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Abstract

In June 2018, an agreement between 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 exceeds the EU climate target. Hence, carbon prices are redundant in reaching the EU climate goal. This policy, however, is not cost efficient.

JEL-Codes: Q280, Q410, Q480, Q540.

Keywords: climate policy, renewables, energy efficiency, nuclear phase out, energy modeling.

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1 Introduction

In June 2018, an agreement between 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 types of energy targets and how ambitious targets should be, the parties then agreed to reduce greenhouse gas (GHG) emissions by 40% (relative to 1990), to reach an EU-wide renewable share in final energy consumption of 32%, and also to improve the EU energy efficiency by 32.5% (relative to 2005). This paper offers a comprehensive assessment of the EU 2030 package. Also, we discuss the impact on the 2030 outcome if, hypothetically, alternative energy policy measures had been agreed upon.

The previous disagreements over policy goals reflect significant differences in the energy mix across countries, and thus infer conflicts of interest between EU member states. Further, countries might have put a different emphasis on the importance of the economic rationality of the policy package. Standard economic theory suggests that reductions in GHG emissions should be implemented by equalizing the marginal cost of emissions across all sources. Policy targets such as a renewable share in final energy consumption and improved energy efficiency are, however, harder to justify relative to economic theory. These targets might reflect commitment problems, for example, current governing bodies fear that future governing bodies will deviate from the current long-run emissions goal, or current governing bodies believe that actors are nonrational, for example, they may not take into account future benefits of present investment in improved energy efficiency (myopic behavior).

Economic theory provides clear advice on how climate and energy targets should be implemented and on the derived economic effects. GHG emissions targets should be implemented by imposing a uniform price on emissions from all sources. In the electricity sector, this will push up the cost of fossil fuel-based electricity, which will reduce the supply of electricity and increase the consumer price of electricity. Among end users, a price on GHG emissions will shift demand for fossil fuels inwards, thereby lowering fossil fuel consumption and the producer price of fossil fuels.

To implement a renewable share in final energy demand, a subsidy on renewable energy can be offered. This policy instrument will stimulate investment in and production of renewables, that is, supply of renewable energy shifts outwards. Hence, the price of energy will fall, and therefore supply of fossil fuel-based energy decreases, that is, GHG emissions are reduced. Improved energy efficiency, which within the EU system has been defined as a reduction in primary or final energy consumption, can be implemented by a tax on energy consumption. Such a measure will shift end-user demand for energy inwards, thereby pushing up the consumer price of energy and decreasing energy consumption. Hence, GHG emissions are reduced.

While the sign of these partial effects is clear, and all targets tend to contribute to lower GHG emissions, a numerical model is needed to identify their magnitudes. A numerical model captures both direct and indirect (i.e., derived) effects, thereby identifying the net equilibrium effects. In this study, we will use the numerical model LIBEMOD to find the equilibrium effects of the EU 2030 climate and energy package. LIBEMOD is a multigood, multiperiod model covering the entire energy industry in 30 European countries; EU-27 (Croatia was not an EU-member state in 2009, the base year of LIBEMOD) plus Iceland, Norway, and Switzerland – henceforth referred to as EU-30. In the model, eight energy goods – oil, natural gas, three types of coal, two types of bioenergy, and electricity – are extracted, produced, traded, and consumed for *each* of the 30 European countries. In each country, electricity can be produced by a number of technologies: nuclear, fuel based (using steam coal, lignite, oil, natural gas, or biomass as an input), fossil-fuel based CCS (using either steam coal or natural gas), hydro (reservoir hydro, run-of-river hydro, and pumped storage hydro), wind power, and solar. We make a distinction between plants with preexisting capacities and new plants; additional capacity is built if such investments are profitable.

All markets for energy goods are assumed to be competitive in 2030. While oil, steam coal, coking coal, LNG and biofuel are traded in global markets in LIBEMOD, natural gas, electricity, and biomass are traded in European markets, although there is import of these goods from non-European countries. For electricity and natural gas, trade takes place between pairs of countries, and such trade requires electricity transmission lines and gas pipelines. While these networks have preexisting capacities, they can be expanded through profitable investments.

LIBEMOD determines all prices and quantities in the European energy industry as well as prices and quantities of energy goods traded globally. In addition, the model determines CO_2 emissions by country and sectors (households; services and public sector; manufacturing; transport; and electricity generation).

In Section 2 we provide a description of LIBEMOD, focusing mainly on supply of electricity. This section builds on an earlier version of the model; see 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 (the services and public sector has 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). In particular, to the best of our knowledge, LIBEMOD is the first energy market model with truly endogenous investment in renewable electricity.

In Section 3, we present an overview of the costs of producing electricity by comparing the total cost of electricity, as well as different cost elements, between electricity technologies. These cost elements have consistent assumptions about the lifetime of a new plant, discount factor, operational hours throughout the year, and fossil fuel prices.

In Section 4, we use the numerical model LIBEMOD to quantify the effects of the 2030 EU climate and energy package. We also examine the robustness of the 2030 equilibrium under alternative cost and policy assumptions. Finally, Section 5 concludes.

We make two contributions to the literature. First, to the best of our knowledge, the present paper is the first study of the 2030 EU climate and energy policy package. We find that the targets for renewables and improved energy efficiency have been set so high that the implied GHG emissions reduction is 50%, which is higher than the agreed-upon 40% target. This result is in line with the announcement from the European Commission that the 2030 package will lower GHG emissions by 45%; see European Commission (2018).

The EU has separate 2030 emissions targets for the ETS and non-ETS sectors. Because achieving the renewable and energy-efficiency targets imply, according to our study, that both of the emissions targets are met, there is no need for a climate policy. Put differently: the climate targets are achieved without imposing any prices on GHG emissions. From an efficiency point of view, this is not attractive: an efficient emissions reduction of 50% would be characterized by equal marginal costs of emissions; this is in general not the case for the emissions reduction obtained by imposing the renewable and energy-efficiency targets.

Further, we examine the robustness of the 2030 equilibrium under alternative cost and policy assumptions. First, we explore the impact of alternative assumptions about: i) whether the renewable policy support is EU-wide (reference scenario) or partly domestic, ii) the cost and efficiency of solar power, and iii) the magnitude of nuclear capacities. The latter scenario reflects that some countries, such as Germany, will phase out nuclear power, whereas other countries are considering downscaling their nuclear capacity. For all three scenarios, we find that the impact on electricity supply, energy consumption, and aggregate welfare is moderate relative to the reference case, whereas welfare by groups may be much more affected. Second, we examine 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 undertake this robustness analysis because prior to adopting the 2030 climate and energy policy package, there were intense debates in the EU on whether an energy-efficiency target should be part of the package, and how ambitious the renewable policy should be.

We also contribute to the energy market modeling literature. Here, our main contribution is to offer a framework for endogenizing investment in intermittent power (wind and solar power). In general, we find the 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 both for wind and solar power, production sites differ with respect to generated energy (kWh) per unit installed capacity (kW). These differences reflect that wind speed, as well as solar radiation, vary across sites. Investment in intermittent power depends on costs and prices, but also on what share of land has been designated and regulated for the development of solar or wind power. For solar power, land availability is taken into account when specifying the constraints of the optimization problem, whereas for wind power, we develop a calibration procedure that handles land availability.

LIBEMOD provides a richer modeling of the energy markets than many other models. In contrast, there is a number of energy models covering different parts of Europe, and most of these are pure electricity models; see, for example, the ATLANTIS model (Gutschi *et al.*, 2009) and the LIMES model (Haller *et al.*, 2012). In contrast, LIBEMOD also covers primary energy goods: five types of fossil fuels and two types of bioenergy.

Typically, pure electricity models have exogenous demand for electricity and total costs are minimized, whereas LIBEMOD endogenizes consumption of energy. Some of the pure electricity models offer very detailed descriptions of the production of electricity as well as the electricity infrastructure (see, for example, ATLANTIS), but pay less attention to investment. In contrast, in LIBEMOD, all types of investments, including electricity production capacity and energy infrastructure, are endogenized.

2 LIBEMOD

In this section we describe the numerical multimarket, multigood equilibrium model LIBEMOD. This model 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. The model also determines all energy prices and quantities traded in world markets, as well as emissions of CO_2 by country and sector; see Figure 1.[2]

Figure 1 The LIBEMOD model

2.1 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. 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 by a number of technologies (see discussion below). Natural gas,

[2] The model is calibrated to 2009 data. Income elasticities are calibrated as the non-price changes in consumption relative to changes in GDP. The income elasticities are calibrated using information from the Current Policies Scenario of World Energy Outlook 2011 (IEA 2011) on projected annual GDP growth rates, projected annual growth rates in energy consumption (for each sector and energy type) and the price elasticities in the LIBEMOD model. Note that the Current Policies Scenario presupposes an annual global energy efficiency rate of 1.6%. For a detailed description of the calibration strategy, see Aune at al. (2008).

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. 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 (all transport demand in 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; this is a truly nonlinear function, making LIBEMOD a 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.

In each model country, there are domestic transport 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 transport 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 transport and distribution. Also, in each model country there is a national capacity market, and each national regulator buys maintained capacity (from nonintermittent technologies except nuclear power) according to a rule of thumb: at least 5% of total maintained capacity should always be available for additional production.

In LIBEMOD, there is a competitive equilibrium for each good. This is the case a) for all goods traded in a model country, b) for all energy goods traded in world markets (oil, steam coal, coking coal, and biofuel), and iii) for 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.

2.2 Supply of electricity

In LIBEMOD, supply of electricity is the most detailed model block. In each model country, there are 11 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 renewable (geothermal power, wave power, tide power). Moreover, there are five new fossil fuel-based technologies: new steam coal power, new steam coal power with CCS, new gas power, new gas power with CCS, and new oil power.[3] Further, 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 (in each model country) as if there were one single plant with decreasing efficiency; this implies increasing marginal costs. For each type of new fuel-based technology, we assume, however, that all plants have the same efficiency. Whereas for preexisting technologies the capacity is exogenous (in each model country), for new plants the capacity is determined by the model.[4]

There are six types of costs involved in electricity supplied from the combustion of fuels. First, there are nonfuel monetary costs directly related to production of electricity, formulated as a constant unit operating cost c^O. Let y_t^E (TWh) be the production of power in period *t*. Then the monetary cost in each period is $c^O y_t^E$, which must be summed over all periods to obtain the total annual operating costs. Second, there are fuel costs. Third, production of electricity requires that capacity is maintained: in addition to choosing an electricity output level, the producer is assumed to choose 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 same season, they will incur start-up or ramping-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 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 may partly be borne by the plant. The cost of grid connection, $c^{gc}(K^{inv})K^{inv}$, is assumed to be increasing and convex.

Each plant maximizes profits subject to a number of technology constraints; for example, 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. Although production of biomass requires land, we do not impose a land use restriction in LIBEMOD. The reason is that the

[3] In addition, "old" coal power and gas power plants can be retrofitted with CCS.
[4] For the preexisting electricity technologies, we use information from ENTSO-E (2011), scenario B, on capacities for 2020. Thus, capacities that are expected to come online by 2020 are included in our study (as preexisting technologies).

equilibrium quantities of biomass mainly consist of waste and by-products from agriculture and industry, that is, products do not require separate land to be manufactured.[5]

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 season *s* 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 season *s* plus the amount of water in the reservoir at the end of season *s* should not exceed the amount of water in the reservoir at the end of the previous season plus the seasonal inflow of water (expressed in energy units, TWh).

For the *run-of-river hydropower* technology, which is an extension of the LIBEMOD model presented in Aune *et al.* (2008), there is 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 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 in order to produce electricity in a different 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 the one for fossil fuel-based technologies, except that the pumped storage producer uses electricity (and not a fossil fuel) as an input.

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

2.2.1 New wind power

We assume that wind sites differ with respect to annual full wind hours and that the best site for wind power (in terms of annual wind hours) is developed for wind power production before the second-best site is developed, and so on. This is formalized by $f(K)$, which shows the average number of full wind hours per year (measured in kh) as a decreasing function of aggregate capacity of wind power plants. The function $f(K)$ reflects the capacity at sites that are developed for wind power production, and annual wind hours at each site.

By multiplying the average number of wind hours per year by how much wind power that can be produced each hour, K (GW), a measure of the annual production of wind power is obtained, $f(K)K$ (TWh).

[5] In LIBEMOD there are two types of bioenergy: biomass and biofuel. For biofuels, that is, energy carriers used in the transport sector, the alternative value of land may be substantial; see, for example, Searchinger *et al.* (2008). In 2012, 2% of the agricultural land was used for biofuel production in the EU. Because the growth in equilibrium consumption of biofuel is moderate in LIBEMOD, there is no need to introduce restrictions on land use for biofuel production.

However, because production of wind power depends on the amount of the capacity that is actually maintained, K^{PM}, annual production of wind power is $f(K^{PM})K^{PM}$.[6]

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

$$K^{PM} \leq K^{inv} \perp \lambda^{E} \geq 0 \tag{1}$$

where λ^{E} is the shadow price of installed power capacity.

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

$$y_t^E \leq \psi_t^W f(K^{PM})K^{PM} \perp \mu_t \geq 0 \tag{2}$$

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

Finally, also for wind power, there is the need for technical maintenance. Therefore, total annual production ($\sum_t y_t^E$) cannot exceed a share (ξ) of the maximum potential wind power production:

$$\sum_t y_t^E \leq \xi \sum_t \psi_t K^{PM} \perp \eta \geq 0 \tag{3}$$

where ψ_t is the number of hours in period *t* ($\sum_t \psi_t = 8.76\,\text{kh}$) and η is the shadow price of the annual electricity production capacity.

Similar to fuel-based technologies, wind power has a constant operating unit cost, c^O, as well as 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:

[6] Note that we have assumed that if the installed capacity of some new wind power plants is not maintained, then these plants are located at sites with the lowest number of annual wind hours. This assumption will be fulfilled if producers maximize profits, as we assume. In fact, with profit-maximizing wind power producers (and no uncertainty) the entire invested capacity will be maintained in the model.

$$\mathcal{L}^E = \sum_{t\in T} P_t^{YE} y_t^E - \sum_{t\in T} c^o y_t^E - c^M K^{PM} - c^{inv} K^{inv} - c^{gc}(K^{inv}) K^{inv}$$

$$-\lambda^E \left\{K^{PM} - K^{inv}\right\} - \sum_{t\in T} \mu_t \left\{y_t^E - \psi_t^W f(K^{PM}) K^{PM}\right\} - \eta \left\{\sum_{t\in T} y_t^E - \xi \sum_{t\in T} \psi_t K^{PM}\right\}. \quad (4)$$

The first-order condition for supply of electricity in each period (y_t^E) is:

$$P_t^{YE} - c^O \le \mu_t + \eta \perp y_t^E \ge 0. \quad (5)$$

This is a standard first-order condition, simply stating that an interior solution, that is, $y_t^E > 0$, requires that the difference between the price of electricity P_t^{YE} and the marginal operating cost of production c^O should be equal to the sum of two shadow prices. The first shadow price (μ_t) reflects the value of receiving one more unit of maintained capacity, K^{PM}. The second shadow price (η) shows the value of receiving one more unit of annual electricity production capacity. Because the maximum number of operating hours during the year $(\xi \sum_{t\in T} \psi_t)$ will, for reasonable values of ξ, always exceed the number of annual full wind hours at the best site (see Appendix A), we have $\eta = 0$.

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

$$(\sum_{t\in T} \mu_t \psi_t^W)(f(K^{PM}) + f'(K^{PM}) K^{PM}) + \eta\, \xi \sum_{t\in T} \psi_t \le c^M + \lambda^E \perp K^{PM} \ge 0. \quad (6)$$

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^E) – 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: i) 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 due to increased maintained capacity $(f(K^{PM}) + f'(K^{PM}) K^{PM})$ is taken into account, plus ii) the value of increased potential annual electricity production, which is the shadow price of the annual electricity production capacity (η) times the maximum number of operating hours during the year $(\xi \sum_{t\in T} \psi_t)$.

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

$$\lambda^E \le c^{inv} + c^{gc}(K^{inv}) + \frac{dc^{gc}(K^{inv})}{dK^{inv}} K^{inv} \perp K^{inv} \ge 0. \tag{7}$$

This condition implies that if investment is positive, then the total annualized investment cost, which is cost of investment (c^{inv}) plus the total marginal cost of connecting to the grid ($c^{gc}(K^{inv}) + \frac{dc^{gc}(K^{inv})}{dK^{inv}} K^{inv}$), must equal the shadow price of installed capacity (λ^E), i.e., the increase in operating surplus resulting from one extra unit of capacity. As always, in addition to the FOCs with respect to the decision variables, the FOCs with respect to the multipliers recover the original optimization restrictions. For calibration of (onshore) wind power parameters, see Appendix A, Part I.

2.2.2 New solar power

The main solar power technologies are centralized solar power (CSP) and photovoltaics (PV). The latter is a method of generating electrical power by converting solar radiation into direct current electricity by using solar panels containing photovoltaic material. We have chosen to model PV, which, based on available cost estimates, seems to be the most promising technology.

The PV technology requires land to produce electricity. Under ideal conditions, the PV technology requires $1/\chi$ m^2 to produce 1 kW momentarily, and therefore χ is the momentary production of electricity (kW) for each m^2 covered with solar panels. Let Ω be the *actual* use of land (measured in Mm^2) to produce solar power. Thus, under ideal conditions, the momentary production capacity of solar energy (measured in GW) is

$$K = \chi\Omega. \tag{8}$$

Further, let $\hat{\Omega}$ be the maximum amount of land available to solar power where $\Omega \le \hat{\Omega}$. Obviously, we must have $K \le \hat{K} = \chi\hat{\Omega}$.

We now derive measures for the annual electricity production capacity of solar power. First, let $\bar{\Omega}$ be annual solar irradiance (kWh per m^2) in a country. Then $\bar{\Omega}\Omega$ measures received energy by the solar panels throughout a year. Second, let $\bar{\theta}$ be the share of energy received by solar panels that is transformed to solar power. The annual electricity production capacity of solar power (TWh) is then $\bar{\theta}\bar{\Omega}\Omega$.. Alternatively, the annual electricity production capacity can be expressed by zK where z measures annual solar hours (measured in kh), defined from the identity $zK \equiv \bar{\theta}\bar{\Omega}\Omega$. Using (8), this identity can be rewritten as

$$z\chi \equiv \bar{\theta}\bar{\Omega}. \tag{9}$$

So far, we have implicitly assumed that each solar panel receives the same amount of energy. However, sites differ with respect to solar irradiance. We now assume that there is a continuum of sites and these can be ranked according to their solar irradiance. Further, we assume that the best solar site is developed before the second-best site, etc. Hence, the more solar power that is developed, the lower is the average amount of energy received by the solar panels. This mechanism is captured by letting the measure of solar irradiance, $\bar{\Omega}$, be a downward-sloping function of capacity utilization: $\bar{\Omega} = \bar{\Omega}(\frac{K}{\hat{K}})$. Note that $\bar{\Omega}(\frac{K}{\hat{K}})$ should be interpreted as the average solar irradiance.

Using the identity (9), we now define our measure of annual solar hours:

$$z(\frac{K}{\hat{K}}) \equiv \frac{\bar{\theta}\bar{\Omega}(\frac{K}{\hat{K}})}{\chi}. \tag{10}$$

By letting ψ_t^S be the share of annual solar hours in period *t*, we have a measure of the electricity production capacity of solar power in this time period: $\psi_t^S z(\frac{K^{PM}}{\hat{K}})K^{PM}$. Here we have substituted actual production capacity (K) by maintained production capacity (K^{PM}) because production requires that panels are maintained and we assume that producers always maintain the panels at the best sites (a profit-maximizing actor investing in solar power will in fact maintain the entire installed new capacity).

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, $K^{PM} \leq K^{inv} \perp \lambda^E \geq 0$. Second, there is a restriction in the periodic production of electricity: $y_t^E \leq \psi_t^S z(\frac{K^{PM}}{\hat{K}})K^{PM} \perp \mu_t \geq 0$. Finally, because of technical maintenance issues, there is a restriction on the total annual production of electricity: $\sum_t y_t^E \leq \xi \sum_t \psi_t K^{PM} \perp \eta \geq 0$. In addition, because of limited availability of land for solar power, there is also a restriction on investment:

$$K^{inv} \leq \hat{K} \perp \bar{\lambda}^E \geq 0 \tag{11}$$

where $\bar{\lambda}^E$ is the shadow price of land. Thus for solar power, which has the same type of costs as wind power, the Lagrangian of the optimization problem is:

$$\mathcal{L}^E = \sum_{t\in T} P_t^{YE} y_t^E - \sum_{t\in T} c^O y_t^E - c^M K^{PM} - c^{inv} K^{inv} - c^{gc}(K^{inv}) K^{inv} -$$

$$\bar{\lambda}^E (K^{inv} - \hat{K}) - \lambda^E (K^{PM} - K^{inv}) - \sum_{t\in T} \mu_t^M \{y_t^E - \psi_t^S z\,(\frac{K^{PM}}{\hat{K}}) K^{PM}\} - \tag{12}$$

$$\eta\left\{\sum_{t\in T} y_t^E - \xi \sum_{t\in T} \psi_t K^{PM}\right\}.$$

The first-order condition with respect to electricity produced in each period is the same as the one for wind power, see (5). The first-order condition for maintained capacity is

$$\sum_{t\in T} \mu_t^M \psi_t^S (z(\frac{K^{PM}}{\hat{K}}) + z'(\frac{K^{PM}}{\hat{K}})\frac{K^{PM}}{\hat{K}}) + \eta\xi \sum_{t\in T} \psi_t \le c^M + \lambda^E \perp K^{PM} \ge 0. \tag{13}$$

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

$$\lambda^E - \bar{\lambda}^E \le c^{inv} + c^{gc}(K^{inv}) + \frac{dc^{gc}(K^{inv})}{dK^{inv}} K^{inv} \perp K^{inv} \ge 0. \tag{14}$$

These conditions have similar interpretations as those for wind power. For calibration of solar power parameters, see Appendix A, Part II.

3 Costs of electricity

In this section we present a selection of LIBEMOD parameter values, focusing on the cost of electricity. For full documentation of LIBEMOD data and parameter values, consult LIBEMOD (2015).

Figure 2 shows the cost of new electricity in 2030 – measured in 2009 € per MWh (the data year of the LIBEMOD model) – by technology: new gas power, new coal power, new biopower, new wind power, new solar power, new gas power with CCS (termed gas CCS greenfield), and new coal power with CCS (termed coal CCS greenfield). In the figure, costs have been split into three factors: costs of investment, costs of operation and maintenance (O&M), and fuel costs.

Figure 2 Costs of new electricity in 2030 (€2009/MWh)

The cost of investment shown in Figure 2 builds on Table 1, which provides information on the cost of investment for new power plants in the LIBEMOD model as well as in other studies. The LIBEMOD cost assumptions in Table 1 are for 2009, measured in €/kW. These have been transformed to the numbers in Figure 2 (€/MWh) by: i) applying standard assumptions about load factors, number of years in operation and the rate of interest, and ii) cost reduction between 2009 and 2030 due to learning.[7] For wind power and solar power, Figure 2 shows the cost of electricity for very good locations in Europe (3500 full wind hours and 2500 full sun hours annually).

The operation and maintenance (O&M) costs are based on the information in Table 2. The last category in Figure 2, fuel costs, consists of two elements: plant efficiency (see Table 2) and fuel prices. In Figure 2, we have used observed fuel prices in 2009 (including taxes) for electricity producers, averaged over EU-30. Note that in the *model runs* in Sections 4 and 5, we find *equilibrium* fuel prices and load factors/wind hours/sun hours in *equilibrium* (for the marginal units); these are used to describe scenario outcomes.

Table 1 Investment costs for power plants

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

As seen from Figure 2, average cost per MWh varies from €40.8 (wind power) to €79.4 (gas CCS greenfield). This clearly suggests that there will be investment in wind power. However, as more wind power is developed, the cost of wind power (€/MWh) will increase as it is assumed that the best sites are developed first. Whereas conventional coal power is the second-cheapest technology, its position may be very different in the 2030 scenarios where the emissions requirement of the ETS sector is taken into account; 43% emissions reduction relative to 2005. This will push up the price of coal, thereby weakening the competitive position of coal power, and thus open up for other technologies. Therefore, there may be investment in solar power as well as in conventional gas power; the latter has a lower emission coefficient than coal power (CO_2/toe), and will thus suffer less than coal power when climate taxes are imposed.

Figure 2 also shows that the potential for investment in new CCS plants is minor. An alternative option is to retrofit existing fossil fuel plants with CCS, as shown in Figure 3, which gives the costs of electricity from CCS plants. For a CCS retrofit, the cost of investment is solely the CCS investment cost. For all CCS technologies, we have used average EU-30 fuel prices for electricity generation in 2009 (as in Figure 2). As seen from Figure 3, coal power CCS is cheaper than gas power CCS. Moreover, for both coal CCS and gas CCS, retrofitting the most efficient plants is cheaper than building new CCS stations. Note that in the *model runs* in Section 4, we use *equilibrium* fuel prices, *not* the observed fuel prices in 2009. Hence, the ranking in Figure 3 may change.

Figure 3 Costs of CCS electricity in 2030 (€2009/MWh)

[7] It is assumed that for some technologies, the annual cost of investment will fall over time: by 3% for solar, 1% for wind power, and 0.5% for all CCS technologies.

4 Results

4.1 2030 scenarios

In 2014, the EU decided that GHG emissions should be reduced by 40% by 2030 relative to 1990. This policy distinguishes between the ETS sectors (electricity generation, carbon-intensive manufacturing firms, petroleum extraction) and the remaining sectors (non-ETS). Whereas the ETS sectors have to reduce their GHG emissions by at least 43% relative to 2005, the corresponding number for the non-ETS sectors is 30%. 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 tax), see Table 3.[8] Because LIBEMOD covers CO_2 only (the most important GHG gas), we transform the GHG emissions targets to CO_2 targets.[9]

In the reference scenario, we also impose the newly agreed upon target of an EU-wide renewable share in final energy consumption of 32% (see Section 1).[10] This policy goal is assumed to have been reached through an EU-wide renewable subsidy offered to all producers of renewable electricity and bioenergy. Finally, we impose the newly agreed upon target that the EU energy efficiency should be 32.5% above the business-as-usual level in 2005.[11] The energy efficiency target is reached through imposing an EU-wide tax on all types of energy (fuels and electricity) consumed by end users.

We now turn to alternative scenarios to the reference scenario. In all these scenarios, emissions in the ETS and non-ETS sectors, the renewable share in final energy consumption, and the energy efficiency are identical to those in the reference equilibrium.

Currently, most European countries have domestic instruments to spur renewable electricity production; see CEER (2015) and CEER (2017). However, the era of national tailor-made subsidies to new renewable generators may have come to an end: in some European countries with significant solar and wind capacity, government support to spur investment in renewables has been lowered or even phased out. This is partly because the competitive position of solar power and wind power has improved radically over the last 10 years, and partly because large transfers generate financial problems.

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[8] In 2017, the EU decided on national non-ETS emissions targets. Our assumption of examining the non-ETS sectors as if there was an EU-wide emissions target can partly by rationalized by the fact that the EU has opened up for substantial trade in non-ETS allowances between member states. However, the assumption of one emissions target is primarily a simplification, which we believe has no major impact on the main results; domestic targets lead to a higher (average) marginal cost of cutting non-ETS emissions.

[9] A detailed description of the calculations of the LIBEMOD climate targets is available from the authors upon request.

[10] 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 kWh) 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 kWh).

[11] We use European Commission (2016) to quantify the energy efficiency target. Here, an improvement in energy efficiency of 30% by 2030 relative to 2005 is estimated to imply “a drop in final energy consumption of 17% 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%.

In the reference scenario, all domestic subsidies are phased out by 2020. In contrast, in the scenario *Domestic Subsidies,* we assume that all countries providing support to a renewable technology in 2014 (CEER (2017)) will also continue do so in 2030. However, if the subsidy exceeds 20 €/MWh, the subsidy in the scenario Domestic Subsidies is set equal to 20 €/MWh. We find that with this cut-off rule, most subsidies are either 0 or 20 €/MWh; see Table 4. Because these subsidies may be too low to reach the renewable target of 32%, we impose (if necessary) one common EU-wide subsidy to: i) all producers of renewable electricity and to ii) all end users of bioenergy (as in the reference scenario).

Over the last decades, there have been radical improvements in PV technology; cost of investment has been reduced at a high rate and also the efficiency of PV has been improved. Needless to say, it is uncertain how these parameters will develop up to 2030. To explore the importance of technology development in solar power, in the scenario *Solar* we assume more optimistic assumptions than in the reference scenario; annual cost of investment is assumed to decrease by 5% (versus 3% in the reference scenario), whereas the efficiency of PV is set to 21% (versus 18% in the reference scenario). Because more favorable technology assumptions will make solar power more profitable, we assume that in each country, more land will be available for solar power generation.

In our reference scenario, nuclear capacities in 2030 reflect predetermined decisions on the country level with respect to whether nuclear plants will be phased out or new nuclear capacity will come online before 2030; see Table 5. Based on information from The World Nuclear Association, IEA (2013), and Eurelectric (2011), there may be a net decrease in nuclear capacity in EU-30 between 2009 and 2030 of about 23.2 GW (see Table 5), which amounts to roughly 20% of the 2009 nuclear capacity in EU-30. Hence, in the reference scenario, total nuclear capacity in EU-30 is 23.2 GW lower than in the data year 2009.

Until the Fukushima accident in Japan in February 2011, nuclear power was seen by many as an important part of a low-carbon future. The accident sparked security concerns and antinuclear sentiments in many European countries, causing a few EU member states to announce a phase-out of nuclear power. In particular, Germany has decided to phase out nuclear by 2022. It is uncertain whether other countries will stick to their original plans for nuclear capacity, or follow in the footsteps of Germany. To explore the importance of nuclear capacity, we have designed a scenario – *Nuclear* – where the 2030 capacities of nuclear power in model countries that did not phase out nuclear power in the reference scenario, are reduced by 50% relative to 2009.

For each of the four scenarios, the LIBEMOD model determines all policy instruments, all energy prices, and all energy quantities (investment, extraction, production, trade, and consumption) in 2030.

Table 3 Scenarios for 2030

Table 4 Domestic renewable subsidies in the scenario Domestic Subsidies (€2009/MWh)

Table 5 Nuclear policies in EU-30

4.2 Reference scenario

In the reference scenario, there are four policy goals: emissions in the ETS sectors in 2030 should be reduced by at least 43% relative to 2005, emissions in the non-ETS sectors in 2030 should be reduced by at least 30%, the renewable share in final energy consumption should be 32% in 2030, and finally the energy efficiency should be improved by 32.5% relative to business-as-usual in 2005. These EU-wide goals are accomplished through four EU-wide instruments: a price of emissions in the ETS sectors, a price of emissions in the non-ETS sectors, a renewable subsidy, and a uniform tax on end-user consumption of energy.

In equilibrium, the combination of a renewable share in final energy consumption of 32% and an improvement in energy efficiency of 32.5%, lowers emissions by more than 43% in the ETS sectors and by more than 30% in the non-ETS sectors. Therefore, the equilibrium emissions prices in the reference scenario are *zero* in both the ETS and the non-ETS sectors; see Figure 4. In fact, we find that GHG emissions are 50% lower than in 1990, that is, the emissions reduction is 10 percentage points higher than the 40% target.

Figure 4 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 subsidy triggers more supply of renewable electricity and bioenergy. This tends to drive down the prices of electricity and energy, thereby replacing fossil fuel electricity and fossil fuel energy with renewable electricity and renewable energy. A tax on energy consumption shifts demand for energy inwards, thereby reducing demand for fossil fuel energy (and also demand for nonfossil fuel energy). Hence, CO_2 emissions are reduced. While these are theory-based arguments, a numerical model is required to quantify the effects. With other values of the renewable share in final energy consumption and the improvement in energy efficiency, the corresponding emissions reductions would be different; see discussion below.

Whereas the emissions prices are identical (zero) in the ETS and the non-ETS sectors, this does not imply that the emissions reduction is cost efficient. If we impose one policy goal only, namely that *total* emissions should be equal to the one obtained in the reference scenario, the resulting distribution of emissions between the ETS and the non-ETS sectors would differ from that in the reference outcome.

Figure 5 shows the renewable subsidy offered to reach the renewable target – 59 €/MWh in the reference scenario, whereas Figure 6 shows the end-user energy tax imposed to reach the energy efficiency target – 1204 €/toe (104 €/MWh) in the reference scenario.

Figure 5 Common renewable subsidy in EU-30 in 2030 (€2009/MWh)

Figure 6 Tax on end-user consumption in EU-30 in 2030 (€2009/MWh)

There is an increase in total production of electricity from 2009 to the equilibrium in the 2030 reference scenario of around 10%; see Figure 7. 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 38% above the 2009 level. The increase in electricity production in the reference scenario of 10% (relative to 2009) reflects the end-user tax on energy consumption, which pushes down demand for electricity.

Figure 7 Electricity production in EU-30 in 2009 and 2030 (TWh)

Increased demand for electricity also impacts the composition of electricity technologies because the change in marginal cost of production varies between technologies. Compared with 2009, the market share has increased by 32 percentage points for wind power, by 9 percentage points for biopower, and by 7 percentage point for solar,[12] whereas it has declined by 22 percentage points for both coal and gas power. These large changes reflect, of course, the renewable subsidy offered to reach a renewable share in final energy consumption of 32%.

The significant changes in the market shares of electricity technologies reflect that, in LIBEMOD, there is much more flexibility in the power sector than among the end users. In the electricity generation sector, LIBEMOD specifies a number of alternative technologies. The composition of these may change radically if prices are altered: for one equilibrium price vector, a technology may become profitable and is thus phased in, whereas for another equilibrium 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 changes in end-user consumption share by energy carrier are more modest than the changes in market share by electricity technology; see Figures 7 and 8.

Figure 8 Energy consumption in EU-30 in 2009 and 2030 (Mtoe)

[12] Note that the capacity shares of wind power and solar power (in the reference scenario) are greater than their market shares; for solar, the difference is as much as 7 percentage points. This observation reflects the low rate of capacity utilization of intermittent power, in particular, for solar power, which typically has an annual rate varying between 10% and 20%, depending on the location of the site.

4.3 Robustness I – policy targets

Above, we examined the effects of a GHG emissions reduction of at least 40%, combined with a renewable share in final energy consumption of 32%, and an improvement in energy efficiency of 32.5%. In this section, we study the importance of the different policy targets.

Table 6 shows a decomposition of the policy goals in the reference scenario. Without any policy targets, GHG emissions would 2% higher in 2030 relative to 1990, whereas the renewable share in final energy consumption would be 11%. If, alternatively, only the ETS and non-ETS emissions goals are imposed, then by construction, GHG emissions in 2030 are 40% lower than in 1990. The necessary CO_2 prices needed to achieve the emissions goals would be 50 € per tCO_2 in the ETS sectors and 236 € per tCO_2 in the non-ETS sectors; see Table 6. These emissions prices would lead to a renewable share of 22%, whereas the improvement in energy efficiency would be 18%.

If, in addition to the two GHG emissions targets a renewable share of 32% is imposed, then the emissions prices in the ETS and non-ETS sectors would be 7 and 239 € per tCO_2, respectively, in order to reach a 40% GHG emissions reduction. The implied improvement in energy efficiency would be 12%. Finally, with all four targets imposed (the reference scenario), the emissions reduction would be greater than the minimum requirements, and thus the prices of CO_2 emissions are zero; see the discussion above. In fact, the total reduction in GHG emissions would be 50%.

As discussed above, the emissions reduction in the reference scenario is not cost efficient. Therefore, we have examined a scenario where GHG emissions are reduced by 50% (as in the reference equilibrium), but without imposing any other targets, that is, there are no ETS and no non-ETS emissions requirements and no restrictions on renewables and improvement in energy efficiency. We find that the common CO_2 price has to be as high as 316 €/tCO_2; see the last column in Table 6. Because there is no tax on end-user consumption of energy, demand for electricity increases (relative to the reference scenario). In fact, consumption of electricity increases by around 20%. Because of the high price of CO_2 emissions, there is massive investment in CCS; this technology obtains a market share of around 25%.

Table 6 Policy target sensitivity

Prior to adopting the 2030 climate and energy policy package, there were 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% targets on GHG emissions, renewables, and energy efficiency; see Skjærseth *et al.* (2016).

Poland was not pleased with the 2020 package, which did not fit well with the Polish energy situation and its climate policy. In particular, a more ambitious renewable policy had hardly reduced Poland's energy imports. Therefore, Poland opposed new GHG targets and also policies directed at renewable energy and energy efficiency. This position was shared by several countries in Eastern and Central Europe.

Norway (a member of the European Economic Area), which had a more mixed experience with the 2020 package, supported a more ambitious GHG target but did not want renewable and energy efficiency targets; energy-imports dependency is of course not a concern for an energy exporter such as Norway. The Norwegian position was shared by the Netherlands and the UK.

Germany had mainly a positive experience with the 2020 package, including achieving diffusion in green technologies and growth in green employment. Therefore, Germany wanted more of the 2020 policy, that is, more ambitious targets for renewable energy and improved energy efficiency. This position was shared by seven EU member states, including France and Italy.

Whereas the European Parliament supported three binding targets – a 40% GHG emissions reduction, a 30% renewable share, and a 40% higher energy efficiency – the Commission was split; see Skjærseth *et al.* (2016). The climate commissioner wanted all three targets, as opposed to the energy commissioner and the industry commissioner. They were negative to a higher renewable energy target, fearing that a new energy-renewable 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% GHG emissions reduction and an EU-wide renewable target of 27%. No new target for energy efficiency was proposed, but the Commission stated that 25% energy savings would be required in order to reach the GHG target.

The response to the proposal of the Commission was split. The "Green Growth Group", consisting of 13 EU member states, plus Norway, 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 protection of coal, more EU subsidies to modernize the energy system, and a heavier burden on rich EU countries that were pushing for greater emissions reductions.

The negotiations over the 2030 climate and energy policies culminated temporarily in the fall of 2014 with the European Council's adoption of targets and policies: a 40% GHG emissions reduction, a renewable share of 27%, and an indicative target of a 27% increase in energy efficiency.

The 2030 package adopted in the fall of 2014 represented a compromise to satisfy the main veto players. As part of the deal, and as a concession to Poland and other 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. After a rematch, an agreement was reached in the summer of 2018 between the Commission, the European Parliament, and the European Council to increase the EU-wide renewable share to 32%, and also to introduce a binding EU-wide improvement in energy efficiency of 32.5%. The fact that these two targets are EU-wide, not national targets, may have made it easier for the parties to reach agreement. The basic idea of the EU is 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, we now discuss the impact of these two targets on the 2030 equilibrium.

First, we explore effects of an alternative renewable share in final energy consumption. We impose that energy efficiency should be improved by 32.5% (as in the reference scenario), and further that emissions in the ETS (non-ETS) sectors are at least 43% (30%) lower than in 2005 (as in the reference scenario). Under these assumptions, we study how emissions change as the renewable share is altered.

The results are shown in Figure 9. Here, *equilibrium emissions* in the ETS and non-ETS sectors in the reference scenario are both set to 1. As the renewable share is increased from 32%, there is a modest drop in ETS emissions, whereas there is a negligible drop in non-ETS emissions.

If the renewable share is decreased from 32%, there is a negligible increase in non-ETS emissions. Also, ETS emissions increase if the renewable share is decreased from 32%, and this effect is much stronger than that for non-ETS emissions. Note that if the renewable share is 24% or lower, ETS emissions are exactly 43% below their 2005 value. Hence, for renewable shares below 24%, it is necessary to have a positive price on CO_2 emissions in the ETS sector in order to meet the requirement that ETS emissions should be at least 43% lower than in 2005.

Figure 10 shows the energy tax and the renewable subsidy that are required to meet the emissions and energy efficiency targets in the reference scenario under alternative renewable targets. In the figure, the equilibrium values of the instruments in the reference scenario have been normalized to one. As we see from Figure 10, the magnitude of both policy instruments is lower for a lower renewable target. In particular, it is not necessary to offer a renewable subsidy if the targeted renewable share is 20% (or lower).[13]

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%, whereas emissions in the ETS (non-ETS) sectors are at least 43% (30%) lower than in 2005. As in the previous case, the values of all targets and instruments in the reference scenario are set equal to one.

Figure 11 shows that a higher energy efficiency improvement than 32.5% will lower emissions in both the ETS and non-ETS sectors slightly relative to the outcome in the reference scenario. Alternatively, a lower imposed improvement in energy efficiency than 32.5% will typically increase both types of emissions. Note, however, that if the improvement in energy efficiency is 25% or lower, the non-ETS emissions restriction bites, that is, emissions are 30% lower than in 2005. This is accomplished through a CO_2 price on non-ETS emissions. Similarly, if the improvement in energy efficiency is 14% or lower, the ETS emissions restriction becomes binding, that is, ETS emissions are 43% lower than in 2005. This is accomplished through a CO_2 price on ETS emissions.

[13] When the renewable share is 20% (and the improvement in energy efficiency is 32.5%), ETS emissions are 43% lower than in 2005, whereas non-ETS emissions are more than 30% lower than in 2005 (but non-ETS emissions are higher than in the reference equilibrium); see discussion above.

Figure 12 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 of course accomplished through a higher tax on energy consumption. As seen from Figure 12, the energy tax is zero if the imposed improvement is 12%. This result reflects that if emissions reductions meet the EU 2030 targets and the renewable share is 32%, then the equilibrium improvement in energy efficiency is 12% (when there is no energy tax). Finally, as seen from Figure 12, a higher imposed improvement in energy efficiency requires a lower renewable subsidy; with improved energy efficiency, emissions, and thus consumption of carbon, are reduced and hence it is easier to reach the renewable target.

Figure 9 Sensitivity of renewable share in final energy consumption – emissions

Figure 10 Sensitivity of renewable share in final energy consumption – policy instruments

Figure 11 Sensitivity of energy-efficiency target – emissions

Figure 12 Sensitivity of energy-efficiency target – policy instruments

4.4 Robustness II – Alternative scenarios

We now examine alternative scenarios to the reference scenario. Here, emissions in the ETS and non-ETS sectors, the renewable share in final energy consumption, and the energy efficiency are identical to those in the reference equilibrium.

Domestic renewable subsidies

When there are domestic subsidies for renewable electricity production, supplemented by an EU-wide renewable subsidy to ensure 32% renewables in final energy consumption, the equilibrium is in general rather similar to the reference outcome. Needless to say, with domestic renewable subsidies, the EU-wide subsidy is of course lower than in the reference scenario (40 versus 59 €/MWh). However, because the domestic subsidies are between 0 and 20 €/MWh, the real difference from the reference scenario is small; the average renewable subsidy is only somewhat lower than in the reference case. Therefore, renewable production is stimulated less than in the reference case, and in order to reach the same emissions reductions as in the reference scenario, (low) prices on CO_2 emissions have to be imposed (3–4 €/tCO_2).

Solar power

With more favorable characteristics for solar power – lower cost, higher efficiency, and more land available – solar energy production almost doubles. There is, however, a strong crowding-out effect among renewable technologies, as total renewable electricity production is almost unchanged (relative to the reference scenario); the drop for biopower and wind power is around 12%. With lower cost and higher efficiency of solar power, the renewable subsidy is lower than in the reference case (50 versus 59 €/MWh), and it is necessary with positive CO_2 prices (around 12 €/tCO_2) in order to obtain the same emission levels as in the reference scenario.

Nuclear power

With a partial phase-out of nuclear capacity (50% in countries with a positive nuclear capacity in the reference scenario), total electricity production decreases slightly (by 4%) relative to the equilibrium in the reference scenario. There are, however, significant changes in the composition of fossil fuel technologies. Conventional coal power is almost completely phased out, whereas production from conventional gas power is increased by a factor of seven. Further, there is now investment in CCS electricity; its market share is 5%. The radical changes in electricity supply are mirrored by the prices of CO_2, which are much higher than in the other scenarios: 51 €/tCO_2 in the ETS sectors and 103 €/tCO_2 in the non-ETS sectors. Because a higher CO_2 price tends to increase the renewable share in final energy consumption, the renewable subsidy is lower than in the reference scenario (28 versus 59 €/MWh).

Welfare effects

By construction, CO_2 emissions in the ETS and the non-ETS sectors, the renewable share in final energy consumption, and energy efficiency are identical across all four scenarios (reference, domestic subsidies, solar, nuclear). Therefore, it is meaningful to compare welfare across scenarios. Below, we compare welfare in a scenario relative to welfare in the reference scenario. These comparisons should be interpreted as follows:

- The domestic subsidy scenario. This scenario shows the cost of using a combination of a domestic and an EU-wide renewable subsidy instead of offering an EU-wide subsidy only. In the latter case, development of renewables will be cost efficient at the EU level.
- The solar scenario. This scenario shows the economic gain if the solar technology has a lower cost of investment and a higher efficiency than in the reference scenario. In principle, this gain should be compared to total (R&D) cost of achieving these improvements in the solar technology, as well as the cost of using more land for solar power. None of these costs are included in the present study.
- The nuclear scenario. This scenario shows the cost of restricting the production possibility set by removing half of the nuclear capacity in the reference scenario. Note that there might be benefits related to this policy, for example, relaxed security concerns and improved social cohesion, and also costs, for example, cost of decommissioning; none of these are included in the present study.

Figure 13 shows *annual* change in economic welfare in EU-30 relative to the reference scenario. For each scenario, the bar to the left shows change in welfare (relative to the reference scenario) by groups, whereas the bar to the right shows net welfare gain (relative to the reference scenario). We distinguish between five groups: i) electricity producers, ii) other producers (those who extract fossil fuels or produce bioenergy), iii) end users (households, services, manufacturing, transport), iv) traders (actors building international pipelines/electricity lines and who use these to trade in energy across countries), and v) the government (the aggregate of all governments in EU-30 plus an EU agency that receives revenues from EU-wide taxes and pays the EU-wide renewable subsidy). Groups placed above the horizontal zero line in Figure 13 gain relative to the reference scenario, whereas groups placed below the horizontal zero line lose relative to the reference scenario.

Figure 13 Change in welfare components relative to reference scenario. EU-30 in 2030 (1000 million €2009)

Annual economic welfare in the *domestic subsidy scenario* is 1 thousand million euros, that is, 1 billion euros, lower than in the reference scenario. The net loss can be decomposed as follows:

- Electricity producers lose around € 17 billion, which corresponds to 0.1% of GDP in EU-30 in 2009.
- Other producers gain around € 1 billion.
- End users lose around € 1 billion.
- The impact on traders' profit is tiny.
- The government gains around € 17 billion, mainly because of income from CO_2 taxes and lower amounts of renewable subsidies being paid to electricity producers.

As seen from Figure 14, most technologies lose relative to the reference scenario, in particular, hydro and wind power. For renewable electricity (bio, hydro, solar, wind), old plants lose simply because by construction these do not obtain any domestic renewable support. The effect on new renewable electricity is in general ambiguous, depending on the impact on the producer price of electricity (which increases slightly), supply of electricity (which increases for biopower and solar power, but decreases for hydro and wind power), and amount of received renewable support. A change in renewable support has a much stronger effect on old plants, which have low, or even no, costs, than on new plants, which adjust both costs and revenue as a response to a shift in renewable support. We find that this factor dominates, that is, each renewable technology loses relative to the reference case. Note that nuclear gains slightly due to a somewhat higher producer price of electricity.

Figure 14 Change in electricity producer surplus by technology relative to reference scenario. EU-30 in 2030 (millions €2009)

With more competitive *solar power*, supply of solar increases. Thus, the producer surplus of solar power is of course higher than in the reference scenario; see Figure 10. With increased solar production, the EU-wide renewable subsidy can be lowered, and thus other renewable electricity technologies lose relative to the reference scenario. In total, electricity producer surplus decreases by € 5 billion, whereas consumer surplus decreases by € 3 billion due to higher energy prices. The government gains € 18 billion, reflecting a lower renewable subsidy (than in the reference scenario) as well as positive CO_2 prices; see Figure 4. In total, annual economic welfare increases by € 7 billion relative to the reference outcome. As noted above, this should be contrasted to costs of achieving the more efficient solar technology.

When half of the *nuclear capacity* in the reference scenario is removed, supply of electricity shifts to the left, which pushes up the price of electricity. With a higher electricity price, there will be more production from fossil-fuel-based electricity, which increases CO_2 emissions. To meet the ETS emissions restriction, it is necessary to impose a price on CO_2 emissions in the ETS sector, which shifts the fossil-fuel-based supply of electricity upwards, thereby pushing up the price of electricity even further. With a higher price of electricity, supply of renewable electricity has increased and therefore the renewable subsidy can be reduced in order to reach the renewable target. A higher price of electricity also decreases the consumption of electricity, which lowers the end use of energy. Thus, the end-user tax on energy, which is imposed to reach the energy-efficiency target, can be lowered, and therefore demand for energy shifts outwards.

To sum up, both supply of electricity and demand for electricity shift upwards. Whereas the change in quantity is only 3%, the producer price of electricity is more than doubled. Therefore, producer surplus of nuclear power actually increases, reflecting that the increase in the producer price of electricity dominates the decrease in quantity.

Whereas producer surplus of nuclear power increases by € 9 billion, the effects on the other electricity technologies are moderate; fossil-fuel-based electricity gains because of a higher price of electricity, but renewable electricity loses due to lower support to renewables. In total, electricity producers lose € 9 billion. Because of higher energy prices, other producers gain (€ 6 billion), whereas consumers lose (€ 15 billion). The government sector loses € 18 billion because of lower income from the end-user tax; this dominates the effects of a carbon tax income and a lower rate for renewable support. Relative to the reference scenario, annual economic welfare decreases by € 17 billion.

6 Concluding remarks

This paper has examined the impact of the EU climate and energy policy package: (i) GHG emissions should be 40% lower in 2030 than in 1990, where ETS (non-ETS) emissions should be 43 (30)% lower than in 2005, (ii) the renewable share in final energy demand should be 32%, and (iii) the improvement in energy efficiency should be 32.5% (relative to business-as-usual in 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, and biomass) along with modeling of the global markets for coal, oil, and biofuels. This model determines investment, extraction, production, trade, and consumption of a number of energy goods in each of 30 European countries, along with consistent equilibrium prices that clear all markets, including tariffs, for the international transport of natural gas and electricity.

In the electricity block of the model, producers determine whether to set up a new plant and how much of the production capacity should be used for electricity production in each time period – the remaining capacity can be sold to a system operator as reserve power capacity. An electricity producer maximizes profits subject to a number of technology constraints; some of these are technology neutral and others are technology specific. For solar and wind power, the modeling takes into account that sites differ both within a country and between countries and it is also taken into account that access to sites is regulated. We calibrate the solar and wind parameters using expert information, for example, about the amount and quality of land available for future solar and wind power production.

We find that the renewable and energy-efficiency targets have been set at such a high level that the derived emissions reductions in the ETS and non-ETS sectors exceed their targets. Hence, the carbon prices are zero. In fact, total GHG emissions reduction is 50%, 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% is 59 €/MWh, whereas the uniform tax on energy consumption has to be 1204 €/toe (104 €/MWh) in order 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 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 an end-user energy tax is imposed to achieve the targeted energy-efficiency improvement (32.5%), and the renewable share in final energy demand is 24% (or lower), ETS emissions are exactly 43% below their 2005 level, which is the EU 2030 emissions target. Similarly, if a renewable subsidy is offered to ensure a renewable share of 32%, and the improvement in energy efficiency is 14% (or lower), ETS emissions are exactly 43% below their 2005 level.

We have also run three alternative scenarios to examine how the 2030 equilibrium depends on the design of the policy to support renewables, the characteristics of solar power and the nuclear policy of European countries. In general, we find that the impacts on quantities, prices, and aggregate welfare are moderate (relative to the reference scenario). The main exception is the effect of a 50% phase-out of nuclear capacity, which tends to push up the consumer price of electricity substantially and to redistribute welfare between groups.

Needless to say, other scenarios are possible. First, in the scenarios above, all markets are assumed to be competitive; this is in line with the EU policy to transform 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 due to concerns about national interests and energy security; see, for example, European Commission (2010). This suggests to run LIBEMOD under different assumptions about market structure, as the market structure in LIBEMOD can be represented by a number of parameters that reflect the degree of deviation from the competitive outcome in different parts of the European energy industry; see Golombek *et al.* (2013).

Second, we have assumed no uncertainty. It is apparent that actors in the energy market face a number of uncertainties, for example, future growth rates and prices. In the stochastic version of LIBEMOD (see Brekke *et al.* (2013)), different sources of uncertainties can be imposed. The modeling of uncertainty in LIBEMOD is similar to that in Debreu's (1959, Chapter 7) classic 'Theory of Value', where uncertainty is represented by a discrete event tree. In the stochastic LIBEMOD, each branch of Debreu's event tree is called a scenario and is assigned a probability. The stochastic LIBEMOD determines investment under uncertainty along with a consistent set of equilibrium quantities and prices for each possible scenario. Hence, the model can be used to study the impact of the EU climate and energy policy package when actors face uncertain growth rates, properties of solar power, or nuclear policy.

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APPENDIX A Calibration

Part I: Calibration of wind power

We impose a linear function on $f(K^{PM})$:

$$f(K^{PM}) = a^W - b^W K^{PM}. \tag{15}$$

Because $f(K^{PM})$ shows the average number of full wind hours (per year) as a decreasing function of aggregate maintained capacity, a^W should be interpreted as the number of wind hours (per year) at the best site (in a country). We have determined this parameter by using information from Storm Weather Centre (2004), EEA (2009), and Hoefnagels *et al.* (2011). From these sources we found the "best" location for wind power in each model country, with annual load hours ranging from 1500 to 3700; see Table A.1. The load hours are defined as the ratio between annual electricity output of a wind turbine and its rated capacity (for details on how this is estimated, see Hoefnagels *et al.* (2011)).

Table A.1 Full wind hours at best site and wind power potential in EU-30

Country	Best *(load hours)*	10% of potential 2030 (TWh)*	Country	Best *(load hours)*	10% of potential 2030 (TWh)*
Austria	2000	26.7	Latvia	3000	85.3
Belgium	2800	43.7	Lithuania	3000	74.4
Bulgaria	2500	27.9	Luxembourg	2000	3
Cyprus	1500**	3.9	Malta	2000	0.7
Czech Republic	2093	51.9	Netherlands	2800	55.3
Denmark	3200	75.2	Norway	3700	162.1
Estonia	2500	67.2	Poland	3000	364.4
Finland	3100	441.1	Portugal	3000	46.8
France	2500	452.4	Romania	2000	47
Germany	2500	367.3	Slovak Republic	2000	13.9
Greece	3000	44.3	Slovenia	2000	1.9
Hungary	2000	21.4	Spain	2500	170.0
Iceland	3700	81.1	Sweden	3100	456
Ireland	3400	131.5	Switzerland	1700**	0.4
Italy	2000	58.1	United Kingdom	3400	440.9

Sources: Eerens and de Visser (2008), EEA (2009), Hoefnagels et al. (2011) and Storm Weather Centre (2004).

**10% of the wind power potential in Hoefnagels et al. (2011) under the assumption of a price of electricity of 0.07 €/kWh. Aggregated over all 30 countries, this amounts to 3816 TWh.*

***According to our data sources, these numbers should be somewhat lower than 2000 hours. In the LIBEMOD runs, we still used 2000 hours to obtain a positive wind power production in the calibration equilibrium.*

To determine the value of b^W, we have to solve the optimization problem of a profit-maximizing actor investing in new wind power. To simplify, we assume that maintained capacity is equal to invested capacity (which is the case for a profit-maximizing agent). We also assume that restriction (3) will never bind because the number of wind hours during the year is too low; this is in line with the information in Table 1. Further, we neglect grid connection costs. Finally, we assume that the price of electricity is constant over the year (P^{YE}), and hence we focus only on annual production (y^E). Our assumptions imply that we have only one restriction on wind power production, which is related to the total annual production of wind power. The Lagrangian of the optimizing problem of new wind power is therefore:

$$\mathcal{L}^E = P^{YE} y^E - \sum_{t \in T} c^o y^E - c^M K^{PM} - c^{inv} K^{PM} - \gamma \left\{ y^E - f(K^{PM}) K^{PM} \right\}. \tag{16}$$

The first-order condition for annual produced electricity is:

$$P^{YE} - c^O \leq \gamma \perp y^E \geq 0. \tag{17}$$

Further, the first-order condition for investment is $\gamma(f(K^{PM}) + \frac{df(K^{PM})}{dK^{PM}} K^{PM}) \leq c^M + c^{inv}.$ Using (15), this condition can be rewritten as:

$$\gamma(a^w - 2b^w K^{PM}) \leq c^M + c^{inv} \perp K^{PM} \geq 0. \tag{18}$$

Finally, the first-order condition with respect to the Lagrange multiplier γ is $y^E \leq f(K^{PM})K^{PM}.$ Using (15) and the fact that a profit-maximizing producer will always use the entire maintained capacity, this first-order condition can be rewritten as:

$$y^E = (a^W - b^W K^{PM}) K^{PM}. \tag{19}$$

We solve the system (17), (18), and (19) by treating $y^E (> 0)$, P^{YE}, and a^W as exogenous variables. Then this system determines γ (from (17)), K^{PM}, and b^W. We now explain how we set values for y^E and P^{YE}.

Our calibration draws on the study by Eerens and de Visser (2008), which provides data for wind power potential (TWh) in Europe for 2030. This report provides a technical potential for each country, which is then reduced by excluding all sites with wind speeds below 4 m/s and land where biodiversity issues could prevent development, that is, all land registered in the Natura 2000 database (see Natura (2005)), as well as nationally designated areas. For each country, the remaining generation potential was categorized into three cost classes: "Competitive", "Most likely competitive", and "Not competitive". The potential of the first two classes is derived from sites with production costs below or equal to 0.07 €/kWh. Thus, the Eerens and Visser study provides information about profitable potential wind power production in 2030 (in a country) if the price of electricity is constant over the year and equal to 0.07 €/kWh in 2030.

Because wind power requires land, which typically has an opportunity cost, actual wind power production will only be a small share of potential wind power production. It is hard to estimate this share, but we assume that if the price of electricity is 0.07 €/kWh in 2030, then total EU-30 production of wind power in 2030 will be of the same magnitude as total production of electricity in EU-30 in our data year 2009. To be more specific, we assume that if the annual price of electricity (P^{YE}) is 0.07 €/kWh in 2030, then annual wind power production in 2030 (y^E) will be 10% of the wind power potential of the cost classes "Competitive" and "Most likely competitive". Using the values for a^W (wind hours at best site in a country) from Table 1, relations (18) and (19) determine K^{PM} and b^W.

Part II: Calibration of solar power

In the LIBEMOD model, it is assumed that PV cells are assembled as modules that are used for electricity generation in centralized power plants. There are several PV technologies either on the market or under development. These are often divided into three categories: (i) first-generation PV systems based on crystalline silicon technology, (ii) second-generation thin-film PV (based on several different materials), and (iii) third-generation PV, which includes new technologies such as concentrated PV, organic solar cells, and dye-sensitized solar cells. The first-generation PV systems are fully commercial, whereas the second-generation are in the stages of early market deployment (IRENA 2012). In the LIBEMOD model, we use technical data and costs of first-generation PV systems.

To estimate the potential of the solar resource in each model country, data for solar insolation around the world from the NASA Surface Meteorology and Solar Energy database has been used; see NASA. This gives information about monthly average insolation incidents, measured in kWh/m^2/day, based on a 22-year average. We use the data for tilted collectors, choosing the tilt angle that gives the highest annual average for each location.[14]

We have created a dataset with a "best" and "worst" location for solar insolation (kWh/m^2/year) for each model country; see Table A.2. These locations have been chosen based on an assessment of each model country using a map of the PV potential in EU regions; see ESPON (2011) and sampling from the NASA database. The data have been aggregated to our two seasons (summer/winter).

[14] There are various ways to measure solar irradiance. Global horizontal irradiance (GHI) is a measure of the density of the available solar resource per surface area. However, solar irradiance can also be measured with tilted collectors that have a fixed optimal angle for the location or even with devices that track the sun. We use data for tilted collectors that have a fixed optimal angle.

Table A.2 Solar insolation kWh/m²/year.
Average radiation incident on an equator-pointed tilted surface

Country	Best site *kWh/m²/yr*	Worst site *kWh/m²/yr*	Country	Best site *kWh/m²/yr*	Worst site *kWh/m²/yr*
Austria	1386	1245	Latvia	1313	1165
Belgium	1143	1134	Lithuania	1300	1137
Bulgaria	1612	1509	Luxembourg	1207	1204
Cyprus	2142	2044	Malta	2095	2078
Czech Republic	1216	1153	Netherlands	1289	1090
Denmark	1287	1090	Norway	1191	813
Estonia	1248	1165	Poland	1181	1131
Finland	1142	956	Portugal	1983	1965
France	1817	1175	Romania	1504	1358
Germany	1272	1079	Slovak Republic	1285	1169
Greece	2065	1516	Slovenia	1568	1386
Hungary	1420	1254	Spain	2114	1601
Iceland	1182	776	Sweden	1217	999
Ireland	1220	1089	Switzerland	1421	1366
Italy	1989	1490	United Kingdom	1291	1109

Sources: All data from the NASA Surface Meteorology and Solar Energy Database.

We assume that the function $\bar{\Omega} = \bar{\Omega}(\frac{K}{\hat{K}})$ is linear: $\bar{\Omega} = a^S - b^S \frac{K}{2\hat{K}}$. Because $\bar{\Omega}(\frac{K}{\hat{K}})$ should be interpreted as the average solar irradiance, the marginal solar irradiance is given by $a^S - b^S \frac{K}{\hat{K}}$. This means that a^S should be interpreted as the irradiance at the best solar site of a country. To determine the value of b^S, note that if the entire available land for solar power is used (and thus $K = \hat{K}$), then the marginal site receives a solar irradiance of $a^S - b^S$. From Table 2 we know, for each country, the values of a^S (best site) and $a^S - b^S$ (worst site), and hence we can find the value of b^S for each country. According to Table 2, solar radiation at the best site, measured in kWh/m²/year, varies between 1182 (Iceland) and 2142 (Cyprus). For most countries, the difference between best and worst sites is less than 25%.

In the model, we assume that over time more land will be available for solar power. In particular, we rely on Hoefnagels *et al.* (2011), who assume that 0.5% of the agricultural land will be made available for solar power plants in each model country by 2050.[15] To formalize, we assume that in year *t*, the amount of land available for solar power is given by the function $h(t) = \frac{k}{2} e^{-l(t-2009)}$, where the parameters k and l are calibrated so that $h(2050) = 0.5$ ($k = 2.5, l = 0.0224$). This means that $h(2030) \approx 0.3$, that is, in 2030 around 0.3% of the agricultural land (in each model country) will be made available for solar power plants. This amount of land corresponds to around 0.2% of the total land mass in EU-30.

[15] Data on agricultural land are gathered from The World Bank: http://data.worldbank.org/indicator/AG.LND.AGRI.ZS. According to this source, for EU-30, agricultural land amounts to 41% of the total land mass.

According to IEA ETSAP (2011), the land requirement of crystalline Si PV cells is roughly between 6 and 9 m^2/kW. In the model, we assume that $\frac{1}{\overline{\theta}}$ m^2 is required to generate 1 kW instantly under *ideal conditions*, that is, $\chi = \overline{\theta}$. Based on the assumptions in IEA ETSAP (2011) and IPCC (2011), the maximum module efficiency of PV panels is assumed to be 18%, that is, $\overline{\theta} = 0.18$. Finally, we assume that the cost of investment in solar is decreasing over time; the annual rate is set to 3%.

Above we derived that the annual production of solar power can be calculated from $\overline{\theta}\overline{\Omega}(\frac{K}{\hat{K}})\Omega$. Using: i) $\overline{\theta} = 0.18$, ii) calibration of the parameters a^S and b^S in the function $\overline{\Omega}(\frac{K}{\hat{K}})$ by following the strategy outlined above, and iii) the assumption that 0.3% of the agricultural land will be made available for solar power plants in each model country in 2030 ($\hat{\Omega}$), we can calculate maximum solar power by country in 2030; see Table A.3. According to this table, maximum solar power in 2030 amounts to 1620 TWh, which is close to 50% of total electricity production in EU-30 in 2009.

Table A.3 Potential solar power production in 2030 by country (TWh)

Country	Potential production *(TWh)*	Country	Potential production *(TWh)*
Austria	24.4	Latvia	13.6
Belgium	9.8	Lithuania	19.6
Bulgaria	46.1	Luxembourg	0.9
Cyprus	1.5	Malta	0.1
Czech Republic	15.4	Netherlands	16.1
Denmark	18.3	Norway	6.2
Estonia	6.9	Poland	110.2
Finland	15.5	Portugal	42.1
France	252.4	Romania	115.4
Germany	116.9	Slovak Republic	13.9
Greece	86.5	Slovenia	4.0
Hungary	45.7	Spain	299.4
Iceland	13.2	Sweden	21.5
Ireland	28.4	Switzerland	12.6
Italy	142.7	United Kingdom	120.4

**Based on solar panel efficiency of 18%, maximum available land for solar power in 2030 (0.33% of agricultural land in each country) and average insolation for each country.*

TABLES

Table 1 Investment costs for power plants

Technology	LIBEMOD (2015)	IEA ETSAP (2010)	Schröder *et al.* (2013)	OECD (2010)	Mott MacDonald (2010)[1]
Natural gas (CCGT)	957	800	800	775 – 1291	806
Coal (PC SC)	1737	1600	1200	1534 – 1988	2009
Oil	1411	-	400	-	-
Nuclear (EPR)	3260	2181	6000[2]	3228 – 5031	3270
Bio	2181	2181	-	1934 – 5482	-
Solar (PV)	2545	2400	1560	2405 – 3802	-
Wind (onshore)	1576	-	1300	1419 - 1742	1707
Natural gas greenfield (CCGT)	2032				
Coal greenfield (IGCC)	3422				
Natural gas retrofit (CCGT)	739				
Coal retrofit (PC)	1150				

[1] The data from Mott MacDonald (2010) are for the "nth of a kind plant" in their medium scenario.
[2] The data from Schröder *et al.* (2013) include decommissioning and waste disposal.

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

	Efficiency	Variable O&M costs €/MWh	Fixed O&M costs €/kW/year
Natural gas	60	2.2	11.6
Coal	46	3.6	18.8
Bio	40	2.8	80.7
Pumped storage		-	20.0
Reservoir hydro		-	20.0
Run-of-river		-	58.8
Solar PV		-	25.4
Wind		7.4	19.5
CCS gas greenfield	52	2.8	33.7
CCS gas retrofit		3.9	46.8
CCS coal greenfield	37	3.3	57.2
CCS coal retrofit		7.1	51.4

Table 3 Scenarios for 2030

Reference	At least 40% GHG emissions reductions in 2030 relative to 1990. Separate emission targets for ETS and non-ETS sectors. A renewable share of 32% in final energy consumption. Energy efficiency should be improved by 32.5% relative to business-as-usual. EU-wide policy instruments only.
Domestic subsidies	National support schemes for renewables in addition to EU-wide support for renewable energy. Same GHG emissions, renewable share, and energy efficiency as in the reference equilibrium.
Solar	More favorable conditions for solar power with respect to PV efficiency, cost of investment, and land availability. Same GHG emissions, renewable share, and energy efficiency as in the reference equilibrium.
Nuclear	Nuclear capacities, which are exogenous, are reduced by 50% in 2030 relative to 2009. Same GHG emissions, renewable share, and energy efficiency as in the reference equilibrium.

Table 4 Common renewable subsidies in the domestic subsidies scenario (€2009/MWh)

Country	Biopower	Reservoir hydropower	Run-of-river	Solar power	Wind power
AT	20	4	4	20	20
BE	20	20	20	20	20
BG	20	20	20	20	20
CH	0	20	20	20	0
CY	20	0	0	20	20
CZ	20	20	20	20	20
DE	20	20	20	20	20
DK	20	0	0	0	20
EE	15	15	15	15	15
ES	20	20	20	20	20
FI	18	0	0	0	20
FR	20	15	15	20	20
GB	20	20	20	20	20
GR	20	6	6	20	7
HU	20	16	16	20	20
IE	20	20	20	0	11
IS	0	0	0	0	0
IT	20	20	20	20	20
LT	20	20	20	20	20
LU	20	20	20	20	20
LV	0	0	0	0	0
MT	0	0	0	0	0
NL	20	20	20	20	20
NO	0	20	20	0	20
PL	20	20	20	20	20
PT	20	20	20	20	20
RO	20	20	20	20	20
SE	20	20	20	20	20
SI	0	20	20	20	0
SK	20	20	20	20	20

Sources: CEER (2015), CEER (2017), and own sources and assessments.

Table 5 Nuclear policies in EU-30

COUNTRY	POLICY	PLANNED CAPACITY CHANGE
Belgium	Complete phase-out by 2025.	866 MWe phase-out by 2015 5077 MWe phase-out by 2025
Bulgaria	Plans to extend lifetime of current reactors. Plans for a new reactor on hold due to lack of financing.	
Czech Rep	National energy plan to 2060 assumes 50% nuclear capacity; however, plans for two reactors were put on hold after the government refused to provide state support.	1200 MWe in 2026 1200 MWe in 2028
Finland	One EPR reactor under construction, expected to be in commercial operation by 2016. Another two reactors planned.	1720 MWe in 2016 1600 MWe around 2020 1200 MWe in 2024
France	One EPR reactor under construction. The current President has pledged to reduce the share of electricity from nuclear to 50% by 2025.	1750 MWE in 2016
Germany	Closed down 8 reactors in March 2011. Plans for complete phase-out by 2022.	8336 MWe shut down in 2011 12003 MWe phase-out by 2022
Hungary	Plans for two new reactors under government ownership.	1200 MWe in 2023 1200 MWe in after 2025
Italy	Plans to revive the national nuclear industry rejected by referendum in 2011.	
Lithuania	Closed down two reactors in 2009 due to EU safety concerns. Plans for one new reactor, expected to start operating in 2022.	1350 MWe in 2022
Netherlands	Previous decision on phase-out was reversed in 2006. However, plans for new reactors are on hold due to economic uncertainties.	
Poland	Cabinet decision to move to nuclear power in 2005. Currently two planned reactors.	3000 MWe in 2024 3000 MWe in 2035
Romania	Two new reactors planned, but currently lacking financing.	720 MWe in 2019 720 MWe in 2020
Slovakia	Plans for new reactors outlined in the 2008 Energy Security Strategy, aiming to keep the share of electricity from nuclear power at 50%.	940 MWe in by 2015 1500 MWe in by 2025
Slovenia	Considering capacity expansion, but no plans confirmed.	
Spain	Political uncertainty surrounding nuclear future. No plans for new reactors, but in 2011 the legal limitation to plant-operating lives was removed (previously 40 years).	
Sweden	Phase-out plan from 1980 repealed in June 2010. Currently plans to uprate/replace old units when decommissioned.	
Switzerland	Parliament decision in June 2011 to not replace any reactors. Complete phase-out by 2034.	1102 MWe phase-out by 2022 (net) 985 MWe phase-out by 2030 (net) 1165 MWe phase-out by 2034 (net)
United Kingdom	Plans for several new reactors between 2023 and 2030. Government goal is 16 GWe new capacity by 2030.	16000 MWe by 2030

Table 6 Policy targets sensitivity

	No targets	Climate targets (ETS and non-ETS targets)	Climate and renewable targets	Climate, renewable and energy efficiency targets (reference scenario)	One climate target (efficiency)
GHG emissions in 2030 relative to 1990	2%	–40%	–40%	–50%	–50%
Renewable share in 2030	11%	22%	32%	32%	28%
Improved energy efficiency in 2030 relative to 2005	5%	18%	12%	32.5%	26%
ETS price (€/tCO_2)	0	50	7	0	316
Non-ETS price (€/tCO_2)	0	236	239	0	316

FIGURES

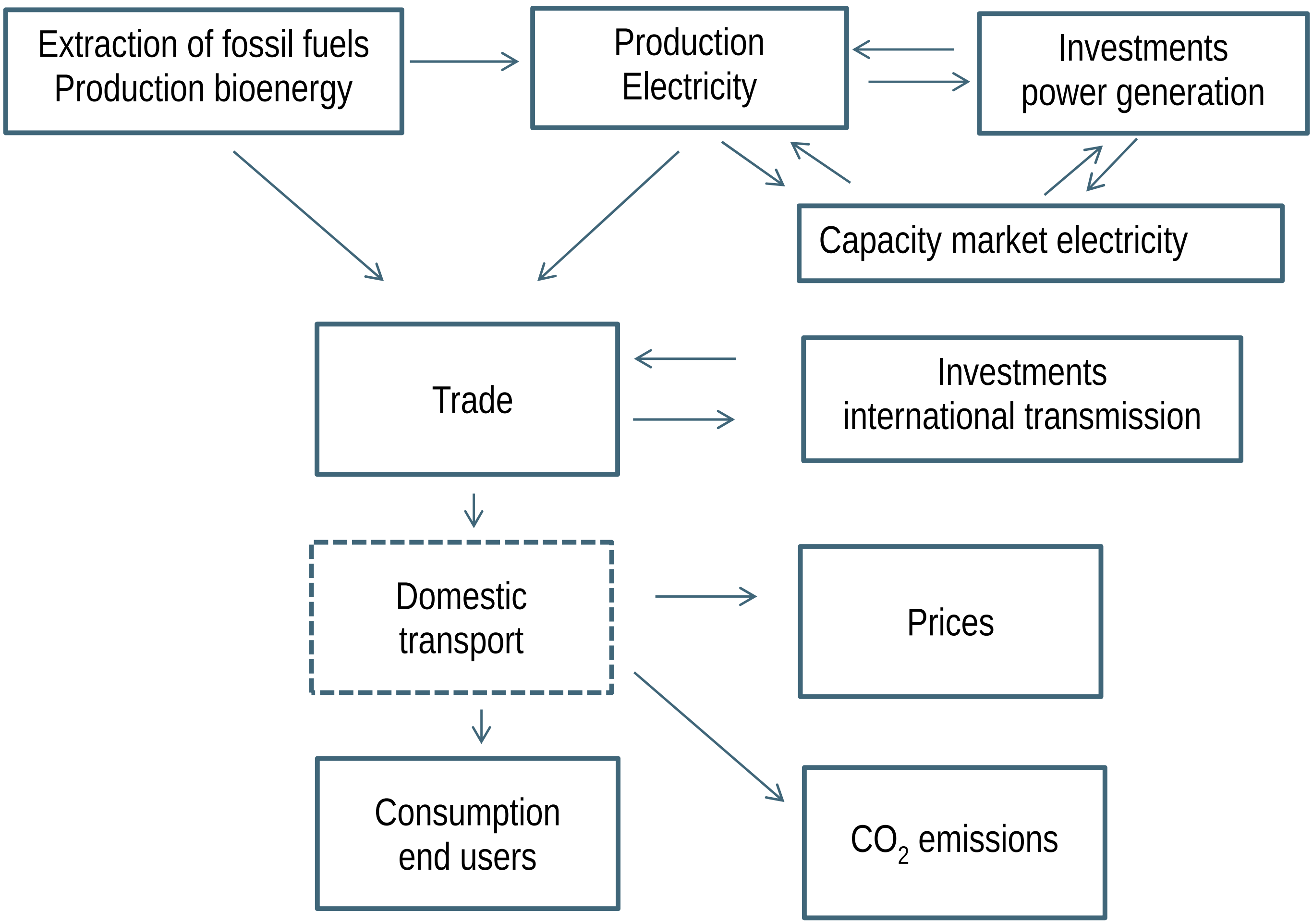

Figure 1 The LIBEMOD model

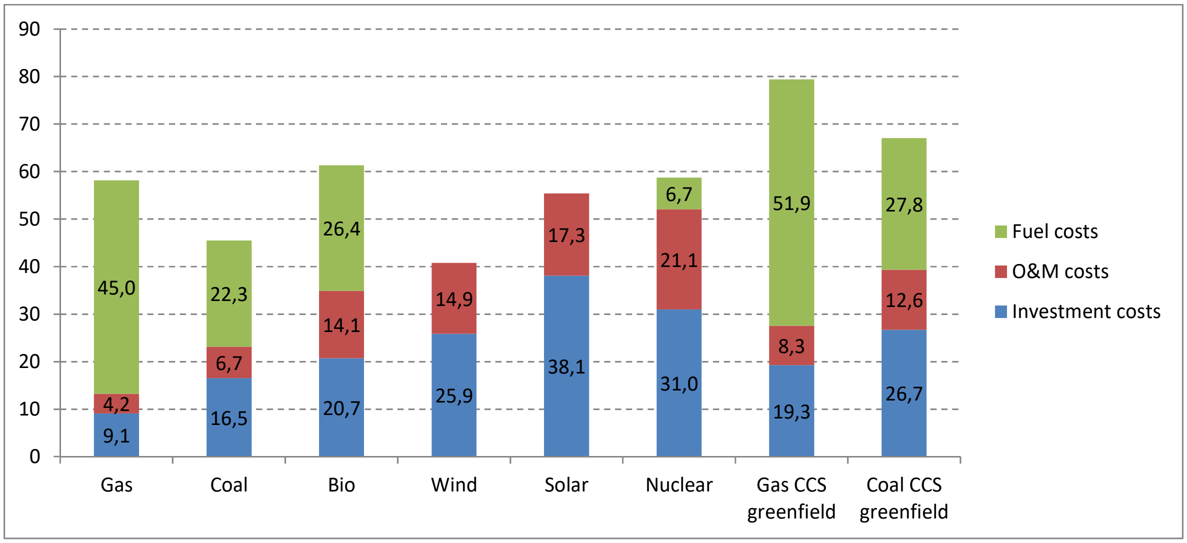

Figure 2 Costs of new electricity in 2030 (€2009/MWh)

Fuel prices: Coal and gas prices in EU-30 in 2009, biomass price based on Schröder *et al.* (2013), cost of nuclear from OECD (2010). Load hours: 70% for coal, gas, nuclear, CCS, and bio. Wind and solar power based on good locations in Europe (3500 and 2500 full hours, respectively). Cost of investment (€2009/MWh) is taken from Table 1, whereas plant efficiency and O&M costs are taken from Table 2.

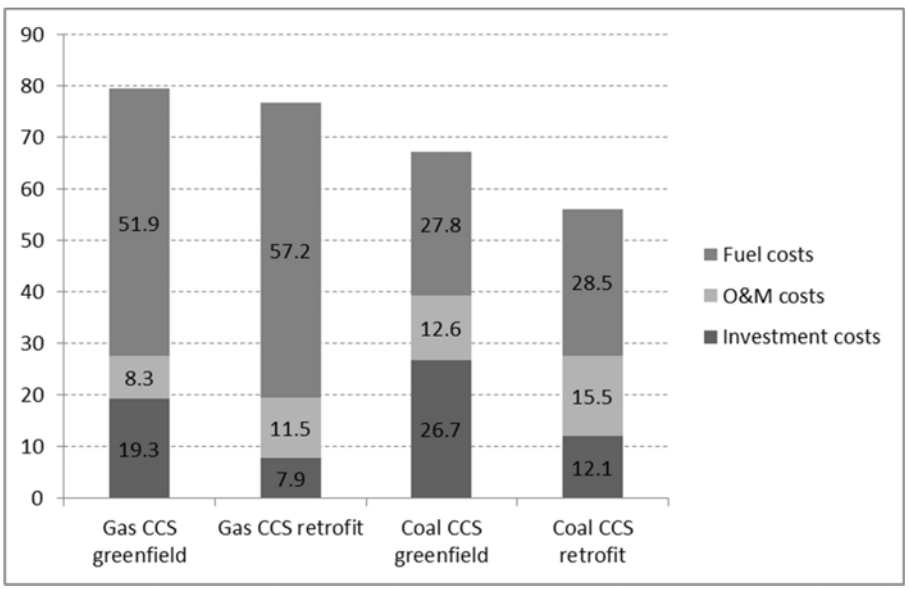

Figure 3 Costs of CCS electricity in 2030 (€2009/MWh)

Sources: ZEP (2011), IEA GHG (2011), and own assumptions.
Efficiencies: Greenfield gas 52%, greenfield coal 37%. Existing coal and gas power plants that are retrofitted with CCS suffer an 8-percentage-point efficiency reduction.
Fuel prices: Coal and gas prices in EU-30 in 2009.

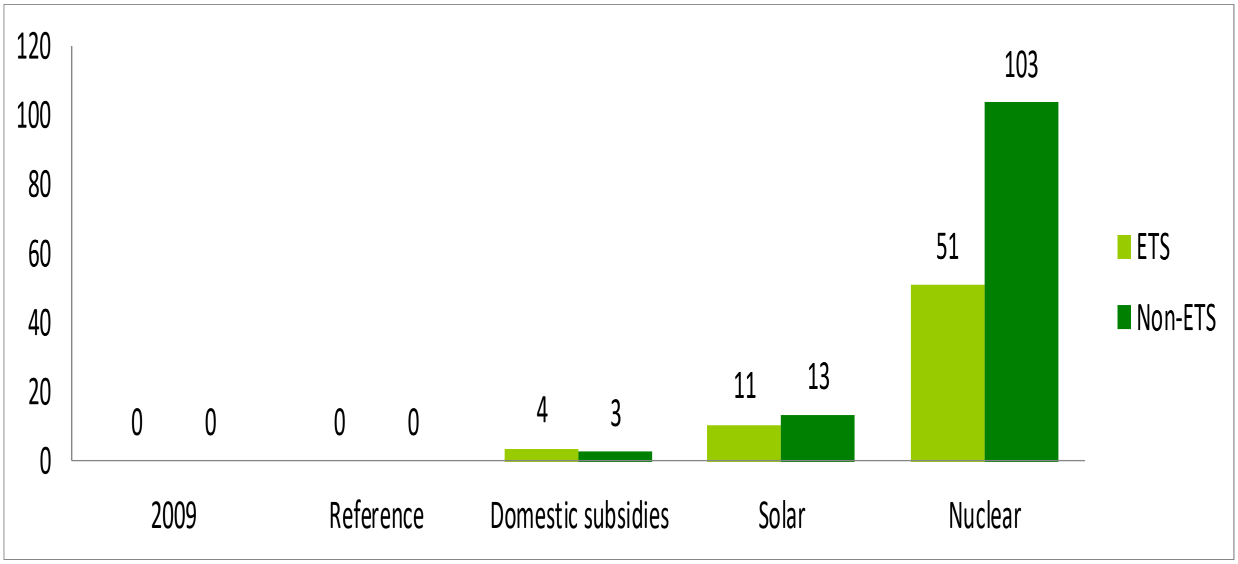

Figure 4 CO_2 prices in EU-30 in 2030 (€2009/tCO_2)

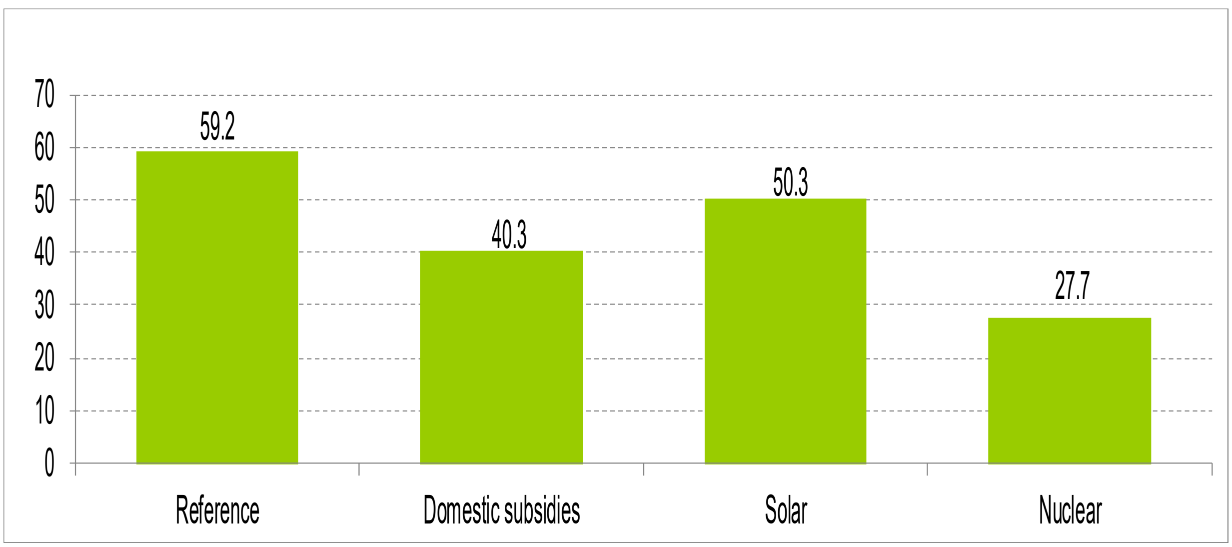

Figure 5 Common renewable subsidy in EU-30 in 2030 (€2009/MWh)

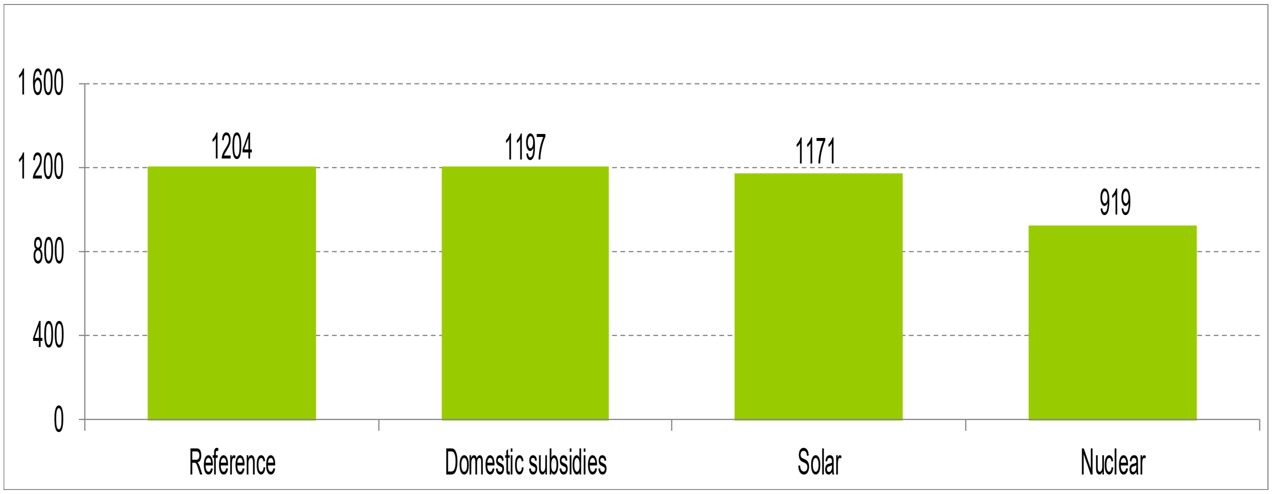

Figure 6 Tax on end-user consumption in EU-30 in 2030 (€2009/MWh)

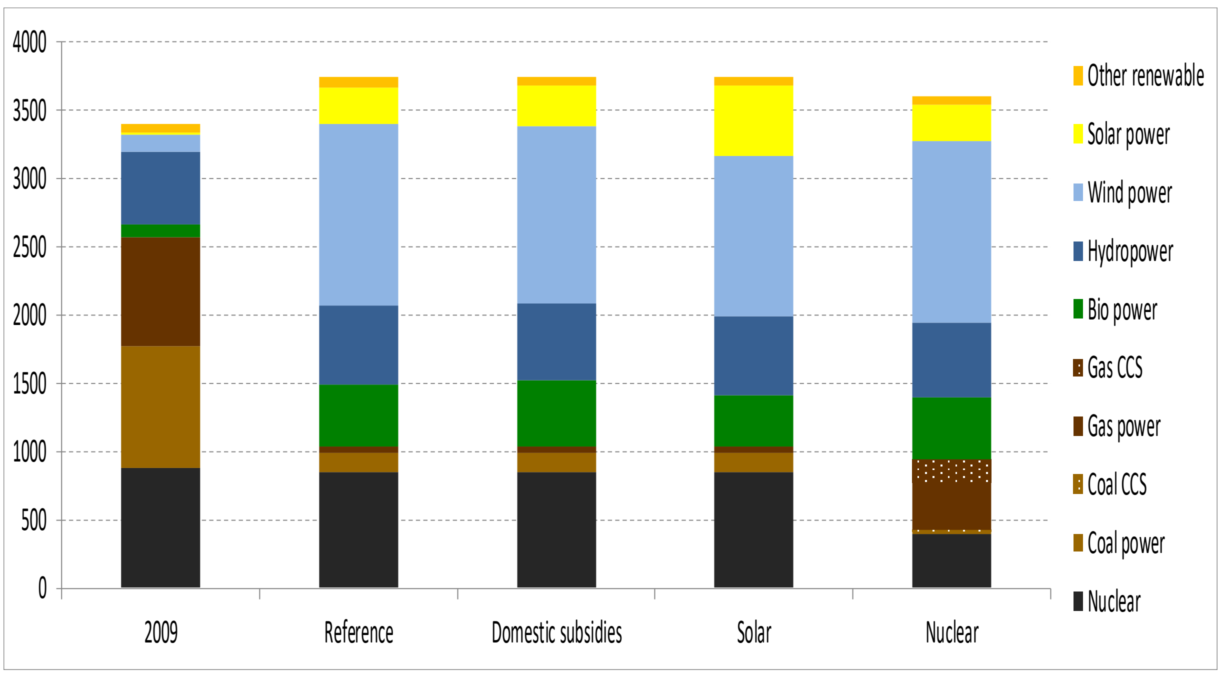

Figure 7 Electricity production in EU-30 in 2009 and 2030 (TWh)

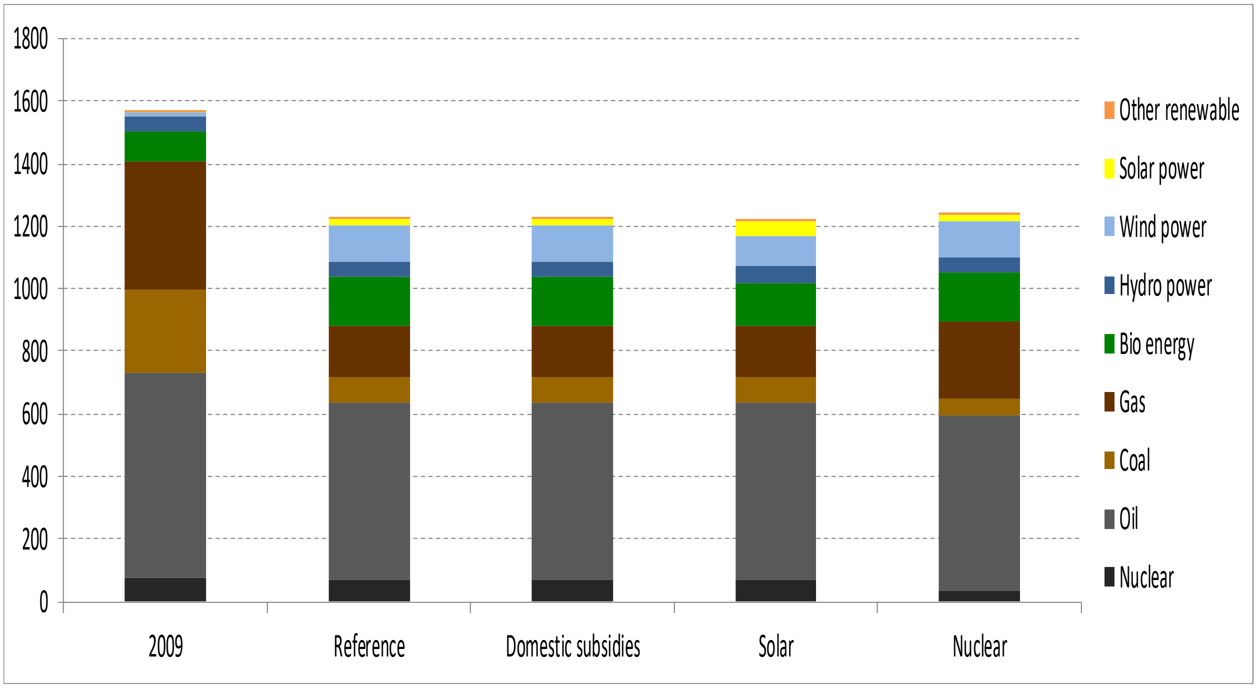

Figure 8 Energy consumption in EU-30 in 2009 and 2030 (Mtoe)

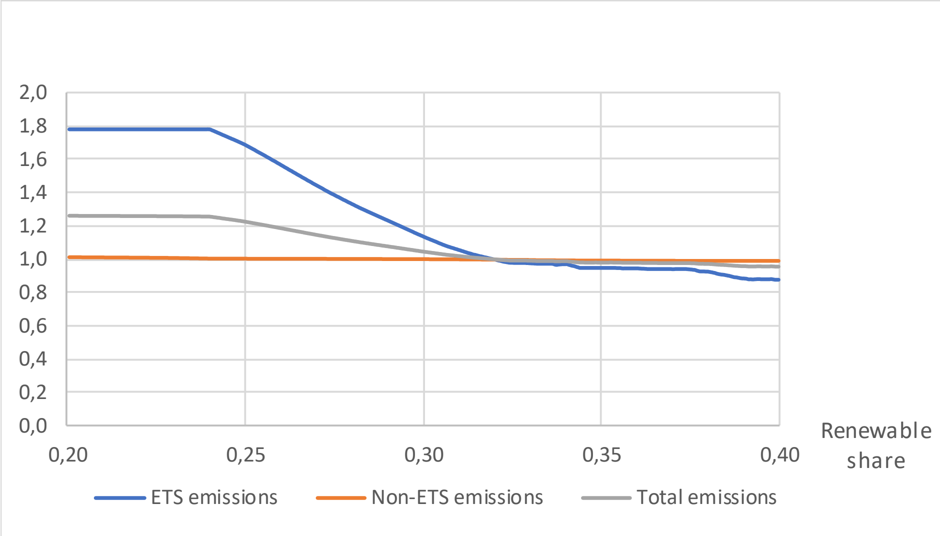

Figure 9 Sensitivity of renewable share in final energy consumption – emissions

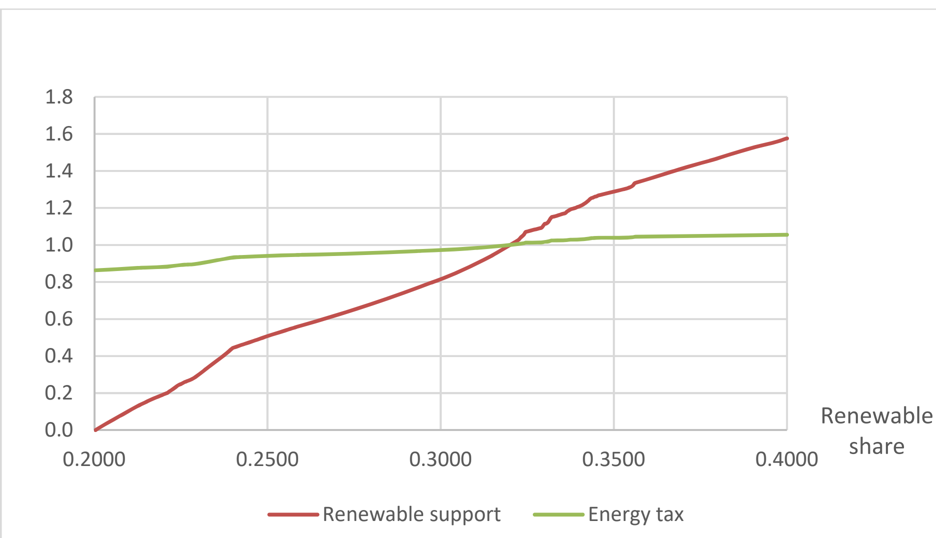

Figure 10 Sensitivity of renewable share in final energy consumption – policy instruments

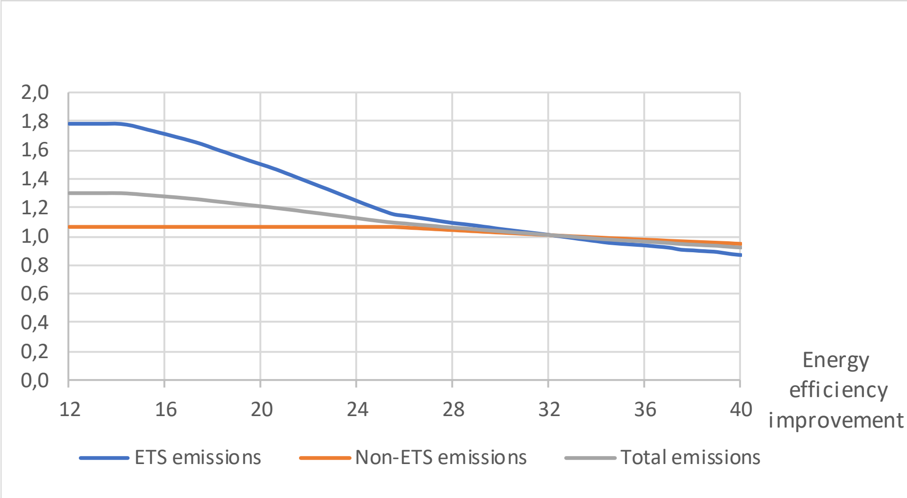

Figure 11 Sensitivity of energy-efficiency target – emissions

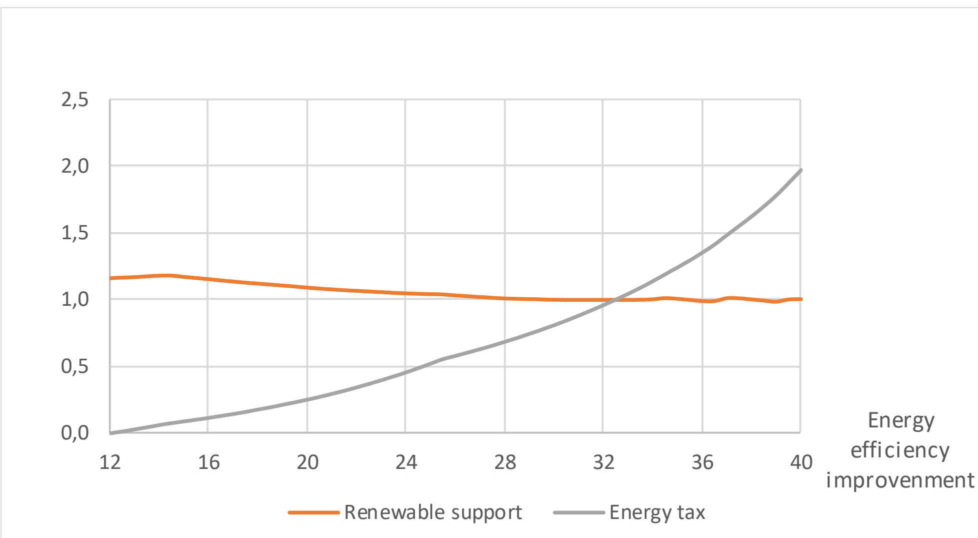

Figure 12 Sensitivity of energy-efficiency target – policy instruments

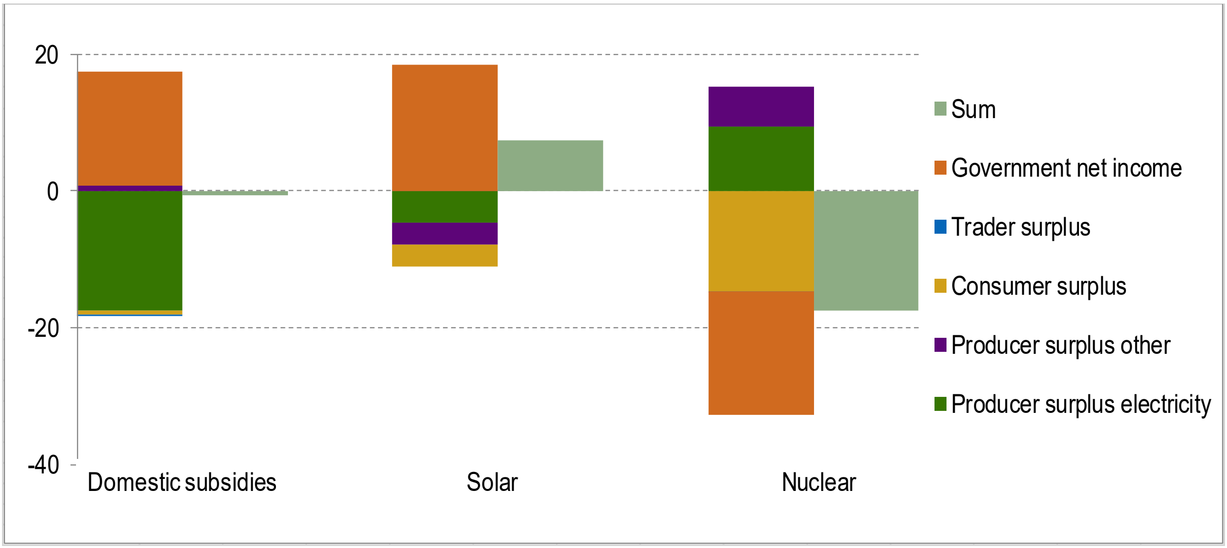

Figure 13 Change in welfare components relative to reference scenario. EU-30 in 2030 (Millions €2009)

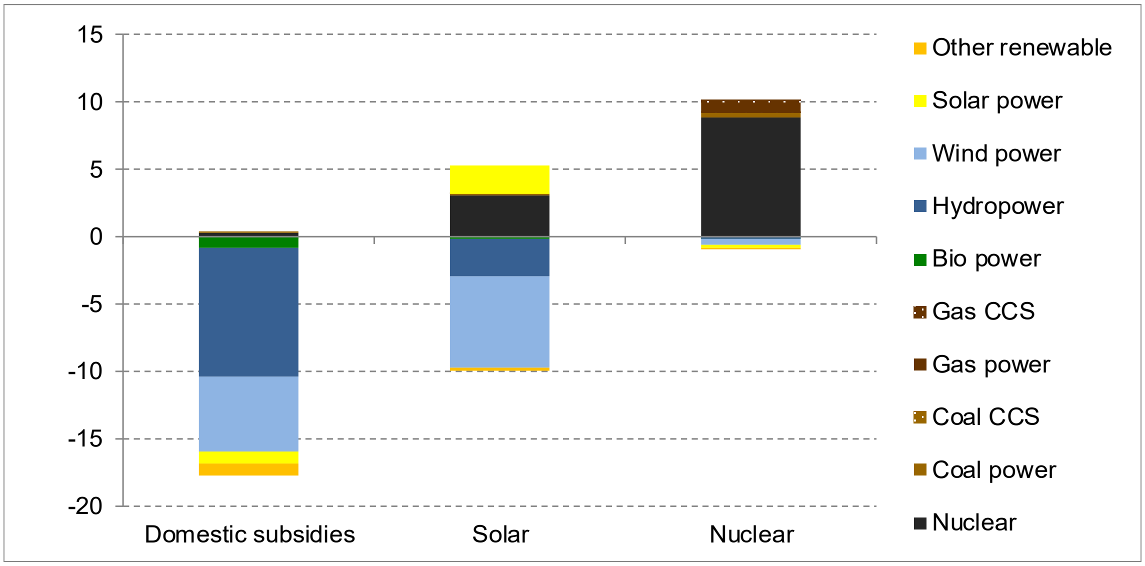

Figure 14 **Change in electricity producer surplus by technology (except nuclear) compared with reference scenario. EU-30 in 2030 (Millions €2009)**