding qualitative analysis undertaken within the AURES II study, cf. Woodman and Fitch-Roy (2020). Later on, we complement these with sensitivity cases concerning key input parameter and assumptions in accordance with the topical focus.

Please note that in general, and if not stated otherwise, all figures and data refer to the aggregated EU27 level (excl. the UK) and all cost data are reported in real terms, using $€_{2020}$ as price basis.

3.2.1 RES uptake within the European Union until 2050

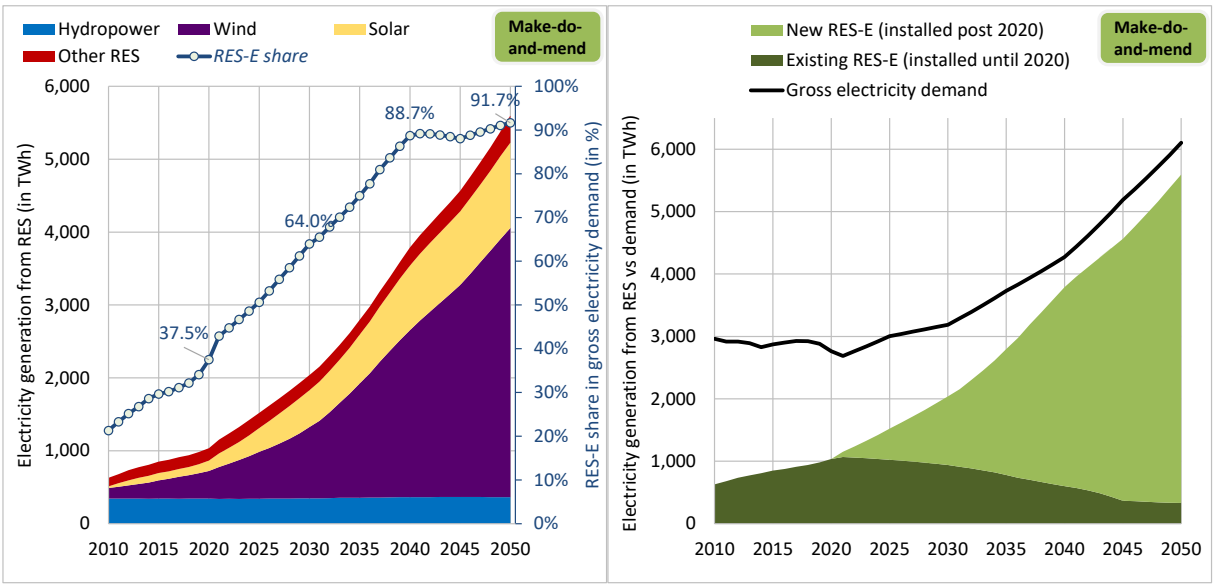
Below we take a closer look at the according to our modelling expected uptake of renewables in Europe's electricity sector. We thereby complement the explanations and insights provided for the power system analysis undertaken by the Balmorel model as provided in the previous section of this report.

As starting point, Figure 3-13 offers a thorough comparison of the historic and expected future development of electricity generation from RES at EU level up to 2050, exemplified for the long-term trend scenario "Make-do-and-Mend". More precisely, the graph on the left provides a breakdown of RES-E generation by technology whereas the graph on the right indicates the age distribution of the power plant stock, distinguishing between existing (installed up to 2020) and new (post 2020) RES installations. Both graphs also show how RES contribute to meet the given demand for electricity by indicating the overall RES share in gross electricity demand (left) or by depicting the demand trend in absolute terms (right).

If we look back in time, we see that a strong renewables growth has been achieved within the EU's electricity sector throughout the past ten years: electricity generation from RES has increased from 630 TWh in 2010 to 1,036 TWh by 2020 – in relative terms this corresponds to an increase of the RES share from 21.3% (2010) to 37.5% (2020). This impressive trend needs to be maintained if we take a look at the expected RES share developments in future years: taking deep decarbonization as our overall guiding principle implies an increase of the overall RES share in the electricity sector to about 64% by 2030, and to more than 91% by 2050. In absolute terms the accompanying strong growth in electricity consumption imposes even a strengthening of RES developments in future years compared to the historic record. Electricity generation from RES needs to at least double within the next ten to eleven years and to more than quadruplicate until 2050 compared to the status quo (2020).

The bulk of electricity generation that stems from already established RES plants (installed until 2020) is marked in dark green at the bottom of Figure 3-13 (right). This share is declining over time and by 2050 only hydropower facilities that typically have the longest technical lifetimes among all RES (and conventional) technologies are expected to remain in the power system by that point in time.

Figure 3-13. Development of electricity generation from RES at EU level, broken down by technology (left) and by age structure (i.e. existing vs. new (post 2020) RES installations) (right) according to the long-term trend scenario "Make-do-and-Mend" (Source: Green-X modelling and Eurostat (2022))



A comparison of the technology trends shown in Figure 3-13 (left) indicates the following aspects:

- Apparently, wind energy dominates the picture – already today (2020) and in future years (2030, 2040, 2050) the largest share of RES-based electricity generation will come from this particular technology. The growth from 376 TWh today (2020) to 3,691 TWh in 2050 appears however impressive. A closer look at the distribution between on- and offshore wind shows the dominance of onshore wind today and in the near future. According to modelling, that picture will change until 2050. According to the exemplified trend scenario "Make-do-and-Mend" offshore is expected to contribute a comparatively similar amount of electricity as onshore wind for meeting our electricity needs at EU level by 2050.
- Apart from wind energy, photovoltaics is the other key technology in future years. Modelling indicates a significant increase in PV deployment – i.e. from 144 TWh today (2020) to 1172 TWh by 2050 according to the exemplified trend scenario "Make-do-and-Mend". Post 2020 newly established residential PV systems are expected to generate 738 TWh by 2050 in the "Cooperation – High Demand" scenario, and slightly less (727 TWh) in the "National Preferences – High Demand" scenario. Central PV systems rank next, achieving slightly lower but among the two scenarios comparatively similar levels of deployment.
- Electricity generation from hydropower is the third largest contributor to RES generation today and in future, compared to wind and photovoltaics the deployment is however less impressive: Electricity generation from hydropower is expected to grow moderately from 345 TWh today (2020) to 364 TWh by 2050 according to the exemplified trend scenario "Make-do-and-Mend". Here already in prior (up to 2020) established plants make up the lion's share, implying that only a small uptake of newly built hydropower plants appears feasible according to modelling. One needs to consider here that according to literature and in accordance with current practice future potentials that acknowledge environmental and societal constraints are limited across Europe.
- Other RES technologies like biomass, geothermal electricity, tidal stream or wave power show only comparatively minor contributions by 2030 and by 2050 under the underlying framework conditions where least-cost options are prioritized in modelling. A growth in electricity from these technology

options is however applicable in our modelling: Electricity generation from other RES is expected to grow from 170 TWh today (2020) to about 367 TWh by 2050, implying more than a doubling compared to today.

Complementary to the above, Table 3-1 provides a comparison of 2050 electricity generation from RES at EU level among assessed long-term scenarios. In general, only small differences between assessed scenarios are applicable therein:

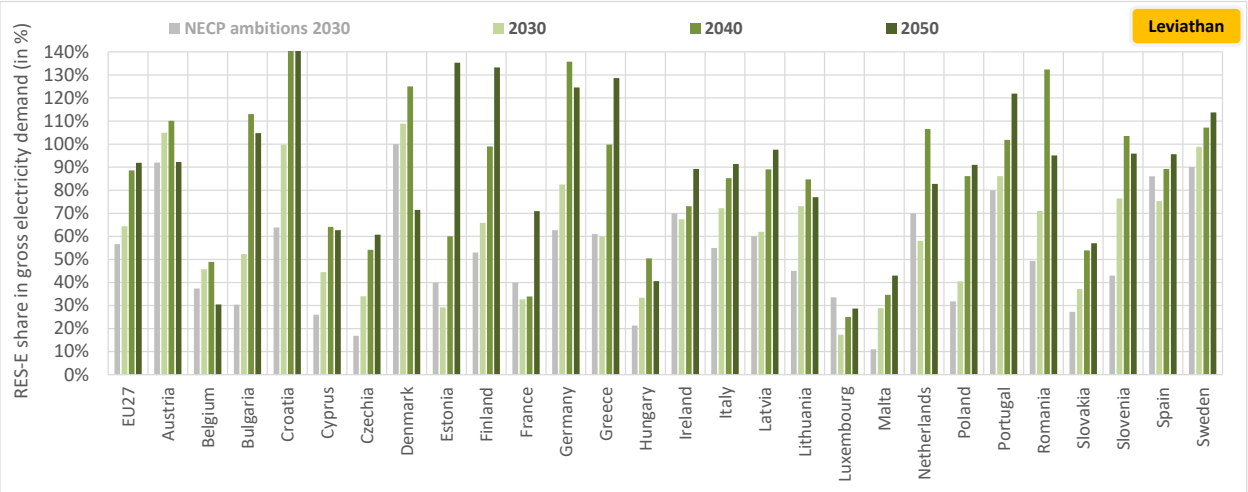
- The overall 2050 RES share in electricity demand varies only at a negligible extent between 91.6% ("Shiny happy energy citizens") and 91.9% ("Leviathan")
- The technology-specific deployment shows also only small variations, with the exception of solar (i.e. Photovoltaics and CSP) where the trend scenarios that have conceptionally put emphasis on decentralisation (i.e. "Make-do-and-mend" and "Shiny happy energy citizens") show a stronger contribution of solar. Reason for that is the prioritisation of decentral PV systems in those scenarios, and, in consequence, the stronger uptake of solar overall.

Table 3-1. Comparison of 2050 electricity generation from RES at EU level for assessed long-term trend scenarios (Source: Green-X modelling)

Comparison of 2050 RES supply at EU level	Scenario:	Make-do-and-mend	Top Down Tech	Leviathan	Shiny happy energy citizens
RES-E generation (total)	TWh	5594.7	5606.3	5607.8	5593.8
RES-E share	%	91.7%	91.8%	91.9%	91.6%
Hydropower	TWh	364.3	364.8	365.1	364.0
Wind	TWh	3691.0	3800.3	3780.9	3692.4
Solar	TWh	1172.2	1060.4	1054.0	1175.3
Other RES	TWh	367.2	380.8	407.8	362.1

Next, Figure 3-14 provides an overview on the expected country-specific RES deployment in the electricity sector. More precisely, this graph allows for a comparison of the planned and the, according to modelling, expected future (2030, 2040, 2050) country-specific RES shares in corresponding gross electricity demand, here exemplified for the long-term trend scenario "Leviathan". Planning indicates here the national perspective for 2030 as proclaimed by Member States in their 2019-edition of National Energy and Climate Plans (NECPs).

Figure 3-14. RES shares in gross electricity demand by MS in selected years (2030, 2040, 2050) according to the long-term trend scenario "Leviathan" (Source: Green-X modelling and Eurostat (2022))



Key results derived from the comparison of country-specific RES shares in future years are:

- With the exception of countries like Estonia, France, Greece, Ireland, Luxembourg and Spain, national planning as postulated in the 2019-edition of NECPs needs to be revised to bring Member States back on track with EU Green Deal needs as presumed in modelling for 2030.
- As in the past strong differences in demand-related RES shares are generally observable across countries. Despite the assumed transformation of the electricity sector towards carbon neutrality by 2050, differences in country-specific RES deployment are also applicable in the years to come. This also holds for 2050 when renewables reach a demand share of more than 91% at EU level.
- By 2050 the list of countries with a significantly higher domestic RES generation than the domestic demand under all illustrated scenarios includes Croatia, Estonia and Finland. In these countries RES shares larger than 130% are expected for 2050.
- Germany, Greece, Portugal and Sweden are among those countries that achieve a moderate oversupply of RES generation compared to domestic demand at a yearly balance by 2050 – but in these countries RES shares are smaller in magnitude compared to the above.
- Austria, Bulgaria, France, Ireland, Italy, Latvia, Lithuania, Netherlands, Poland, Romania, Slovenia and Spain are countries that expectably achieve a comparatively even balance between RES generation and overall domestic electricity demand in 2050 according to modelling.
- Countries that have to heavily rely on (RES-based) electricity imports by 2050 are Belgium, Cyprus, Czechia, Hungary, Luxembourg, Malta and Slovakia – i.e. in these countries the 2050 RES share is (well) below 70%.

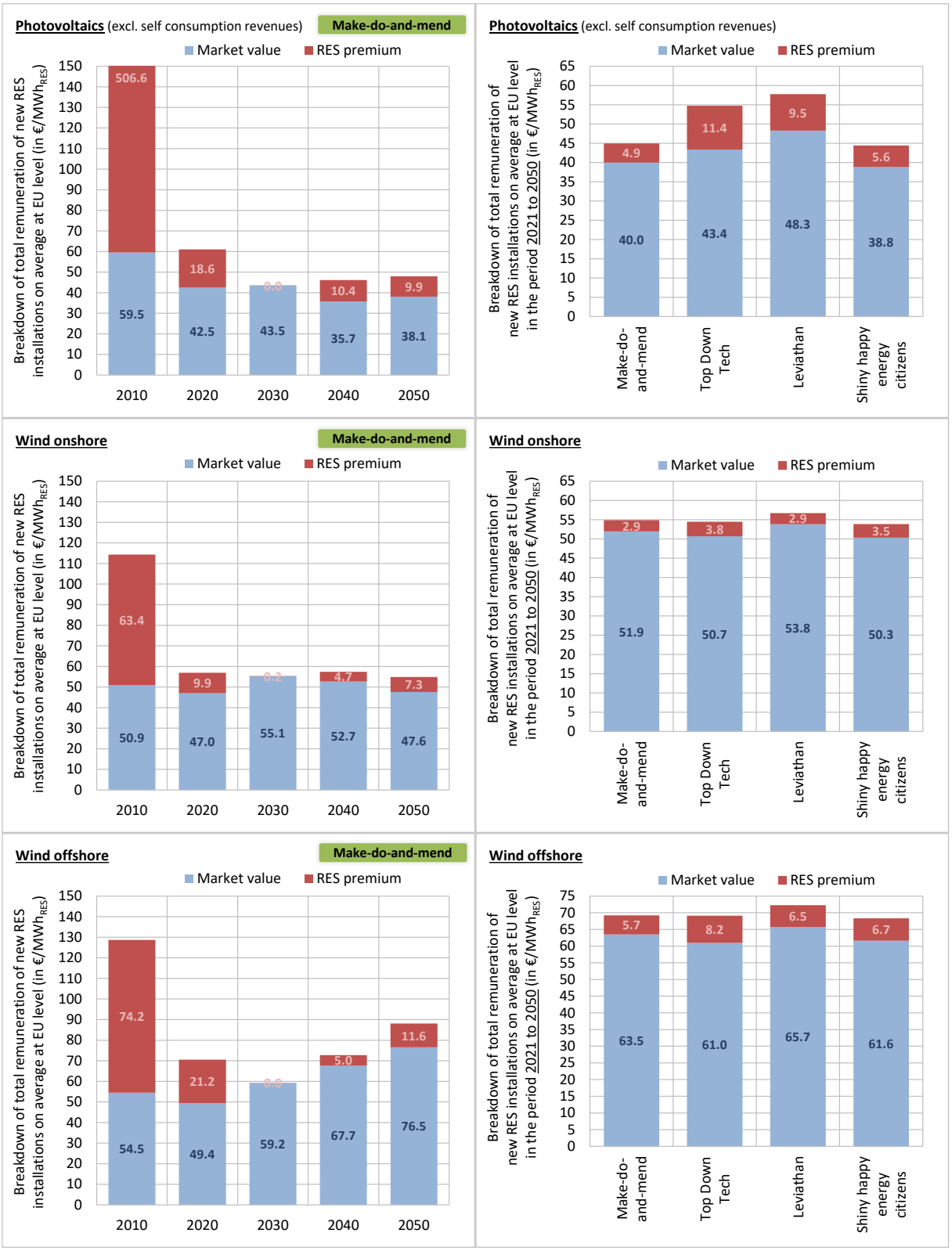
3.2.2 The impact of long-term electricity market trends on total remuneration of RES technologies

This section is dedicated to assess the impact of long-term electricity market trends on total remuneration of RES technologies, shedding light apart from overall remuneration needs on their distribution. Here a distinction between market and support revenues is applied in subsequent graphs. Doing so allows for identifying the need for dedicated RES support, provided via RES auctions, in the mid to long future. Our analysis comprises all four distinct long-term trends scenarios of a changing European electricity system and builds within this section on default assumptions as discussed in section 6.3, incl. default (low) prices for fossil fuels in combination with default (high) prices for green gas as key contributor for meeting future power system flexibility needs.

Concerning levelized cost of electricity (LCOE) from RES, a moderate to strong decline in RES technology cost is generally presumed, in accordance with technological learning trends (cf. Figure 6-3). The imposed strong RES uptake implies however to use also less preferable sites which, in turn, may countervail the cost decline caused by technological learning.

A detailed illustration of the future development of total remuneration of key RES technologies (i.e. PV, on- and offshore wind) at EU level in the period up to 2050 is provided by Figure 3-15. More precisely, the graphs on the left-hand side of Figure 3-15 show the development of total remuneration of new RES installations from key RES technologies (i.e. PV (top), onshore wind (middle) and offshore wind (bottom)) at EU level over time, exemplified for the long-term trend scenario “Make-do-and-mend”. The graphs on the right-hand side complement the above via a comparison of average (2021 to 2050) total remuneration between all assessed long-term trend scenarios. In overall terms, in accordance with LCOE trends, total remuneration of key RES technologies like onshore wind and PV is generally expected to decline in future years compared to 2020 levels. One can observe a decline in total remuneration in the near future, i.e. by 2030. In subsequent years up to 2050, according to modelling total remuneration is projected to increase again – but total remuneration for both technologies will remain below 2020 levels.

Figure 3-15. Comparison of total remuneration of new RES installations from key RES technologies (i.e. PV (top), onshore wind (middle) and offshore wind (bottom)) at EU level over time for the long-term trend scenario "Make-do-and-mend" (left) and on average in the period 2021 to 2050 for all assessed long-term trend scenarios (right). (Source: Green-X modelling)

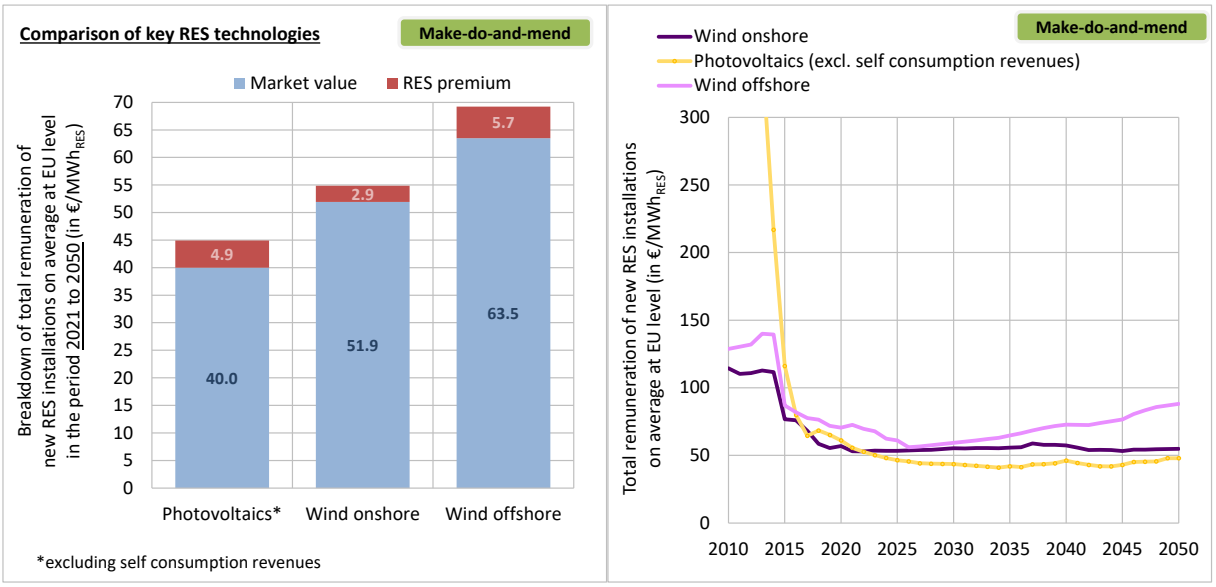


Since Figure 3-15 informs also on the decomposition of total remuneration, i.e. on the market-driven income (cf. the pale blue bars named as "market value") and on the support-driven income (cf. the red bars named as "RES premium"), we can elaborate on the need for dedicated RES support in forthcoming years below. As applicable from the graphs on the left-hand side, by 2030, under default (high) prices for green gases and, in consequence, moderately high wholesale price levels, zero-subsidy auctions can be expected for all key RES technologies. By 2040 and beyond, moderate RES support is however again required to fill the remuneration gap according to the illustrated long-term trend scenario "Make-do-and-mend". Reason for that is generally the decline of market values driven by self-cannibalism, specifically for PV – as a consequence of the required strong PV uptake in accordance with decarbonization needs. According to modelling, similar trends are applicable for wind onshore, although market values are higher compared to PV. For offshore wind Figure 3-15 indicates, in contrast to PV and onshore wind, an increase in total remuneration over time – a consequence of the impressive offshore deployment in the years closer to 2050, implying that also moderate sites need to be used. Since the market value of offshore wind is higher compared to PV and onshore wind, on-top RES support for offshore wind remains moderate. As a general observation, the graphs indicate for all key RES technologies a comparatively similar and moderate height of dedicated RES support.

A comparison of average total remuneration between the distinct long-term trend scenarios – cf. the graphs on the right-hand side of Figure 3-15 – shows that total remuneration is comparatively similar in the case of on- and offshore wind. In the case of PV stronger differences are applicable: the two scenarios emphasizing decentralisation (i.e. "Make-do-and-mend" and "Shiny happy energy citizens") require significantly lower total remuneration and dedicated support compared to the scenarios where centralisation is presumed. Reason for that is the assumed self-consumption privilege for small scale PV installations across the whole EU in the trend scenarios with emphasis on towards decentralisation. This implies additional revenues and, in turn, reduces the need for dedicated RES support provided e.g. via RES auctions.

Complementary to the above, Figure 3-16 compares average (2021 to 2050) total remuneration of new RES installations at EU level across all key RES technologies (i.e. PV, onshore and offshore wind) according to the long-term trend scenario "Make-do-and-mend". As applicable from this graph, total remuneration is lowest for PV, followed by onshore wind and offshore wind. For dedicated RES support, a different ranking occurs as a consequence of differences in market values: here onshore wind appears as least-cost option, followed by PV and offshore wind.

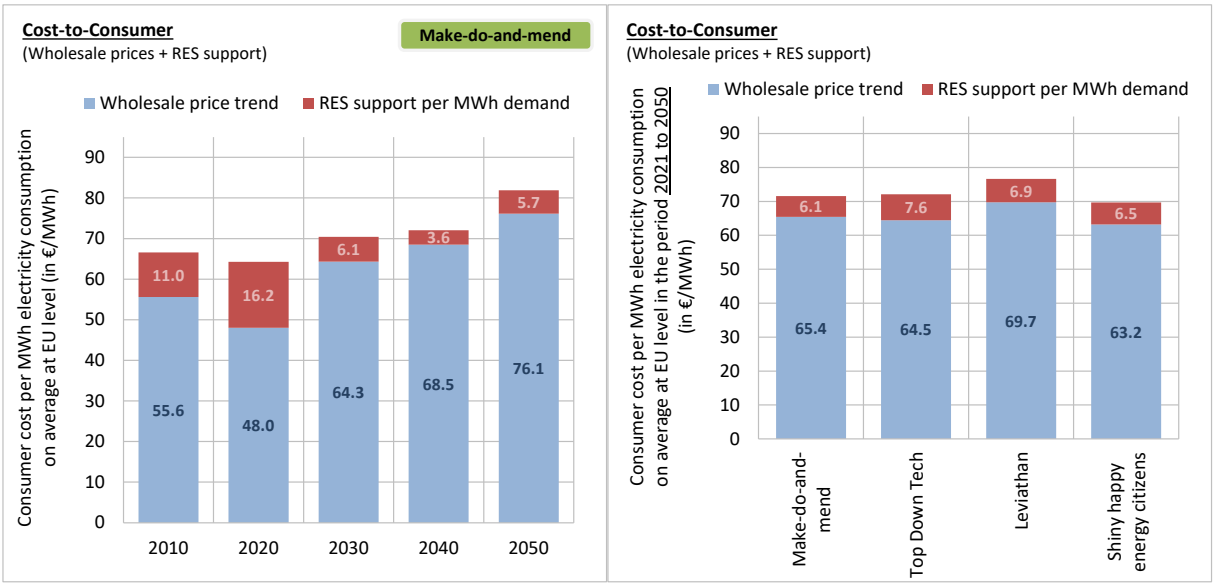
Figure 3-16. Comparison of average (2021 to 2050) total remuneration (left) and over time (right) of new RES installations from key RES technologies (i.e. PV, onshore and offshore wind) at EU level according to the long-term trend scenario "Make-do-and-mend". (Source: Green-X modelling)



Finally, Figure 3-17 indicates the impacts electricity consumers may face, showing the average yearly consumer cost in specific terms (per MWh electricity consumption). More precisely, the graph on the left-

hand side shows the development over time, exemplified for the long-term trend scenario "Make-do-and-mend", and the graph on the right-hand side compares average (2021 to 2050) cost-to-consumer among all assessed long-term trend scenarios. The cost elements taken up in that comparison comprise the wholesale electricity price and the RES-related support.[4] Under default (high) prices for green gas consumer cost per MWh of electricity consumed are expected to increase steadily over the whole period up to 2050, with a peak value of 81.9 €/MWh at that point in time. The comparison of the different trend scenarios shows a similar cost range across all assessed scenarios. Differences between the trend scenarios are however applicable: In accordance with the naming "Shiny happy energy citizens" ranks best, followed by "Make-do-and-mend" and "Top Down Tech". Highest consumer cost can be expected under the trend scenario "Leviathan" as a consequence of highest wholesale prices among all four scenarios.

Figure 3-17. Comparison of cost-to-consumer of the RES uptake at EU level over time for the long-term trend scenario "Make-do-and-mend" (left) and on average in the period 2021 to 2050 for all assessed long-term trend scenarios (right). (Source: Green-X modelling)



3.2.3 Sensitivity analysis on the impact of RES policy design

This section is dedicated to a sensitivity analysis on the impact of RES policy design on the need for and height of dedicated RES support in future years. Within our modelling different policy instruments for providing the required financial support to RES-E technologies have been assessed, ranging from umbrella policies approaches, e.g. technology-neutral quotas with certificate trading, on to targeted technology-specific policy approaches, e.g. auctions for feed-in premiums, that offer incentives tailored to individual needs.

We exemplify this for the long-term trend scenario "Make-do-and-mend". Two graphs provide a sound summary of the key results derived: Firstly, Figure 3-18 shows the impact of RES policy design on the development over time of RES-related support expenditures (left) and of RES-related impacts on cost-to-consumer (right) at EU level. This is then complemented by Figure 3-19, indicating the policy design-driven changes in RES-related support expenditures and in cost-to-consumer at EU level on average throughout the whole assessment period 2021 to 2050.

[4] Our comparison of cost impacts on electricity consumer does however not provide the "full picture" since network charges as well as energy-related or general taxes are not taken into consideration. This would however not add value to the scope of our analysis where we aim to assess impacts from electricity market developments and RES-related support requirements, and the overall consequences of these from a consumer perspective.

Figure 3-18. Impact of RES policy design on RES-related support expenditures (left) and on cost-to-consumer (right) at EU level in the period up to 2050 according to the long-term trend scenario "Make-do-and-mend". (Source: Green-X modelling)

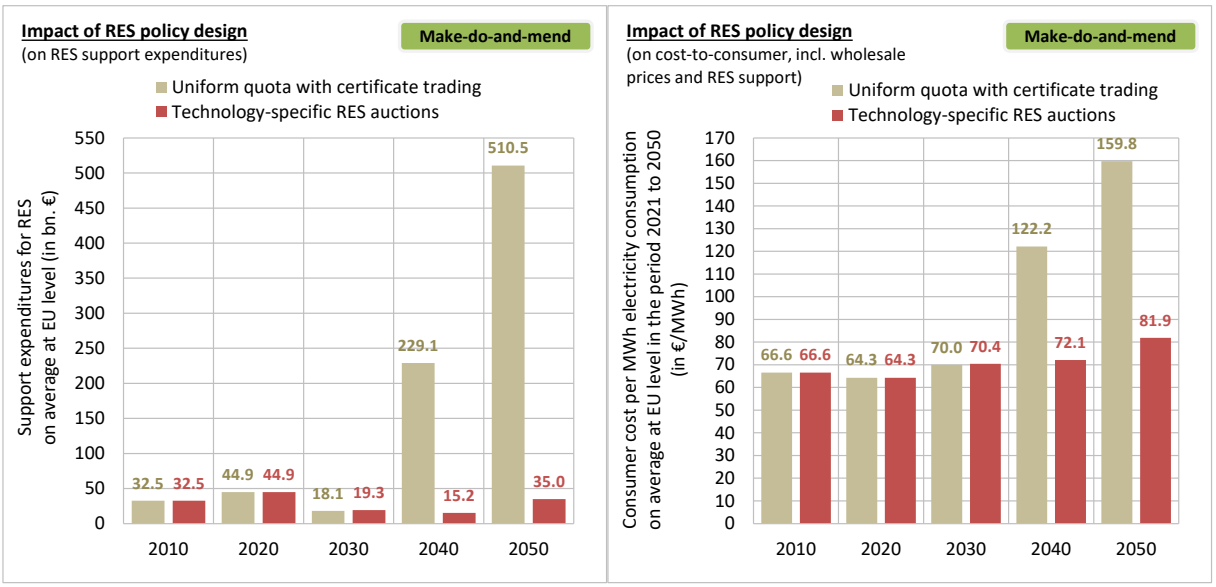
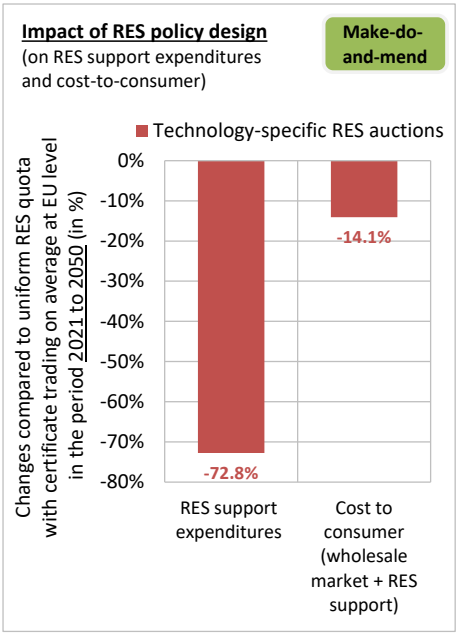


Figure 3-19. Changes in RES-related support expenditures and in cost-to-consumer at EU level on average (2021-2050) driven by RES policy design according to the long-term trend scenario "Make-do-and-mend". (Source: Green-X modelling)



As applicable from these graphs, the selection of an appropriate RES policy framework appears of key relevance for reaching a cost-effective uptake of renewables, specifically if ambitious RES targets are to be met. More precisely, our modelling reveals that targeted policies offering technology-specific incentives tailored to individual needs, done e.g. by use of auctions for feed-in premiums, appear highly beneficial for triggering a cost-effective uptake of RES in the electricity sector. Modelling results show cost savings of ca. 73% when comparing average RES-related support expenditures under targeted RES policy approaches (e.g. technology-specific RES auctions) with umbrella policy approaches (e.g. technology-neutral quotas with certificate trading). Impacts on cost-to-consumer as assessed in a simplified manner within our model-based assessment are expected to decline by ca. 14%.

The outcomes underpin the importance of an appropriate RES policy design for achieving a cost-effective strong RES uptake in forthcoming years. RES support tailored to the technology-specific needs allows for keeping the cost burden for consumer at moderate levels which may, in turn, increase or maintain public acceptance towards decarbonisation that builds to a large extent on renewables.

3.2.4 Sensitivity analysis on the impact of high fossil fuel prices

This section is dedicated to a sensitivity analysis on the impact of high fossil fuel prices on the need for and height of dedicated RES support in future years.

As stated in the intro part, a look at this year's (2022) and last year's economic and political developments, specifically the Russian invasion of the Ukraine, shows that price increases or price turbulence can currently (as of Spring 2022) be observed worldwide in raw material and energy markets, affecting the energy sector and the whole economy significantly, specifically within Europe. Under current high energy prices, even in the absence of dedicated RES support, investments in RES technologies appear cost-competitive and highly attractive for investors despite of the increase of investment cost triggered by the above. The question remains however how long the period of high energy prices may last and how the trend will continue in forthcoming years.

In our modelling default fossil fuel price trends (as illustrated in Table 2-1) are taken from IEA modelling, specifically the IEA's Sustainable Development scenario (IEA WEO 2020). These trends reflect a strong climate ambition globally and, in consequence, compared to today's developments, low fossil fuel prices. This sensitivity analysis builds on an alternative set of price trend assumptions (cf. Table 2-2). Under that trend natural gas prices as well as prices for other fossil fuels are expected to decline compared to current price peaks but, later on, remain at – compared to default assumptions – higher price levels in the near and mid future. This is currently of particular importance given the discussions on the requirement to limit the imports of Russian natural gas.

Below we exemplify the impact of high fossil fuel prices on the need for and height of dedicated RES support for the long-term trend scenario "Make-do-and-mend". Two graphs offer a sound summary of related impacts: Firstly, Figure 3-20 shows at EU level the impact of fossil fuel price trends on the future development of RES-related support expenditures (left) and of RES-related impacts on cost-to-consumer (right). This is then complemented by Figure 3-21, indicating the price-driven changes in RES-related support expenditures and in cost-to-consumer at EU level on average throughout the whole assessment period 2021 to 2050.

Figure 3-20. Impact of high energy prices on RES-related support expenditures (left) and on cost-to-consumer (right) at EU level in the period up to 2050 according to the long-term trend scenario "Make-do-and-mend". (Source: Green-X modelling)

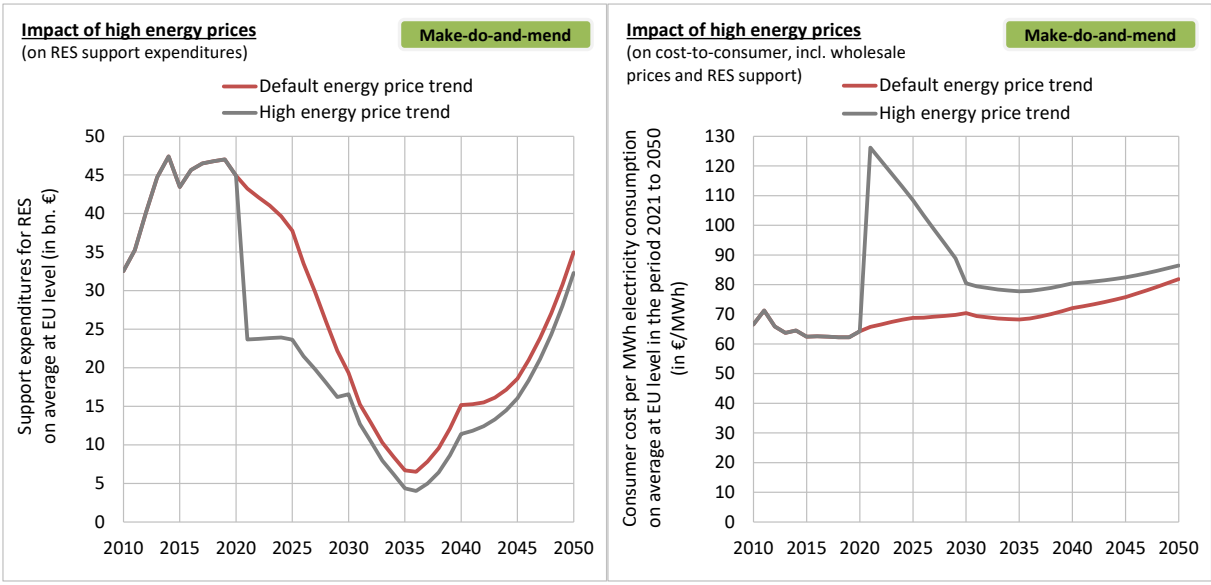
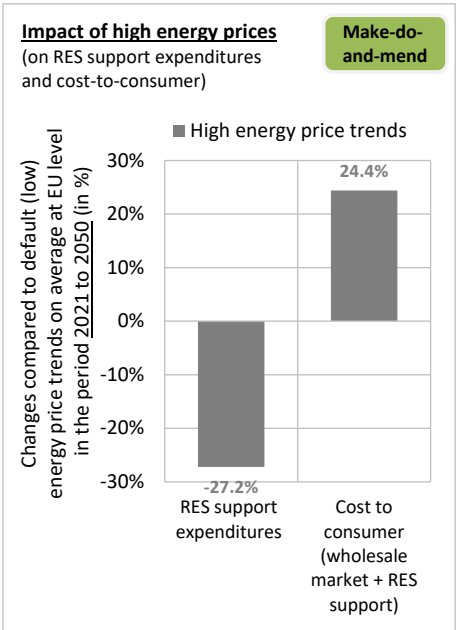


Figure 3-21. Changes in RES-related support expenditures and in cost-to-consumer at EU level on average (2021-2050) driven by high energy prices according to the long-term trend scenario "Make-do-and-mend". (Source: Green-X modelling)



As applicable from these depictions, a continuation of current high energy prices has severe impacts on both the need for and height of dedicated RES support as well as on cost-to-consumer.

On the one hand, high energy prices increase the viability of RES and, in consequence, reduce the need for dedicated RES support significantly. As shown in Figure 3-20, RES-related support expenditures are cut to the half at present. If the phase of high energy prices continues over the near to mid future, modelling shows that this reduction will have a strong impact on support expenditures in the whole period up to 2030. Later on, a convergence process can be expected so that the reduction in support expenditures compared to default levels will get smaller. Throughout the whole assessment period up to 2050 we expect a reduction by ca. 27% (compared to the case of default (low) energy prices), cf. Figure 3-21.

On the other hand, we see a change in the opposite direction for cost-to-consumer in the electricity sector. Here the significant increase in wholesale prices, driven by the high gas prices, is responsible for that change. Over the whole assessment period, cost-to-consumer are expected to increase by ca. 24% compared to default (where low energy prices are presumed).

We can conclude that severe impacts at both ends (i.e. on the height of dedicated RES support and on consumer cost) can be expected from a continuation of currently high energy prices. Renewables can help to lower the cost burden by decreasing our dependency on fossil fuel imports, and they are more than ever economically viable. Thus, an increase in the RES ambition as reaction to the current crisis appears highly recommendable.

3.2.5 Future price trends for green gas – a key determinant on the need for dedicated RES support

For achieving a full decarbonisation of the energy sector, it is expected that natural gas will be fully replaced by green gases of renewable origin, including green hydrogen, biogas or other synthetic carbon-neutral gases, by 2050. As stated in section 2.3, for this decarbonisation option, representing a key option for the provision of power system flexibility in future years, future cost/prices are highly uncertain. In order to reflect that in our modelling, two distinct price trends were assumed:

- As default, In the (default) high price scenario it was assumed that the price for green gases takes orientation on the price of natural gas plus the cost for related CO_2 emission allowances under the EU Emission Trading Scheme. That price trends reflects a high demand for green gas combined with limited supply options and in consequence limited competition on the supply side of the market.
- As sensitivity, a low price scenario was derived and related impacts assessed as discussed within this section of the report. Here former bottom-up price projections for biogas fed into the gas grid served as basis, reflecting first lessons learned from demo projects in the Netherlands and expert judgements concerning expected future progress.

As applicable from Table 2-3, by 2050, the difference between both price trends is significant: In the (default) high price scenario green gas was assumed to be available at around 155 €/MWh by 2050 whereas in the

low price scenario less than a third of that was assumed (i.e. ca. 50 €/MWh).

This sensitivity assessment analyses the impact of low prices for prices on the need for and height of dedicated RES support for the long-term trend scenario "Make-do-and-mend". As done for other sensitivity cases, the two graphs below offer a sound summary of related impacts: Firstly, Figure 3-22 illustrates at EU level the impact of green gas price trends on the future development of RES-related support expenditures (left) and of RES-related impacts on cost-to-consumer (right). This is then complemented by Figure 3-23, indicating the price-driven changes in RES-related support expenditures and in cost-to-consumer at EU level on average throughout the whole assessment period 2021 to 2050.

The graphs show that low instead of high prices for green gas in future has severe impacts on both the need for and height of dedicated RES support as well as on cost-to-consumer, specifically in later years close to 2050.

On the one hand, low prices for green gas increase the need for and height of dedicated RES support significantly, in particular in the period post 2030. As applicable from Figure 3-22, RES-related support expenditures are only to a minor extent affected in the near future (2030) but post 2035 a strong increase in RES-related support expenditures can be expected. Throughout the whole assessment period up to 2050 modelling indicates more than a doubling of RES support expenditures, i.e. an increase by 111% (compared to the case of default (high) green gas price trend), cf. Figure 3-23.

On the other hand, we see a change in the opposite direction for cost-to-consumer in the electricity sector. Here lower prices for green gas lead to a decline of wholesale prices, specifically in the years close to 2050. Over the whole assessment period, cost-to-consumer are expected to decrease by ca. 20% compared to default (where high prices for green gas are presumed).

Figure 3-22. Impact of low prices for green gas on RES-related support expenditures (left) and on cost-to-consumer (right) at EU level in the period up to 2050 according to the long-term trend scenario "Make-do-and-mend". (Source: Green-X modelling)

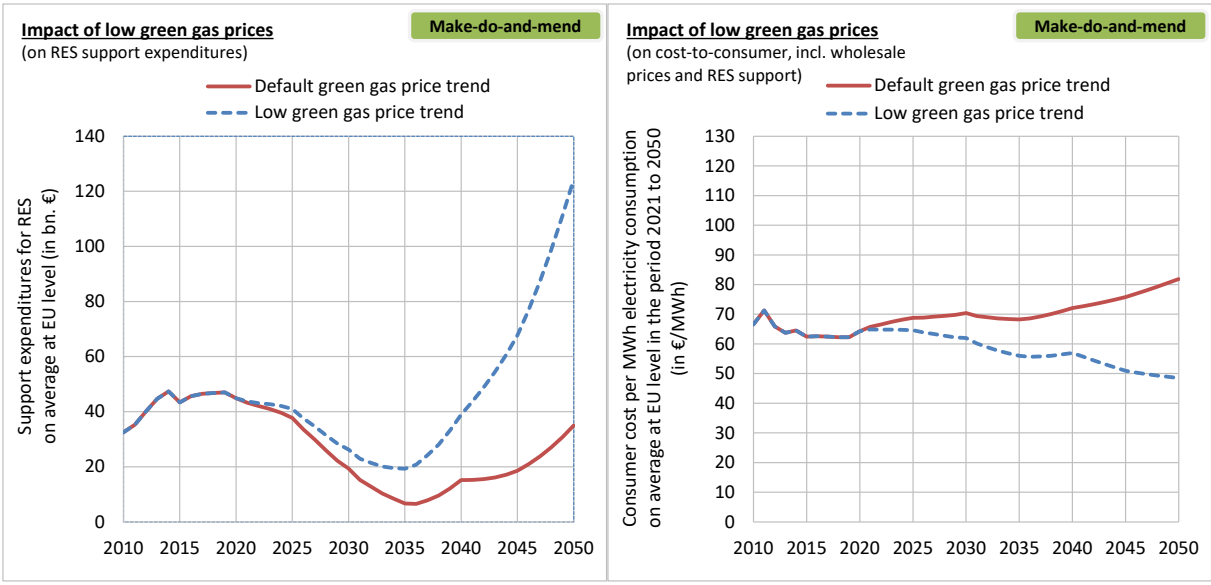
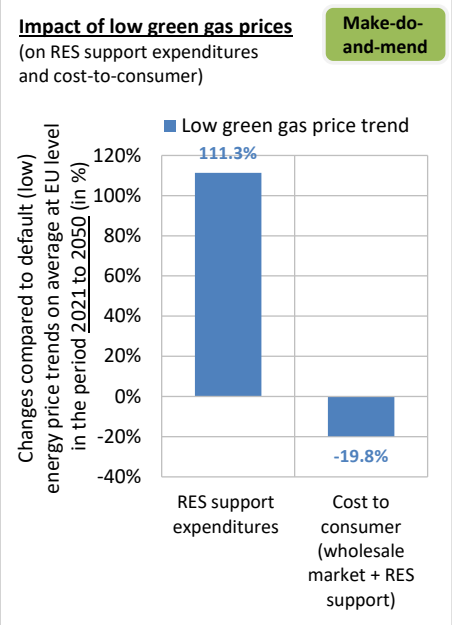


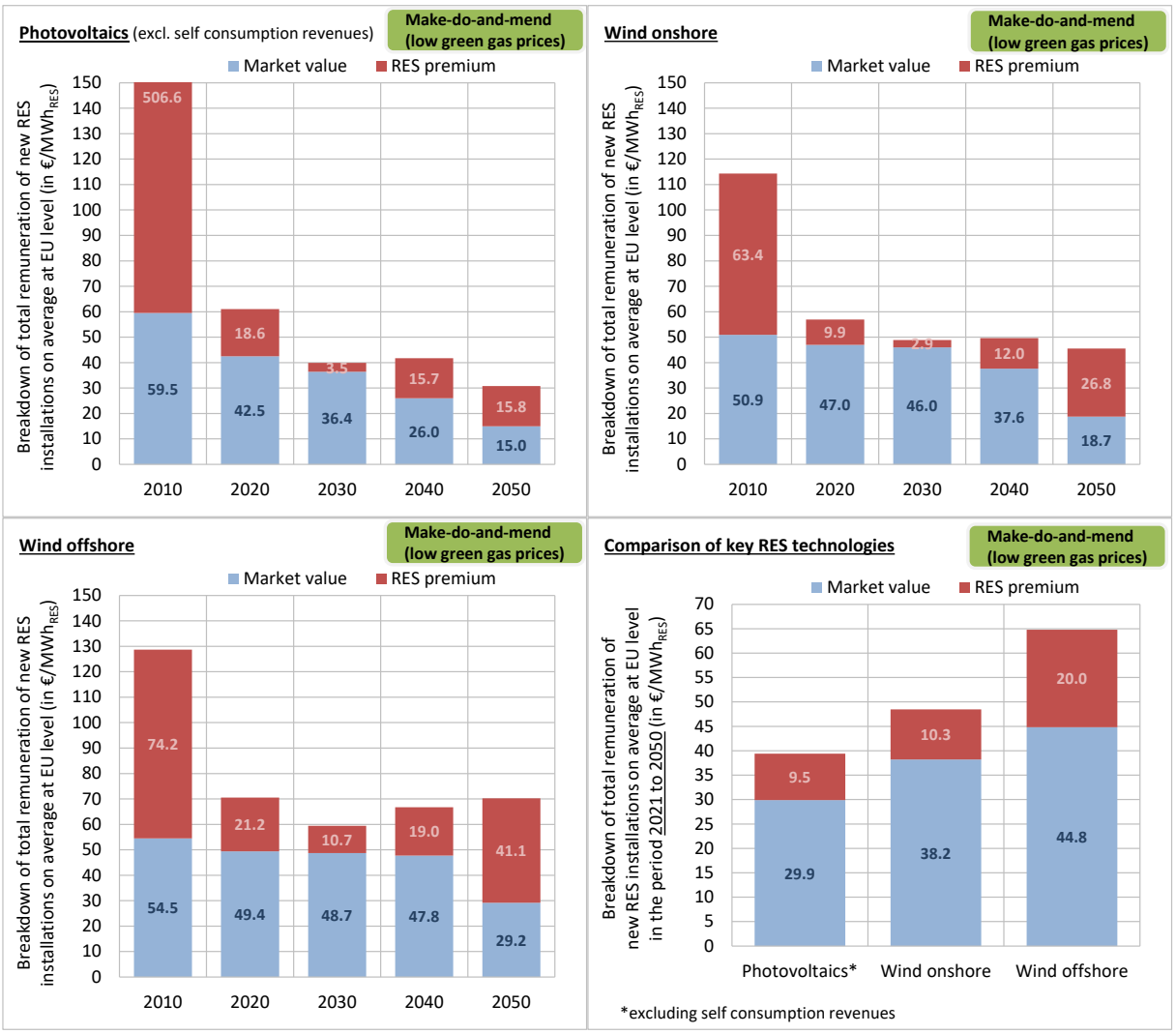
Figure 3-23. Changes in RES-related support expenditures and in cost-to-consumer at EU level on average (2021-2050) driven by low prices for green gas according to the long-term trend scenario "Make-do-and-mend". (Source: Green-X modelling)



Similar to the default case of high green gas prices, we subsequently show the impact on total remuneration for key RES technologies. Thus, a detailed illustration of the future development of total remuneration of key RES technologies (i.e. PV, on- and offshore wind) at EU level in the period up to 2050 is given in Figure 3-24. More precisely, the graphs show the development of total remuneration of new RES installations from key RES technologies (i.e. PV (top, left), onshore wind (top, right) and offshore wind (bottom, left)) at EU level over time, exemplified for the long-term trend scenario "Make-do-and-mend". At the right bottom we then complement the above via a cross-technology comparison of total remuneration looking at the whole assessment period (2021 to 2050)

Since Figure 3-24 informs also on the decomposition of total remuneration, i.e. on the market-driven income (cf. the pale blue bars named as "market value") and on the support-driven income (cf. the red bars named as "RES premium"), we can elaborate on the need for dedicated RES support in forthcoming years below. As applicable from the graphs, by 2030, even under low prices for green gases and, in consequence, moderately low wholesale price levels, (almost) zero-subsidy auctions can be expected for PV and wind onshore. In the case of offshore wind this might then be limited to best sites only. By 2040 and beyond, RES support is however again required to fill the remuneration gap according to the illustrated long-term trend scenario "Make-do-and-mend". One can also identify here an increasing tendency, meaning that RES support is higher by 2050 compared to 2040. Reason for that is generally the decline of market values driven by self-cannibalism, specifically for PV – as a consequence of the required strong PV uptake in accordance with decarbonization needs. Remarkably, total remuneration is expected to decline towards 2050, driven by the anticipated cost reductions over the whole assessment period. According to modelling, similar trends are applicable for onshore wind, despite higher market values compared to PV. For offshore wind, in contrast to PV and onshore wind, an increase in total remuneration over time – a consequence of the impressive offshore deployment in the years closer to 2050, implying that also sites characterised by higher cost need to be exploited. Thus, the required on-top RES support for offshore wind is expected to reach high levels by 2050.

Figure 3-24. Development of total remuneration of key RES technologies (i.e. PV, on- and offshore wind) at EU level in the period up to 2050 under low prices for green gas according to the long-term trend scenario "Make-do-and-mend". Source: Green-X and Balmorel modelling (cf. Resch et al., 2022)



This sensitivity analysis has shown that the key parameter to determine whether or not only low (or almost zero) subsidies will be required to accommodate the future RES uptake is the future price level on the wholesale electricity market. These prices are, in turn, determined by the future prices at which key zero-carbon flexibility options on the supply side like biogas or green hydrogen will be available. Low prices for green gas would increase RES support but cause at the same time a decline of consumer cost, and vice versa.

4 Conclusions

As RES technologies become more and more competitive, auction prices may fall below wholesale prices in some countries in Europe, especially in those with more favourable resource potentials (mostly PV and wind). The case studies prepared under the AURES II project already provide some examples for this trend. Yet, it is still uncertain whether the current trend of a market-based RES expansion will continue and whether zero-subsidy auctions and/or PPAs will make a significant contribution to the RES increase needed to meet future European RES targets. One critical factor opposing this trend is the limited ability of the electricity system to integrate vRES leading to a reduction in market values and thus a reduction in incentives for market-based expansion. In this context, qualitative scenario developments and accompanying modelling activities carried out within AURES II aimed for shedding light on the above, informing on the need for dedicated RES support in forthcoming years. The outcomes of the modelling have shown that a high degree of system flexibility and decentralisation can act as enabler, and even be a prerequisite for a successful RES market integration. The key parameter to determine whether or not only low (or almost zero) subsidies will be required to accommodate the future RES uptake is however the future price level on the wholesale electricity market. These prices are, in turn, determined by the future prices at which key flexibility options on the supply side like biogas or green hydrogen will be available. If these flexibility options are available at low cost/prices, the need for dedicated RES support increases but, due to the lower wholesale prices, consumer cost that include both the wholesale prices and the RES support are expected to decline. The opposite trends can be expected in the case of high prices for green gas.

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AURES II is a European research project on auction designs for renewable energy support (RES) in the EU Member States.

The general objective of the project is to promote an effective use and efficient implementation of auctions for RES to improve the performance of electricity from renewable energy sources in Europe.

www.aures2project.eu

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