Are carbon prices redundant in the 2030 EU climate and energy policy package?

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Abstract:

In 2018, an agreement between the key EU institutions – the Commission, the European Parliament, and the European Council – was reached after a long-lasting discourse over the 2030 EU climate and energy policy package. This paper offers a comprehensive assessment of the EU package, with its three main targets: lower greenhouse gas emissions, higher renewable share in final energy consumption, and improved energy efficiency. We find that the renewable and energy efficiency targets have been set so high that the derived emissions reduction (50 percent) exceeds the EU climate target (40 percent). Hence, there is no need for an EU climate policy, for example, to use carbon prices to reach the EU climate goals. It is, however, not cost-efficient to achieve the climate target by imposing the three EU targets. We demonstrate that a cost-efficient policy that obtains a 50 percent GHG emissions reduction would increase annual welfare (relative to the Reference scenario) by an amount corresponding to 0.6 percent of GDP in Europe.

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Sammendrag

I 2018 ble det oppnådd en avtale mellom de viktigste EU-institusjonene - Kommisjonen, Europaparlamentet og Det europeiske råd - etter en langvarig diskusjon om EUs klima- og energipolitiske pakke i 2030. Denne artikkelen presenterer en omfattende analyse av EU-pakken, med de tre hovedmålene: lavere klimagassutslipp, høyere fornybar andel i det endelige energiforbruket og forbedret energieffektivitet. I analysen finner vi at målene for fornybar energi og energieffektivitet (i referansescenariet) er satt så høyt at den avledede utslippsreduksjonen (50 prosent) overstiger EUs klimamål (40 prosent). Gitt dette er EUs klimapolitikk oppnådd uten for eksempel å bruke karbonpriser eller kvotemarkeder. Dette er imidlertid ikke kostnadseffektivt. En kostnadseffektiv politikk som oppnår en reduksjon av utslipp av drivhusgasser med 50 prosent ville øke den årlige velferden (relativt til referansescenariet) med et beløp som tilsvarer 0,6 prosent av BNP i Europa.

1 Introduction

In 2018, an agreement between the key EU institutions – the Commission, the European Parliament, and the European Council – was reached after a long-lasting discourse over the 2030 EU climate and energy policy package. While there had been disagreement over the types of energy targets and how ambitious the targets should be, the parties agreed to an EU-wide renewable share in final energy consumption of 32 percent (Eur-lex (2018a)), to improve EU energy efficiency by 32.5 percent (relative to 2005) (Eur-lex (2018b)), and also to reduce greenhouse gas (GHG) emissions by (at least) 40 percent (relative to 1990) (Europa (2019a)). The aim of this paper is to offer a comprehensive assessment of the approved EU 2030 climate and energy package. As there have been intense debates on which targets the EU should reach, we also analyze the 2030 outcome if, hypothetically, alternative energy policy targets had been agreed upon (or the EU energy targets are changed in the future).

The motivation of this paper is that the EU 2030 policy package is probably the single most important factor with respect to the development of the European energy markets and it also has powerful implications for policy design. The package is complex as it contains three types of targets: GHG emissions, renewables, and energy efficiency. Each target will contribute to decreased GHG emissions, although the partial effects of reaching each target differ: standard economic theory suggests that if a higher share of renewables in energy consumption is obtained through producing more renewable electricity, the price of electricity is pushed down. Then units such as fossil-fuel power plants with high operating costs will be phased out. With less fossil-based electricity, GHG emissions drop.[1] Economic theory also suggests that improved energy efficiency tends to lower the demand for fossil energy. Therefore, the price of fossil energy declines and fossil fuel-based energy production is phased out.

While standard economic theory predicts the main effects of reaching *each* of the targets in the EU 2030 package, the net effects of reaching *all* targets, as well as the *magnitude* of the effects, cannot be predicted from theory; a numerical model is needed. In this study, we will use the numerical model LIBEMOD to find the equilibrium effects of the EU 2030 climate and energy package, see LIBEMOD (2015).

LIBEMOD is a multigood, multiperiod model covering the entire value chain in the energy markets in 30 European countries from investment, extraction, and production via trade to consumption. In

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[1] For econometric assessments of the emissions offset by renewable energy, see Cullen (2013) for Texas, Callaway et al. (2018) for the US, and Abrell et al. (2019) for Germany and Spain.

LIBEMOD, emissions reductions in the electricity generation sector are accomplished through a different mix and scale of electricity technologies; a higher price of emissions triggers less investment in, and production of, fossil fuel-based electricity. In the end-user sectors, emissions reductions require higher end-user prices. LIBEMOD determines all energy prices and quantities in the European energy markets. Because renewable electricity plays a critical role in reaching the 2030 EU targets, investment in hydro, bio, wind, and solar power is endogenous in LIBEMOD. The model finds the combination of policy instruments that is consistent with reaching all policy goals.

This paper makes three contributions to the literature. Whereas the 2030 EU climate and energy policy package was analyzed in a commissioned work by the EU Commission, see PRIMES (2019), the present paper is the first "external" study of the 2030 package. Our first contribution is to characterize the outcome when all EU climate and energy targets are required to be met. We find that the targets for renewables and improved energy efficiency have been set so high that the implied GHG emissions reduction is 50 percent, which is *higher* than the agreed-upon 40 percent target. This result is in line with PRIMES (2019), which found that the 2030 package will lower GHG emissions by 46 percent. We compare our results to PRIMES (2019) as well as to other studies that have imposed some of the targets in the 2030 package.

The EU climate target of a 40 percent emissions reduction by 2030 should, according to EU decisions, be reached by cutting emissions in the ETS sectors (electricity generation, carbon-intensive manufacturing firms, petroleum extraction and most of aviation) by 43 percent relative to 2005, whereas emissions in the remaining sectors (non-ETS) should be reduced by 30 percent relative to 2005. We find that by achieving the renewable and energy efficiency targets, both the ETS and non-ETS emissions targets are met (see Section 5). Hence, there is no need for a climate policy. However, while an efficient emissions reduction is characterized by equal marginal cost of emissions reduction in the ETS and non-ETS sectors, there is no reason to believe that cost efficiency will be reached when the emissions reduction is obtained through achieving the renewable and energy efficiency targets. In fact, we demonstrate that if a 50 percent GHG emissions reduction is reached cost-efficiently, then annual welfare increases (relative to the Reference scenario above) by an amount corresponding to 0.6 percent of GDP in Europe (see Section 6.3).

For years there has been a heated debate in the EU on whether there should be policy targets for renewables and improvement in energy efficiency, and if so, how ambitious these should be (see Section 3). Our second contribution is to examine how a renewable share in final energy consumption

other than 32 percent, as well as an improvement in energy efficiency other than 32.5 percent, will affect emissions in the ETS and non-ETS sectors (see Section 6.1). We also show how the policy instruments imposed to reach the two energy policy targets need to be adjusted when the energy targets take alternative values. For example, we examine by how much the renewable share can be reduced below 32 percent (or the improvement in energy efficiency can be reduced below 32.5 percent) before either the ETS or the non-ETS emissions reduction target bites. We find that if the renewable share is 23 percent (and the improvement in energy efficiency is 32.5 percent), then ETS emissions are exactly 43 percent below their 2005 value. Hence, if the renewable share is below 23 percent (and the improvement in energy efficiency is 32.5 percent), it is necessary to have a positive price on CO_2 emissions in the ETS sector in 2030 in order to meet the requirement that ETS emissions should be 43 percent lower than in 2005.

Our third contribution is to the energy modeling literature. Here, our main contribution is to offer a framework for endogenizing investment in intermittent power (wind and solar power) and to present a calibration strategy that quantifies structural wind and solar parameters. We derive first-order conditions for investment in and production of intermittent power by solving an optimization problem with the same structure as for any other technology. However, we take into account that production sites differ with respect to wind conditions and solar irradiance. This is captured by a structural relationship between a measure for generated wind (or solar) power in a country and installed wind (or solar) capacity. We calibrate these relationships by utilizing detailed, spatial information about hourly wind speed, solar irradiance, reflection, and air temperature. For calibration, we have to make assumptions about the share of grid cells that will be available for the development of wind and solar power. We can, however, easily test how alternative land-availability assumptions affect energy markets (Section 6.2).

The remainder of the paper is structured as follows. Section 2 provides a short review of two strands of the literature that are related to the present paper, namely achieving climate and energy targets, and efficiency of electricity markets. In Section 3, we give a summary of the debate that culminated in 2018 when the key EU institutions agreed upon the 2030 policy package. The numerical model LIBEMOD, which is used to analyze the 2030 climate and energy package, is presented in Section 4, whereas the resulting 2030 equilibrium is described in Section 5. In Section 6, we provide two types of robustness analysis: alternative policy targets and alternative parameter values. Section 7 concludes.

2 Related literature

Our paper is linked to two strands of the energy economics literature: policy instruments used to reach climate and energy targets, and the efficiency of electricity markets with a high share of intermittent supply.

2.1 Climate and energy policy targets

Our paper contributes to the empirical literature on how climate and energy targets have impacted European energy markets.[2] This literature covers the following: (i) the 2020 EU climate and energy package with its three 20 percent targets (GHG emissions, renewables, and energy efficiency); (ii) the 2030 EU climate target; and (iii) the European energy market in 2050, in particular, how the way the EU intends to reduce GHG emissions by at least 80 percent by 2050 affects the energy sector.

EU 2020

Böhringer et al. (2009) provide an economic impact assessment of the 2020 EU goal to reduce emissions by at least 20 percent relative to 1990. To identify the impacts of the EU climate policy, they use a computable general equilibrium model of international trade and energy and simulate alternative scenarios. Boeters and Koornneef (2011) examine the cost of imposing a 20 percent renewable target in addition to the climate target of a 20 percent emissions reduction by 2020. Using the computable general equilibrium model WorldScan, they find that the renewable target increases costs by 6 percent; however, this estimate is sensitive to a number of key assumptions. Landis and Heindl (2019) study the distributional effects of the 2020 EU climate and energy policy. Using the computable general equilibrium model PACE, they explore how higher renewable shares, which push down the ETS price, generate distributional effects within and between EU member countries. Their results indicate that the effort of the EU to redistribute policy costs through permit allocation has been successful.

EU 2030

PRIMES (2019), a study commissioned by the EU Commission, examines the 2030 Climate and Energy Package, as we do. They find that GHG emissions will be reduced by 46 percent by 2030 (relative to 1990), which is rather similar to our result of a 50 percent emissions reduction. Sandbag (2019) examines emissions reduction in the EU by 2030 taking all policies already in place into

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[2] There is a comprehensive literature on how to reach international climate policy targets, in which numerous numerical models have been developed and applied. Results from a large share of these studies have been included in various IPCC reports, in particular, the most recent report on global warming of 1.5°C, see IPCC (2019).

account. These include the clean energy package, the mobility packages, and announced coal phaseouts. The implied GHG emissions reduction is estimated to 50 percent. ECF (2011) investigates changes in the European power market by 2030 that are considered to be consistent with the 2050 target of reducing GHG emissions by 80–95 percent relative to 1990, see European Commission (2011). Babonneau et al. (2018) use the computable general equilibrium model GEMINI-E3 to examine how the EU Effort Sharing Agreement, which sets emissions requirements for 2030 for the non-ETS sectors, generates costs on member states. Finally, Panos and Densing (2020) examine how the European electricity market is affected by the Clean energy for all Europeans package,[3] which implements the Nationally Determined Contributions of the EU member states as part of the Paris Agreement. They find that the price of electricity will increase substantially from the current level, mainly because of increased fuel and CO_2 prices, although batteries will lower price peaks.

EU 2050

Egerer et al. (2016) apply a spatial, bottom-up, techno-economic electricity sector model to study the need for expansion of the electricity transmission capacity by 2050 under alternative assumptions about EU 2050 emissions targets. For most 2050 climate targets being investigated, upgrading of domestic electricity networks is required, whereas only modest investment in interconnectors is needed. Furthermore, Abrell and Weigt (2016) examine required network investment by 2050, but in contrast to Egerer et al. (2016), they also consider natural gas; through liberalization of the European energy markets, there is increased interfuel competition between these two energy carriers. Thus, network investments should be studied jointly.

Jägemann et al. (2013) analyze alternative pathways for the European electricity generation sector toward 2050 under the assumption that the GHG emission target should be a reduction of at least 80 percent. This requires an almost complete decarbonization of the electricity sector. Applying a linear dynamic electricity system optimization model, their study shows that if there is also a renewable target in addition to the GHG target, or if there are restrictions on investment in nuclear power or power stations with carbon capture and storage (CCS), the costs of obtaining the GHG target increase significantly.

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[3] Based on Commission proposals published in November 2016, the Clean energy for all Europeans package, see Europa (2019b), consists of eight legislative acts. After political agreement by the Council and the European Parliament in 2018 and early 2019, enabling all of the new rules to be in force by mid-2019, EU countries have 1–2 years to transpose the new directives into national law.

This short review reveals that, to our knowledge, there is only one previous study of the 2030 EU climate and energy policy package. In fact, most studies focus on either 2020 or 2050, or on the emissions reduction in the electricity sector by 2030. In Section 5.2, we discuss the 2030 studies referred to above and compare these with our results.

2.2 Competition and efficiency

Our paper is also related to the extensive literature on market design of an electricity sector with a high share of renewables. Here, contributions cover theoretical considerations, policy evaluations, as well as econometric ex post assessments.

Theoretical considerations

With a high share of intermittent power, the functioning of the electricity industry changes and therefore regulation should be redesigned. For a discussion of appropriate market design, see, for example, Perez-Arriaga and Batlle (2012), Egerer et al. (2015), Neuhoff et al. (2016), Pollitt and Anaya (2016), De Vries and Verzijlbergh (2018), and Newbery et al. (2018). Egerer et al. (2015) describe conditions under which incentive regulation performs better than cost-based regulation. Burger et al. (2019a; 2019b) discuss regulatory design of an electricity retail sector with substantial distributed electricity production, and Wolak (2019) discusses efficient pricing in the entire electricity value chain that will sustain a low-carbon electricity sector. Finally, Ambec and Crampes (2019) demonstrate that in a model with two sources of energy — polluting thermal power and emission-free intermittent supply — it is necessary with a price cap and volume-limited capacity payments to implement the first-best social outcome if a carbon tax cannot be imposed.

Part of the literature focuses on instrument choice to promote renewables, and the related question of how to avoid underinvestment in renewables. Newbery (2012) discusses what type of feed-in tariffs government should offer low-carbon technologies in order to encourage investment and reduce risk. Whereas the UK government had a preference for a contract for difference for all generation, Newbery (2012) supports fixed feed-in tariffs. Green and Yatchew (2012) point out that feed-in tariffs have been effective in supporting a rapid growth in intermittent capacity, mainly because risk has been shifted away from suppliers and tariffs have been generous. They advise policy makers to design instruments that provide better locational and temporal price signals.

Newbery (2018) argues that well-designed electricity liberalization has delivered efficiency gains, but investment incentives in energy-only markets have been undermined because of the political risk of

decarbonization. Drawing on principles from economic theory, the paper proposes guidelines to ensure optimal investment. Léautier (2016) also analyzes various corrective mechanisms that have been proposed to alleviate underinvestment in the electricity generation sector. The paper demonstrates that markets for capacity certificates restore optimal investment if and only if producers cannot sell more certificates than their installed capacity. Furthermore, financial reliability options are effective at curbing market power, although they do not fully restore correct investment incentives.

Empirical assessments

Böhringer et al. (2017) examine the Energiewende, the transformation of the German electricity system from fossil based to mainly renewable electricity through massive subsidies to zero-emission technologies. Using both a computable general equilibrium model and microsimulations, Böhringer et al. (2017) identify the economic impact of the Energiewende. While the results indicate that low-income households bear a high share of the cost, this harmful distributional effect can be alleviated by imposing alternative subsidy arrangements. Andor et al. (2017) also analyze the Energiewende. Drawing on two stated-preference surveys, they conclude that there is a strong contrast between households' general acceptance of supporting renewable technologies and their willingness to pay for renewable electricity production. Finally, Marcantonini and Ellerman (2015) analyze the derived costs of promoting wind and solar power in the Energiewende.

Grubb and Newbery (2018) assess the UK 2013 market reform, which aimed at securing funding for investment in low-carbon technologies and at the same time ensuring energy security. The reform was successful to the extent that the market share of coal power dropped substantially because of a carbon price floor, whereas the opposite was the case for renewable electricity. However, the reform revealed that to achieve a low-emission society, transmission pricing and locational signals are decisive.

Keppler et al. (2016) examine how increased intermittent supply impacts price variation across countries. Using a sample of hourly day-ahead prices in Germany and France from November 2009 to June 2013, they find that when transmission capacity between the two countries is limited, more intermittent supply in Germany leads to increased price spreads between the two countries.

Haar and Haar (2017) study support schemes for renewable electricity in some large EU economies. Using data for 2009–2013, they argue that the schemes that were used provided sufficient incentives to reach the target capacities, but at an unnecessarily high cost. This justifies the question of whether almost mature renewable electricity technologies, such as onshore wind, should continue to receive financial support; see Held et al. (2019) for a discussion.

Turning to the EU, Duso et al. (2019) examine the impact of competition policy on the effectiveness of the European energy markets. They find that EU merger policy had a positive significant effect on investment and productivity in low-regulated sectors. Gugler et al. (2018) investigate the degree of market integration in the European electricity market by examining the variability of day-ahead spot prices. Using co-integration analysis, they conclude that market integration increased between 2010 and 2012, but then declined until 2015, despite market coupling being introduced.

In the LIBEMOD model, the EU has access to a set of instruments that ensures that all targets are reached. For example, we use an EU-wide subsidy to achieve the EU-wide target for renewables. This will ensure that the policy target is reached efficiently; the same is the case for each of the other policy goals of the 2030 EU policy package. In Section 6, we discuss economic efficiency and policy targets.

3 Climate, renewables, and energy efficiency targets in the EU

The primary aim of this paper is to investigate how the 2030 EU climate and energy policy targets may impact energy markets in 2030. Prior to adopting the 2030 climate and energy policy package in 2018, there had been intense debates in the EU on whether it was sufficient to impose climate and renewable targets, or whether energy efficiency targets should also be imposed. The position of countries on this question reflected their experience with implementing the 2020 policy package with its 20 percent targets on GHG emissions, renewables, and energy efficiency. According to Skjærseth et al. (2016), countries can be divided into three groups.[4]

First, there was a group of countries that were not pleased with the 2020 package. This group includes countries in Eastern and Central Europe that use coal as their major energy source. The group was headed by Poland, which discovered that the 2020 package was inappropriate given the nature of its energy sector and climate policy. In particular, a more ambitious renewables policy had reduced Poland's energy imports only marginally. These countries opposed new GHG targets and also policies directed at renewable energy and energy efficiency.

Second, there was a group of countries that had a mixed experience with the 2020 package. This group includes the major energy-exporting countries Norway and the Netherlands, and also the UK. These countries supported a more ambitious GHG target but did not want renewable and energy efficiency targets; energy-import dependency is not a concern for these countries.

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[4] For a discussion on the development of policy targets and instruments in EU member states, see Boasson et al. (2020).

Third, there was another group of countries that had a mainly positive experience with the 2020 package. This group includes the key EU member states Germany, France, and Italy. Germany, which had achieved diffusion in green technologies and growth in green employment, wanted more ambitious targets for renewable energy and improved energy efficiency. This position was shared by six other EU member states.

Whereas the European Parliament supported three binding targets – a 40 percent GHG emissions reduction, a 30 percent renewable share in final energy consumption, and a 40 percent higher energy efficiency – the Commission was split. The Climate Commissioner wanted all three targets, as opposed to the Energy Commissioner and the Industry Commissioner. They opposed a higher renewable energy target, fearing that a new renewable-energy goal could push up energy prices, thereby threatening the competitiveness of key EU industries.

In January 2014, the Commission announced its compromise proposal: a 40 percent GHG emissions reduction and an EU-wide renewable target of 27 percent. Although no new target for energy efficiency was proposed, the Commission stated that 25 percent energy savings would be required in order to reach the GHG target.

The response to the proposal of the Commission was split. A "Green Growth Group" of 14 countries endorsed the key elements of the proposal. In contrast, a group led by Poland, with support from several Eastern and Central European countries, demanded full national sovereignty over the energy mix as well as the protection of coal, more EU subsidies to modernize the energy system, and more costs borne by rich EU countries.

The negotiations over the 2030 climate and energy policies culminated temporarily in the fall of 2014 with the European Council's adoption of a 40 percent GHG emissions reduction, a renewable share of 27 percent, and an indicative target of a 27 percent increase in energy efficiency. This was a compromise to satisfy the main veto players. As a carrot for Eastern and Central European countries, burden sharing for non-ETS emissions reduction would be based on GDP per capita, which had also been the case for the 2020 package. Other countries, as well as EU institutions, had mixed feelings about the adopted policy of the European Council.

In the summer of 2018, a *final* agreement was reached between the Commission, the European Parliament, and the European Council. The parties agreed on an EU-wide renewable share of 32

percent, and also to introduce a binding EU-wide improvement in energy efficiency of 32.5 percent. The fact that these two targets are EU-wide, not national targets, may have made it easier for the parties to reach an agreement. The EU intends to use its governance system to ensure that these targets will be met.

Because it has been widely debated how ambitious the renewable policy target and the imposed improvement in energy efficiency should be, and because the climate and energy policy of the EU will be revised in 2023, this paper discusses, using the numeric energy model LIBEMOD, how alternative values of these two targets will impact the 2030 equilibrium (see Section 6).
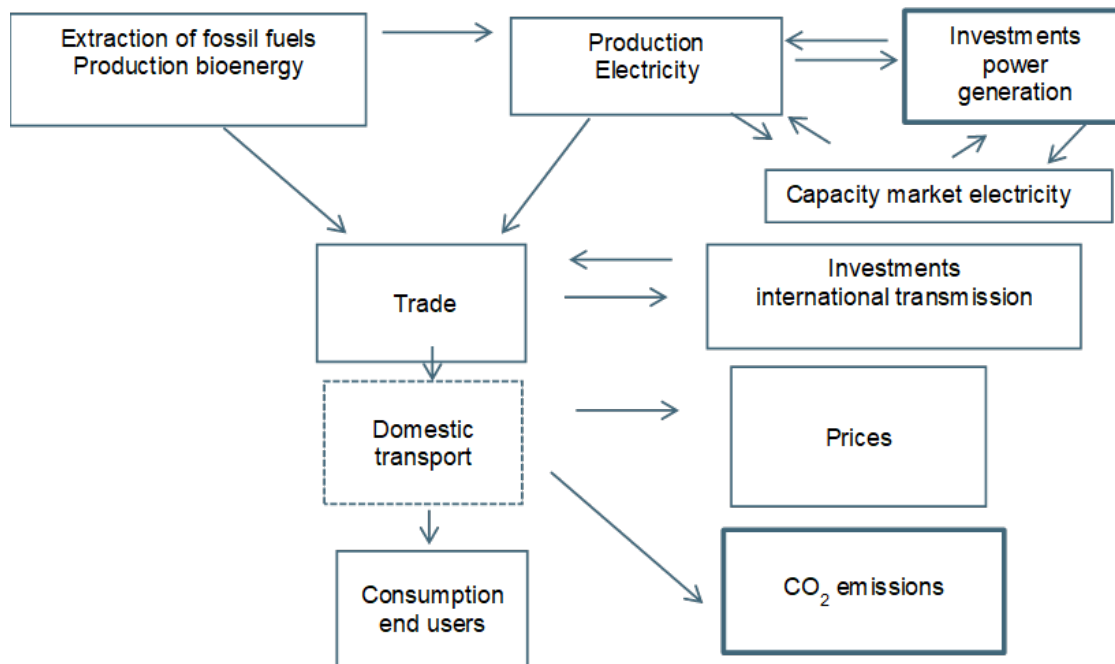
4 Libemod

In this section, we describe the numerical multimarket, multigood equilibrium model LIBEMOD, which is applied to examine how EU climate and energy targets for 2030 impact the energy markets. LIBEMOD allows for a detailed study of the energy markets in Europe, taking into account factors such as fossil fuel extraction, interfuel competition, technological differences in electricity supply, key characteristics of renewable electricity technologies, transport of energy through gas pipes/electricity lines, and investment in the energy industry. The model determines simultaneously all energy prices and all energy quantities invested, extracted, produced, traded, and consumed in each of 30 European countries – henceforth referred to as EU-30.[5] The model also determines all energy prices and quantities traded in world markets, as well as emissions of CO_2 by country and sector (Figure 1).

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[5] See Table B.1 in Appendix B for a list of these 30 countries.

Figure 1 The LIBEMOD model

4.1 General description

The core of LIBEMOD is a set of competitive markets for eight energy goods: natural gas, oil, steam coal, coking coal, lignite, biomass, biofuel, and electricity.[6] Energy goods are extracted/produced, traded, and consumed in each country in EU-30.

Extraction of all fossil fuels and production of biomass are modeled by standard (nonlinear) supply functions, whereas electricity is produced using a number of technologies (see discussion below). Natural gas, biomass, and electricity are traded in competitive European markets. Trade in natural gas requires gas pipelines that connect pairs of countries. Similarly, trade in electricity requires electricity transmission lines that connect pairs of countries. The capacity of transmission gas pipes and electricity lines can be extended through investment; see Appendix A, Part I, for details.

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[6] The European Commission has for more than 25 years aimed at establishing efficient European energy markets. We assume that this goal is reached by 2030. There are several indications that the European markets have become substantially more competitive, see, for example, European Commission (2019). This report finds that wholesale energy prices have fallen in recent years because of increasing competition in wholesale markets from greater amounts of renewable energy, improved interconnections, and a more integrated internal electricity market. Furthermore, for the first time since 2008, household electricity prices decreased. Pollitt (2019) examines the Commission's own work on evaluating the benefits of the single electricity market and also considers the evidence of the impact on prices, security of supply, the environment, and innovation. Pollitt concludes that the institutional changes are extensive and there has been significant market harmonization and integration. For a similar study on the European natural gas market, see Chyong (2019), which argues that arbitrage possibilities are now fully exploited.

In LIBEMOD, there are competitive world markets for coking coal, steam coal, oil, and biofuel, and competitive domestic markets for lignite. While fuels are traded in annual markets, there are seasonal (summer vs. winter) and time-of-day markets for electricity.

In each country in EU-30 (henceforth referred to as a model country), there is demand for all types of energy from four groups of end users: the household sector, the services and public sector, the industry sector, and the transport sector (which covers transport demand in the other end-user sectors). Demand from each end-user group (in each model country) is derived from a nested multigood, multiperiod constant elasticity of substitution (CES) utility function, making LIBEMOD a truly nonlinear model. In addition, there is intermediate demand for fuels from fuel-based electricity producers; gas-fired power stations demand natural gas, biopower stations demand biomass, etc. Intermediate demand for fuels from power plants is derived from maximizing profits subject to a number of restrictions. In LIBEMOD, these are expressed as standard first-order conditions.

In each model country, there is domestic transportation and distribution of energy with corresponding costs. The end-user price of an energy good is thus the sum of (i) the producer price of this good, (ii) costs of domestic transportation and distribution of this energy good (which differ between countries, end-user groups, and energy goods), (iii) end-user taxes, and (iv) losses in domestic transportation and distribution.

Furthermore, in each model country the national regulator has to ensure that the domestic electricity market does not break down if there is an unexpected increase in net demand because of, for example, technical operational problems of power plants, lower supply from intermittent sources (wind power and solar), or higher demand. To avoid a blackout, the regulator acquires idle maintained capacity in the national capacity market; see Appendix A, Part II, for details.

In LIBEMOD, there is a competitive equilibrium for each good. This is the case for (i) all goods traded in a model country, (ii) all energy goods traded in world markets (oil, steam coal, coking coal, and biofuel), and (iii) transport services relating to natural gas and electricity between model countries. The price of each transport service consists of a unit cost and an endogenous capacity term; the latter ensures that demand for transport does not exceed the capacity of the gas pipe/electricity line. International transport capacities consist of two terms: predetermined capacities (according to observed capacities in the data year of the model) and investment in capacities; the latter is undertaken if it is profitable.

4.2 Supply of electricity

In LIBEMOD, supply of electricity is the most detailed model block. In each model country, there are 13 preexisting ("old") electricity technologies: steam coal power, lignite power, gas power, oil power, biopower, reservoir hydropower, run-of-river hydropower, pumped storage hydropower, nuclear power, waste power, wind power, solar power, and a composite technology referred to as other renewables (geothermal power, wave power, and tide power). Moreover, there are four new fossil fuel-based technologies: new steam coal power, new steam coal power with CCS, new gas power, and new gas power with CCS.[7,8,9] Furthermore, there are six new renewable technologies: new reservoir hydropower, new run-of-river hydropower, new pumped storage hydropower, new biopower, new wind power, and new solar power.

In general, for each old fuel-based technology and each model country, efficiency varies across electricity plants. However, instead of specifying heterogeneous plants for each old technology, we model the supply of electricity from each old fuel-based technology as if there were one single plant with decreasing efficiency; this implies increasing marginal costs in each model country. For each type of new fuel-based technology, we assume, however, that all plants have the same efficiency. Whereas capacities for old technologies are exogenous (in each model country), for new plants, capacity, that is, investment, is determined by the model according to profitability.

There are six types of costs involved in electricity supply from the *combustion of fuels*. First, there are nonfuel monetary costs directly related to the production of electricity in period t, y_t, where $t \in T$. Second, there are fuel costs. Third, production of electricity requires that capacity is maintained: in addition to choosing an electricity output level (TWh), the producer chooses the level of power capacity (GW) that is maintained, K^{PM}, thereby incurring a unit maintenance cost c^M per power unit. Fourth, if producers choose to produce more electricity in one period than in the previous period in the

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[7] In addition, old coal power and old gas power plants can be retrofitted with CCS.

[8] In the global electricity generation sector, there were only two CCS power stations in operation by the end of 2017; both are coal power plants with retrofitted CCS. Their aggregated annual capture capacity was 2.4 Mt CO_2. This number can be compared with the capture capacity in the Sustainable Development Scenario in IEA (2018); this global scenario has been constructed to provide a cost-efficient path that is consistent with the Paris Agreement and sustainable water use. Annual capture in the electricity sector in the Sustainable Development Scenario is 350 Mt CO_2 in 2030 and 1500 Mt CO_2 in 2040. Note that worldwide, there are currently seven CCS power station projects under early development. Their aggregated annual capture capacity is "only" 10.5 Mt CO_2.

[9] Because of high costs, there is no investment in oil power in the LIBEMOD model runs, whereas investment and disinvestment in nuclear are exogenous because a number of noneconomic factors are also of importance when deciding future nuclear capacity. For all EU-30 countries, nuclear capacities in 2030 are taken from the World Nuclear Association; see https://www.world-nuclear.org

same season, they will incur start-up costs. In LIBEMOD, these costs are partly expressed as an extra fuel requirement, but also as a monetary cost per unit of started power capacity.

For investments in new power capacity, K^{inv}, there are annualized capital costs c^{inv} related to the investment. Finally, for new plants, there are also costs related to connecting to the grid; these reflect either that the site of the plant is not located at the grid or that connecting a new plant to the grid requires upgrading of the grid and these costs are borne by the plant. The cost of grid connection (gc), $c^{gc}(K^{inv})K^{inv}$, is assumed to be increasing and convex.

Each fossil fuel-based plant maximizes profits subject to a number of technology constraints: (i) maintained power capacity should not exceed installed power capacity; (ii) instantaneous production of electricity should not exceed the net power capacity; and (iii) during the year, there should be some downtime for technical maintenance.

Biopower is modeled in exactly the same way as electricity supply from fossil fuel-based technologies. The only difference is that biopower uses biomass as an input. Like fossil fuels, biomass is supplied competitively and there is one thermal efficiency rate of new biopower plants.[10]

In LIBEMOD, there are three types of hydroelectricity technologies: reservoir hydro, run-of-river hydro, and pumped storage hydro. Relative to the modeling of electricity supply from fuel-based technologies, *reservoir hydro*, which has a reservoir to store water, has two additional technology constraints. First, the reservoir filling at the end of a season cannot exceed the reservoir capacity. Second, total use of water should not exceed total supply of water, that is, total production of reservoir hydropower in a season plus the amount of water in the reservoir at the end of this season should not exceed the amount of water in the reservoir at the end of the previous season plus the seasonal inflow of water.

For the *run-of-river hydropower* technology, there is, as per definition, no reservoir. In each time period, production of electricity cannot exceed the inflow of water. The run-of-river hydropower technology has, like reservoir hydro, increasing marginal cost of investment, which reflects the

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[10] In LIBEMOD there are two types of bioenergy: biomass (used in the electricity generation sector) and biofuel (used in the transport sector). Whereas production of biomass requires land, we do not impose a biomass land-use restriction in LIBEMOD. The reason is that the equilibrium quantities of biomass mainly consist of waste and by-products from agriculture and industry, that is, biomass products do not require separate land. For biofuels, the alternative value of land may be substantial; see, for example, Searchinger et al. (2008). Because equilibrium consumption of biofuel is moderate in LIBEMOD, there is no need to introduce restrictions on land use for biofuel production.

heterogeneity of sites. The *pumped storage hydropower* technology is characterized by buying electricity in one period (typically during the night) and using that energy to pump water up to the reservoir to produce electricity in a different time period (typically during the day when the price is high). As demonstrated by Aune et al. (2008), the optimization problem of this technology is similar to that for fossil fuel-based technologies, except that the pumped storage producer uses electricity (not a fossil fuel) as an input.[11]

We now turn to a detailed discussion of the modeling of wind power and solar power.

4.2.1 New wind power

Wind sites differ with respect to wind speed. By using a power curve, that is, the relationship between wind speed and wind energy, 1 MW capacity of wind power is transformed into generated wind energy at each point in time. If the wind speed is below a threshold value, say, 3.5 m/s, no wind energy is generated. In contrast, 1 MW capacity generates 1 MWh energy under ideal wind conditions, that is, the wind speed exceeds another threshold value, say, 15 m/s, at each point in time during an hour. For a given power curve and detailed information on wind speed, total generated wind energy can be calculated over a year at a site with 1 MW installed capacity. Next, one can calculate the number of hours with ideal wind conditions that are required to generate the observed annual wind power production. We refer to this number as the full-load wind hours.

We assume that wind power producers maximize profits. Hence, the site with the highest full-load wind hours is developed first, then the site with the second highest full-load wind hours is developed, and so on until the marginal site is developed; here profit is zero. In general, the more sites that are developed, the lower is the *average* full-load wind hours. This is formalized by $f(K^{PM})$, $f' < 0$, where K^{PM} denotes maintained capacity; capacity has to be maintained in order to be used for electricity production; see discussion in Section 4.2. By multiplying the average full-load wind hours per year, $f(K^{PM})$, by how much wind power can be produced at each point in time, K^{PM}, a measure of annual production of wind power is obtained, $f(K^{PM})K^{PM}$.

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[11] We use an extended and updated version of LIBEMOD that builds on the earlier version that was documented in Aune et al. (2008). In the new version of the model, more countries have been added (mainly Eastern European countries); the end-user sectors have been refined (services and the public sector have been separated from the household segment); the modeling of wind power has been changed and more renewable technologies have been included (run-of-river hydro and solar power); the modeling of natural gas has been refined (LNG has been included); bioenergy has been split into biomass and biofuel; all data have been updated (the data year has been changed from 2000 to 2009); and the complete model has been recalibrated (see LIBEMOD 2015).

There are technical constraints also for new wind power. First, maintained power capacity should be less than or equal to installed power capacity, which for a new power plant is equal to investment in electricity production capacity:

(1) $\quad K^{PM} \le K^{inv} \perp \lambda \ge 0$

where λ is the shadow price of installed power capacity.

Second, let ψ_t^w be the share in period t of the annual full-load wind hours. This means that production of wind power in period t is $\psi_t^w f(K^{PM})K^{PM}$. Hence, there is an upper limit on the production of electricity in this period:

(2) $\quad y_t \le \psi_t^w f(K^{PM})K^{PM} \perp \mu_t \ge 0$

where μ_t is the shadow price of the periodic electricity production capacity.

Similar to fuel-based technologies, wind power has a constant unit maintenance cost, c^M. However, there is of course no fuel cost and there are no start-up costs for a wind power plant. Therefore, the Lagrangian of the optimizing problem of new wind power is:

(3) $\quad L = \sum_{t \in T} p_t y_t - c^M K^{PM} - c^{inv} K^{inv} - c^{gc}(K^{inv})K^{inv}$

$\quad\quad\quad - \lambda\{K^{PM} - K^{inv}\} - \sum_{t \in T} \mu_t\{y_t - \psi_t^w f(K^{PM})K^{PM}\}.$

Here, p_t is the price of electricity in time period t.

The first-order condition for the supply of electricity in each period (y_t) is:[12]

(4) $\quad p_t \le \mu_t \perp y_t \ge 0.$

This is a standard first-order condition, simply stating that an interior solution, that is, $y_t > 0$, requires that the price of electricity, p_t, should be equal to the shadow price of periodic electricity production capacity, μ_t.

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[12] In LIBEMOD, investment, maintenance of the capacity, and production of electricity follow from the solution of maximizing profits subject to a number of constraints. The derived Kuhn–Tucker first-order conditions, which allow corner solutions, are used to find the equilibrium. Because of corner solutions (i.e., zero equilibrium quantity), it is more convenient to use the Kuhn–Tucker first-order conditions than to derive demand functions for inputs.

The first-order condition for maintained capacity (K^{PM}) is:

$$(5) \qquad (\textstyle\sum_{t \in T} \mu_t \psi_t^w)(f(K^{PM}) + f'(K^{PM})K^{PM}) \leq c^M + \lambda \perp K^{PM} \geq 0.$$

This first-order condition states that the cost of increasing maintained capacity marginally – the sum of the maintenance cost (c^M) and the shadow price of installed capacity (λ) – should (in an interior solution) be equal to the value of increased annual production following from this policy. Increased maintained capacity raises potential periodic and annual electricity production. Therefore, the value of increased production is equal to the shadow price of periodic electricity production capacity (μ_t) weighted by the wind share in this period (ψ_t^w) and summed over the year when the effect on annual production of wind power from increased maintained capacity ($f(K^{PM}) + f'(K^{PM})K^{PM}$) is taken into account.

Finally, the first-order condition for investment is given by:

$$(6) \qquad \lambda \leq c^{inv} + c^{gc}(K^{inv}) + \frac{dc^{gc}(K^{inv})}{dK^{inv}} K^{inv} \perp K^{inv} \geq 0.$$

This condition implies that if investment is positive, then total annualized investment cost, which is the cost of investment (c^{inv}) plus total marginal cost of connecting to the grid ($c^{gc}(K^{inv}) + \frac{dc^{gc}(K^{inv})}{dK^{inv}} K^{inv}$), should be equal to the shadow price of installed capacity (λ^E), that is, the increase in operating surplus resulting from one extra unit of capacity. For calibration of (onshore) wind power parameters, see Appendix B, Part I.

4.2.2 New solar power

The main solar power technologies are centralized solar power (CSP) and photovoltaics (PV). We have chosen to model PV, which, based on available cost estimates (see, e.g., IEA (2016)), is the most promising technology.

Solar sites differ with respect to solar irradiance, and hence by the annual amount of electricity delivered to the grid per m^2 of solar park. We assume that solar power producers maximize profits. Hence, the site with the highest annual amount of electricity delivered to the grid per m^2 is developed first, then the site with the second highest amount of electricity is developed, and so on. Hence, the

more solar power that is developed, the lower is the average amount of generated electricity per m^2. This mechanism is captured by letting annual generated electricity delivered to the grid per m^2 be a downward-sloping function of maintained solar power capacity, K^{PM}, that is, by the amount of solar power that can be produced momentarily: $g(K^{PM})$, $g' < 0$. Let Ω be the amount of land used to produce solar power. Then $g(K^{PM})\Omega$ measures annual solar power production delivered to the grid. Finally, let ψ_t^s be the share of annual solar power production in period t. We then have a measure of solar production in this time period: $\psi_t^s g(K^{PM})\Omega$.

A producer investing in solar power faces the same type of technical constraints as an agent investing in wind power. First, maintained power capacity should be less than or equal to installed power capacity, that is, $K^{PM} \leq K^{inv}$. Second, period production of electricity is restricted: $y_t^E \leq \psi_t^s g(K^{PM})\Omega$. Therefore, the Lagrangian of new solar power is similar to the Lagrangian of new wind power. Hence, the first-order conditions for solar power have similar interpretations as those for wind power. For calibration of the solar power parameters, see Appendix B, Part II.

4.3 Parameterization

Appendix B, Part III explains the main principle for calibrating the demand block of LIBEMOD, whereas LIBEMOD (2015) provides a full documentation of the LIBEMOD data and parameters. We mainly use these parameters, except for the electricity sector, where we use updated values for wind and solar power; see Appendix B, Parts I and II. Costs and efficiency of electricity plants coming online in 2030 are taken from IEA (2016); see Tables 1 and 2. In Table 1, we have gathered estimates of investment costs for a number of electricity technologies from five sources. As seen from Table 1, costs differ substantially across sources, which reflects different assumptions with respect to type of technology and installment year.

Table 1 Investment costs for power plants (€2009/kW)

Technology	IEA (2016)[1]	IEA ETSAP (2010)	Schröder et al. (2013)	OECD (2010)	Mott MacDonald (2010)[2]
Natural gas	819	800	800	775–1291	806
Coal	1802	1600	1200	1534–1988	2009
Bio	1884	2181	–	1934–5482	–
Solar (PV)	704	2400	1560	2405–3802	–
Wind (onshore)	1409	–	1300	1419–1742	1707
CCS natural gas	2293				
CCS coal	4095				

[1] The data from IEA (2016) are for the New Policy Scenario in 2030.

[2] The data from Mott MacDonald (2010) are for the "nth of a kind plant" in their medium scenario.

Table 2 Efficiency (%) and operation and maintenance (O&M) costs for new power plants in 2030 (€2009/kW) in LIBEMOD

	Efficiency	O&M costs[1]
Natural gas	60	20
Coal	47	53
Bio	35	66
Solar (PV)		10
Wind (onshore)		36
CCS natural gas	53	74
CCS coal	39	147

Source: IEA (2016).

[1] The O&M costs have been decomposed into a fixed term (USD/kW) and a variable term (USD/MWh) using information from OECD (2010) and IRENA (2012), and then transformed to €2009. For solar and wind power, we assume there is no variable cost term.

5 Reference scenario

5.1 Equilibrium

The EU has decided that GHG emissions should be reduced by 40 percent by 2030 relative to 1990. This policy distinguishes between the ETS sectors (electricity generation, carbon-intensive manufacturing firms, petroleum extraction and aviation) and the remaining sectors (non-ETS). Whereas the ETS sectors have to reduce their GHG emissions by at least 43 percent relative to 2005, the corresponding reduction for the non-ETS sectors is 30 percent.

In the Reference scenario, we therefore have one common EU-30 target for emissions in the ETS sectors (implemented by a common quota system) and one common EU-30 target for emissions in the non-ETS sectors (implemented by a common uniform carbon tax); see Table 3.[13] Because LIBEMOD covers CO_2 only (the most important GHG gas), we transform the GHG emissions targets to CO_2 targets; see Appendix B, Part IV, for details.

In the Reference scenario, we also impose the agreed-upon target of an EU-wide renewable share in final energy consumption of 32 percent.[14] In LIBEMOD, this policy goal is assumed to be reached through an EU-wide renewable subsidy offered to all producers of renewable electricity. Finally, we impose the agreed-upon target that EU energy efficiency should be 32.5 percent above the business-

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[13] In 2017, the EU decided on national non-ETS emissions targets. Our assumption of examining the non-ETS sectors as if there were an EU-wide emissions target is mainly a simplification, but it can partly be rationalized by the fact that the EU has allowed substantial flexibility mechanisms in non-ETS emissions reductions.

[14] We define the share of renewables in final energy demand as: i) the sum of renewable electricity production and total end use of bioenergy (transformed to TWh) relative to ii) total consumption of electricity (less the electricity used in pumped storage hydro) and total consumption of primary energy among end users (transformed to TWh).

as-usual level in 2005.[15] In our study, the energy efficiency target is reached through imposing an EU-wide tax on all types of energy (fuels and electricity) consumed by end users.

Table 3 Scenarios for 2030

|	
Reference	At least 40% GHG emissions reductions in 2030 relative to 1990. Separate emissions targets for ETS and non-ETS sectors. A renewable share of 32 percent in final energy consumption. Energy efficiency should be improved by 32.5 percent relative to business as usual. EU-wide policy instruments only.
No Targets	No policy targets.
Climate Targets	40 percent GHG emissions reductions in 2030 relative to 1990. Separate emissions targets for ETS and non-ETS sectors.
Climate and Renewable Targets	40 percent GHG emissions reductions in 2030 relative to 1990. Separate emissions targets for ETS and non-ETS sectors. A renewable share of 32 percent in final energy consumption.
Cheap Solar	Same as Reference scenario, but all costs of solar power are reduced by one-third.
More Land	Same as Reference scenario, but in each grid cell twice as much land is available for both wind and solar power park development than in the Reference scenario.
Low Growth	Same as Reference scenario, but GDP growth rates are halved (2018–2030).
Climate Efficiency	Total GHG emissions equal to the equilibrium emissions level in the Reference scenario. One climate target.

In equilibrium, the combination of a renewable share in final energy consumption of 32 percent and an improvement in energy efficiency of 32.5 percent lowers emissions by more than 43 percent in the ETS sectors (67 percent) and by more than 30 percent in the non-ETS sectors (35 percent). Therefore, the equilibrium emissions prices in the Reference scenario are *zero* in both the ETS and the non-ETS sectors; see Figure 2.[16] In fact, we find that GHG emissions are 50 percent lower than in 1990, that is, the emissions reduction is 10 percentage points higher than the 40 percent target.

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[15] We use European Commission (2016) to quantify the energy efficiency target. Here, an improvement in energy efficiency of 30 percent by 2030 relative to 2005 is estimated to imply "a drop in final energy consumption of 17 percent compared with 2005." We can then calibrate what the final energy consumption in LIBEMOD should be in 2030 if energy efficiency is improved by 32.5 percent.

[16] The result that it is not "necessary" to use instruments directly targeting GHG emissions, like a price on GHG emissions, to reach the climate target seems to be in line with the long-term vision of the Commission for a climate-neutral economy by 2050; see Europa (2018). Here, seven so-called strategic areas are highlighted: i) energy efficiency; ii) deployment of renewables; iii) clean, safe, and connected mobility; iv) competitive industry and a circular economy; v) infrastructure and interconnections; vi) bioeconomy and natural carbon sinks; and vii) CCS to address remaining emissions. While all these actions tend to reduce emissions, standard economic theory suggests that such a package is not cost-efficient.

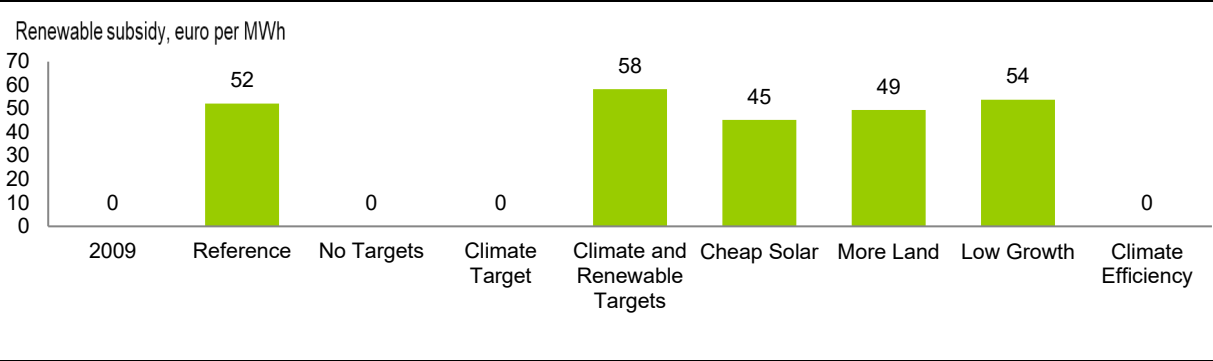**Figure 2 CO$_2$ prices in EU-30 in 2030 (€2009/tCO$_2$)**
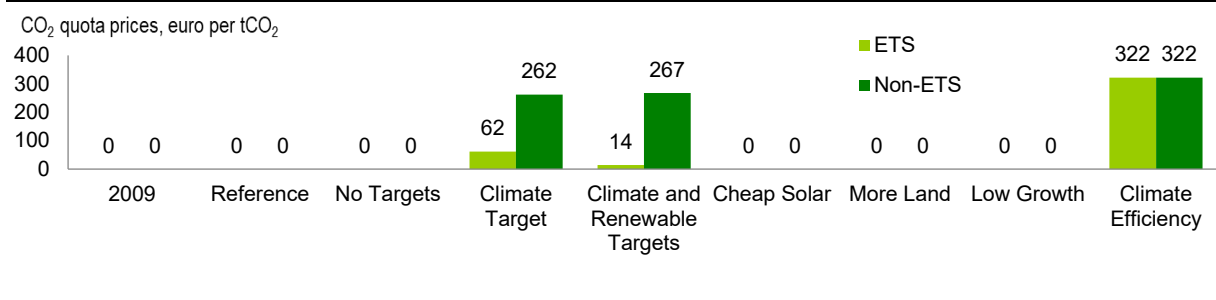
The mechanisms that drive down emissions below the EU targets are easy to understand: a renewable energy subsidy triggers more supply of renewable electricity. This tends to decrease the prices of electricity, thereby replacing fossil fuel electricity with renewable electricity. A tax on energy consumption shifts demand for energy inward, thereby reducing demand for fossil (and nonfossil) energy. Hence, CO$_2$ emissions are reduced. While these are theory-based arguments, a numerical model is required to quantify the effects.[17]

Whereas the equilibrium emissions prices are identical (zero) in the ETS and the non-ETS sectors, this does *not* imply that the emissions reduction is cost-efficient. As is well known, a cost-efficient emissions reduction requires that marginal cost of emissions reduction is equalized between the ETS and the non-ETS sectors. There is no reason to believe that this is accomplished when the emissions reduction is generated from a higher share of renewables and improved energy efficiency. If we impose one policy goal only, namely that *total* emissions should be equal to that in the Reference scenario, then the marginal cost of emissions reduction will be equalized across sectors; the resulting distribution of emissions between the ETS and the non-ETS sectors will differ from that in the Reference scenario; see the discussion in Section 6.3.

Figure 3 shows the renewable subsidy offered to reach the renewable target – €55/MWh in the Reference scenario. Figure 4 shows the end-user energy tax imposed to reach the energy efficiency target – €1297/toe, which corresponds to €112/MWh.

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[17] Under other targets for the renewable share in final energy consumption and improvement in energy efficiency, the corresponding emissions reductions would be different; see discussion in Section 6.1.
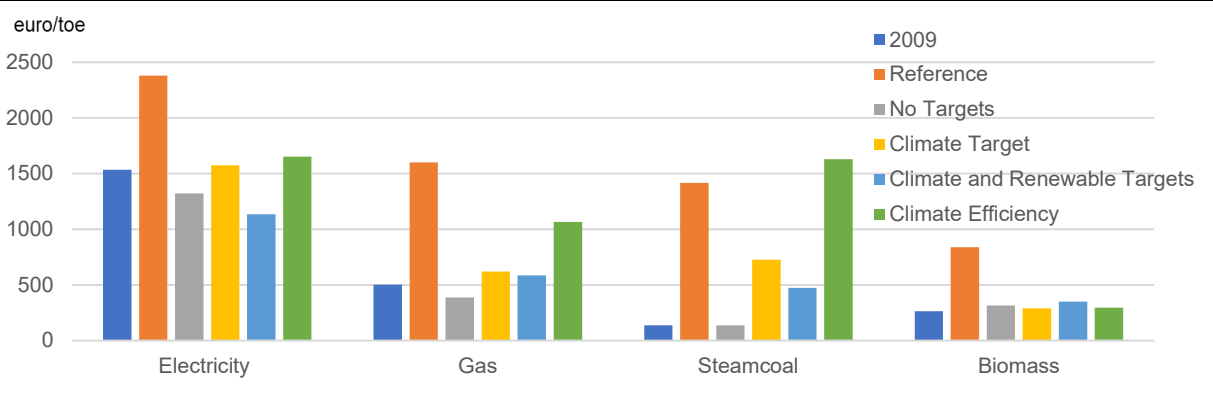
Figure 3 Common renewable subsidy in EU-30 in 2030 (€2009/MWh)

Renewable subsidy, euro per MWh

2009	Reference	No Targets	Climate Target	Climate and Renewable Targets	Cheap Solar	More Land	Low Growth	Climate Efficiency
0	52	0	0	58	45	49	54	0

Figure 4 Uniform energy consumption tax in EU-30 in 2030 (€2009/MWh)

Energy consumption tax, euro per toe

Reference	Cheap Solar	More Land	Low Growth
1297	1296	1297	1098
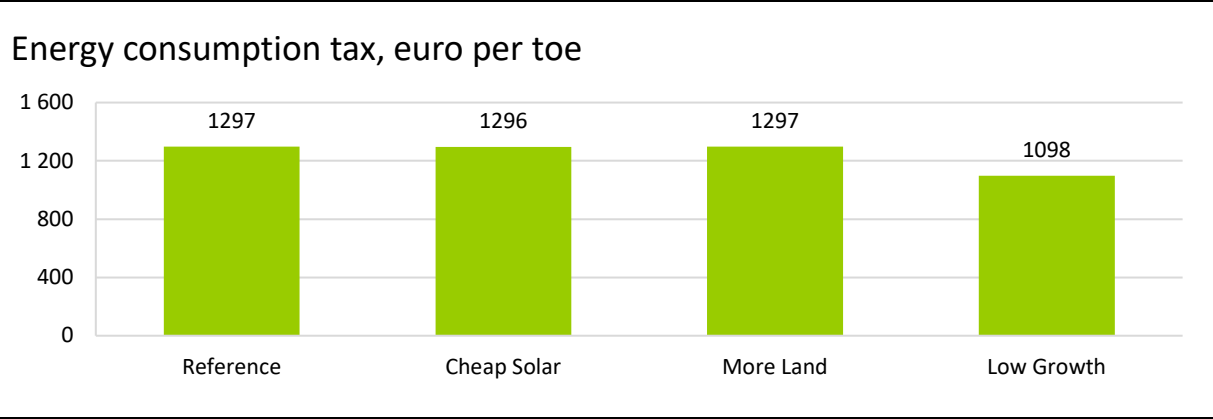
Figure 5 Consumer prices in EU-30 (€2009/toe)

euro/toe

- 2009
- Reference
- No Targets
- Climate Target
- Climate and Renewable Targets
- Climate Efficiency

(Categories: Electricity, Gas, Steamcoal, Biomass)

End-user prices for energy goods are shown in Figure 5. As seen, the prices in the Reference scenario are much higher than the observed 2009 prices; this is because of the end-user tax. From Figures 3–5, we can calculate the renewable subsidy and the end-user tax as percentages of end-user prices. We find that the renewable subsidy, which is offered to renewable electricity producers, amounts to 26 percent of the end-user price of electricity. The end-user tax corresponds to 54 percent of the end-user

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price of electricity, or alternatively, 79 percent of the end-user price of steam coal and 74 percent of the end-user price of natural gas.

There is an increase in total production of electricity from 2009 to the equilibrium in the Reference scenario of 13 percent (Figure 6). The main reason is economic growth, which, adjusted for technology improvements among end users, raises demand for electricity. Without any policy targets, equilibrium production in 2030 would have been 41 percent above the 2009 level, see the No Targets scenario in Figure 6. The moderate increase in electricity production in the Reference scenario reflects primarily the heavy end-user tax on energy consumption, which reduces the demand for electricity.

Figure 6 Electricity production in EU-30 in 2009 and 2030 (TWh)
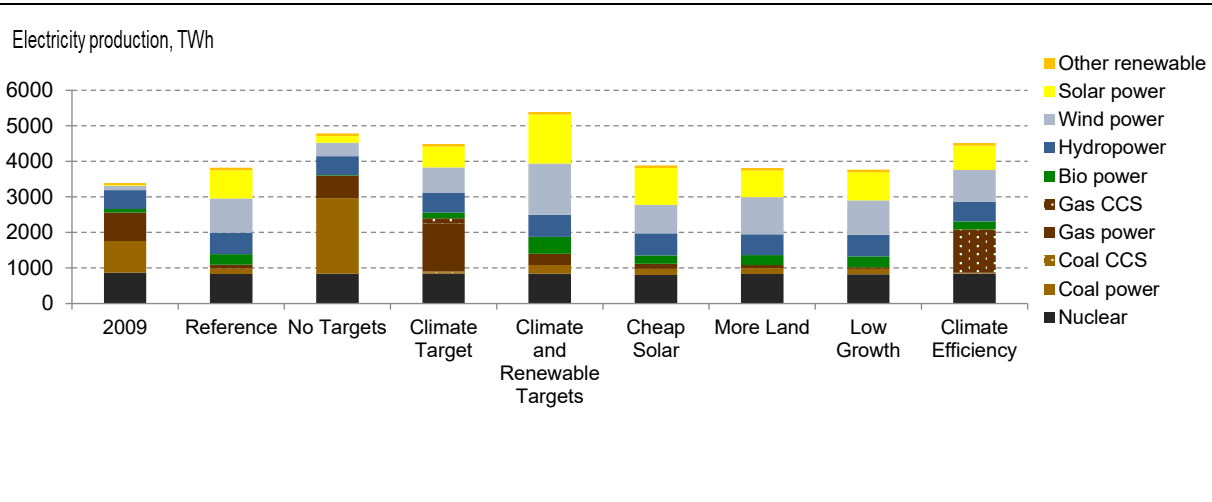

The combination of the renewable subsidy and the tax on end-user demand for energy has a significant impact on the composition of electricity technologies. Compared with 2009, the market share of both wind and solar power has increased by 21 percentage points, whereas the market share of biopower has increased by 5 percentage points. In contrast, the market share of coal power and gas power has decreased by 22 and 21 percentage points, respectively. Whereas the increase in total electricity production is "only" 13 percent (see the discussion above), total power capacity in the Reference scenario is as much is 80 percent above the level in 2009. The radical increase in power capacity reflects the low full-load hours of wind power and solar; the rate of capacity utilization of wind power and solar, which is typically less than 20 percent, is much lower than the 2009 capacity utilization rates of coal and gas power.

The significant changes in the market shares of electricity technologies reflect that, in LIBEMOD, there is substantial flexibility in the electricity generation sector. Here, LIBEMOD specifies a number

of alternative technologies. The composition of these may change radically if prices are altered: for one price vector, a technology may become profitable and is thus phased in, whereas for another price vector, a technology may become unprofitable and is thus phased out.

In contrast to the electricity generation sector, in LIBEMOD, end-user demand is derived from nested CES utility functions, and hence there is no direct substitution between technologies. With a CES utility function, even a moderate change in consumption requires significant price changes. However, in the real world, large changes in end-user prices may trigger a switch to alternative technologies, for example, installation of rooftop solar panels or acquisition of electric vehicles. Because LIBEMOD neglects end-user technology substitution, the change in consumption share by energy carrier is more modest than the change in market share by electricity technology (Figures 6 and 7).

Figure 7 Energy consumption in EU-30 in 2009 and 2030 (Mtoe)
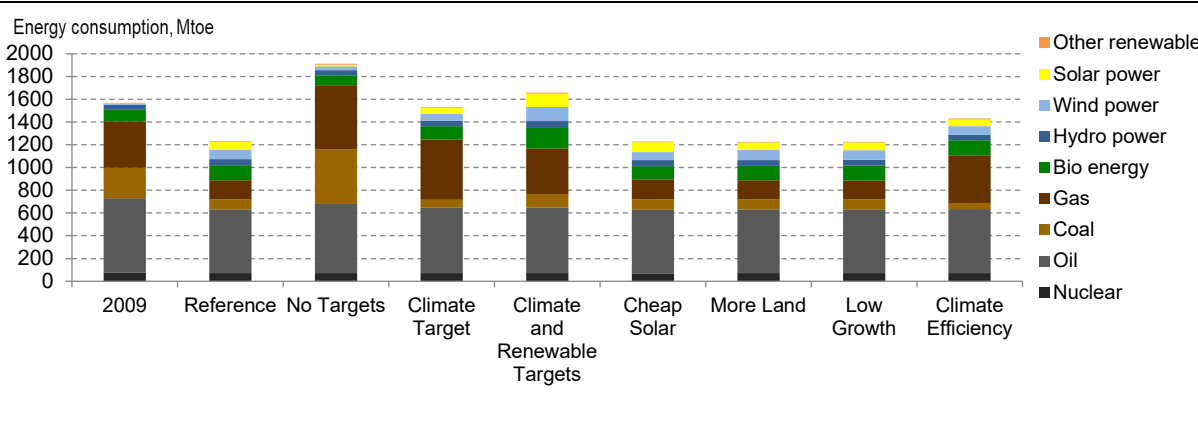
5.2 Comparison with other studies

In Section 2.1, we referred to studies examining different aspects of the 2030 EU energy policy package. We now provide a more detailed discussion of some of these studies and compare a selection of their results with corresponding results in our study.

PRIMES (2019) analyzes the effects of achieving the 2030 EU energy policy package using the EU-wide partial energy market model PRIMES. Whereas emissions reductions in the ETS sectors are obtained through imposing carbon prices – for 2030 these are set (exogenously) to €$_{2013}$28 – command-and-control policies are used in the non-ETS sectors to reach climate targets. Here, policies include "rate and depth of buildings renovation," "eco-design standards," and "application of best available technologies" (see Table 1 in PRIMES (2019)). That study estimates a GHG emissions reduction by 2030 of 46 percent, that is, 4 percentage points less than we obtain. Furthermore, the end-

user price of electricity in PRIMES (2019) is €$_{2013}$163/MWh in 2030, which is about 25 percent lower than the end-user price in our LIBEMOD study. The difference reflects primarily the high end-user tax imposed in the LIBEMOD study to reach the energy efficiency target.

ECF (2011) investigates changes in the European power market by 2030 that are considered to be consistent with the EU 2050 target of reducing GHG emissions. The ECF study finds that substantial investment between 2020 and 2030 in both electricity production capacity and electricity interconnectors is necessary to achieve the EU 2050 CO_2 emissions reduction target in the power sector, that is, a 95 percent cut relative to 1990.[18] For the period 2010–2030, investment in international electricity transmission should be 173 GW, which is 37 TWh more than we obtain for the period 2009–2030.

Table 4 shows market share by technology in 2030 in our study, PRIMES (2019), and ECF (2011). The main difference between our study and PRIMES (2019) is that the latter has a much higher market share for fossil fuel-based electricity (23 percent vs. 7 percent in our study), whereas we have a much higher market share for solar (21 percent vs. 11 percent in PRIMES). The ECF study has an even higher market share for fossil fuel-based electricity than PRIMES (34 percent vs. 23 percent in PRIMES), whereas the market share of solar is only 6 percent in ECF (2011).

Table 4 Market share of electricity technologies in 2030

Technology	LIBEMOD	PRIMES (2019)	ECF (2011)
Nuclear	22	21	16
Coal power	4	12	6
Gas power	3	11	28
Biomass power	9	8	10
Hydro	16	11	11
Wind power	25	26	22
Solar power	21	11	6

Sandbag (2019) argues that climate policies already agreed upon by the EU and its member states are on track to deliver a 50 percent GHG emissions reduction by 2030. Half of the cut is obtained in the power sector. According to Sandbag (2019), the main difference between the PRIMES (2019) estimate of a 46 percent GHG emissions reduction and the 50 percent reduction in Sandbag (2019) is that the latter takes into account all announced coal phaseouts by 2030. Thus, Sandbag (2019) has 198 TWh of

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[18] According to European Commission (2011), by 2030, emissions reductions in the power sector should be in the range 54–68 percent (relative to 1990).

coal power in 2030, whereas the PRIMES estimate is 371 TWh. Our estimate of coal power production is even lower than in the Sandbag study, namely 158 TWh, which reflects the substantial renewable subsidy.

By imposing alternative model assumptions in the Sandbag model on coal phaseout dates, energy efficiency, renewable energy penetration, electric vehicle penetration, and carbon prices, two scenarios are constructed: a "moderate" scenario with a 53 percent cut by 2030, and an "advanced" scenario with a 58 percent cut by 2030. While these numbers exceed our estimate of a 50 percent cut, they are not directly comparable because the Sandbag study does not examine the implications of the EU renewables and energy efficiency targets, as we do.

6 Robustness

We now turn to alternative scenarios to the Reference scenario. These can be divided into two classes: (i) scenarios where policy targets differ from the targets in the Reference scenario, but all LIBEMOD parameters take the same values as in the Reference scenario (Section 6.1); and (ii) scenarios where at least one LIBEMOD parameter takes a different value than in the Reference scenario, but policy targets are the same as in the Reference scenario (Section 6.2).

6.1 Robustness I – policy targets

6.1.1 Decomposition of the policy targets of the Reference scenario

In the Reference scenario, we examined the effects of a GHG emissions reduction of (at least) 40 percent, combined with a renewable share in final energy consumption of 32 percent, and an improvement in energy efficiency of 32.5 percent. To understand the partial effects of different policy targets, we now introduce three alternative scenarios that decompose the policy goals in the Reference scenario.

First, we remove all the policy goals in the Reference scenario; this scenario is termed No Targets (Table 3). Next, we introduce the ETS and non-ETS emissions targets, which are implemented by one ETS quota price and one non-ETS CO_2 tax; this is the Climate Targets scenario. Finally, we add the goal of a renewable share of 32 percent in final energy demand to the climate targets; the resulting scenario is termed Climate and Renewable Targets. As in the Reference scenario, the warranted renewable share is reached through a renewable subsidy.

Table 5 shows the decomposition of the policy goals of the Reference scenario. Without any policy targets (No Targets), GHG emissions would be 2 percent lower in 2030 than in 1990 and the renewable share in final energy consumption would be 11 percent; this outcome reflects the low cost of wind and solar power in 2030 as well as exogenous improvement in end-user technologies. Relative to the 2009 outcome, both electricity supply and total energy consumption increase (Figures 6 and 7).

Without any emissions targets, the price of emissions is zero, by construction. If, alternatively, the ETS and non-ETS emissions goals are imposed (Climate Targets), then, by construction, GHG emissions in 2030 are 40 percent lower than in 1990. The CO_2 prices needed to achieve the emissions goals would be €62/tCO_2 in the ETS sectors and €262/tCO_2 in the non-ETS sectors (Figure 2 and Table 5). The difference in CO_2 prices reflects substantial technology flexibility in the electricity sector (which is part of the ETS sectors); this is in contrast to the non-ETS sectors in LIBEMOD where emissions can be reduced through higher energy prices only. The emissions prices of €62 and €262/tCO_2 would, through a lower supply of fossil energy, lead to a renewable share of 24 percent, whereas the improvement in energy efficiency would be 17 percent (Table 5).

If, in addition to the two GHG emissions targets, a renewable share of 32 percent is imposed (Climate and Renewable Targets), then electricity production becomes higher than in the Climate Targets scenario (because of the renewable subsidy) (Figure 6), and total energy consumption is higher than in the Climate Targets scenario (Figure 7). In the Climate and Renewable Targets scenario, emissions prices in the ETS and non-ETS sectors are €14 and €267/tCO_2, respectively (Table 5). The ETS price is lower than in the Climate Targets scenario because with a renewable subsidy (offered in order to reach the renewable target), supply of renewable electricity is stimulated. Therefore, the price of electricity decreases, and low-efficiency fossil fuel plants become nonprofitable. With lower supply of fossil electricity, the prices of emissions should be reduced in order to reach the same emissions target.

Note that the carbon price in the non-ETS sectors is slightly higher in the Climate and Renewable Targets scenario than in the Climate Targets scenario (€267 vs. €262/tCO_2). When the renewable target is imposed (in addition to the climate targets), supply of fossil-based electricity decreases (see previous paragraph). Therefore, the price of fossil fuels drops, which tends to increase demand for fossil fuels in the end-user sectors. To meet the GHG emissions target in the non-ETS sectors, the non-ETS emissions price should increase.[19]

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[19] Imposing the renewable target increases (annual) consumer surplus by 204 billion € (relative to the Climate Target scenario) because of lower consumer prices. However, government net income decreases by 290 billion € (relative to the

Finally, with all four targets imposed (Reference scenario), the emissions reduction would be greater than the minimum requirements, and thus the prices of CO_2 emissions are zero (see Section 4). In fact, total reduction in GHG emissions would be 50 percent. Both electricity production and total energy consumption are lower in the Reference scenario than in the other 2030 scenarios referred to above.

Table 5 Policy target sensitivity

	No targets	Climate Targets (ETS and non-ETS targets)	Climate and Renewable Targets	Climate, Renewable and Energy Efficiency Targets (Reference scenario)	Climate Efficiency (one climate target)
GHG emissions in 2030 relative to 1990	–2%	–40%	–40%	–50%	–50%
Renewable share in 2030	11%	24%	32%	32%	28%
Improved energy efficiency in 2030 relative to 2005	3%	17%	11%	32.5%	24%
ETS price (€2009/tCO2)	0	62	14	0	322
Non-ETS price (€2009/tCO2)	0	262	267	0	322
Renewable subsidy (€2009/MWh)	0	0	58	55	0
End-user tax (€2009/toe)	0	0	0	1297	0

6.1.2 Alternative renewable and energy efficiency targets

As discussed in Section 2, there have been heated debates in the EU on whether a renewable target and an improvement in energy efficiency should be imposed for 2030, and if so, how ambitious these targets should be. Therefore, we discuss below the implications of alternative energy policy targets.

First, we explore the effects of an alternative renewable share in final energy consumption. We impose that energy efficiency should be improved by 32.5 percent (as in the Reference scenario), and further

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Climate Target scenario) because of a significantly lower carbon price in the ETS sectors and also because of government expenses to support renewable power production. When all groups are taken into account, that is, also energy producers and traders, we find that total welfare decreases by 28 billion €, which corresponds to roughly 0.1 percent of GDP in EU-30. In Section 2.1, we referred to Boeters and Koornneef (2011) who conclude that cost will increase if a 20 percent renewable share is imposed in addition to a 20 percent emissions reduction for the EU in 2020. Hence, this is the same type of result as ours.

that emissions in the ETS (non-ETS) sectors are at least 43 percent (30 percent) lower than in 2005 (as in the Reference scenario). Under these assumptions, we study how emissions change as the renewable share is altered.

Next, we study the impact of alternative improvements in energy efficiency. Now we vary the energy efficiency improvement, keeping the renewable share in final energy demand fixed at 32 percent, whereas emissions in the ETS (non-ETS) sectors are at least 43 percent (30 percent) lower than in 2005. Under these assumptions, we study how emissions change as the improvement in energy efficiency is altered.

The implications of alternative renewable shares in final energy consumption are shown in Figure 8. Here, *equilibrium emissions* in the ETS and non-ETS sectors in the Reference scenario are both set equal to one. As the renewable share is *increased* from 32 percent, there is a modest drop in ETS emissions, whereas there is a negligible drop in non-ETS emissions. The difference reflects that there are substantial technology-switching options in the ETS sectors in LIBEMOD, which is not the case in the non-ETS sectors.

If the renewable share is *decreased* from 32 percent, there is a negligible increase in non-ETS emissions. Furthermore, ETS emissions increase if the renewable share is decreased from 32 percent, and this effect is much stronger than in the non-ETS sectors (Figure 8). Note that if the renewable share is 23 percent, ETS emissions are exactly 43 percent below their 2005 value. Hence, for renewable shares below 23 percent, it is necessary to have a positive price on CO_2 emissions in the ETS sector to meet the requirement that ETS emissions should be (at least) 43 percent lower than in 2005. Furthermore, also for a renewable share below 20 percent, it is necessary to have a positive price on CO_2 emissions in the non-ETS sectors to ensure that these emissions are (at least) 30 percent lower than in 2005.

Figure 9 shows the end-user energy tax and the renewable subsidy that are required to achieve the emissions and energy efficiency targets under alternative renewable targets. In the figure, the *equilibrium* values of the instruments in the Reference scenario have been normalized to one. As seen from Figure 9, if the renewable target is lower than in the Reference scenario, then the magnitude of both policy instruments should also be lower than in the Reference scenario. Note that the instruments imposed to reach the ETS target of a 43 percent emissions reduction, the non-ETS target of a 30 percent emissions reduction, and a 32.5 percent improvement in energy efficiency imply that the renewable share becomes 23 percent or lower (Figure 8). Then the renewable subsidy is at least 60

percent lower than in the Reference scenario, whereas the end-user tax is slightly lower than in the Reference scenario (Figure 9).

Figure 10 shows the effects on emissions of alternative targets for improved energy efficiency when the renewable share in final energy consumption is 32 percent. In the figure, *equilibrium emissions* in the ETS and non-ETS sectors, the renewable subsidy, and the end-user energy tax in the Reference scenario are all set equal to one. From Figure 10 we see that a higher energy efficiency improvement than 32.5 percent will lower emissions in both the ETS and non-ETS sectors slightly relative to the outcome in the Reference scenario. Alternatively, an imposed improvement in energy efficiency lower than 32.5 percent will increase emissions in both sectors (relative to the outcome in the Reference scenario). Note, however, that if the improvement in energy efficiency is 25 percent or lower, then the non-ETS emissions restriction bites, that is, emissions are exactly 30 percent lower than in 2005. This is accomplished through a CO_2 price on non-ETS emissions. Hence, the CO_2 price in the non-ETS sectors is zero if the improvement in energy efficiency is exactly 25 percent, and positive if the improvement in energy efficiency is less than 25 percent. Furthermore, if the improvement in energy efficiency is 13 percent or lower, then the ETS emissions restriction becomes binding, that is, ETS emissions are exactly 43 percent lower than in 2005. This is accomplished through a CO_2 price on ETS emissions.

Figure 11 shows how the renewable subsidy and the energy tax vary with the improvement in energy efficiency. A higher required improvement in energy efficiency, which means lower consumption of primary energy, is accomplished through a higher tax on energy consumption. As seen from Figure 11, the energy tax is almost zero if the imposed improvement is as low as 12 percent.[20] Finally, as seen from Figure 11, if the imposed improvement in energy efficiency is increased, the renewable subsidy should in general be lowered; with improved energy efficiency, demand for energy decreases and thus production of fossil energy is reduced. Hence, it is easier to reach the renewable target. The renewable subsidy can therefore be lowered.[21]

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[20] For energy-efficiency improvements below 10.5 percent, the associated energy tax is zero.

[21] As seen from Figure 11, if the improvement in energy efficiency is raised from 12 percent by less than 2 percentage points, then the renewable subsidy should be increased slightly. This effect reflects that for energy-efficiency improvements between 12 and 14 percent, there is a positive CO_2 price in the ETS sectors. When the energy-efficiency target is increased slightly from 12 percent, the CO_2 price (necessary to meet the ETS emissions target) is decreased, thereby strengthening the competitive position of fossil energy relative to renewable energy. Therefore, the renewable subsidy has to be greater in order to reach the renewable target of 32 percent.

Figure 8 Sensitivity of renewable share in final energy consumption – emissions*
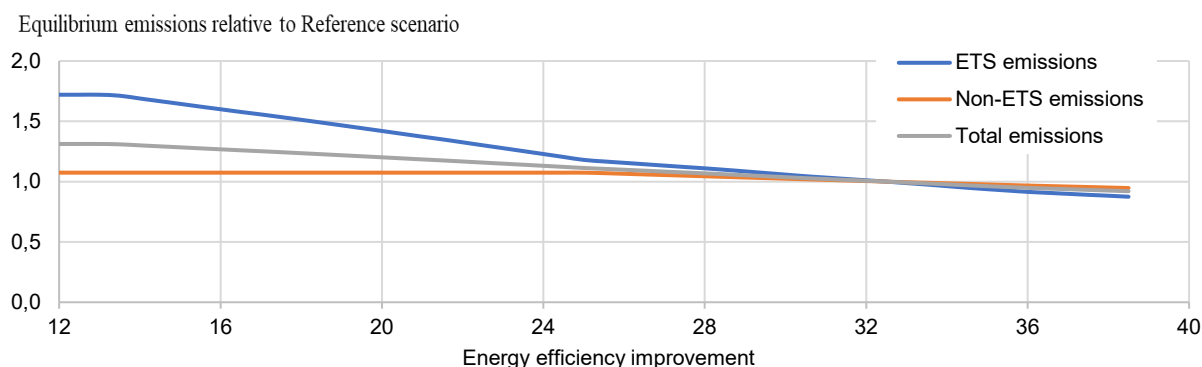

Equilibrium emissions relative to Reference scenario
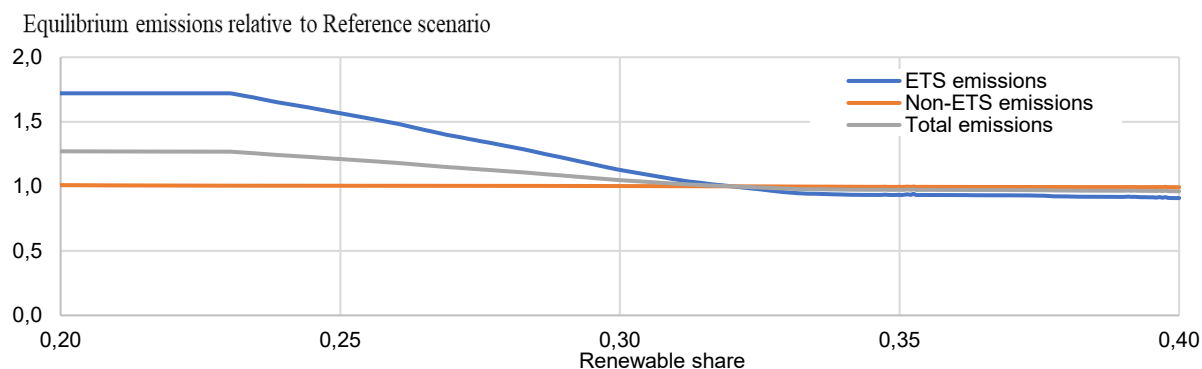
*Equilibrium relationships between (i) the share of renewables in final energy consumption and (ii) emissions in the ETS sectors and the non-ETS sectors, when the energy efficiency improvement is fixed at 32.5 percent. Emissions in the ETS and non-ETS sectors are measured relative to equilibrium emissions in the Reference scenario.

Figure 9 Sensitivity of renewable share in final energy consumption – policy instruments*
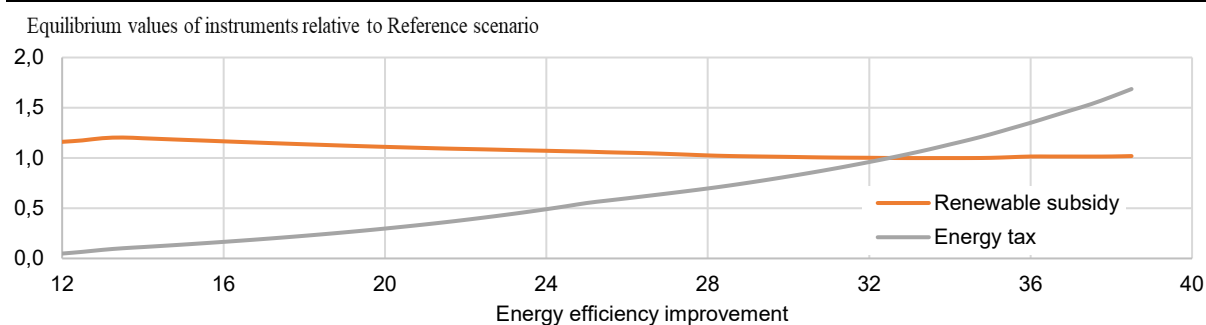

Equilibrium values of instruments relative to Reference scenario
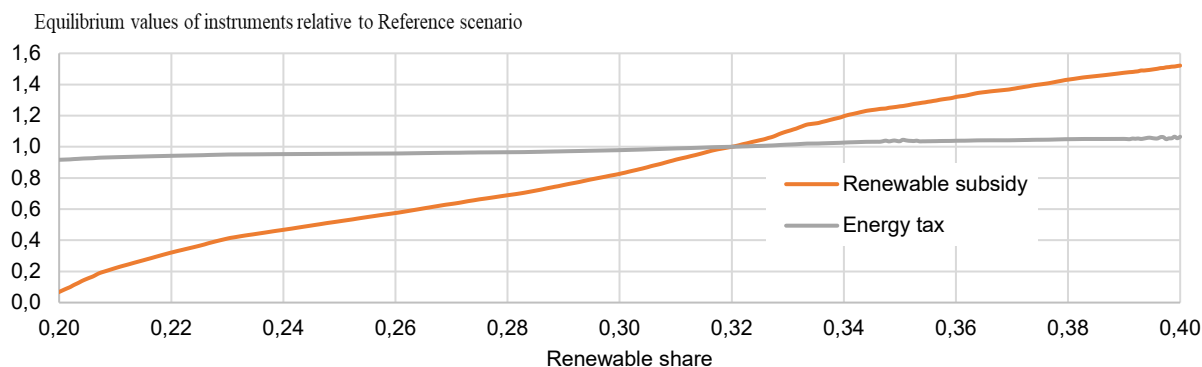
*Renewable subsidy and end-user energy tax as functions of the renewable share in final energy consumption when the energy efficiency improvement is fixed at 32.5 percent and the emissions targets of the ETS and non-ETS sectors are met.

Figure 10 Sensitivity of energy efficiency target – emissions*

Equilibrium emissions relative to Reference scenario

*Equilibrium relationships between (i) the improvement in energy efficiency and (ii) emissions in the ETS sectors and the non-ETS sectors, when the renewable share in final energy consumption is fixed at 32 percent. Emissions in the ETS and non-ETS sectors are measured relative to equilibrium emissions in the Reference scenario.

Figure 11 Sensitivity of energy efficiency target – policy instruments*

Equilibrium values of instruments relative to Reference scenario

*Renewable subsidy and end-user energy tax as functions of the energy efficiency improvement when the renewable share in final energy consumption is fixed at 32 percent and the emissions targets of the ETS and non-ETS sectors are met.

6.2 Robustness II – alternative parameter values

In this subsection, we study three scenarios that have the same policy targets as the Reference scenario, but they differ from the Reference scenario with respect to parameter values.

First, the cost of solar power has decreased substantially over the last 10–15 years; see, for example, Figure S5 in IRENA (2019), p. 22. Whereas experts agree that solar costs in 2030 will be significantly lower than today, it is still highly uncertain what the 2030 cost will be. Therefore, in the *Cheap Solar* scenario, costs of solar are cut by one-third relative to the Reference scenario (Table 3).

Second, the development of wind and solar parks requires land. In the Reference scenario, it is assumed that in each grid cells (which covers roughly 2500 km^2), 5 percent of the (gross) land can be used for wind parks (then 1 GW wind power capacity can be installed in each grid cell), whereas 1 percent of the land can be used for solar parks (then 2.5 GW solar capacity can be installed in each grid cell) (see Appendix B). Needless to say, future land regulation for renewable electricity is highly uncertain. We test the importance of land regulation by exploring the impact of allowing 10 percent of the land in each grid cell to be used for wind parks (as opposed to 5 percent in the Reference scenario). The corresponding assumption for solar parks is 2 percent (as opposed to 1 percent in the Reference scenario). This scenario is termed *More Land*.

Finally, the national CES demand systems in 2030 reflect GDP growth rates between the years 2009 and 2030. For the period 2009–2017, these are observed growth rates taken from International Monetary Fund (2019), whereas the expected rates for 2018–2024 and 2025–2030 are taken from International Monetary Fund (2018; 2019) and OECD (2018), respectively. Because the growth rates up to 2030 are uncertain – there may, for example, be another financial crisis – we run a scenario

where the expected *growth* in GDP (for the period 2018–2030) is cut by 50 percent in each country (relative to the Reference scenario). Below, this scenario is referred to as *Low Growth* (Table 3).

Cheap Solar
With the lower cost of solar power, the market share of solar increases by 6 percentage points (relative to the Reference scenario), that is, its market share is now as high as 27 percent. Increased solar production mainly reduces other sources of renewable electricity supply; the market share of wind falls by 4 percentage points, whereas the reduction in biopower is 2 percentage points. The lower cost of solar allows a lower renewable subsidy; the drop is almost 20 percent (Figure 3). Because the supply of electricity has become cheaper, total electricity supply increases, but the change is modest (2 percent). The EU-30 producer price of electricity falls by a few percent, whereas the EU-30 end-user price of electricity, which is much higher than the producer price because of end-user taxes, falls even less (measured in percent).

More Land
With more land available for wind and solar development, the competitive position of wind power is strengthened. The competitive position of solar is weakened relative to wind power but strengthened relative to other technologies.[22] We find that total electricity production hardly changes (relative to the Reference scenario), but wind power increases its market share by 2 percentage points, whereas gas power and biopower lose market share. As expected, with more competitive wind and solar power, there is a drop in the renewable subsidy (by 7 percent relative to the Reference scenario; Figure 3), whereas other variables hardly change.

Low Growth
With substantially lower economic growth than in the Reference scenario, energy demand is reduced. Hence, the energy consumption tax, which is imposed to reach the energy efficiency target, is much lower (24 percent) than in the Reference scenario (Figure 4). The tax effect is so strong that energy consumption in the Low Growth scenario is just marginally below the level in the Reference scenario. For other variables, the difference from the Reference scenario is marginal. For example, carbon emissions are slightly lower than in the Reference scenario, and hence also in the Low Growth scenario carbon prices are zero.

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[22] With our calibration procedure for wind and solar power (see Appendix B), these assumptions imply that maximum wind and solar production in a country (of course) doubles. Technically, the parameters b_w and b_s, which reflect how a unit increase in capacity lowers the number of full-load hours of wind power and solar, are halved. This makes both types of intermittent power more competitive. However, because $b_w > b_s$, wind power gains more than solar from a 50 percent cut in the parameter value.

6.3 Climate efficiency

As discussed in Section 5.1, the emissions reduction in the Reference scenario is not cost-efficient. Therefore, we have examined a scenario termed Climate Efficiency where total GHG emissions are reduced by 50 percent (as in the Reference equilibrium), but without imposing any other targets, that is, there are no specific ETS and non-ETS emissions requirements (only a requirement on total emissions) and no restrictions on the share of renewables, nor on the improvement in energy efficiency. We find that the common CO_2 price has to be as high as €322/tCO2, which is even greater than the non-ETS price in the Climate Targets scenario (€267/tCO$_2$) (Table 5).

Why is the carbon tax so high in the Climate Efficiency scenario? In contrast to the Reference scenario, there is no renewable subsidy in the Climate Efficiency scenario; such a subsidy tends to decrease the price of electricity, thereby phasing out some of the fossil-based supply of electricity. Furthermore, in contrast to the Reference scenario, there is no tax on end-user consumption of energy in the Climate Efficiency scenario; such a tax tends to decrease demand for energy, thereby reducing fossil-based consumption. Without a renewable subsidy and an end-user tax, the carbon tax in the Climate Efficiency scenario must solely ensure a 50 percent emissions reduction.

Furthermore, in LIBEMOD, there is technology switching in the electricity generation sector but not in the end-user sectors where demand for fuels is represented by rigid CES systems. Therefore, a "moderate" price of emissions will generate a large emissions reduction in the electricity generation sector, whereas a "very high" price of emissions is required to obtain a large emissions reduction in the end-user sectors. Because the electricity generation sector accounts for a moderate share of total emissions, a high price of emissions is required to obtain a 50 percent GHG emissions reduction.

Note that both electricity production and total energy consumption are higher in the Climate Efficiency scenario than in the Reference scenario (Figures 6 and 7). The ranking reflects the efficiency gain of imposing a common CO_2 price for all sectors.

Table 6 shows welfare in the Climate Efficiency scenario relative to the Reference scenario by welfare component and the total difference, measured in €1000 million (i.e., billions of €). The annual increase in consumer surplus is €596 billion (consumer surplus aggregated over all end-user sectors), reflecting lower consumer prices in the Climate Efficiency scenario than in the Reference scenario. In contrast, the annual decrease in government net income is €530 billion. Here, there are several counteracting effects when moving from the Reference scenario to the Climate Efficiency scenario: no income from

a tax on end-user consumption (which lowers government net income), no payment of renewable subsidies (which increases government net income), and a higher CO_2 price (which increases government net income). Our result shows that the first effect dominates, that is, government net income is greater in the Reference scenario than in the Climate Efficiency scenario. The net effect for other welfare components (i.e., surplus for electricity producers, surplus for other energy producers, and trader surplus) is positive but smaller, and adds up to €46 billion. The net effect is that annual welfare is €111 billion higher in the Climate Efficiency scenario than in the Reference scenario, which corresponds to roughly 0.5 percent of GDP in EU-30.

Table 6 Welfare components in the Climate Efficiency scenario relative to the Reference scenario for EU-30, Poland, the Netherlands and Germany. 1000 million €2009

	EU-30	Poland	The Netherlands	Germany
Producer surplus, electricity	38.7	0.4	0.2	1.2
Producer surplus, other energy carriers	6.8	0.4	1.2	0.2
Consumer surplus	595.5	114.0	32.0	31.0
Trader surplus	0.3	0.2	0.0	0.0
Government net income	−529.8	−108.8	−27.4	−30.0
Sum	**111.5**	**6.2**	**6.0**	**2.4**

In Section 3, we referred to the process of obtaining an agreement over the EU 2030 climate and energy target package. Here, we divided countries into three (bargaining) groups; those not pleased with the EU 2020 package, for example, Poland; those with a mixed experience with the EU 2020 package, for example, the Netherlands, and those that mainly had a positive experience with the EU 2020 package, for example, Germany. While Germany wanted more ambitious targets, which in the end was agreed upon, neither the Netherlands nor Poland wanted any energy policy targets. Therefore, it is interesting to compare welfare for these three countries between the Climate Efficiency scenario and the Reference scenario. As seen from Table 6, all three countries have the highest welfare in the Climate Efficiency scenario, that is, the scenario without energy targets. Note that for all three countries, government net income is lower in the Climate Efficiency scenario than in the Reference scenario. This is in particular the case for Poland.

Figure 12 provides more information on the Reference and Climate Efficiency scenarios. Here, we measure imports of electricity, natural gas, and coal relative to the *sum* of end-user consumption of

these three energy goods in the Reference scenario. A bar above the horizontal axis reflects imports, whereas a bar below the horizontal axis shows exports.

As seen from Figure 12, each of the three countries imports more natural gas in the Climate Efficiency scenario than in the Reference scenario, whereas the opposite is the case for electricity. In the Climate Efficiency scenario, there is increased imports of natural gas from Russia, reflecting that the producer price of natural gas is higher in the Climate Efficiency scenario than in the Reference scenario. The reason is simply that there is no end-user tax in the Climate Efficiency scenario; this tax decreases producer prices. The increased imports of natural gas in the Climate Efficiency scenario are mainly used for gas power production, either by retrofitting existing gas power stations or by investing in new CCS gas power. This effect is so strong that the Netherlands changes from an exporter of natural gas in the Reference scenario to an importer of natural gas in the Climate Efficiency scenario, whereas the opposite is the case for electricity in the Netherlands.

Additional policy instruments

In Section 6.1.2, we studied the impacts of alternative energy targets when the emissions targets were fixed. We now conduct a similar analysis under the Climate Efficiency scenario. We keep the assumption of a common emissions target that leads to the same GHG emissions reduction as in the Reference scenario, and study how the common CO_2 price must be adjusted if the EU imposes either a common renewable subsidy to stimulate renewable electricity or imposes a common end-user tax on energy to improve energy efficiency.

Figure 13 shows the case when the EU offers a subsidy to all producers of renewable electricity. Here, a zero subsidy corresponds to the equilibrium in the Climate Efficiency scenario. As seen from the figure, as the renewable subsidy is increased, the CO_2 price drops. A higher renewable subsidy stimulates supply of renewable electricity, which reduces the producer price of electricity. Hence, fossil fuel-based electricity production, which is mainly CCS gas power production, drops. This tends to lower emissions from the electricity generation sector. Because total emissions per assumption are constant, emissions in the end-user sectors should increase. This requires a *reduction* in the common CO_2 price; if not, end-user emissions would be too low.

If, alternatively, the EU imposes a common energy tax on all end users, demand for electricity drops and hence total production of electricity, as well as the producer price of electricity, decreases. As the energy tax is increased up to €600/MWh, fossil fuel-based electricity production, which is mainly CCS gas power production, decreases. Hence, emissions in the electricity generation sector decrease.

Because total emissions per assumption are constant, emissions in the end-user sectors should increase. This is accomplished by decreasing the common CO_2 price (Figure 14).

When the energy tax is increased from €600/MWh to €1200/MWh, CCS gas power production continues to fall, but now it becomes profitable to invest in conventional gas power stations. Because gas power production generates substantial emissions, in the electricity generation sector emissions increase, but not by very much. To ensure that total emissions are constant, emissions among the end users have to drop slightly. This is accomplished by lowering the common CO_2 price moderately. To sum up, a higher energy tax leads to a lower CO_2 price, and the effect is strongest when the tax is below €600/MWh (Figure 14).

Figure 12 Imports of electricity, coal and natural gas as a percentage of total end-user consumption of these three energy goods in the Reference scenario. EU-30, Poland, the Netherlands, and Germany

Import in per cent of end-user consumption in Reference scenario
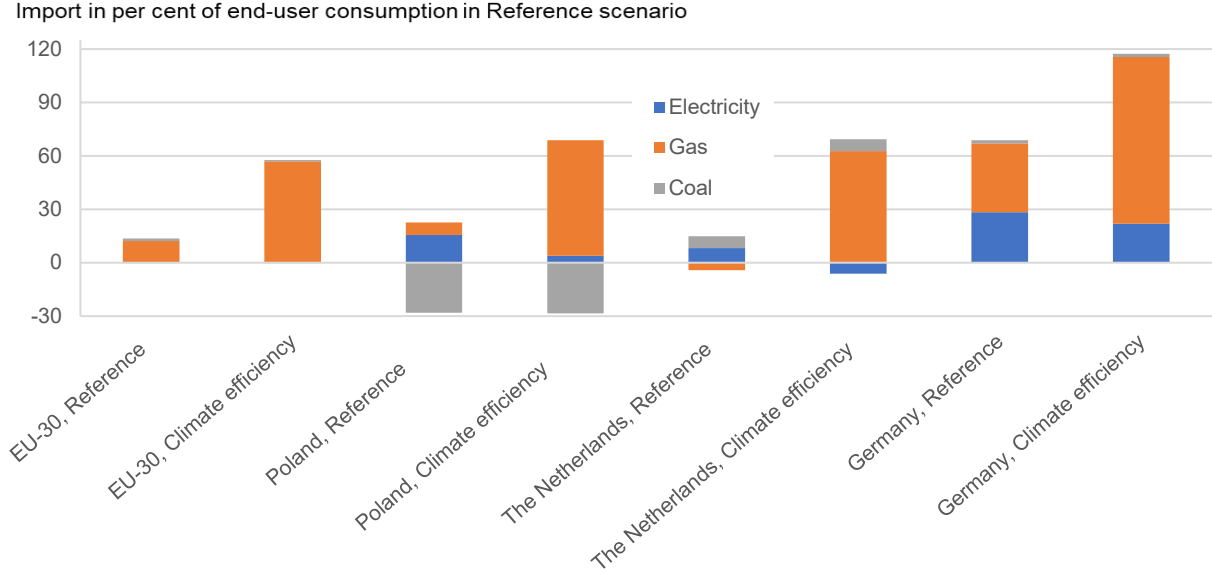
Figure 13 Equilibrium relationship between renewable subsidy and CO_2 price when total emissions are fixed

CO_2 quota price euro/tCO_2

Renewable subsidy euro/MWh
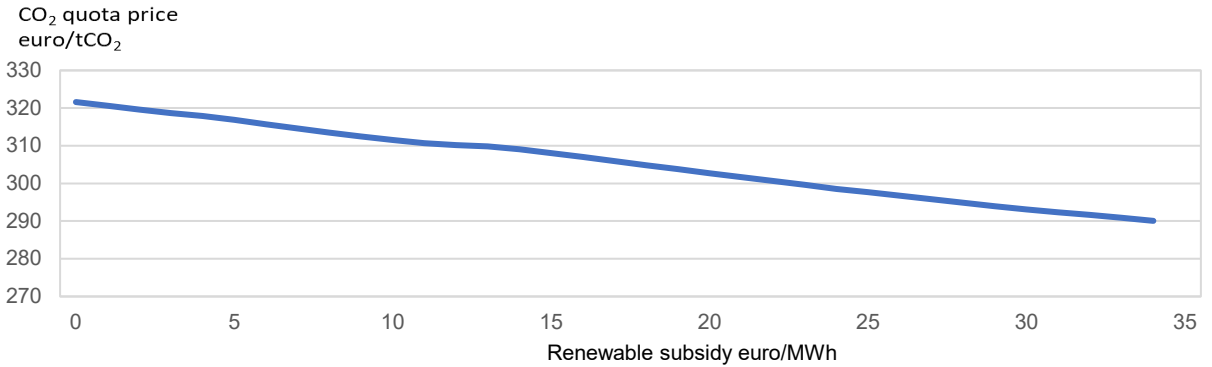
Figure 14 Equilibrium relationship between end-user tax on energy and CO₂ price when total emissions are fixed.

CO₂ quota price
euro/tCO₂

Energy tax euro/toe
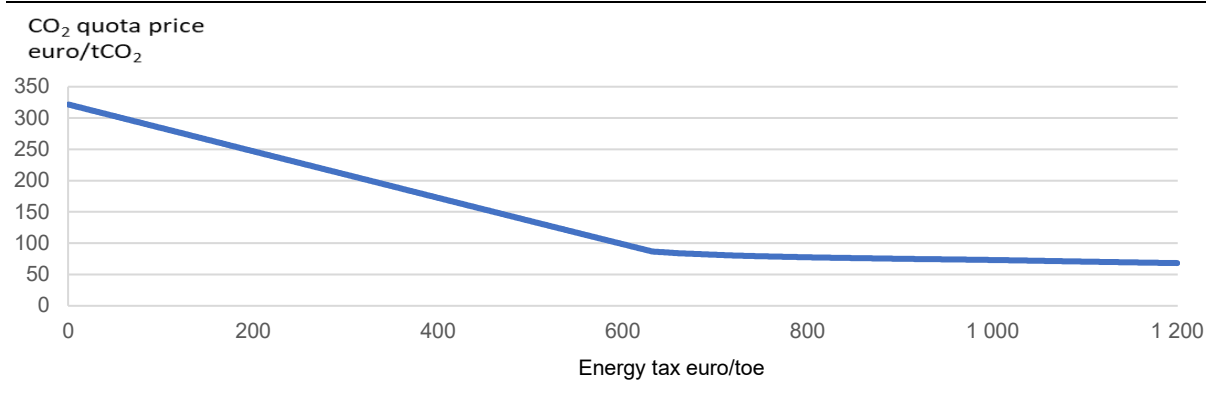
7 Concluding remarks

This paper has examined the impact of the 2030 EU climate and energy policy package: (i) GHG emissions should be (at least) 40 percent lower in 2030 than in 1990, which has been specified as ETS (non-ETS) emissions should be 43 (30) percent lower than in 2005; (ii) the renewable share in final energy demand should be 32 percent; and (iii) the improvement in energy efficiency should be 32.5 percent (relative to 2005). To this end, we have used the numerical multimarket, multiperiod equilibrium model LIBEMOD, which gives a detailed description of the energy markets in EU-30 (electricity, natural gas, coal and biomass) along with modeling of the global markets for coal, oil, and biofuels. This model determines investment, extraction, production, trade, and consumption of energy goods in each of 30 European countries, along with consistent equilibrium prices that clear all markets, including tariffs for the international transportation of natural gas and electricity.

We find that the renewable and energy efficiency targets have been set so high that the derived emissions reductions in the ETS and non-ETS sectors exceed their targets. Hence, carbon prices are zero. In fact, total GHG emissions reduction is 50 percent, that is, 10 percentage points higher than the goal of the EU. The renewable subsidy required to achieve a renewable share in final energy demand of 32 percent is €₂₀₀₉55/MWh, whereas the uniform tax on energy consumption has to be €₂₀₀₉1297/toe (€₂₀₀₉112/MWh) to achieve the required improvement in energy efficiency.

Because there have been intense debates in the EU on whether an energy efficiency target should be part of the 2030 package, and how ambitious the renewable policy should be, we have examined the impact on the 2030 equilibrium under alternative assumptions about the improvement in energy efficiency and the share of renewables in final energy consumption. We find that if the improvement in energy efficiency is 32.5 percent, and the renewable share in final energy demand is only 23

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percent, then ETS emissions are exactly 43 percent below the 2005 level, which is the EU 2030 emissions target. Similarly, if the renewable share in final energy consumption is 32 percent, and the improvement in energy efficiency is only 13 percent, then ETS emissions are exactly 43 percent below the 2005 level.

Throughout the paper, we have assumed EU-wide policy instruments. This is fine with respect to the EU-wide climate target for the ETS sectors, which, according to the EU, should be reached by an EU-wide tradable permit system, namely the EU ETS. For the EU-wide renewables and energy efficiency targets, the basic idea of the EU is to let countries select policy instruments and use the EU governance system to ensure that EU-wide targets are met. While a governance regulation has been passed requiring each member state to draft integrated 10-year national energy and climate plans for 2021–2030 (Eur-lex (2018c)), it is not quite clear how the potential conflict between EU-wide targets and discretionary domestic policy instruments will be handled. If the EU believes implemented domestic instruments are too lax to achieve the EU-wide targets, which countries will be instructed to impose a stricter policy and how much should domestic instruments be adjusted? The basic assumption of the present paper is that the EU system will work out a solution; our specific choice of instruments should be seen as a way to model sufficient incentives for the agents to reach the policy goals. For a discussion on the EU governance system, see Ringel and Knodt (2018). Based on a review of stakeholder positions, this paper finds strong acceptance for enhanced coordination.

Needless to say, other scenarios than those studied are possible. One direction is to allow for uncertainty in LIBEMOD (Brekke et al. (2017)). Another option is to deviate from the assumption of competitive markets. The EU has for years aimed at transforming the European electricity and natural gas markets into efficient ("internal") markets. However, the transition has been partial and incremental. In particular, there have been setbacks because of concerns about national interests and energy security; see, for example, European Commission (2010). This suggests running LIBEMOD under different assumptions about market structure; in LIBEMOD, the market structure can be represented by a set of parameters that reflect the degree of deviation from the competitive outcome in different parts of the European energy industry; see Golombek et al. (2013a).

In the present study, the LIBEMOD model has been developed to be suitable for analyzing the 2030 EU climate and energy package, with its emphasis on renewable energy. The model has previously been used to analyze a number of issues: for example, the potential for CCS in the European electricity market (Golombek et al. 2011); how climate change may impact the future European electricity

market (Golombek et al. 2012); the importance of EU rules on emission quota allocation (Golombek et al. 2013b); and the Russian energy market and its impact on the European energy market (Aune et al. 2015; 2017). Needless to say, the model can be developed to analyze a number of topics related to the future European energy market: for example, (i) electrification of different means of transportation, which will impact both the demand for and supply of electricity; (ii) rooftop PV as a source of heating and the resulting effects in the energy markets; (iii) integration of electricity and heat markets; and (iv) how imports of cheap shale gas can crowd out European natural gas supply and the derived implications for Europe as well as Russia.

Finally, the 2030 EU target of a 40 percent GHG emissions reduction may be adjusted in the future. Referring to three clean energy laws that had been sealed recently, the EU's top energy and climate official announced in June 2019 that "the bloc is now set to increase the emissions reduction pledge from 40 percent by 2030 to 45 percent" (Euractiv (2019a)). However, several Central and Eastern European countries are against raising the EU target, and Germany is also against such a move, whereas climate-progressive countries such as the Netherlands and Sweden consider a 45 percent cut to be too small. The latter position is consistent with the European Parliament, which in March 2019 voted in favor of increasing the EU's 2030 emission target to 55 percent (Euractiv (2019b)).[23] Therefore, in the future, the LIBEMOD model may be used to analyze more ambitious climate targets than a 40 percent emissions reduction.

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[23] In March 2019, the European Parliament also voted in favor of a net-zero emissions target by 2050. This was strengthened in November 2019 when the Parliament approved a resolution declaring a climate and environmental emergency in Europe and globally; see European Parliament (2019). The European Parliament also wanted all relevant legislative and budgetary proposals to be fully aligned with the objective of limiting global warming to under 1.5°C. For steering of renewable support schemes by the EU, see Boasson (2019).

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Appendix A: Modeling

Part I: Trade and investment in electricity

Electricity can be traded via international transmission lines. Each transmission line is owned by a single agent. Let m and n be two countries, and let z_{mn} be the electricity exported from m to n, measured at the node of the importing country n. Because there is some loss in transmission (θ_{mn}), the quantity $z_{mn}/(1 - \theta_{mn})$ is exported from country m. The transmission line owner transports electricity as long as there is a positive difference between (i) the purchasing price in the import country, p_n, and (ii) the loss-adjusted purchasing value in the exporting country, $p_m/(1 - \theta_{mn})$, less exogenous costs of transmission, c_{mn}. Hence, all arbitrage possibilities are exploited. In each time period t, $t \in T$, the pipeline can be used either for imports to country n from country m or for exports from country n to country m. In addition, the owner can expand the initial capacity of the pipeline, K_{mn}^0, through investments, K^{inv}. Hence, the profits of the owner of the pipeline between country m and n are:

$$(7) \qquad \Pi_{mn} = \sum_{t \in T} \left\{ \left[p_{nt} - \frac{p_{mt}}{1-\theta_{mn}} - c_{mn} \right] z_{mnt} + \left[p_{mt} - \frac{p_{nt}}{1-\theta_{nm}} - c_{nm} \right] z_{nmt} \right\} - c_{mn}^{inv} K_{mn}^{inv}$$

where c_{mn}^{inv} is the annualized unit capital cost for expansion of electricity transmission lines. Moreover, the owner faces the following constraints:

$$(8) \qquad z_{mnt} - z_{nmt} \leq \alpha_t K_{mn} \perp v_{mnt} \geq 0$$

where α_t is the number of hours in period t. According to (8), which is valid for trade between m and n in both directions (two inequalities), net trade in either direction in period t cannot exceed total transmission capacity in this period, $\alpha_t K_{mn}$. Momentarily pipeline capacity is the sum of initial capacity (K_{mn}^0) and investments in capacity (K_{mn}^{inv}):

$$(9) \qquad K_{mn} = K_{nm} = K_{mn}^0 + K_{mn}^{inv}$$

where the first equality ensures that the capacity is the same in both directions. The shadow price v_{mnt} can be interpreted as the tariff (in excess of c_{mn}) that ensures that demand for transport services does not exceed the available capacity.

The first-order conditions of the transmission line owners for trade in either direction in any period are given by:

(10) $\qquad p_{nt} - \frac{p_{mt}}{1-\theta_{mn}} - c_{mn} - v_{mnt} + v_{nmt} \le 0 \perp z_{mnt} \ge 0,$

whereas the first-order condition for investment in electricity transmission is given by:

(11) $\qquad \sum_{t \in T} \alpha_t (v_{mnt} + v_{nmt}) \le c_{mn}^{inv} \perp K_{mn}^{inv} \ge 0.$

Inequality (11) takes into account that investment increases capacity in both directions, and also that the increased capacity can be utilized in all periods.

Part II: Capacity market

In each model country, the national regulator has to avoid a domestic electricity market breakdown triggered by either an unexpected increase in demand or an unexpected decrease in supply. In the case of an unexpected event, the national regulator acquires idle maintained capacity from the domestic power producers (except intermittent producers, run-of-river plants and nuclear plants). Through demand for, and supply of, capacity, a competitive price of reserve capacity, p_t^{KR}, is determined in each time period.

Supply of reserve capacity from a power plant is determined as part of the problem of maximizing profits subject to a number of constraints. A power producer l can use its maintained capacity, K_l^{PM}, either to produce electricity or to sell it at the capacity market in period t, K_{lt}^{PR}. Hence, in each time period, production of electricity is constrained by the maintained capacity available for production:

(12) $\qquad y_{tl} \le \alpha_t (K_l^{PM} - K_{tl}^{PR}) \perp \varepsilon_{tl} \ge 0$

where α_t is the number of hours in period t.
The first-order condition with respect to reserve power capacity sold in each period is:

(13) $\qquad p_t^{KR} \le \varepsilon_{tl} \alpha_t \perp K_{tl}^{PR} \ge 0.$

Hence, for positive reserve power sales in period t, the reserve power price in this period, p_t^{KR}, must equal the shadow value (in period t) of increasing the power capacity available to produce electricity

$(\varepsilon_{tl}\alpha_t)$, that is, for each power producer that is allowed to sell idle capacity, the marginal unit of power capacity should be worth the same either if it is sold as reserve power or used to produce electricity.

In LIBEMOD, the requirement that sufficient idle capacity is available in case there is an unexpected increase in net demand is modeled as follows: in each time period, total idle capacity ($\sum_l K_{tl}^{PR}$) should exceed a share (ρ) of total maintained capacity ($\sum_l K_l^{PM}$):

(14) $\qquad \rho \sum_l K_l^{PM} \leq \sum_l K_{tl}^{PR} \perp p_t^{KR} \geq 0.$

The price of capacity is positive only if the constraint is binding.

Appendix B: Calibration

Part I: Calibration of wind power

In Section 4.2.1, we defined full-load wind hours as the number of hours with ideal wind conditions (wind speed exceeding, say, 15 m/s)[24] that are required to generate the observed annual wind power production. We also introduced $f(K^{PM})$, which shows the average number of full-load wind hours per year as a decreasing function of aggregate maintained capacity, K^{PM}. We now let w denote wind power and impose that $f(K_w^{PM})$ is linear:

$$(15) \qquad f(K_w^{PM}) = a_w - b_w K_w^{PM}.$$

The interpretation of the parameter a_w is simply the full-load wind hours per year at the best site (in a country).

From MERRA-2 (Modern-Era Retrospective analysis for Research and Applications, version 2; see Gelaro et al. (2017)), we have access to hourly weather observations, such as wind speed and solar irradiance, for the period 2006–2015 for each of the 30 LIBEMOD countries. The spatial resolution is a latitude–longitude grid of cells of $0.5° \times 0.625°$. Roughly, each cell is 50 km $\times$ 50 km in size.

Using detailed information about a Norwegian wind park, we have estimated a wind power curve; for details, see the Appendix in Gaure and Golombek (2019).[25] Combining this power curve with information on site-specific hourly wind speeds from MERRA-2, and taking the system electricity loss in wind parks into account, which, according to industry experts, is in the order of 3 percent, we can simulate hourly wind power production in the period 2006–2015. Therefore, we can identify the grid cell with the highest full-load wind hour (a_w) and the cell with the lowest full-load wind hour (henceforth referred to as d_w) in each country (Table B.1). From the simulations, we also find the parameter ψ_t^w, that is, the share in period t of annual full-load wind hours (in each country).

By using detailed information on a number of Norwegian onshore wind parks, Gaure and Golombek (2019) find that if 1 GW of wind capacity is installed (and maintained) in a grid cell, then roughly 5

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[24] Strictly speaking, above another threshold, say, 25 m/s, the wind mill must be shut down to avoid damage.

[25] We have used information from the Høg-Jæren wind park, located in the southwest of Norway, to estimate the power curve. With this power curve, the full-load wind hours among the best 10 percent onshore wind cells in Germany (2658 hours) is close to the "expected full-load hours for the new wind turbines" in Germany (2788 hours); see Fraunhofer (2019).

percent of the *gross* land in the grid cell is used for wind parks.[26] We use this relationship for all grid cells in all countries. Furthermore, in the Reference scenario, we assume that because of land regulation, 1 GW capacity can be installed in each grid cell.

Table B.1 Full-load wind hours at best site and worst site in wind parks by country

Country	Full-load wind hours at best site	Full-load wind hours at worst site	Country	Full-load wind hours at best site	Full-load wind hours at worst site
Austria	1 923	128	Latvia	2 933	796
Belgium	2 449	2034	Lithuania	2 655	780
Bulgaria	1 732	243	Luxembourg	1 758	1758
Cyprus	1 122	1026	Malta	2 016	2016
Czech Republic	2 125	1109	Netherlands	3 398	2206
Denmark	3 544	2840	Norway	3 085	464
Estonia	3 176	1469	Poland	2 783	1049
Finland	2 097	673	Portugal	2 235	552
France	3 130	57	Romania	1 932	414
Germany	3 187	230	Slovak Republic	1 734	561
Greece	2 421	282	Slovenia	1 154	201
Hungary	1 898	819	Spain	2 314	572
Iceland	3 951	1844	Sweden	3 022	586
Ireland	3 834	2779	Switzerland	1 119	126
Italy	2 090	52	United Kingdom	4 122	2 244

Source: Own calculations based on MERRA-2 data on wind speed and using the estimated power curve for the Norwegian wind park Høg-Jæren. Note that the estimated power curve reflects maintenance work. Furthermore, full-load wind hours have been adjusted for system electricity losses.

By multiplying maximum maintained wind power capacity in each grid cell (1 GW) by the number of (onshore) cells in a country, we find a measure of *maximum* maintained (onshore) wind power capacity, $\hat{K}_w^{PM}$. Hence, *actual* maintained capacity should be below this number, that is,

(16) $K_w^{PM} \leq \hat{K}_w^{PM}$.

Inequality (16) reflects land scarcity with respect to wind power production.

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[26] The land share differs slightly by grid cell because the size of cells (measured in km²) differs. Note that the area between the wind turbines in the wind parks is available for public or private activities; the exact nature of these activities (agriculture, forestry, recreation, private hunting, etc.) will depend on local conditions. The area used for wind mills and infrastructure is substantially lower than the gross area, see the Appendix in Gaure and Golombek (2019).

Annual production of wind power is $f(K_w^{PM})K_w^{PM} = a_w K_w^{PM} - b_w (K_w^{PM})^2$, where we have used (15). Therefore, marginal productivity of annual production of wind power is given by $a_w - 2b_w K_w^{PM}$. If maintained capacity is equal to $\widehat{K}_w^{PM}$, then the site with the lowest full-load wind hours is utilized. By construction, the full-load wind hours at this site are d_w. Hence, $a_w - 2b_w \widehat{K}_w^{PM} = d_w$, and thus

(17) $$b_w = \frac{a_w - d_w}{2\widehat{K}_w^{PM}},$$

which is easy to calculate.

In the LIBEMOD model, restriction (16) is included in the Lagrangian of the wind power producer. Let κ be the Lagrange parameter associated with restriction (16). Then the term $c^M + \lambda$ in the first-order condition for maintained capacity (see (5)) is modified to $c^M + \lambda + \kappa$.

Part II: Calibration of solar power

Calibration of the solar parameters is similar to the calibration of the wind power parameters. Let s denote solar power. In Section 4.2.2, we introduced the function $g(K_s^{PM})$, which shows how annual generated electricity delivered to the grid per m^2 of solar park depends on maintained solar power capacity (K_s^{PM}). We now assume that this function is linear:

(18) $$g(K_s^{PM}) = a_s - b_s K_s^{PM}.$$

The parameter a_s is annual generated electricity delivered to the grid per m^2 of land at the best site (i.e., in the best grid cell).

Gaure and Golombek (2019) study optimal design of solar parks: for a given amount of land available for solar power, what is the tilt of solar panels and what is the distance between rows of solar panels that maximize profits? Using data from MERRA-2, including solar irradiance (measured as surface incoming shortwave flux), reflection (albedo), and temperature in the air, they construct a measure for diffuse radiation and also take into account how the efficiency of solar panels depends on the temperature. The collected and derived variables are used to find optimal solar panel tilts and optimal distance between rows of solar panels; both differ by MERRA-2 grid cells. They find that installation

of 1 kW of capacity in a solar park requires approximately 10 m^2 of land. Hence, the total amount of land used for solar parks is $\Omega_s = 10\frac{m^2}{kW}K_s^{PM}$.[27]

Once the optimal tilts are identified, Gaure and Golombek (2019) simulate how much electricity is generated annually and delivered to the grid by a capacity of 0.1 kW, which requires 1 m^2 of land. To this end, they take into account the system electricity loss in solar parks, which, according to industry experts, is in the order of 16 percent. Table B.2 shows the results for the best site (a_s) and the worst site (henceforth referred to as d_s) for each of the 30 LIBEMOD countries.

Table B.2 Solar power output in solar parks, kWh/m²/year

Country	Best site kWh/m²/yr	Worst site kWh/m²/yr	Country	Best site kWh/m²/yr	Worst site kWh/m²/yr
Austria	154	128	Latvia	112	104
Belgium	121	119	Lithuania	114	106
Bulgaria	157	144	Luxembourg	125	125
Cyprus	182	181	Malta	174	174
Czech Republic	133	122	Netherlands	121	115
Denmark	114	109	Norway	105	31
Estonia	109	102	Poland	128	113
Finland	104	52	Portugal	173	155
France	164	120	Romania	146	131
Germany	136	114	Slovak Republic	135	125
Greece	182	151	Slovenia	142	134
Hungary	139	131	Spain	182	139
Iceland	92	66	Sweden	113	77
Ireland	115	97	Switzerland	165	131
Italy	170	134	United Kingdom	124	87

Source: Own calculations based on MERRA-2 data. Key assumptions: optimal fixed tilt of cells, 18 percent efficiency, and correction for 16 percent system electricity losses.

We now determine the value of b_s in (18). To this end, we first calculate the required maintained solar power capacity if all grid cells are developed. This requires an assumption on the share of land available for solar parks. In the Reference scenario, we assume that 1 percent of the land in each grid cell can be used for solar parks. Drawing on the derived relationship between land use and capacity

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[27] Because the optimal tilt differs by grid cell, the amount of land necessary to install 1 kW of solar capacity differs slightly by grid cell.

between land use and capacity referred to above, $\Omega_s = 10 \frac{m^2}{kW} K_s^{PM}$, this means that 2.5 GW of solar capacity can be installed in each grid cell.[28] By multiplying *maximum* maintained solar power capacity in each grid cell (2.5 GW) by the number of grid cells in a country, we find the maximum maintained solar power capacity, which is henceforth referred to as $\widehat{K}_s^{PM}$. Of course, *actual* capacity should be lower than this number:

(19) $K_s^{PM} \leq_s \quad \widehat{K}^{PM}.$

Because $g(K_s^{PM})K_s^{PM} = a_s K_s^{PM} - b_s(K_s^{PM})^2$ shows annual solar power production per m^2, marginal productivity of annual solar production per m^2 is $a_s - 2b_s K_s^{PM}$. If maintained solar power capacity is $\widehat{K}_s^{PM}$, then the site with the lowest output per m^2 (d_s) has been developed and per construction $a_s - 2b_s\widehat{K}_s^{PM} = d_s$. Solving this equation with respect to b_s, we find a relationship similar to (17).

Part III: Calibration of the demand block

In LIBEMOD, end-user demand is derived from a nested CES utility function with five levels. At the top-nest level, there are substitution possibilities between energy-related goods and other forms of consumption. At the second level, consumers face a trade-off between consumption based on the different energy sources. Each of these is a nest describing complementarity between the actual energy source and consumption goods that use this energy source (e.g., electricity and light bulbs). Finally, the fourth and fifth levels are specific to electricity in defining the substitution possibilities between the summer and winter seasons (fourth level) and time periods over the 24-hour cycle (fifth level).

The CES function contains three types of parameters: endowment, share, and substitution. Briefly, the parameters are determined as follows. First, we calibrate income elasticities as the nonprice changes in consumption relative to changes in GDP, assuming an annual global energy efficiency rate of 1.6 percent. This rate is taken from the Current Policies Scenario of World Energy Outlook 2011 (IEA 2011). Next, given the calibrated income elasticities and demand observations, the endowment and share parameters are determined. Based on a literature review, we then select direct and cross-price elasticities (henceforth referred to as target value elasticities) for all energy goods. These are used to determine the distribution parameters by minimizing the mean squared error, summed over all goods, between each target value elasticity and the corresponding calibrated elasticity; see Aune et al. (2008),

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[28] Note that the entire area will be covered by solar panels; there is no space for other activities.

The model is calibrated to 2009 data. For a detailed description of the calibration strategy, see Aune et al. (2008).

Part IV: Transforming the GHG target to a CO_2 target

While the EU emissions target is set in terms of GHG gases, the LIBEMOD model covers CO_2 only. Therefore, we have to transform the GHG target to a CO_2 target. Our transformation strategy is as follows. We use EEA (2013) to find GHG emissions for EU-27 in 1990. The emission target for EU-27 in 2030 is set to 40 percent below this emission level. Furthermore, because Iceland, Norway, and Switzerland have each committed through the Paris Agreement to an emissions reduction of at least 40 percent (https://www4.unfccc.int/sites/NDCStaging/Pages/All.aspx), we assume that these countries will reduce their GHG emissions by 40 percent by 2030.

Based on Höglund-Isaksson et al. (2010), who provide projections for non-CO_2 emissions for the ETS and non-ETS sectors, we find ETS and non-ETS CO_2 targets. Furthermore, we take into account that LIBEMOD cannot distinguish between manufacturing firms that belong to the ETS sector (large carbon-intensive units) and manufacturing firms not covered by the ETS sector. When setting the CO_2 target for LIBEMOD, we also take into consideration that in the transport sector there is likely to be considerable substitution to other fuels toward 2030. This is not captured by the LIBEMOD model: in the LIBEMOD transport sector, the CES demand structure allows little room for substitution because of the initial share of oil being close to 100 percent.

We believe that there are two main errors in transforming the GHG target to a CO_2 target. First, we have used the baseline scenario in Höglund-Isaksson et al. (2010), which is consistent with a low carbon price, as we find in our paper. With higher carbon prices, Höglund-Isaksson et al. (2010) predict larger reductions in non-CO_2 emissions, which would lower our estimate of the required emissions reduction for CO_2. Second, we have assumed a technology shift in the transport sector that will reduce emissions by 250 $MtCO_2$ by 2030. This estimate builds on the Sustainable Development Scenario in World Energy Outlook 2018 (IEA (2018), p. 550). Whereas PRIMES (2019) and Global EV Outlook (IEA, 2019) indicate that the assumed emissions reduction of 250 $MtCO_2$ by 2030 is a good estimate, recent developments in EV and ambitious targets for electrification of the car fleet in several European countries (see, e.g., Transport & Environment (2019)) suggest that there is a high probability that we have underestimated the emissions reduction. If so, this factor will also lower our estimate of the required emissions reduction for CO_2.