MSc Program
Renewable Energy in Central and Eastern Europe

Emissions Trading and Support Schemes: Effects on Renewable Electricity Generation

A Master's Thesis submitted for the degree of
"Master of Science"

supervised by
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AFFIDAVIT

I, Claudia Kettner, hereby declare

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ABSTRACT

The Energy and Climate Package of the European Commission sets ambitious targets for the EU Member States. These comprise a reduction of greenhouse gas emissions of 20% in 2020 compared to 1990 levels, a higher share of renewable energy sources, i.e. 20% renewables in total gross final energy consumption in 2020 and 10% renewables in transport final energy consumption, and a significant improvement of energy efficiency. The targets require a fundamental restructuring of existing energy systems, i.e. of current patterns of energy use and supply.

With respect to the targets for renewable energy sources and greenhouse gas emissions the following policy instruments are particularly relevant in the EU: renewable support schemes and the EU Emission Trading System (EU ETS). While often considered isolated, inter-linkages between the EU ETS and renewable support schemes prevail: On the one hand, the carbon price generated by the EU ETS might increase the competitiveness of low carbon fuels such as renewables. On the other hand, an increasing share of – carbon neutral – renewables that is not taken into account in the definition of the emission cap might undermine incentives for implementing other emission reductions options. However, in general the coexistence of both policies is advocated for as emissions trading allows exploiting a broader range of abatement potentials and especially immature renewable technologies require additional support.

This thesis analyses the impacts of the EU ETS on selected renewable electricity generation technologies (biomass and biogas, photovoltaics, wind and hydro power) focussing on three case study countries in Central and Eastern Europe: Austria, the Czech Republic and Hungary. Using two carbon price scenarios (€ 36 and € 60 per ton CO_2) and two renewable policy scenarios (default scenario and optimistic scenario), the competitiveness of the renewable electricity generation technologies compared to non-renewable reference technologies in 2030 is analysed.

Without carbon pricing the short run marginal costs of hydro and wind power are generally lower than the short run marginal costs of coal and gas power plants. At a CO_2 price of € 36, also PV exhibits lower short run marginal costs than coal and gas power plants in the case study countries. Biomass and biogas do only exhibit lower short run marginal costs than coal and gas in the optimistic scenario assuming a CO_2 price of € 60. With respect to long run marginal costs, hydro power does also exhibit lower costs than the reference technologies even without carbon pricing. At a carbon price of € 36, the long run marginal costs of all reference technologies do also exceed those of wind power. Comparing the long run marginal costs of the renewable electricity generation technologies with the short run marginal costs of the reference technologies shows that at a carbon price of € 36 per ton CO_2 wind power and hydro power become competitive against the incumbent reference technologies in the optimistic scenario, i.e. the long run marginal costs of the renewable technologies is below the short run marginal costs of the reference technologies. The same is true for a carbon price of € 60 independent of the scenario.

Whether investments in renewable electricity generation technologies will occur, depends, however, on the expected electricity price and non-monetary factors. At a stable electricity price that is determined by the short run marginal costs of coal or gas power plants, some renewable electricity generation technologies (wind power as well as small and large hydro power) will not require a feed-in tariff or other support measures due to the higher market price resulting from pricing CO_2 emissions of fossil electricity generation.

When renewable electricity generation technologies do gain in importance, spot market prices will, however, tend to decline as renewable electricity generation technologies exhibit lower short run marginal costs than fossil electricity generation. Furthermore, variable renewable electricity generation technologies in times of (full) in-feed might deteriorate the prices on electricity markets, and hence receive a lower income than suggested by average market figures. In such a situation, the market price will not be sufficient for the expansion of renewable electricity generation.

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1 INTRODUCTION

The Energy and Climate Package of the European Commission[1] sets ambitious targets for the EU Member States. These comprise a reduction of greenhouse gas (GHG) emissions of 20% in 2020 compared to 1990 levels, a higher share of renewable energy sources (RES), i.e. 20% renewables in total gross final energy consumption in 2020 and 10% renewables in transport final energy consumption, and a significant improvement of energy efficiency. These targets require a fundamental restructuring of existing energy systems, i.e. of current patterns of energy use and supply.

With respect to the targets for renewable energy sources and greenhouse gas emissions the following policy instruments are particularly relevant in the EU: renewable support schemes and the EU Emission Trading System (EU ETS)[2]. While often considered isolated, inter-linkages between the EU ETS and renewable support schemes prevail: On the one hand, the carbon price generated by the EU ETS might increase the competitiveness of low carbon fuels such as renewables. On the other hand, an increasing share of – carbon neutral – renewables that is not taken into account in the definition of the GHG emission cap might undermine incentives for implementing other emission reductions options. However, in general the co-existence of both policies is advocated for as emissions trading allows exploiting a broader range of abatement potentials (instead of a mere shift from fossil fuels to renewables) and especially immature renewable technologies require additional support (see e.g. Sonneborn, 2004; Sijm, 2005; del Río Gonzalez, 2007; Möst and Fichtner, 2010).

Focussing on electricity generation, this thesis investigates to which extent the EU ETS has supported in the past and might support in forthcoming years the use of

[1] The Energy and Climate Package includes the following key documents: Directive 2009/29/EC amending Directive 2003/87/EC so as to improve and extend the greenhouse gas emission allowance trading scheme of the Community; Decision No 406/2009/EC on the effort of Member States to reduce their greenhouse gas emissions to meet the Community's greenhouse gas emission reduction commitments up to 2020 ("Effort Sharing Decision"); and Directive 2009/28/EC on the promotion of the use of energy from renewable sources and amending and subsequently repealing Directives 2001/77/EC and 2003/30/EC ("Renewable energy Directive").

[2] These instruments of course are not conclusive. For renewable energies, e.g., Member States may also use flexible mechanisms - statistical transfers between Member States, joint projects and joint support schemes - in order to reach national targets (see Directive 2009/28/EC).

renewable energy sources in three Central and Eastern European case study countries: Austria, the Czech Republic and Hungary. Based on a simple numerical framework following Schwaiger et al. (2012) it is analysed whether and for which technologies changes in electricity prices triggered by the EU ETS could substitute or would allow a change in current renewable support schemes. The assessment is limited to average annual electricity generation, i.e. the fact that variable renewable electricity generation technologies (wind power, PV) in times of (full) in-feed deteriorate the prices on electricity markets, and hence receive a lower income than suggested by average market figures is not considered.

The thesis is structured as follows: After an introduction into the subject, the theoretical aspects of emissions trading and renewable support schemes will be described. This is followed by a description of the EU ETS (including its current and post-Kyoto design) and the support schemes for renewable electricity generation used in the EU with a special emphasis on the case study countries Austria, Hungary and the Czech Republic. Following Schwaiger et al. (2012) then the impact of the EU ETS on the long and short run marginal costs of fossil electricity generation, i.e. coal and gas based electricity generation, is analysed and changes in the merit order of fossil electricity generation and selected renewable electricity generation technologies (biomass and biogas, photovoltaics, wind and hydro power) resulting from the emissions trading scheme are examined. It is then discussed whether and to which extent, i.e. for which technologies, changes in electricity prices triggered by the EU ETS could substitute renewable support schemes or for which technologies.

2 Economic Instruments for Greenhouse Gas Mitigation and Renewable Electricity Support

Economic theory suggests the use of market-based instruments to limit greenhouse gas emissions and to increase the share of renewable energy. These include price-based instruments, like carbon taxes or feed-in tariffs, on the one hand, and quantity-based instruments, like emissions trading or tendering schemes, on the other hand. Price-based instruments fix the price for greenhouse gas emissions and renewables, while the level of renewable energy or the emission abatement achieved is then determined by the market. In contrast quantity-based instruments determine the emission level or the amount of renewable energy produced and then the price is formed by the market (see e.g. Metcalf, 2009; de Jonghe et al., 2009).

Relevant criteria for the choice of instruments and funding schemes are[3]:

- The environmental effectiveness of the instrument − i.e. the contribution of the instrument to the achievement of objectives (the development of renewable energy or the realisation of greenhouse gas emission savings).
- The economic efficiency of the instrument − i.e. the achievement of the target at the lowest possible economic cost (static efficiency) and the promotion of technological progress and innovation (dynamic efficiency) in order to ensure sustainable long-term energy supply.
- The minimisation of transaction costs − for the authorities on the one hand (e.g. with respect to the implementation and monitoring of the system) and for the companies on the other hand (e.g. with respect to the application for funding, the contract negotiations and the reporting obligations).
- The acceptance and political feasibility of the instrument − this relates to reconciliation of various interests of directly affected stakeholders (plant and grid operators, local authorities, local residents) on the one hand and the general political acceptance, for instance with possible conflicts with other

[3] See e.g. Kettner et al. (2009).

policies (e.g. environmental protection), the financing of the system or the compliance with the existing regulatory framework, on the other hand.

- The distributional implications − the possibility of making profits should constitute an incentive for investment. The design of the RES support schemes or emissions trading schemes should, however, minimize excessive profits (windfall profits), which is also required in terms of the static efficiency criterion. In the context of the support of renewable energies, distributional effects depend also on the financing of the system, i.e. on whether the costs are incurred by the public sector or by the electricity consumers, as well as the distribution of other costs related to the grid integration of renewable energy (especially grid connection costs and costs for grid expansion).

Between the individual criteria trade-offs can exist, e.g. between the environmental effectiveness and the economic efficiency or between static and dynamic efficiency, which may require a balancing of objectives.

2.1 Economic Instruments for Greenhouse Gas Mitigation

There has been an extensive scientific discussion focussing on the optimal instrument choice to control emissions. Economic theory advocates market-based instruments such as taxes or emission trading over command-and-control regulation as these instruments do not only ensure environmental effectiveness but also economic efficiency, i.e. emission reductions at lowest costs (see e.g. Grüll and Taschini, 2011; Cló, 2011).

With respect to market-based instruments, there has been a lively discussion whether emission trading systems are preferable compared to a carbon tax or vice versa. According to economic theory, the outcomes of the two instruments would be identical (see Figure 1). In the case of an emission trading system, the regulator would set an emission target, the cap (E_T). Complying with the emission target E_T, i.e. reducing the emissions from E_0 to E_T, would imply a cost of the shaded area. In the case of a carbon tax, the regulator would define a price for each unit of carbon emitted (c_T). Firms would then reduce their emissions until the tax equals their marginal abatement costs (MAC; i.e. the cost of reducing an additional unit of carbon) which would again result in the emission limit of E_T.

(a) Emissions trading (b) Carbon tax

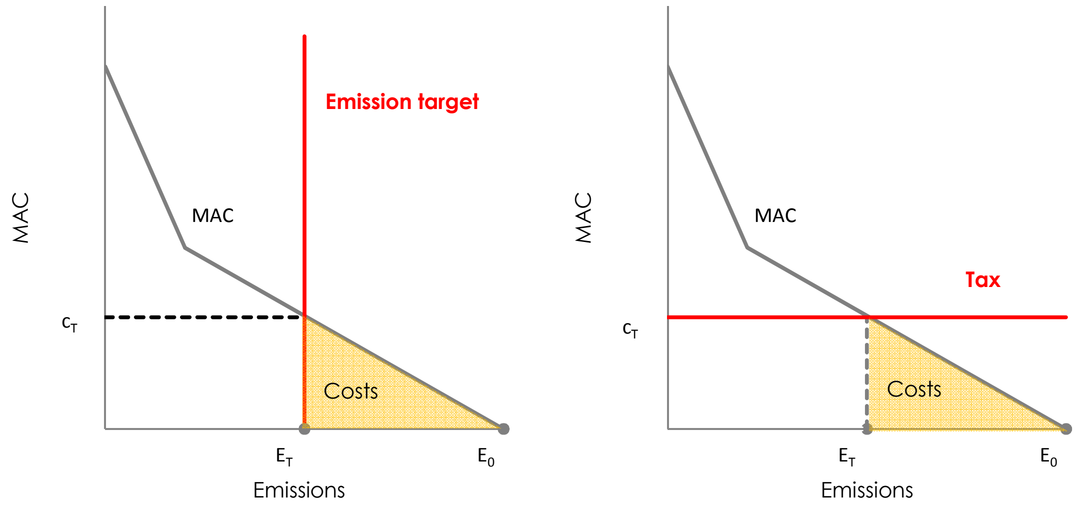

Figure 1. Emissions trading vs. a carbon tax

Source: Own illustration.

The identical outcomes are the result of assuming a world without externalities and uncertainty, i.e. perfect information, rational agents and the absence of market failures (see e.g. McKibbin and Wilcoxen, 2002; Hepburn, 2006). However, in the real world numerous uncertainties prevail including (see Kettner et al., 2011b):

- uncertainty regarding the optimal emission reduction target;
- uncertainty and / or asymmetric information regarding abatement and technological options; and
- uncertainty about the future development of energy prices, innovation and economic growth.

In his seminal paper, Weitzman (1974) showed that under uncertainty of marginal abatement costs and marginal benefits emission taxes and carbon trading do not yield identical outcomes and that the relative slopes of the marginal abatement cost and marginal benefits curves ultimately determine the policy outcome. Therefore, both market-based instruments have advantages and disadvantages; policy-makers have to choose between uncertainty about carbon prices and uncertainty about emission reductions (see Murray et al., 2009).[4]

2.1.1 Emission Trading Schemes

In an emission trading scheme, the emission target (cap) is determined by the regulator, while the price for emissions is formed on the market by demand and supply of emission permits.

The regulator sets an individual cap for each installation included in the emission trading scheme as illustrated in Figure 2 and Figure 3 for an emissions trading system with only two installations. Without trading, the required emission reduction for plant 1 (from E_1 to E_1') would imply costs in the magnitude of the shaded area. Analogue, for plant 2 reaching the emission reduction target of E_2' would imply costs of the shaded area (see Figure 2). As illustrated in the graphs, plant 1 would have to incur higher costs per unit of emissions abated than plant 2 due to the steeper marginal abatement cost curve indicating that the exploitation of emission reduction potentials is more expensive for plant 1.

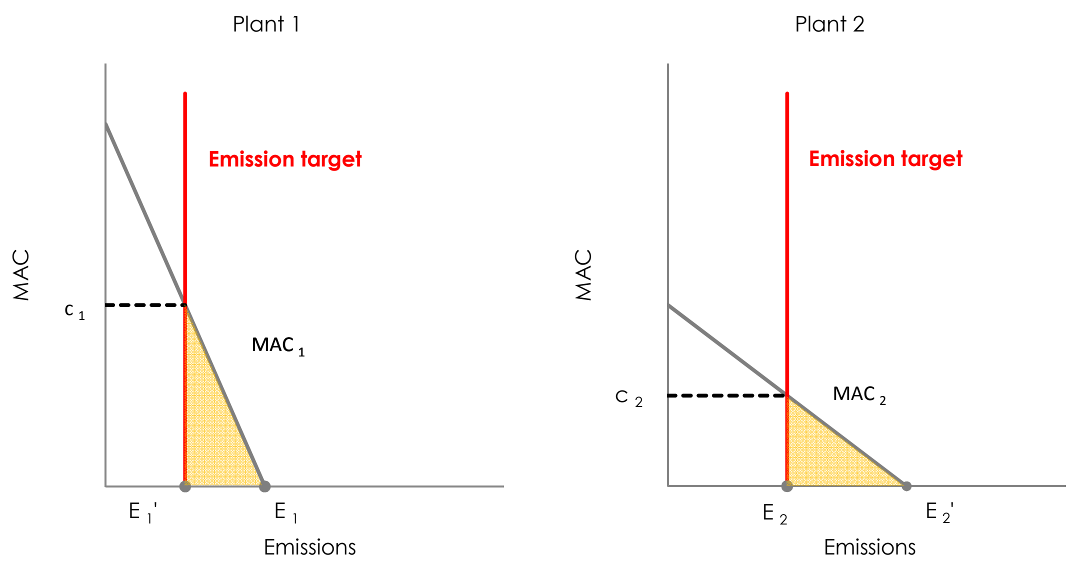

Figure 2. Emissions trading: Cost of emission reductions without trading

Source: Own illustration.

[4] From an investor's point of view, emission trading schemes entail higher uncertainty as the price is not fixed but formed on the market. Emission trading schemes, however, allow the reduction of emissions where they can be achieved at least cost.

Both installations could profit in a situation where emissions trading is allowed as illustrated in Figure 3. The price for the emission reductions (p), i.e. the price of permits, would be determined on the market based on the aggregate cap and the aggregate marginal abatement cost curve. At price p, plant 2 would reduce its emissions below its cap to the level of E_2'' and sell the certificates from the additional emission reduction to plant 1. Plant 1 in turn would reduce its emissions only to the level of E_1'' and meet its emission reduction target partly using the certificates bought from plant 2. Plant 2 would benefit from selling the certificates; plant 1 would benefit from the lower emission reduction[5].

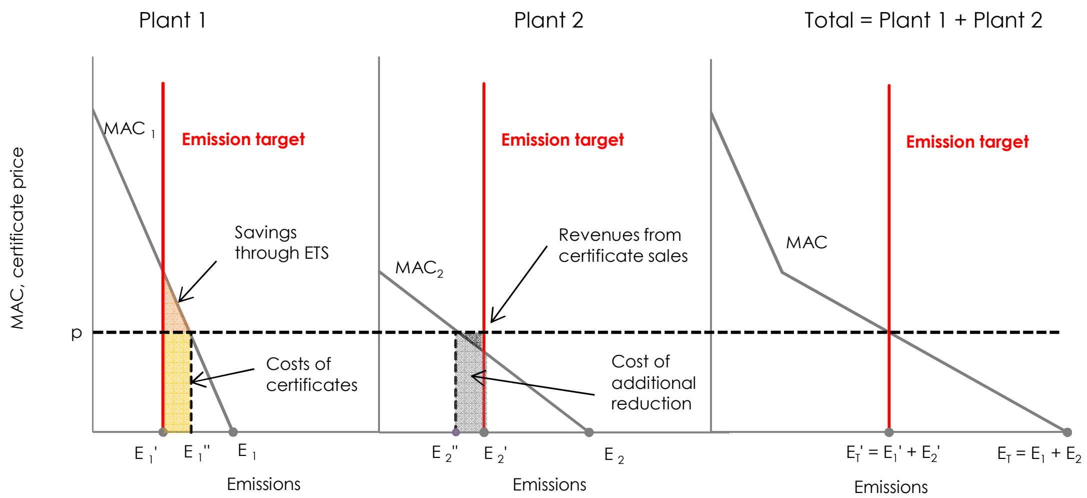

Figure 3. Emissions trading: Cost of emission reductions with trading

Source: Own illustration.

2.1.2 Carbon Taxes

In the case of a carbon tax, the price of CO_2 emissions is determined by the regulator while the level of emissions is the result of abatement activities, determined by the firms' adjustments to the tax and their respective marginal abatement costs; i.e. emissions are adjusted until the tax rate is equal to marginal abatement costs as illustrated in Figure 4.

[5] In economic theory, the result (i.e. the certificate price and individual emission reductions) is independent of the allocation method (auctioning vs. free allocation based on historical emissions ('grandfathering')): Grandfathering also involves costs for the installations covered by an emissions trading scheme, i.e. they represent opportunity costs. The opportunity cost of the certificates can be defined as the "revenue forgone by not selling the allowances, but by employing them in producing output" (Woerdman et al., 2008). The distributional effects of the different allocation principles, however, vary (see Woerdman et al., 2008; Hepburn et al., 2006; Cló, 2011)

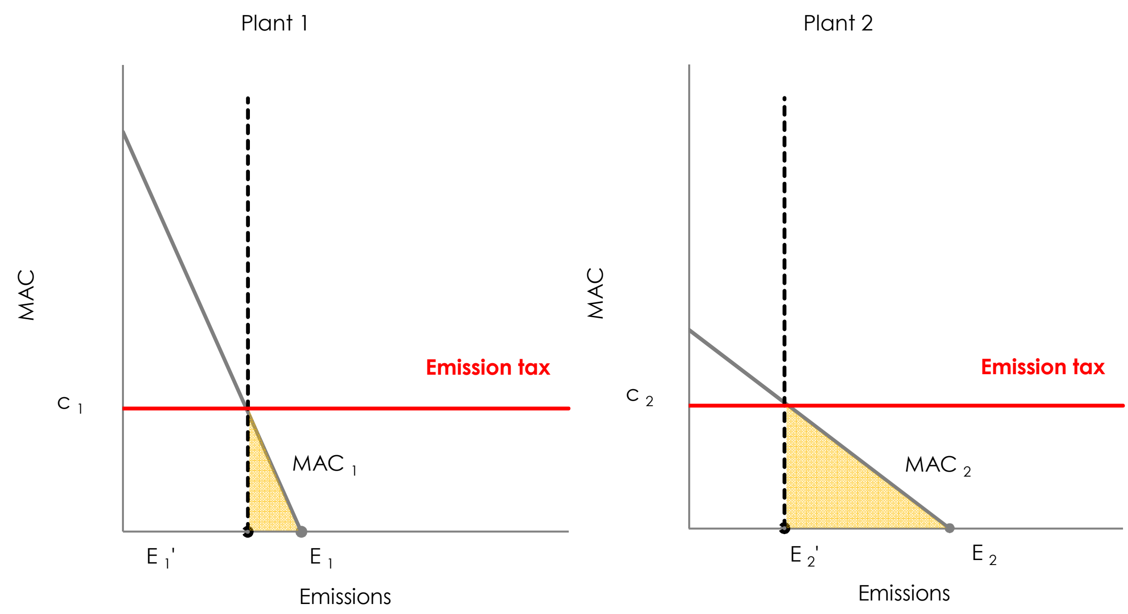

Figure 4. Carbon tax

Source: Own illustration.

As argued above, under uncertainty emission taxes and carbon trading do not yield identical outcomes. Therefore, both market-based instruments have advantages and disadvantages; policy-makers have to choose between uncertainty about carbon prices and uncertainty about emission reductions (see Murray et al., 2009). Currently policy is in favour of emissions trading over a carbon tax as it guarantees the achievement of a defined reduction target. In addition to the European Emission Trading Scheme, emissions trading schemes have e.g. been developed in Australia, in the US and in Japan (see Kettner et al., 2011b).

2.2 Economic Instruments for Renewable Electricity Support

The aim of renewable electricity support is to offset the higher cost of electricity from renewable energy sources thereby achieving a certain share of renewables in total electricity generation.

Generally, support schemes for renewable energy sources should reduce the economic risk associated with such projects, leading in consequence to an increased deployment of renewable energy sources. The policy measures reduce the project risk (primarily in the operational phase) through a remuneration of electricity from renewable sources. Through the design of the support system and the guarantee of stable conditions risk perception (regulatory risk) can be influenced thus increasing investment incentives (see Figure 5 and Kettner et al., 2009).

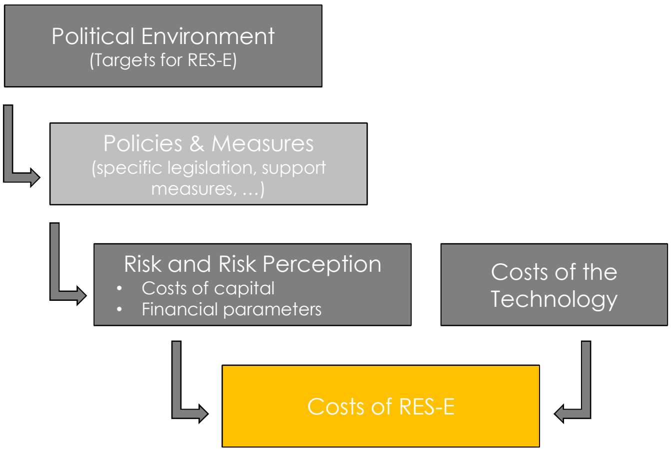

Figure 5. Effects of policy measures on the cost of renewable energy

Source: Adapted from Kettner et al. (2009).

For the promotion of electricity from renewable energy sources generally the following instruments can be distinguished:

- feed-in tariffs;
- feed-in bonus;
- quota systems with tradable green certificates;
- tendering schemes; and
- fiscal measures and other forms of support (investment subsidies, tax reductions or exemptions, low interest loans, etc.).

The support instruments are either price-based (feed-in system, bonus system) or quantity based (quota system, tendering scheme). In the following the different support instruments are described in detail.

2.2.1 PRICE-BASED INSTRUMENTS

The underlying principle of price-based instruments is that a specific ‘fee’ for each unit of electricity generated from renewable energy sources is paid. This fee is either a lump-sum compensation (feed-in tariff) or is paid in addition to the current market price (feed-in bonus). The level of compensation is related to the specific electricity generation costs (possibly including a risk premium) and is guaranteed for a certain period. The funding intensity is thus determined by the duration and the level of compensation.

The guaranteed compensation provides high investment security for the supported projects and favourable financing conditions. The revenues are predictable for the investors: In a feed-in tariff system, the only uncertainty is related to the development of operating costs. In the feed-in bonus system, the predictability is slightly lower as the revenues also depend on the future market price of electricity.

The tariffs and bonuses can be designed according to different criteria (see Kettner et al., 2009):

- Technology-specific tariffs can reflect differences in cost structures.
- Tariffs can also be differentiated according to location of the plants (resource availability) or their size (larger plants in general exhibit some economies of scale).
- Tariffs can be degressive (i.e. decreasing over time) in order to support learning and economies of scale and reduce producer surpluses.
- Tariffs can be differentiated by time of day or season in order to achieve a better match between supply and demand on the electricity market.

With respect to price-based instruments, the challenge lies in determining the “right” level of compensation, i.e. to avoid excessive or insufficient support. In theory, feed-in tariffs should be based on the marginal electricity generation costs. In fact, however, producer surpluses (the difference by which the compensation level exceeds production costs) can occur, when the production costs are comparably low (e.g. due to favourable locations). Producer surpluses can be reduced by technology-specific and differentiated tariffs (see Figure 6), which increase the static efficiency of the system. However, producer surpluses also offer potentials for research and development as well as for investments in less mature technologies, which contributes to technological diversification. Since the objective of renewable energy promotion does not only lie in achieving current renewable targets at the lowest possible cost, but also in developing future potentials, in terms of technological diversification also technologies should be supported that are currently still exhibit high specific electricity generation costs (see Kettner et al., 2009).

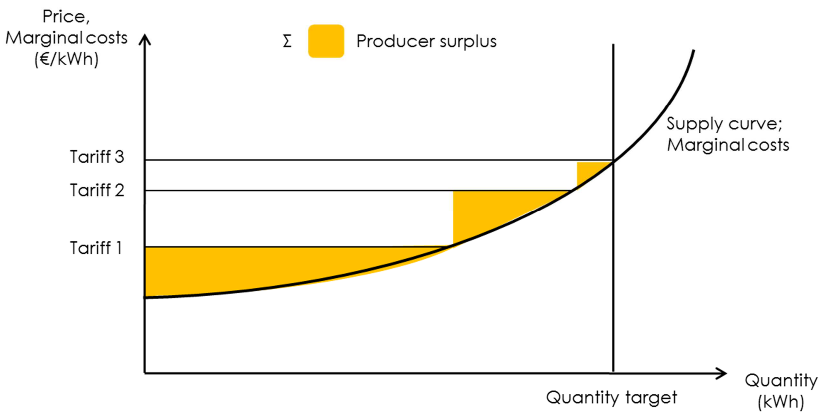

Figure 6. Producer surpluses in a model with differentiated feed-in tariffs

Source: Adapted from Kettner et al. (2009).

Degressive tariffs ensure dynamic efficiency, i.e. the realization of learning effects and cost reductions due to an increased implementation of the technologies. When in turn the marginal costs of electricity generation decrease, a further expansion of renewable electricity generation as well as rising producer surpluses (if untackled by a higher tariff degression) will occur. A pre-determined path for the degression of the tariffs can increase the transparency and predictability for investors. However, rising prices for inputs (e.g. fuel prices for biomass plants, prices for raw materials for plant construction such as steel) can also lead to an increase in electricity generation. In this case, temporary surcharges (such as for biomass in Austria in 2008) can be used to reduce the pressure on costs for plant operators (see e.g. Kettner et al., 2009).

Periodic reviews and adjustments of the tariffs that reflect changes in the production cost can be integrated in the design of a support scheme in order to maintain the effectiveness and efficiency of the system.

In case of feed-in tariffs, an increase in electricity prices does not affect the amount of electricity generated from renewable sources, but reduces the difference between the market price and the feed-in tariff. In a bonus system, in contrast, with increasing market prices the specific remuneration for renewable electricity increases as well as the exploitation of renewable energy (see e.g. Kettner et al., 2009).

The costs of the renewable support are passed on to the end-users. With respect to feed-in tariffs the costs of the total remuneration are passed, while for the bonus system only the surcharges compared to the market price are passed on to the consumers.

The main advantage of feed-in tariffs − and to a somewhat lesser extent also of bonus systems − is that the financial risk for investors and plant operators are minimized. Empirical studies generally also show a high effectiveness and high efficiency of the instrument (see e.g. Kettner et al., 2009).

2.2.2 QUOTA SYSTEMS WITH TRADABLE GREEN CERTIFICATES

In quota systems, a minimum share of electricity from renewable sources is set as target. Evidence of the achievement of the renewable targets has to be provided by the parties (electricity generators, traders) via tradable green electricity certificates. The compensation is based on the market price of electricity and the market price of the green certificates, i.e. the compensation is formed on two separate markets. Future revenues are hence subject to considerable uncertainty as both remuneration components are variable (see e.g. Kettner et al., 2009).

The value of allowances is determined by the quantity target (supply and demand on the certificate market). A price ceiling is established by the fines that have to be paid by a party in case the target is failed. Penalties should be set at a level well above the average certificate price in order to establish a functioning market (i.e. to provide an incentive for buying and selling certificates) and to guarantee the environmental effectiveness of the system (see e.g. Kettner et al., 2009).

The quantity target should be set ex ante in quota systems; it should rise continuously − in accordance with a defined path − and be valid over a longer period of time.

Quota systems with tradable green certificates in theory lead to competition among electricity generators and thereby to the development of cost-effective technology options (see Figure 7), which should lead to lower overall system cost compared to feed-in tariffs (see e.g. Kettner et al., 2009).

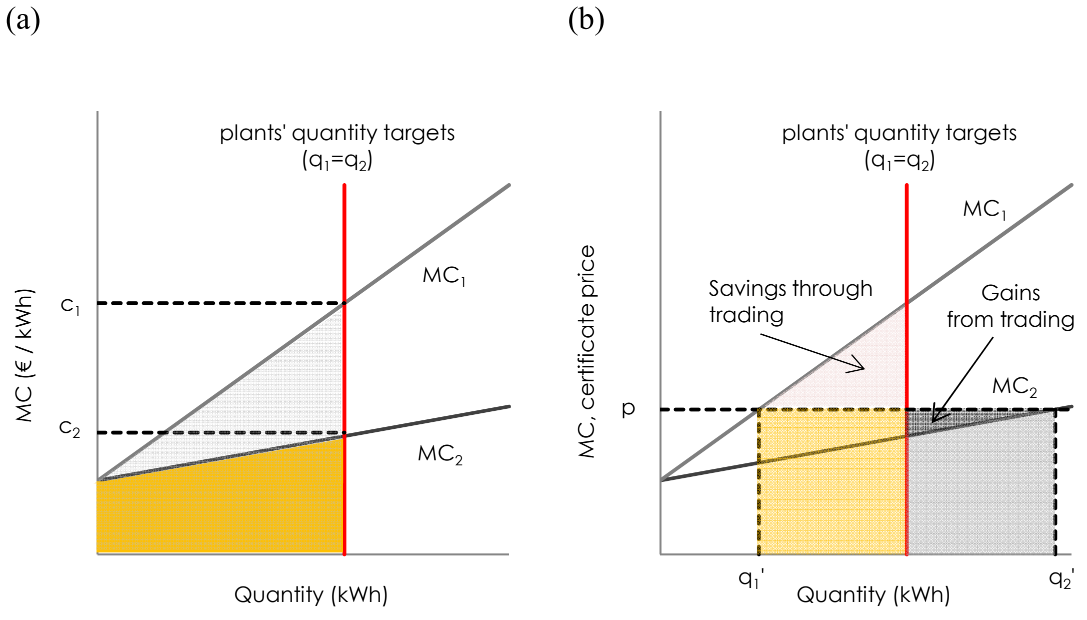

Figure 7. Quota systems with tradable green certificates

Source: Adapted from Kettner et al. (2009).

The principle of a tradable green certificate scheme can be illustrated using an example with only two electricity generators. Figure 7 shows a situation where two producers have the same renewable target (q_1, q_2), but use different technologies with different marginal costs (MC_1, MC_2). Without trading, each generator fulfils its RES target of q_1 and q_2 respectively; the costs for meeting the target for producer 2 are illustrated by the orange triangle, the costs for producer 1 are illustrated by the orange and the grey triangle (see Figure 7 (a)). In a situation with trading, the producer that faces higher marginal costs (generator 1) will produce less than his quota (q_1') and buy the missing certificates. This results in a saving to him in comparison to meeting the target on his own as indicated in Figure 7. Generator 2, in contrast, will produce more than required by his quota (q_2') and can sell surplus allowances.

In practice, the financing conditions are unfavourable for plant operators in quota systems as due to the uncertain revenues risk premiums are added to the capital costs in order to hedge against the price risk. These higher costs of capital may lead to higher producer surpluses and lower technological diversity, since investments will be primarily limited to lower-risk, mature technologies. In order to reduce the risk for plant operators, minimum prices for the certificates can be defined (see e.g. Kettner et al., 2009)[6].

The cost of the support, i.e. the certificate prices, will be first incurred by the parties covered by the quota obligation (electricity generators, traders) and then be passed on to the consumers.

Quota systems usually aim at a general promotion of electricity from renewable energy sources, i.e. there is no technological differentiation. Technology-specific differentiation of the certificate market is, however, possible, but leads to small market segments and lesser liquidity if carve-outs are used. Since also a weighting of issued certificates according to the technology type is possible less liquidity on the certificate market may not represent a problem under these circumstances (e.g. Italy, UK, Romania, (likely to be implemented also in Poland)).Technology-specific differentiation also reduces the risk of windfall profits for mature technologies.[7]

Another aspect of a quota system with tradable green certificates are transaction costs for the plant operators who need to carry out transactions on the electricity and on the certificate market (as in emission trading schemes, see above).

2.2.3 Tendering Schemes

Tendering schemes represent another quantity-based instrument, in which projects are selected in a competitive process by specifying a desired capacity, production volume or specific technologies. The projects that are selected in this process usually receive long-term purchase contracts; the price that is paid for the electricity is determined in the competitive process (see e.g. Kettner et al., 2009).

Changes in electricity prices have no impact on the quantity produced in a tendering system, as the quantity produced is determined exogenously (i.e. ex-ante).

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6 Minimum prices for tradable green certificates exist e.g. in Belgium.

77 If the diversity of renewable electricity generation technologies (and especially cost differences) are not taken into account in the design of a quota system, investors in mature renewable technologies might gain considerable windfall profits when the tradable green certificate scheme operates at "at the edge of the marginal RES-E technology" (Verbruggen, 2004).

The risk for plant operators lies in the case of tendering schemes on the one hand in the uncertainty of the competition process and on the other hand in the fact that the actual costs might exceed the projected costs. Great Britain and Ireland have abandoned tendering schemes due to a lack of success, as even projects that succeeded in the competitive process had not been realised due to insufficient profitability. Even the planning effort for the tenders can be significant for the administrative entities on the one hand and for the non-winning bidders on the other hand (see e.g. Kettner et al., 2009).

The financing of the tendering scheme can be − depending on the definition of the model − incurred by public entities or by the final consumers.

Tendering schemes are regarded more appropriate for single, clearly defined projects or project categories than for general support systems (see e.g. Kettner et al., 2009).

2.2.4 FISCAL INSTRUMENTS

Fiscal measures − such as tax incentives, investment subsidies, loans, etc. − are often used as complementary support measures. These instruments reduce the capital costs of renewable electricity projects (investment promotion, flexible depreciation models, loans) or the operating costs (tax reductions, exemptions). One drawback of fiscal instruments is their dependence on the public budget, i.e. the level of available funds can vary from year to year. In case of budget constraints, funding might also be suspended entirely. In order to provide a stable investment signal, these fiscal incentives should hence also be guaranteed ex ante for a few years in order to create predictability and reduce the risk (see e.g. Kettner et al., 2009).

2.2.5 SUMMARY OF PRICE-BASED AND QUANTITY-BASED INSTRUMENTS

The composition of the remuneration for electricity from renewable energy sources as well as the market risk for electricity generators in the price- and quantity-based schemes are summarised in Figure 22 schematically. In a tradable green certificate scheme, the electricity generators receive a two-part compensation, the market price of electricity and the price of the certificates. As both components are variable, green certificate schemes are connected with a comparably high risk for the plant operators. In a feed-in bonus system, the remuneration also consists of two components, the (variable) market price of electricity and the fixed bonus for renewable electricity. Compared to tradable green certificate schemes, the market risks are partly reduced by the fixed remuneration component[8]. Feed-in tariffs (or tendering schemes) in contrast consist of a single, fixed compensation component. Feed-in tariffs hence largely remove the market risk related to renewable electricity projects (see e.g. Kettner et al., 2009).

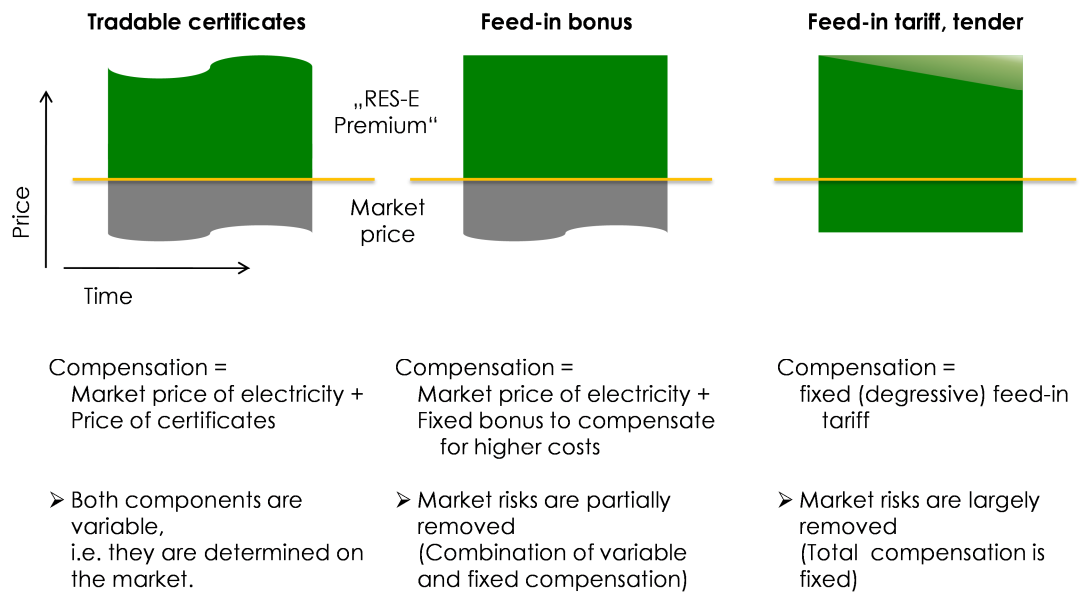

Figure 8. Remuneration of electricity from renewable energy sources in different support systems

Source: Adapted from Kettner et al. (2009).

[8] A fixed premium tariff as describe here is only one of different feed-in premium models. Other models are e.g. floating premiums or contracts for difference.

3 Greenhouse Gas Mitigation Policies and Renewable Electricity Support in the EU

3.1 The EU Emission Trading Scheme

In the EU there has been a lively discussion whether to opt for an emissions trading scheme or for a carbon tax as a policy instrument for meeting the emission reduction target as committed to in the Kyoto Protocol. While the EU initially has initially been in favour of a carbon tax, eventually an emissions trading scheme was set up, partly due to lobbying activities of the industry (see e.g. Skjærseth and Wettestad, 2008).

In the following sections, the main characteristics of the EU ETS are summarised as in Kettner et al. (2010).

The EU ETS features a very short history. In 2000 the Green Paper on greenhouse gas emissions trading within the European Union (European Commission, 2000) was issued, and several design issues for such a system were analysed (Stewart and Sands, 2000). The 'Directive 2003/87/EC was adopted by the European Parliament and of the Council on 13 October 2003 establishing a scheme for greenhouse gas emission allowance trading within the Community and amending Council Directive 96/61/EC', which defines the benchmarks and criteria used to operate the system and identifies the framework governing national legislation.

3.1.1 Provisions in the pilot phase and the Kyoto period

Since the beginning of 2005, the European Union regulates CO_2 emissions from energy intensive industries in the framework of the EU ETS. In the following paragraphs the main characteristics of the emissions trading scheme in the first trading phase that ran from 2005 to 2007 ('pilot phase') and the second trading phase that runs from 2008 to 2012 and hence coincides with the Kyoto commitment period are summarised.

Coverage of the EU ETS

In the pilot phase the EU ETS was limited to four emissions intensive sectors:

- energy activities (combustion installations with a rated thermal input exceeding 20 MW, mineral oil refineries, coke ovens);
- production and processing of ferrous metals (metal ore sintering or roasting, production of pig iron and steel);
- mineral industry (cement clinker, glass, ceramic products); and
- other activities (pulp and paper).

For the second trading period, some Member States including Austria, France and the Netherlands unilaterally also included installations emitting nitrous oxide (Capoor and Ambrosi, 2008).

Allocation Principles

Using guidelines provided by the Commission, each Member State decided on the total national emissions allowances to be allocated to the installations involved. These EU Allowances (EUAs), which were issued for the pilot phase, were tradable between 2005 and 2007. EUAs issued for the Kyoto commitment period 2008-2012 are also tradable in the post-Kyoto period, that means from 2008 banking of allowances is allowed. At least 95% of allowances in the first trading phase and 90% in the second trading phase are allocated free of charge in accordance with the installations' historical emissions ('grandfathering'). The rest of the certificates can be auctioned by the Member States.[9]

Definition of the Cap

The Member States are responsible for allocating emission allowances to sectors and installations in a National Allocation Plan. In the first two trading phases the EU wide cap hence has been the result of the individual caps set by the individual Member States.

The EU provided guidelines (European Commission, 2003) for the allocation process, but left the allocation details up to Member States. Nevertheless, National

[9] In the first trading period, only four Member States decided to auction a small share of allowances (Betz and Sato, 2006).

Allocation Plans had to be approved by the Commission, which set criteria in Directive 2003/87/EC with respect to the allocated quantities of allowances.

In Annex III of the Directive, criteria for the design of the National Allocation Plans are provided. These include consistency with the Member State's emission target and projected progress towards fulfilling the target, considerations regarding the activities' (technical) potential for reducing emissions, consistency with other Community legislation and policy instruments, avoidance of unduly favouring certain undertakings (related to State aid provisions), required information on the treatment of new entrants, and early action.

For the second trading period Member States' National Allocation Plans were cut by 10.4% in the Commission review. Only caps of four EU Member States (Denmark, France, Slovenia and UK) were not revised. Caps proposed by the new Member States were most strongly corrected downward (Capoor and Ambrosi, 2008).

Linking with the Kyoto mechanisms

Certified Emission Reductions (CERs) from the Clean Development Mechanism (CDM) have been acknowledged in the EU ETS since 2005, and Emission Reduction Units (ERUs) from the Joint Implementation (JI) mechanism for offsetting domestic emissions are acknowledged since 2008, with Member States determining the limit on the linkage which, in turn, has to be approved by the Commission.

Penalties for Non-Compliance

Emissions are strictly monitored and must be verified. Penalties for non-compliance are €40 per tonne of CO_2 in Phase 1 and €100 per tonne of CO_2 in Phase 2.

3.1.2 PROVISIONS FOR THE PERIOD 2013 TO 2020

The evaluation of the pilot phase led to essential changes of the design of the EU trading system for the period 2013 to 2020 in the context of the EU energy and climate package (European Commission, 2008a, 2008b). The revision of the trading system accounts for lessons learnt in the first trading phase 2005-2007.

Definition of the Cap

The overall 2020 GHG reduction target is split between the sectors subject to the European Emissions Trading Scheme, the ETS sectors, and the remaining Non-ETS sectors (European Commission, 2008a, 2008b). Approximately 40% of EU-27 GHG emissions in 2005 originated from the ETS sectors, whereas the Non-ETS sectors were responsible for approximately 60%. For the Non-ETS sectors an overall emissions reduction of 14% compared to 2005, for the EU ETS sector an emissions reduction of 21% were proposed by the Commission. A major change compared to the first two trading periods is the proposed EU-wide cap from 2013 on instead of national caps to achieve the EU reduction target (European Commission, 2008a, 2008b).

Allocation principles

Article 10 of Directive 2009/29/EC stresses that auctioning should be the dominating allocation method. Sectoral differences in particular with regard to the potential of carbon leakage are taken into account. Grandfathering of allowances for exposed sectors is allowed for, so that effectively auctioning is focused on the energy sector.

Directive 2009/29/EC differentiates between three groups of sectors and respective allocation procedures:

- *Power sector* − with full auctioning from the beginning[10].
- *"Normal" sectors* − without potential carbon leakage and 80% free allocation at the beginning reduced to 30% in 2020.
- *"Exposed" sectors"* − with potential carbon leakage and up to 100% free allocation.

The difference in allocation methods between sectors mirrors competitiveness concerns of the Commission as well as well as preventing unwanted GHG shifts to countries outside the emission trading system. The underlying measure for competitiveness disadvantages is seen in an increase in costs due to allowance prices that cannot be passed on in prices and that would lead to a significant loss in market

[10] With exceptions for some New Member States.

shares. For sectors with grandfathering allocation of allowances is based on Community-wide benchmarks.

The power sector is the only sector subject to full auctioning from 2013 on (except for some new EU Member States) as it is assumed that any cost increases due to emissions trading can be passed on in prices. Exceptions are foreseen for electricity producers that also produce heat with efficient cogeneration technologies and district heating. Transitional free allocation as well as free allocation for sectors or sub-sectors with the risk of adverse competitiveness effects should follow community-wide harmonized rules. This should guarantee a level playing field for all installations within the ETS.

Exclusion of small installations

Evidence from the first trading period showed that a large number of small installations were included in the ETS that account only for a small share on total GHG emissions. Member States are allowed to exclude small installations from the ETS if measures are in place to monitor their emissions and to ensure that equivalent emissions reductions will take place (Article 27).

An installation is considered small if it has a rated thermal input of less than 25 MW and emissions of less than 25,000 t of CO_2e per year. On the one hand the exclusion of small installations could reduce transaction costs from trading for these installations. On the other hand Member States would be responsible for regulatory measures that result in emission reductions in line with the emission path of the EU ETS.

Provisions against excessive price increases

In the Directive 2009/29 a rather weak formulation in order to insure against excessive price increases is included (Article 29a). It states that if the allowances price for more than six month exceeds the average of the last two years, Member States might be allowed to bring forward the auctioning of some allowances or auction up to 25% of the allowances in the new entrants reserve.

3.1.3 PERFORMANCE OF THE EU ETS IN THE PERIOD 2005 - 2011

This section provides an overview of the performance of the EU ETS in the period 2005 to 2011 focussing on the stringency of the emission caps on European, Member State and sector level as well as on the development of the carbon price in the EU ETS.

For the analysis of the stringency of the cap the concept of "long" and "short" positions as put forward in Kettner et al. (2008) is used. The analysis is based on the following indicators:

- the short or long position of an installation as the difference between allocated and verified emissions of an installation;
- the gross long (short) position of a country as the sum of all long (short) positions of installations in a country; and
- the net long (short) position of a country as the difference of gross long positions and gross short positions of a country if this difference is positive (negative).

Data on allocation and emissions have been derived from the EU ETS on installation level and have been assigned to sectors using information from the Member States' National Allocation Plans. The analysis does only include those installations for which data on allocation and emission were available for the whole period 2005 to 2011[11]. Due to the limited availability of emissions data, Bulgaria is not included in the analysis.

Stringency of the EU wide cap

In the first as well as in the second trading phase the EU wide ETS cap is the result of the national emission caps set by Member States in their National Allocation Plans (see above). In the ETS pilot phase substantial over-allocation of emission allowances was observed in most EU Member States and the overall EU emission cap was not stringent for any year. Due to rising emissions in the EU ETS over the period 2005 to 2007 the surplus of allowances or the net long position declined, however, from year to year: While the EU ETS was in a net long position of 3.47%

[11] An exception applies for Romanian installations as Romania joined the EU ETS not until 2007.

in 2005, for 2006 and 2007 a net long position of 1.23% and 0.73% was observed respectively (see Figure 9 and Kettner, 2012).

For the second trading phase the European Commission took more influence in the Member States' National Allocation Plans. Most proposed national caps had to be adjusted downwards by the Member States after the European Commission's review process. With cuts of 47% to 56% the Baltic States faced the strongest adjustments (see Capoor and Ambrosi, 2008). For 2008, total allocated allowances were reduced by 278 Mt (13%) compared to the first trading phase (from 2,023 Mt to 1,790 Mt). EU ETS emissions, in contrast, only showed a minor decline of 4% from 2,053 Mt to 1,949 Mt between 2007 and the first trading phase (see Kettner, 2012).

For 2008 the overall EU cap was binding with verified emissions exceeding allocated allowances on aggregate by 8.88%. Under the assumption of a regular development of economic growth and production activities this would suggest an increased incentive for emission abatement measures resulting from the cap and rising allowance prices. For 2009, however, a totally different picture was observed: The unexpected exogenous shock of the economic crisis to the sectors/installations in the trading system translated into a sharp drop in verified emissions. Allocation again exceeded verified emissions showing a net long position of 4.01%. Although 2010 already exhibits a recovery of the economy which also results in a modest rise in emissions, the EU wide emissions cap is again not binding, i.e. a net long position of 2.82%, is observed. 2011 shows as net long position of 5.65% due to slow economic development and warm winters (see Figure 9 and Kettner, 2012).

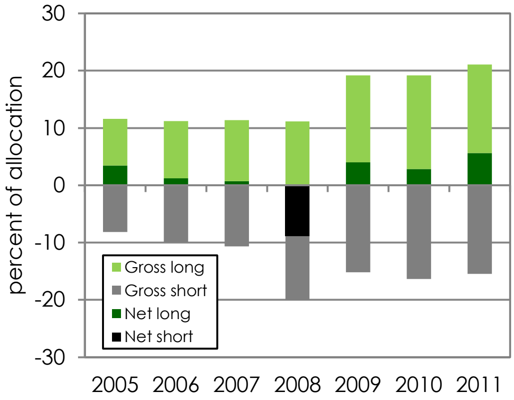

Figure 9. Stringency of the EU wide emission cap, 2005 - 2011

Source: Own illustration based on CITL.

Stringency of national caps

The Member States' shares in total allocated allowances reflect on both the size and the industry structure of the countries. With 23% of total EU allocated allowances the largest share accrues to Germany which, together with Poland, Italy and the UK, accounts for more than half of the emissions covered by the EU ETS (see Figure 10).

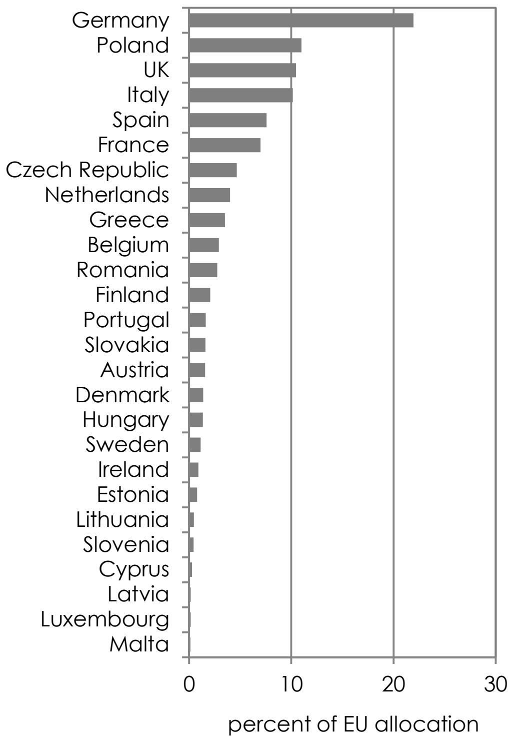

Figure 10. Member States' shares in EU allocation

Source: Own illustration based on CITL.

In Figure 11 the long and short positions by countries in the first and second trading phase are compared. As indicated in the figure, the market on aggregate was in a net long position in the first trading period. On average over the three years, the market was long with 37 million of certificates corresponding to 1.8% of allocated allowances. This net long position is the balance of a 231 Mt (11.4%) gross long position, the relative amount of allowances allocated to installations above their verified emissions, and a 194 Mt (9.6%) gross short position, the relative amount of allowances below their verified emissions. As indicated in Figure 2, only six out of the 26 countries were in a short position up to 18.8% (Ireland) in the first trading period. The remaining 19 countries were long up to 43.4% (Lithuania).[12]

In the first four years of the second trading phase the EU ETS on aggregate was in a net short position of 0.9% or 16.4 Mt that was the result of a 16.7% gross short position and a 17.7% gross long position. Five out of the 26 countries were in a net short position; the remaining 21 countries exhibited a net long position. The highest relative net long position showed for Slovakia with 31%, the highest percentage net short position accrued to Germany with 15%.

[12] In absolute terms, the highest net short position was realised in the UK with 36 Mt while the highest net long position showed for Poland with 29 Mt.

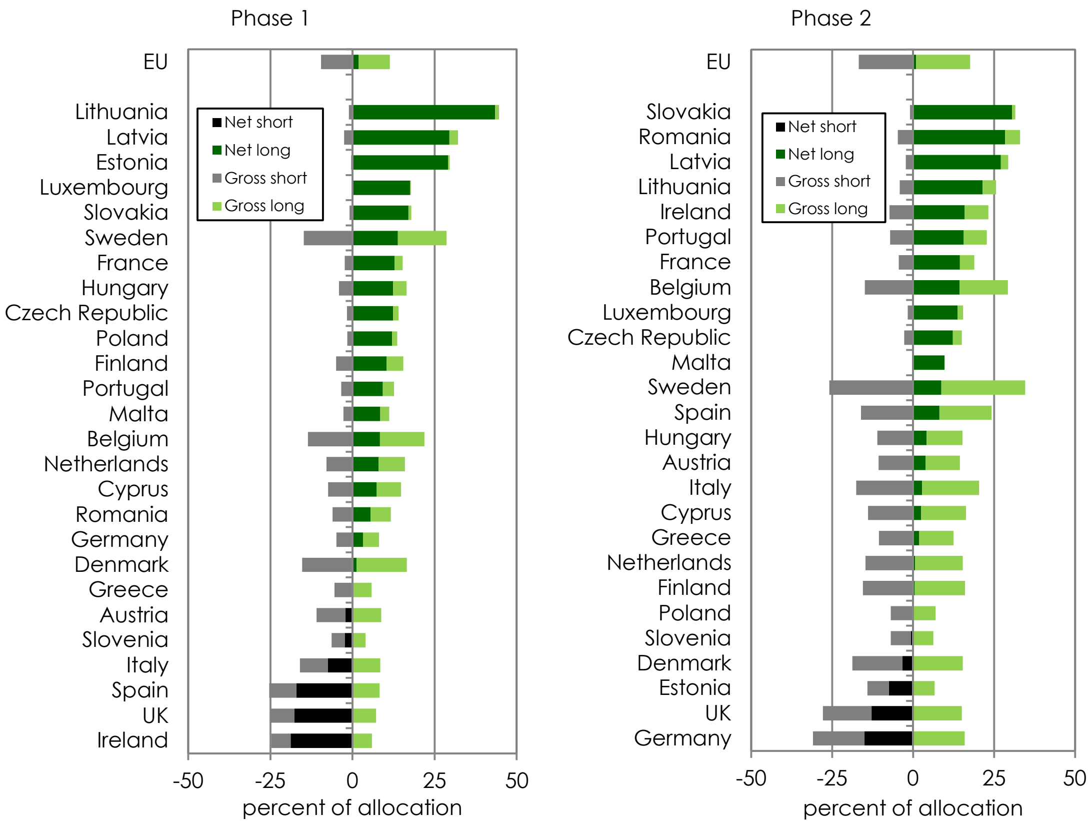

Figure 11. Stringency of national emission caps

Source: Own illustration based on CITL.

Figure 11 shows that between the pilot phase and the first years of the Kyoto period substantial changes in allocation discrepancies can be observed for several Member States: In the first trading phase the New Member States generally exhibited higher net long positions than the EU-15 and only one of the New Member States (Slovenia) but five EU-15 countries were in a net short position. In the second trading phase these regional differences largely disappeared as a result of the Commission's intervention in National Allocation Plans. Figure 11 furthermore illustrates that differences in the stringency of the installations' reduction targets have increased in the second trading phase compared to the first trading phase.

Stringency of sectoral caps

On the sector level, the sector 'electricity and heat' dominates the EU ETS in both trading phases (see Figure 12). In the first trading period almost 60% of total allocated allowances in the EU accrued to this sector. The sectors 'iron and steel' and 'cement and lime' each accounted for approximately 9% of the total EU allowances. In the second trading period the power and heat sector's share in total EU allocation declined by approximately 7%. The shares of the other sectors in turn slightly increased, especially for the sectors 'iron and steel' and 'cement and lime' (see Kettner, 2012).

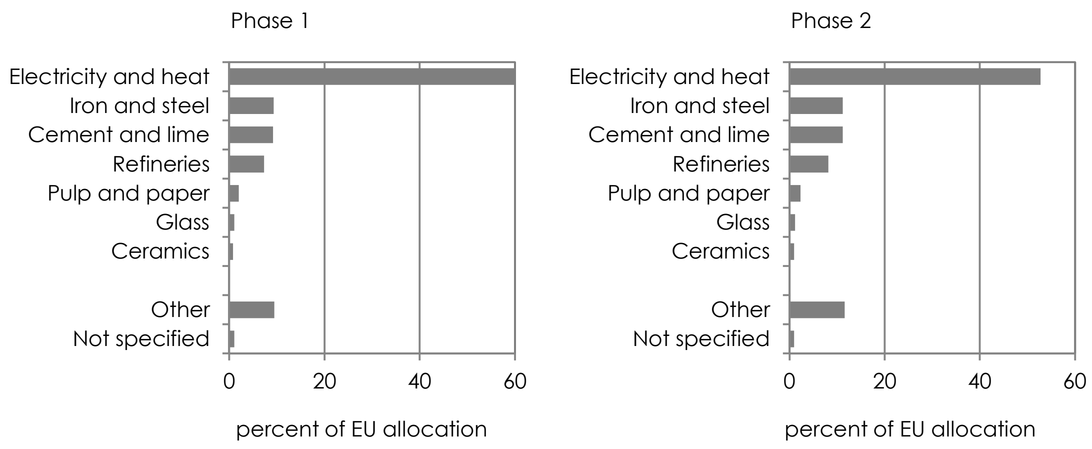

Figure 12. Sectors' shares in EU allocation

Source: Own illustration based on CITL.

The stringency of sectoral allocation caps in the first two trading phases is compared in Figure 12. In both trading phases, the sector 'power and heat' has been the only sector in a net short position, i.e. only in this sector verified emissions on average exceeded allocated allowances. The net short position of the energy sector was even more pronounced in the second trading phase (19% compared to 5% in the EU ETS pilot phase) illustrating also its lower share in allowance allocation as described above. All other sectors in contrast showed rather pronounced net long positions in both trading periods, i.e. in these sectors allocation significantly exceeded verified emissions. The highest surplus of certificates is observed for the sectors 'ceramics', 'iron and steel' as well as for 'pulp and paper'.

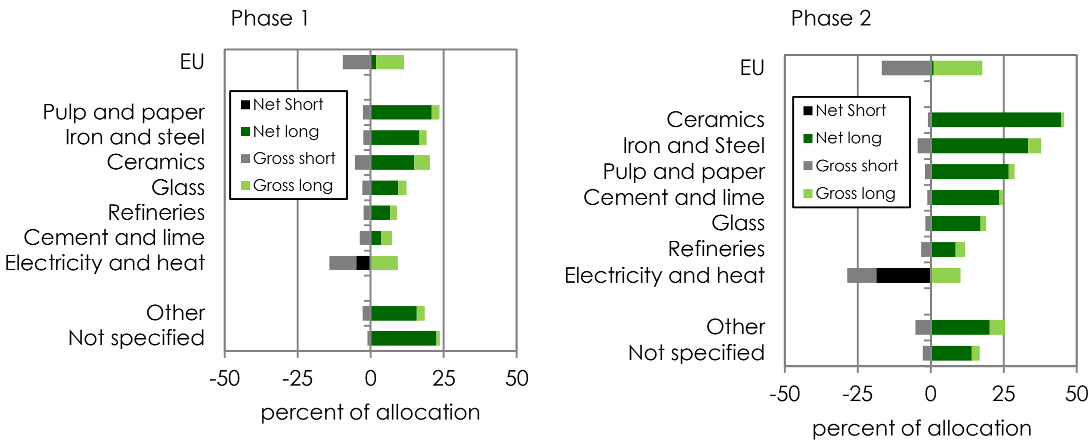

Figure 13. Stringency of sectoral emission caps

Source: Own illustration based on CITL.

On Member State level, however, the position of the sector 'electricity and heat' is not as clear-cut. On average, in the first trading phase the 'power and heat' sector was in a net short position in eleven countries (Figure 14). With 52% the Spanish electricity and heat sector exhibited the highest net short position[13].

In the second trading phase, the sector power and heat has been in a net short position in 16 out of the 25 countries. The highest net short position in percent of allocated allowances arose in Sweden with 140% where a strict cap was imposed on installations in the sector.[14] Ten countries were in a net short position up to 36% in Slovakia; in general the highest net long positions of the sector showed for New Member States.

Compared to the first trading phase a slightly higher spread of allocation discrepancies, i.e. more pronounced gross long and gross short positions, was observed within Member States. The overall spread of long and short positions remained, however, small within the sector.

[13] This high net short position resulted from the fact that in Spain in 2007 no allowances were assigned to oil and gas power plants and a comparably strong cap in the years 2005 and 2006 (see Kettner et al., 2011c).

[14] As elaborated in Kettner et al. (2011c), the reason for the restrictive allocation of allowances were the higher emission reduction potential in electricity and heat generation and that the sector is "not exposed to competition from other countries outside the European trading scheme to any significant extent" (Swedish Ministry of Sustainable Development, 2006).

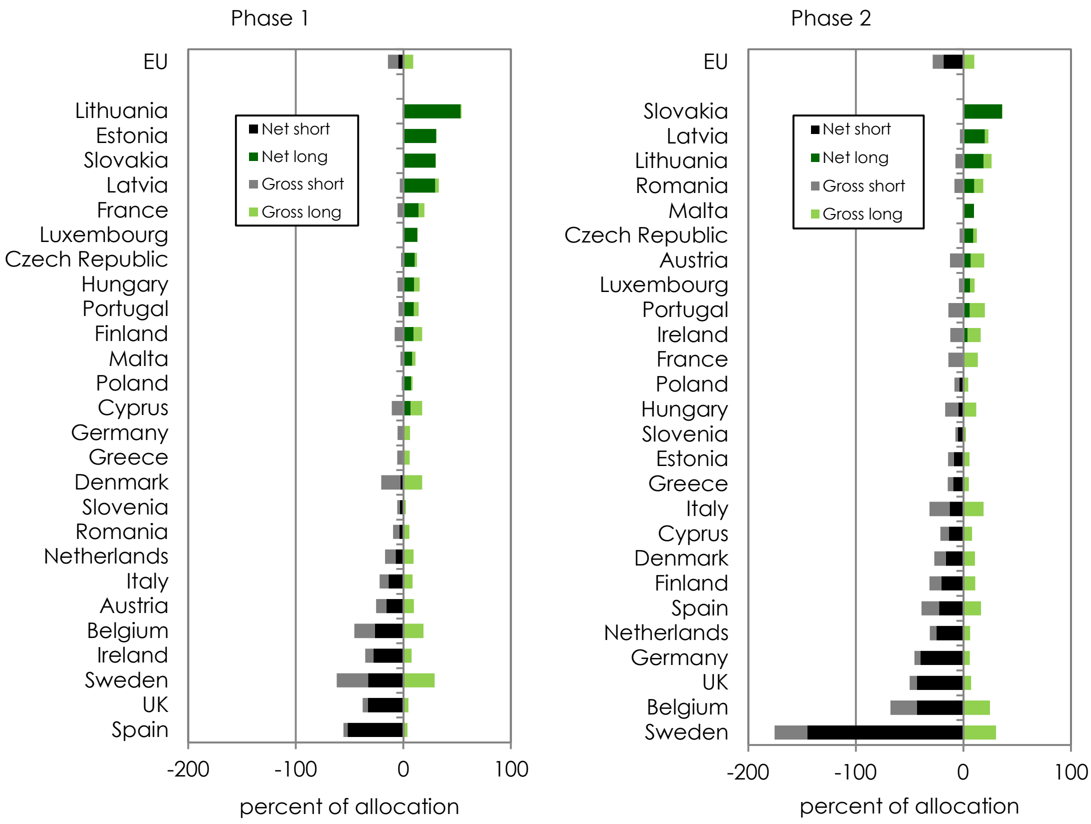

Figure 14. Stringency of the emission cap for 'power and heat' by Member State

Source: Own illustration based on CITL.

Price developments

The emissions cap imposed by the EU ETS should create a stable price signal for investments in low carbon technologies. Since its start in 2005, the EU ETS has, however, not succeeded in providing a stable price signal (see e.g. Kettner et al., 2010; Kettner et al., 2011a; Kettner et al., 2012). Between 2005 and spring 2006 carbon prices rose from € 7 to € 30 as companies expected scarcity of emission certificates and energy prices rose. When the verified emissions of 2005 where published in spring 2006 prices for certificates for the pilot phase plumped, as no banking of allowances between the first and the second trading phase. Prices for certificates valid for the second trading phase in contrast increased driven also be rising energy prices. In fall 2008, carbon prices, however, declined again in the course of the financial and economic crisis as companies sold their surplus allowances in order to improve their cash flow or in anticipation of decreasing production. Since the Greek crisis prices have further declined. As of October 2012 carbon prices in the EU ETS range between to € 7.6 and € 8.3 per ton of CO_2 (Point Carbon, 2012).

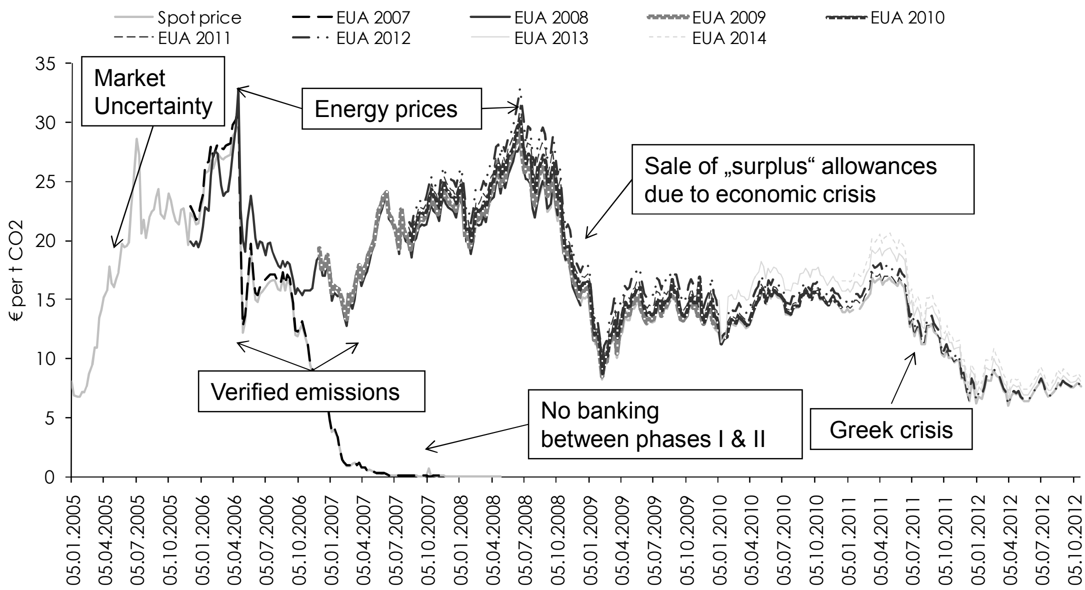

Figure 15. Price development in the EU ETS, 2005 - 2012

Source: Adapted from Kettner et al. (2012).

Further economic development will be one of the key factors determining allowance prices in the third trading period. In the impact assessment of the European Climate and Energy Package (2008c) a carbon price of € 49 was estimated as a precondition for meeting the 2020 greenhouse gas reduction targets assuming a business as usual growth path. Given the current prospects for economic development, this estimate can be interpreted as an upper boundary for the price development in the post-Kyoto period until 2020.

For the period 2020 to 2050, estimates of the carbon price range between € 20 and € 370 per ton CO_2 depending on the scenario assumed in the '*Energy Roadmap 2050*' or the '*Roadmap for moving to a competitive low carbon economy in 2050*' (European Commission, 2011a, 2011b, 2011c, 2011d). For the medium term (2030), carbon prices in the range of € 36 to € 60 per ton CO_2 are estimated. A carbon price of € 36 corresponds to the price level assumed in the reference scenario of the EU's roadmap to a low carbon society where the long term climate targets defined are not met; a price of € 60 respectively corresponds to the price assumed in the most ambitious decarbonisation scenario without CCS.

3.2 Renewable Electricity Support in the EU

3.2.1 Renewable Electricity Generation in the EU: Targets and Status Quo

The renewables directive (EC Directive 2009/28) defines a 20% share of renewable energy sources in gross final energy consumption as target for the European Union for 2020. This overall 20% target is broken down to mandatory national targets for the overall share of energy from renewable sources in gross final energy consumption that vary between Member States and a mandatory share of energy from renewable sources in the transport sector of 10% for all Member States in 2020[15].

The share of renewable energy sources in gross final energy consumption (S_{RES}) is calculated according to equation (1)[16]

$$S_{RES} = \frac{F_{RES}+E_{RES}+H_{RES}}{F+DL+OC} \tag{1}$$

where F_{RES} denotes final consumption of renewables, E_{RES} and H_{RES} denote electricity and heat generation from renewable energy sources respectively, F denotes final energy consumption and DL and OC represent distribution losses of electricity and heat and the energy sector's own consumption of electricity and heat respectively. Electricity generation from hydro power and wind power is normalised for the calculations according to Annex 2 of Directive 2009/28.

The Member States' targets for energy from renewable sources have been defined in an approach that includes a flat-rate for all Member States (i.e. an equal increase in each Member State of 5.5%) but also takes into account the countries' GDP as well as the national status of renewable energy use. Furthermore, the targets must not exceed a share of 50% (Nakicenovic et al., 2008). Figure 16 illustrates the Member

[15] The 10% target for the transport sector can be met by increasing the share of biofuels as well as by increasing the share of renewable electricity generation in the transport sector.

[16] See Article 3 of Directive 2009/28.

States' the shares of renewable energy sources in the based year 2005 as well as their renewables targets as defined in Annex 1 and compares it with the current shares of renewables.

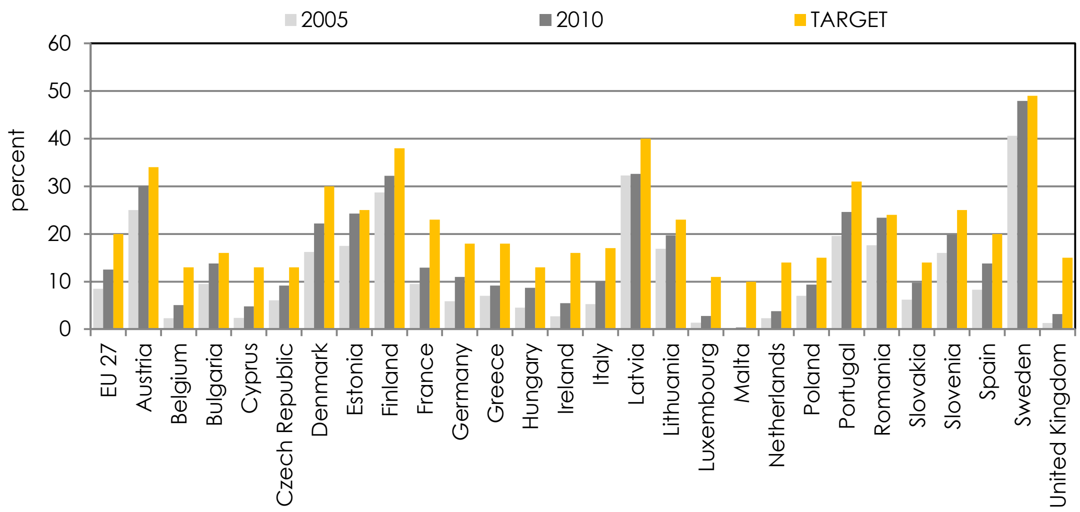

Figure 16. Member States' targets for the shares of renewables and actual shares in 2010 in percent

Source: Own illustration based on Eurostat.

Figure 17 provides a disaggregation of the Member States' shares of renewable energy sources in gross final energy consumption in 2010 by energy source. Sweden exhibits the highest share of renewable energy sources (47.9%) followed by Latvia (32.6%), Finland (32.2%) and Austria (30.4%). In all Member States, biomass accounts for the largest share of renewables. Hydro power and wind power also make significant contributions to the share of renewable energy sources. Solar energy and geothermal energy are of comparably low importance.

The Member States' shares of renewable energy sources in electricity generation in 2010 are shown in Figure 18. In the EU-27 the share of renewables amounted to 19.9% in 2010. The Member States' shares ranged between 0% in Malta and 61.4% in Austria.

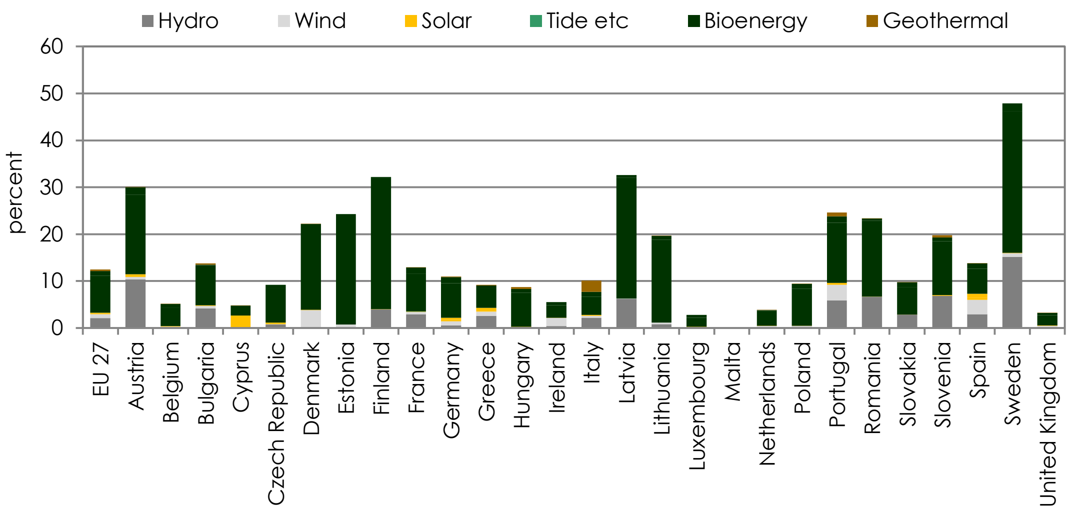

Figure 17. Disaggregation of Member States' shares of renewables in 2010 by energy source

Source: Own illustration based on Eurostat.

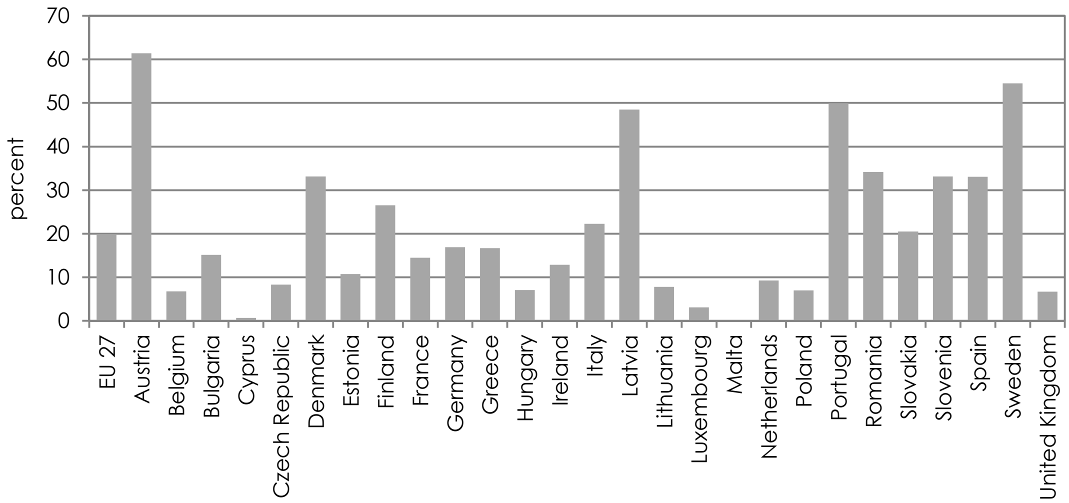

Figure 18. Member States' shares of renewables in electricity generation in 2010

Source: Own illustration based on Eurostat.

In addition to the definition of targets, the renewables directive confirms the eligibility of support schemes for renewable energy as well as of co-operation mechanisms[17] in order to reach the targets for renewable energy sources, but leaves the choice of support mechanism to the Member States.

3.2.2 Overview of Renewable Electricity Support Schemes in the EU

Renewable electricity support schemes differ between the European countries (see Ragwitz et al., 2011). Generally, feed-in tariffs, feed-in premiums and quota obligation systems (and combinations of these instruments) are the most frequently applied support schemes in the European Union (see Figure 19 and Table 1). Feed-in tariffs for renewable electricity generation are used in Austria, Bulgaria, Cyprus, France, Greece, Hungary, Ireland, Latvia, Lithuania, Portugal and Slovakia. In Denmark and the Netherlands, a feed-in premium system is used to support renewable electricity generation. The Czech Republic, Estonia, Slovenia and Spain use a combination of feed-in tariffs and feed-in premiums. Quota obligations are implemented in five Member States: Belgium, Italy, Poland, Romania, Sweden and the United Kingdom. Frequently the instrument is also combined with feed-in tariffs for specific technologies: For instance, in Belgium minimum tariffs are offered as an alternative; Italy and the United Kingdom respectively offer feed-in tariffs for small projects. Policy schemes such as tender schemes, production tax incentives and investment grants are of minor importance.

In addition to the instruments chosen, the support level for renewable energies also differs significantly between EU Member States. Ragwitz et al. (2007) show that the support level is not adequate to cover the costs of renewable electricity generation in all Member States.

[17] Directive 2009/28 provides for the following co-operation mechanisms: Statistical transfers between Member States (Article 6), joint projects between Member States (Article 7), joint projects between Member States and third countries (Article 9) and joint support schemes (Article 11).

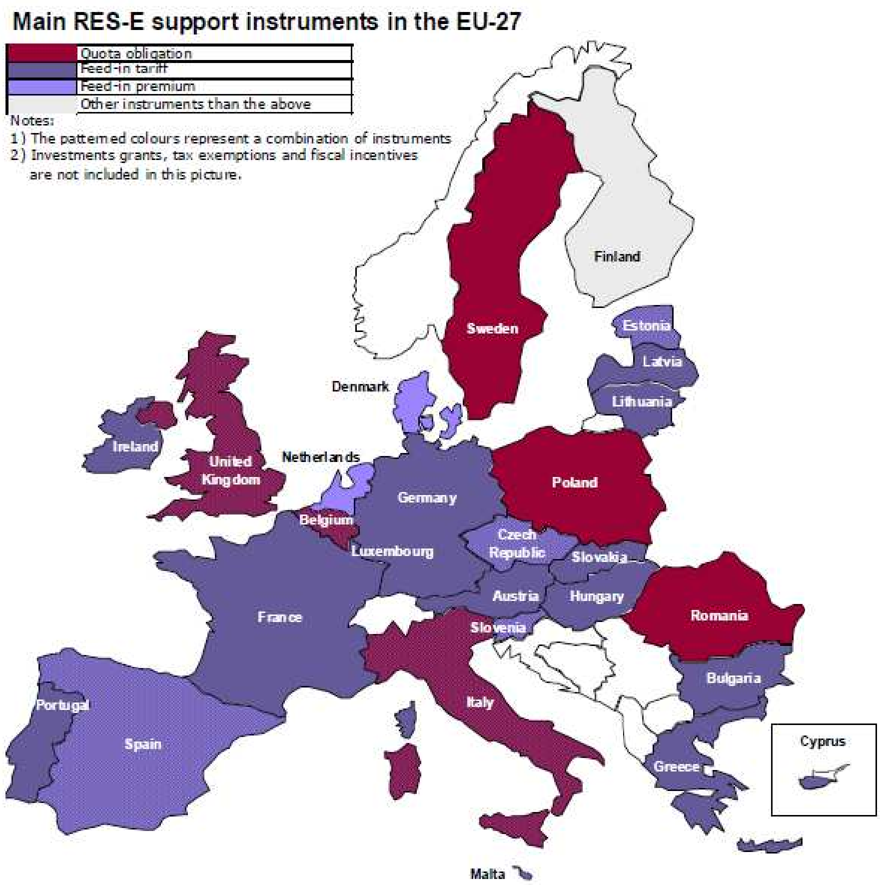

Figure 19. Overview of Renewable Electricity Support Schemes in the EU

Source: Ragwitz et al. (2011).

Table 1. Overview of Renewable Electricity Support Schemes in the EU

	Austria	Belgium	Bulgaria	Cyprus	Czech Republic	Denmark	Estonia	Finland	France	Germany	Greece	Hungary	Ireland	Italy	Latvia	Lithuania	Luxembourg	Malta	Netherlands	Poland	Portugal	Romania	Slovakia	Slovenia	Spain	Sweden	UK
Feed-in tariff	x	x	x	x	x		x		x	x	x	x	x	x	x	x	x	x			x		x	x	x		x
Feed-in premium					x	x	x												x					x	x		
Quota obligation		x						x			x	x		x						x		x				x	x
Investment grants		x		x	x			x			x				x	x	x	x							x		
Tax exemptions		x					x								x				x	x			x			x	x
Fiscal incentives			x							x								x	x	x				x			
Tendering schemes						x			x										x		x						

Source: Klessmann et al. (2011).

4 Renewable Electricity Generation in Austria, Hungary and the Czech Republic

The renewables directive (Directive 2009/28) requires each Member State to adopt a National Renewable Energy Action Plan (NREAP). These NREAPS must specify the national targets for the share of renewable energy in the sectors transport, electricity and heating and cooling in 2020 as well as the aspired target path.

In the following, an overview of the current status of renewable energy sources in Austria, the Czech Republic and Hungary as well as of the targets for renewables for 2020 and the current RES support schemes is presented.

4.1 Renewable Electricity Generation in Austria

4.1.1 Renewable Energies in Austria: Status quo

Austria is one of the EU Member States with the highest share of renewable energy sources (see above). As indicated in Figure 20, primary energy supply from renewable energy sources in Austria has been constantly rising over the past years. In 2010, 380 PJ of primary energy supply have been derived from renewable energy sources[18]. Biomass (especially solid biomass) and hydro power contribute the largest shares.

With respect to electricity generation from renewable energy sources, increases can be observed for the period 2005 to 2009. In 2010, however, renewable electricity generation in Austria declined reflecting lower transformation output from hydro power plants that could not be offset by increasing electricity generation from biomass and wind (see Figure 21). In 2010, renewable electricity generation in Austria amounted to 167 PJ corresponding to 61% of total Austrian electricity generation.

[18] This corresponds to a share of 28% of total primary energy supply.

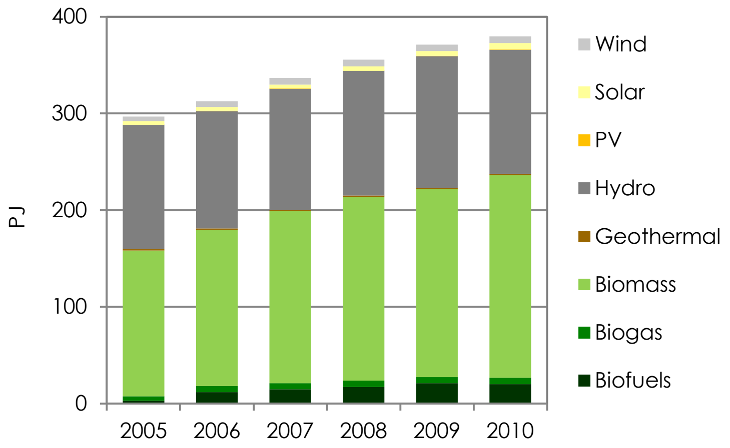

Figure 20. Development of primary energy supply from RES in Austria by energy source, 2005 - 2010

Source: Own illustration based on Eurostat.

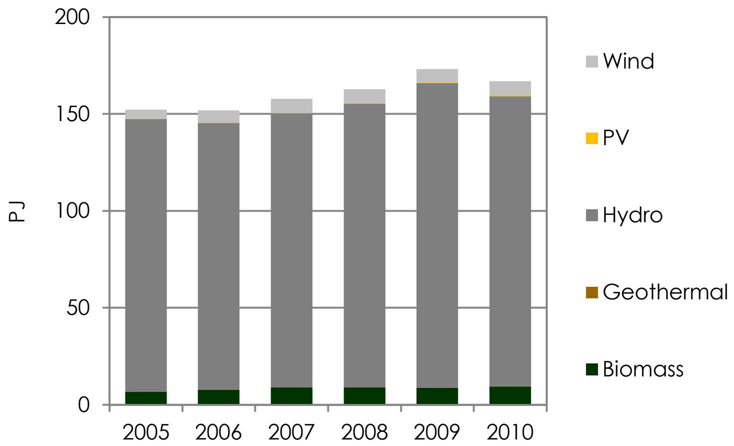

Figure 21. Development of RES-E generation in Austria by energy source, 2005 - 2010

Source: Own illustration based on Eurostat.

4.1.2 Renewable Energies in Austria: Potentials for 2030

Austria's potentials for renewable electricity generation as identified by the Green-X model (see Resch et al., 2012) are contrasted with the 2010 RES-E generation in Figure 22. For the period 2010 to 2020, Green-X finds the highest expansion potentials for PV and wind power (11.5 TWh and 6.5 TWh respectively). For hydro power, biomass and biogas the additional potential compared to 2010 ranges between 2.3 TWh and 3.1 TWh. For biowaste based and geothermal electricity generation until 2030 comparably low expansion potentials are identified by the Green-X model for Austria.

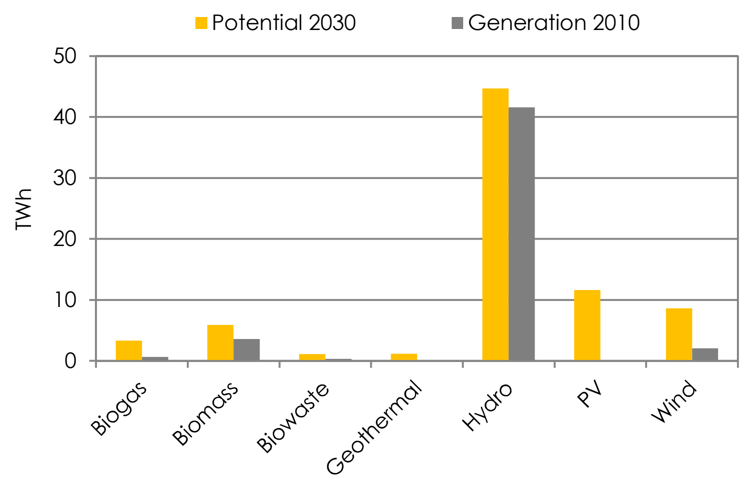

Figure 22. 2030 potentials for RES-E and RES-E generation in 2010 in Austria by energy source

Source: Own illustration based on Green-X database and Eurostat.

4.1.3 Renewable Energies in Austria: Targets for 2020

Figure 23 illustrates the development of the share of renewable energy sources in gross final energy consumption in Austria in the period 2005 to 2010 as well as the target value for 2020 as defined in the renewables directive. Between 2005 and 2009 the share of renewables increased from 25% to 31%. In 2010 it declined, however, to 30% in line with lower electricity generation from hydro power. Until 2020, Austria needs to increase its share of renewable energy sources in gross final energy consumption to 34%.

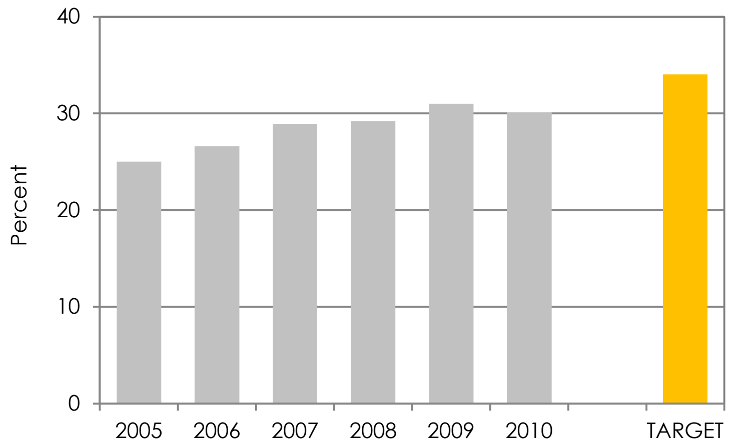

Figure 23. Development of the share of RES in gross final energy consumption 2005 - 2010 and 2020 target for Austria

Source: Own illustration based on Eurostat.

Table 2 shows the target path for the share of renewable energy sources as defined in the Austrian NREAP as well as a detailed sectoral breakdown of the target. Gross final energy consumption of renewables should increase by 106 PJ (corresponding to 10 percentage points) compared to 2005. The sectors ‘heating and cooling’ and ‘electricity’ should each contribute approximately 40 PJ to this increase while the transport sector should contribute approximately 27 PJ. In relative terms this corresponds to an increase of the share of renewable energy sources of 8 to 10 percentage points in each sector compared to 2005.

With respect to electricity generation, the Austrian NREAP defines the following detailed targets: Until 2020, the renewable electricity generation capacity should be increased from 9.6 GW to 13.2 GW. Capacity of hydro power and geothermal energy should stay at 2010 levels, while increases in the capacity of wind power (+ 1.9 GW) as well as of biomass and PV (approximately + 0.3 GW each) are planned (see Figure 24).

Table 2. Target path for the development of RES in Austria by sector

	2005	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
in % of gross final energy consumption												
Heating and Cooling	24.3	30.5	30.6	30.7	30.8	31	31.2	31.4	31.7	31.9	32.3	32.6
Electricity	60.8	69.3	69.8	70.3	70.7	71	71.2	71.4	71.4	71.2	71	70.6
Transport (incl. Electricity)	2.3	6.8	6.9	7	7.2	7.4	7.7	8.1	8.5	9.2	10.1	11.4
Total	24.4	30.9	31.1	31.4	31.6	31.9	32.1	32.4	32.8	33.2	33.6	34.2
in PJ												
Heating and Cooling	135	153	154	155	156	158	159	161	164	167	171	175
Electricity	146	163	165	167	169	171	174	176	178	181	185	189
Transport (incl. Electricity)	9	24	24	24	25	26	26	28	29	31	33	36
Total	282	333	336	339	343	347	351	356	362	369	378	388

Source: Own illustration based on the Austrian NREAP.

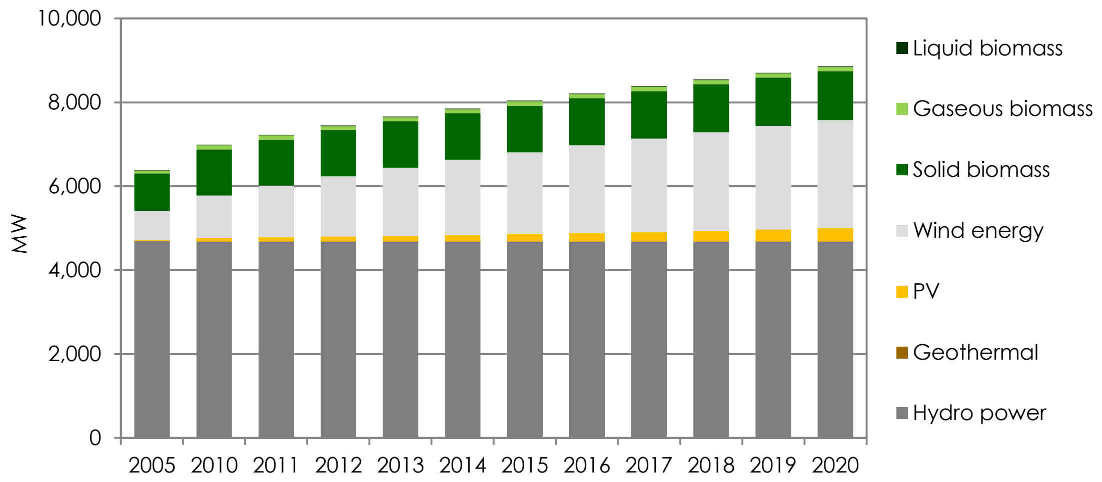

Figure 24. Target path for RES-E capacity in Austria

Source: Own illustration based on the Austrian NREAP.

Based on the capacity increases described above, electricity generation from wind power is estimated to increase by 12.5 PJ in 2020 compared to 2005; for biomass based electricity generation and PV increases of 8.4 PJ and 1.0 PJ are estimated respectively. Despite no increase in hydro power capacity is planned, an increase in electricity generation from hydro power plants is estimated resulting from the repowering of existing plants (see Figure 25).

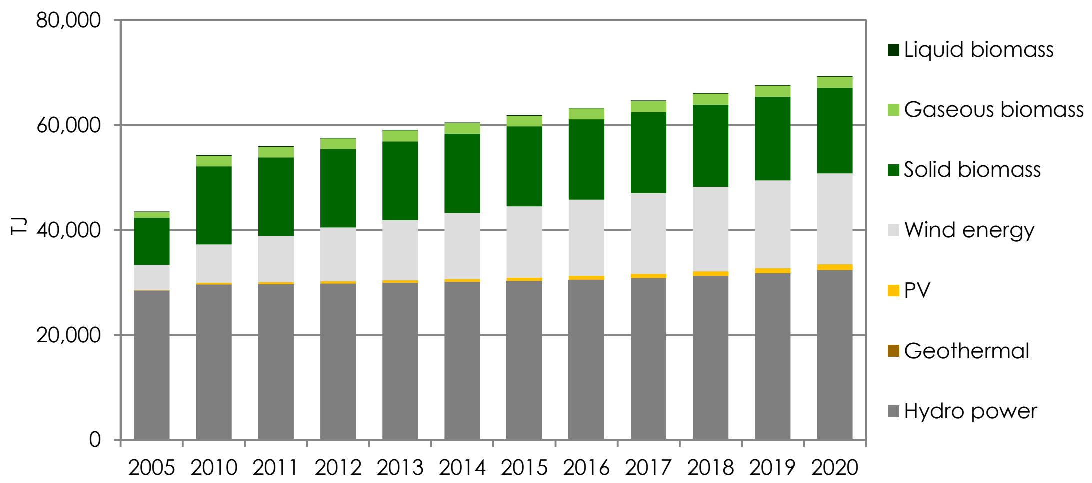

Figure 25. Target path for RES-E generation in Austria

Source: Own illustration based on the Austrian NREAP.

4.1.4 Renewable Energies in Austria: Support Schemes

The promotion of electricity from renewable energy sources in Austria is regulated under the Green Electricity Act ("Ökostromgesetz")[19]. With the Green Electricity Act 2002 the framework for the promotion of green electricity in Austria has been unified. Since the 2006 amendment of the Green Electricity Act (BGBl. I 2006/105), in addition to feed-in tariffs investment grants for certain renewable energy sources are regulated under the Green Electricity Act[20].

From 2002 on, small hydro power and other renewable technologies have been supported through feed-in tariffs under the Green Electricity Act. The second amendment of the Green Electricity Act 2008 (BGBl. I 2008/104) contained the following changes regarding the plants eligible for feed-in tariffs:

- Small hydro power plants since then are granted an investment subsidy instead of a feed-in tariff. This provision has been revised in the Green Electricity Act 2012: Small hydro power plants with a capacity of up to 2 MW can now choose between a feed-in tariff and an investment subsidy.
- Photovoltaic systems with a capacity below 5 kW are no longer promoted under the Green Electricity Act, but receive an investment subsidy from the Austrian Climate and Energy Fund.

Feed-in tariffs

In the context of the Green Electricity Act 2002 (BGBl. I 2002/149) and the Green Electricity Regulation 2002 (BGBl. II 2002/508), the feed-in tariffs were guaranteed for 13 years. In the amendment of the Green Electricity Act and the Green Electricity Regulation in 2006 (BGBl. I 2006/105, BGBl. II 2006/401), the feed-in tariffs were reduced to 12 years[21], while in the second green amendment to the Green Electricity Act in 2008 (BGBl. I 2008/104) an opportunity for extending the funding period

[19] Since 2002, the support of renewable electricity generation (with a focus on feed-in tariffs) has been regulated in Austria under the Green Electricity Act 2002 (BGBl. I 2002/149) and the respective amendments in the years 2006, 2007, 2008 and 2009. The Green Electricity Act 2012 (BGBl. I Nr. 75/2011) has replaced previous regulation.

[20] The concrete level of the feed-in tariffs is regulated by the respective Green Electricity Regulation ("Ökostromverordnung").

[21] According to 2006 amendment, the feed-in tariffs were valid for a period of ten years, in the eleventh year the level of the feed-in tariff was reduced to 75% and respectively to 50% in the twelfth year.

again has been created: For resource-dependent technologies (i.e. solid and liquid biomass, biogas) the support period was extended to 15 years[22], for all other technologies it has been extended to 13 years. These provisions have been confirmed in the Green Electricity Act 2012 (§ 11).

In Austria feed-in tariffs for renewable electricity generation differ both with respect to the technology and the plant size. When the market price for electricity is higher than the feed-in tariff, installations may opt-out of the support scheme and receive instead the market price.

The level of feed-in tariffs has been regulated under seven Green Electricity Regulations (BGBl. II 2002/508, BGBl. II 2006/401, BGBl. II 2008/59, BGBl. II 2009/53, BGBl. II Nr. 42/2010, BGBl. II Nr. 25/2011, BGBl. II Nr. 471/2011, BGBl. II Nr. 307/2012). Table 2 gives an overview of the feed-in tariffs guaranteed under the Green Electricity Regulations 2012. Compared to the first Green Electricity Regulation 2012 (BGBl. II Nr. 471/2011), in the second Green Electricity Regulation 2012 (BGBl. II Nr. 307/2012) support of PV has been reduced while the support of biomass and biogas has been expanded: In addition to an increase of feed-in tariffs that are granted for 15 years now also supported prices (that are below the level of the feed-in tariffs) are granted for 5 years.

The maximum annual support volume is split between the different technologies according to § 23 of the Green Electricity Act 2012. For PV an annual support level of € 8 million is defined, for bioenergy (solid and liquid biomass as well as biogas) the annual support volume amounts to € 12 million. For wind power and small hydro power the minimum support levels are € 11.5 million and € 1.5 million per annum respectively.

[22] In the first amendment of the Green Electricity Act 2008 (BGBl. I 2008/44) also subsidies for the feedstock have been provided for liquid biomass and biogas. For 2008, this additional funding amounted to €-ct. 4 per kWh. In the second amendment to the Green Electricity Act 2008, the possibility to extend this additional funding over the following years, but limited to €-ct. 4 per kWh has been included (ÖSG, § 11a). As these additional subsidies, however, are not in line with European law, the additional support for resource-dependent technologies has been abolished.

Table 3. Feed-in tariffs according to the first and second Austrian Green Electricity Regulation 2012

	Technology	Capacity	Fee-in tariff (€-ct per kWh)		
			1/2012	2/2012	2013
§ 5(1)	Building-integrated PV	5 - 500 kW_p	27.60	19.70	18.12
§ 5(2)	Free-mounted PV	5 - 500 kW_p	25.00	18.43	16.59
§ 6	Wind power		9.50	9.50	9.45
§ 7	Geothermal electricity		7.50	7.50	7.43
§ 8(1)	Solid biomass	< 500 kW (highly efficient)	n.a.	20.00	19.90
		< 500 kW	14.98	18.00	17.91
		500 kW - 1 MW	13.54	15.80	15.72
		> 1 MW - 1.5 MW	13.10	15.50	15.42
		> 1.5 MW - 2 MW	12.97	15.00	14.92
		> 2 MW - 5 MW	12.26	14.37	14.30
		> 5 MW - 10 MW	12.06	13.88	13.81
		> 10 MW	10.00	11.00	10.94
§ 9(1)	Liquid biomass		5.80	5.80	5.74
§ 10(1)	Biogas	0 - 250 kW	18.50	19.60	19.50
		> 250 kW - 500 kW	16.50	17.02	16.93
		> 500 kW - 750 kW	13.00	13.41	13.34
		> 750 kW	13.00	13.00	12.93
§ 11(1)	Landfill gas		6.00	6.00	5.94
§ 11(1)	Sewage gas		5.00	5.00	4.95

Source: Own elaboration based on Green Electricity Regulation (2012a, 2012b). Plants based on biomass, biogas or geothermal energy must achieve an overall efficiency of 60% in order to be eligible for the feed-in tariff according to § 12 of the Green Electricity Act 2012; for mixed furnaces and waste certain discounts apply. Until July 2012, the feed-in tariff for PV plants was differentiated into two size categories: 5 kW - 20 kW and > 20 kW. The table displays the tariffs for the first category. Feed-in tariff for the second size category were €-ct. 23 per kWh for building-integrated plants and €-ct. 19 per kWh for free-mounted plants

Investment subsidies

For medium-sized hydro power plants, investment grants instead of feed-in tariffs already apply since the 2006 amendment Green Electricity Act (BGBl. I 2006/105). In the second amendment of the Green Electricity Act 2008 (BGBl. I 2008/114) investment grants have been furthermore introduced for small hydro power plants as well as for power plants based on waste liquor.

According to the Green Electricity Act 2012 § 25, for systems based on waste liquor, the investment subsidy is limited to 30% of the investment. In addition, the following limits apply:

- € 300 per kW for systems with a maximum capacity up to 100 MW;

- € 180 per kW for systems with a maximum capacity between 100 - 400 MW; and
- € 120 per kW for systems with a maximum capacity of more than 400 MW.

Total investment support for systems based on waste liquor between 2009 and 2012 is limited to € 2.5 million per annum.

Small hydro power plants, which do not receive a feed-in tariff, are also eligible for investment subsidies. The investment subsidy can be granted for new constructions as well as for plant revitalisations that increase the plant's standard capacity by at least 15% (Green Electricity Act 2012, § 26). The maximum investment subsidy again depends on the plant size:

- In hydro power systems with a maximum capacity of 500 kW, 30% of the investment costs (at most € 1,500 per kW) are subsidised.
- In hydro power systems with a maximum capacity of 2 MW, 20% of the investment costs (at most € 1,000 per kW) are subsidised.
- For hydro power systems with a capacity of 10 MW, the investment subsidy is limited to 10% of the investment (€ 400 per kW maximum).

For hydro power plants with a capacity between 500 kW and 2 MW or between 2 MW and 10 MW, the investment subsidy is determined via linear interpolation. The overall support volume for small hydro power plants is limited to € 20 million per annum.

Medium-sized hydropower plants are also eligible for investment grants under the Green Electricity Act 2012 (§ 27)[23]. For these plants, funding generally must not exceed 10% of the investment cost and is also limited to a maximum of € 400 per kW and respectively € 6 million per facility. For the support of medium-sized hydro power plants a budget of € 50 million is available.

[23] Again, both new constructions and revitalisations are eligible for the investment subsidy.

4.2 Renewable Electricity Generation in the Czech Republic

4.2.1 Renewable Energies in the Czech Republic: Status quo

In the Czech Republic renewable energy sources are currently still of minor importance. While primary energy supply from renewable energy sources has been constantly increasing in the period 2005 to 2010 (from 75 PJ to 116 PJ), the share of renewables in primary energy supply in 2010 was still below 7%. The most important renewable energy source in the Czech Republic is biomass; it accounted for more than four quarters of primary energy supply from RES in 2010. During the last years, the importance of PV and solar thermal energy as well as of wind power has, however, increased (see Figure 26).

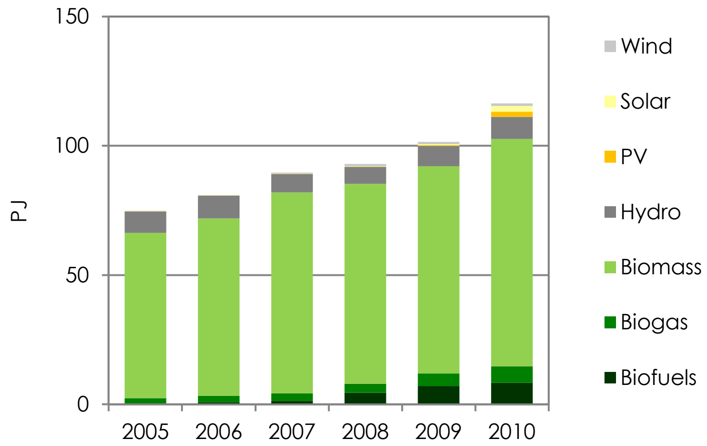

Figure 26. Development of primary energy supply from RES in the Czech Republic by energy source, 2005 - 2010

Source: Own illustration based on Eurostat.

Figure 27 shows the development of electricity generation from renewable energy sources in the Czech Republic in the period 2005 to 2010. Renewable electricity generation has been fluctuating during this period due to variations in the output of hydro power plants that contribute the largest share to RES-E generation in the Czech Republic (more than 60% in 2010). Electricity generation from other renewables has, however, considerably risen between 2005 and 2010.

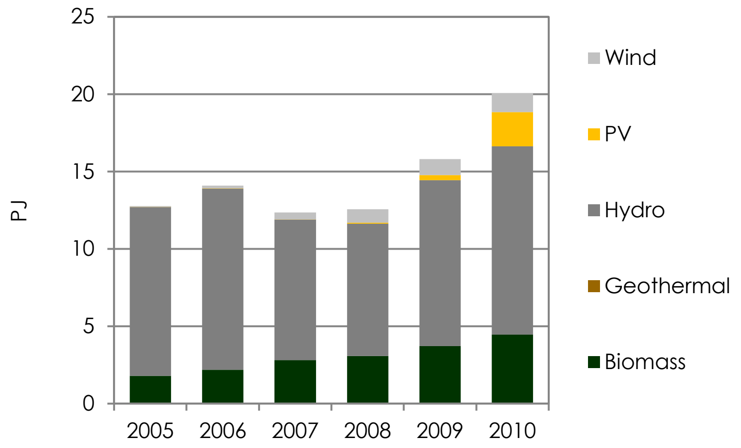

Figure 27. Development of renewable electricity generation in the Czech Republic

Source: Own illustration based on Eurostat.

4.2.2 Renewable Energies in the Czech Republic: Potentials for 2030

In Figure 28 the potentials for renewable electricity generation in the Czech Republic until 2030 as identified by the Green-X model (see Resch et al., 2012) are compared with renewable electricity generation in 2010. The largest expansion potentials are identified for PV (+ 8.2 TWh) and wind power (+ 11.1 TWh). Considerable potentials are also found for biomass and biogas with 2.7 TWh and 3.3 TWh respectively. Biowaste and geothermal electricity exhibit comparably low potentials.

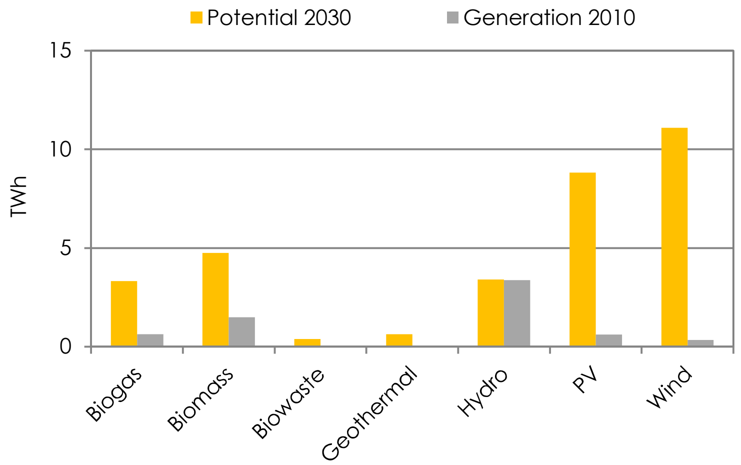

Figure 28. 2030 potentials for RES-E and RES-E generation in 2010 in the Czech Republic by energy source

Source: Own illustration based on Green-X database and Eurostat.

4.2.3 RENEWABLE ENERGIES IN THE CZECH REPUBLIC: TARGETS FOR 2020

Figure 29 shows the development of the share of renewable energy sources in gross final energy consumption in the Czech Republic between 2005 and 2010 as well as the target value for 2020 as defined in Directive 2009/28. Since 2005 the share of renewables constantly increased from 6% to 9% in 2010. Until 2020, the share of renewables needs to be increased to 13% in the Czech Republic according to the renewables directive.

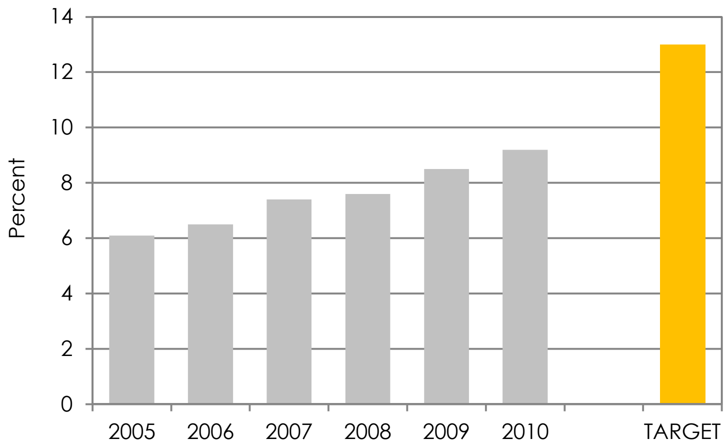

Figure 29. Development of the share of renewable energy sources in gross final energy consumption and 2020 target for the Czech Republic

Source: Own illustration based on Eurostat.

Table 4. Target path for the development of RES in the Czech Republic by sector

	2005	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
in % of gross final energy consumption												
Heating and Cooling	8.4	10.2	10.9	11.6	12.3	12.7	13.1	13.4	13.8	13.8	14	14.1
Electricity	4.5	7.4	9.8	10.9	11.8	12.5	12.9	13.2	13.5	13.8	14.1	14.3
Transport (incl. Electricity)	0.1	4.1	4.6	5.2	5.9	6.5	7.1	7.7	8.3	9.6	10.2	10.8
Total	6.1	8.3	9.4	10.1	10.8	11.3	11.8	12.1	12.5	12.9	13.2	13.5
in PJ												
Heating and Cooling	62	76	81	87	91	95	99	102	105	107	110	112
Electricity	11	19	25	29	32	34	36	38	39	41	42	43
Transport (incl. Electricity)	0	10	12	14	16	17	19	21	22	26	27	29
Total	74	105	119	129	139	147	154	160	166	174	179	184

Source: Own illustration based on the Czech NREAP.

Table 4 shows the target path for the share of renewable energy sources as defined in the Czech NREAP as well as a sectoral disaggregation. According to the NREAP of the Czech Republic, until 2020 gross final energy consumption of renewables should increase by 110 PJ (corresponding to 7 percentage points) compared to 2005. The sector 'heating and cooling' should make the highest contribution to this increase (50 PJ); the sectors 'electricity' and 'transport' should increase the use of renewable energy sources by 32 PJ and 29 PJ respectively. In relative terms this corresponds to an increase of the share of renewable energy sources of 6 percentage points in the sector 'heating and cooling' and to an increase of 10 and 11 percentage points in the sectors electricity and transport compared to 2005.

With respect to electricity generation, the Czech NREAP defines the following detailed targets for 2020: Hydro power capacity should be increased from 1,047 MW in 2010 to 1,125 MW. PV capacity should increase by 45 MW compared 2010; for wind power and biogas capacity increases of 500 MW and 304 MW respectively are planned (see Figure 30).

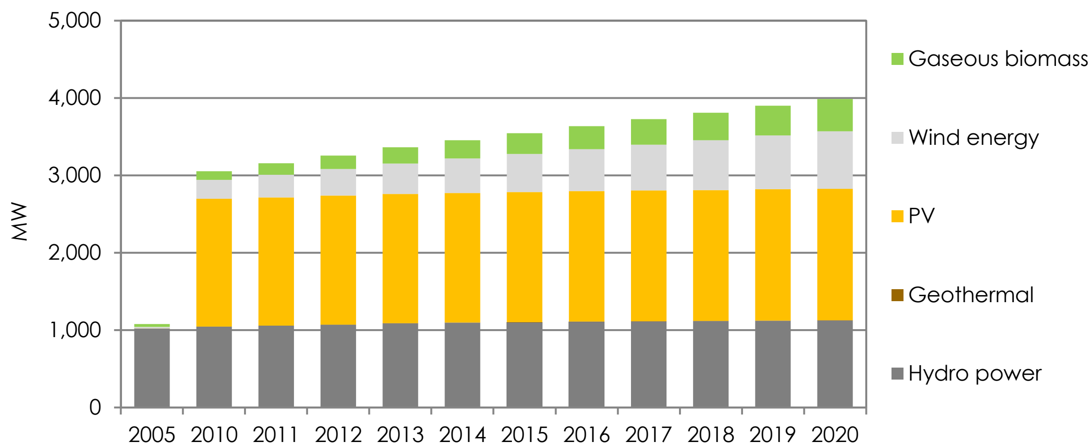

Figure 30. Target path for RES-E capacity in the Czech Republic

Source: Own illustration based on the Czech NREAP. For solid biomass, data on electricity generation capacity is not available.

Based on the capacity increases described above, in the Czech NREAP electricity generation from biogas is estimated to increase by 8.1 PJ in 2020 compared to 2010; for wind energy and hydro power increases of 3.8 PJ and 0.6 PJ are estimated respectively. Electricity generation from solid biomass is estimated to increase by 7.2 PJ while electricity from PV is estimated to rise by 4.1 PJ.

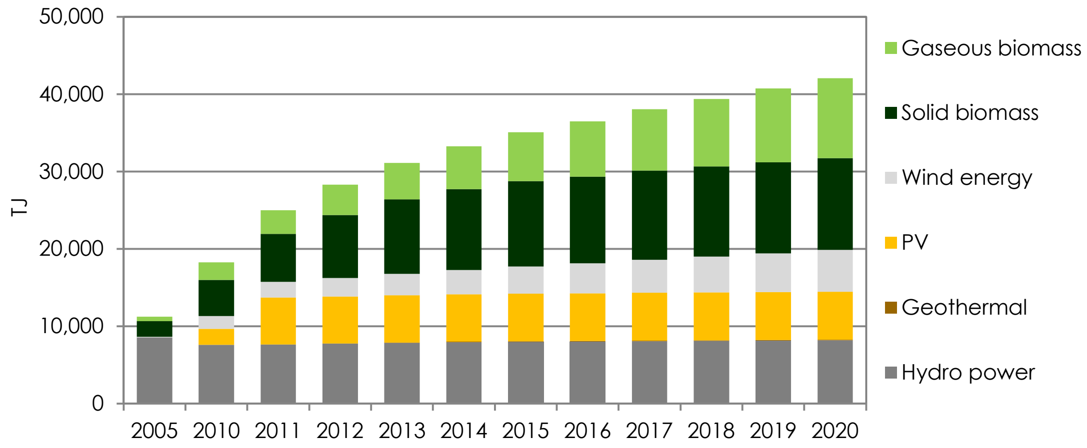

Figure 31. Target path for RES-E generation in the Czech Republic

Source: Own illustration based on the Czech NREAP.

4.2.4 Renewable Energies in the Czech Republic: Support Schemes

In the Czech Republic electricity generators generally can chose between a feed-in tariff and a feed-in premium system as support system[24]. Furthermore, subsidies are available for supporting renewable electricity generation (see RES LEGAL, 2012a).

Feed-in tariffs and feed-in premiums

Generally, all renewable electricity generation technologies are eligible for the feed-in tariff or a feed-in premium with the exception of ground mounted PV plants connected to the grid after 1 March 2011. For wind energy and hydro power, however, restrictions regarding the plant size apply: With respect to wind power, only those installations that cover an area of less than 1 km^2 and have a capacity below 20 MW are eligible for a feed-in tariff in the Czech Republic. With respect to hydro power, only small plants with a capacity up to 10 MW are supported under the feed-in tariff system (see RES LEGAL, 2012a).

The feed-in tariffs and feed-in premiums for the different renewable electricity generation technologies are determined by the Czech Energy Regulatory Office for the subsequent calendar year. For each year, the feed-in tariffs for new plants shall

[24] Most plant operators chose the feed-in tariff (see RES LEGAL, 2012a).

generally not be decreased by more than 5% compared to the previous year (see RES LEGAL, 2012a).[25]

The feed-in tariffs and feed-in premiums for existing plants are adjusted for inflation annually, i.e. they are "indexed to the industrial production index" (RES LEGAL, 2012a) hence increasing by 2% to 4% per year[26].

In general, the feed-in tariffs and feed-in premiums are granted over a period of 20 years; for hydro power plants they are guaranteed over a period of 30 years. The level of the feed-in tariff and the feed-in premium in the Czech Republic vary according to the energy source as well as according to plant size and start date of operation (see RES LEGAL, 2012a). Table 5 summarises the feed-in tariffs and feed in premiums according to Price Decision 7/2011.

Table 5. Feed-in tariffs in the Czech Republic according to Price Decision 7/2011

Technology	Feed-in tariff (in €-ct. per kWh)	Feed-in premium (in €-ct. per kWh)
Wind energy	9 - 14[1)]	7 - 13[1)]
PV	22 - 65[2), 3)]	18 - 55[2), 3)]
Geothermal energy	18	14
Biogas	11 - 17[4)]	6 - 12[4)]
Biomass	6 - 19[4)]	0 - 14[4)]
Hydro power	5 - 15[1)]	3 - 11[1)]

1) Tariffs are differentiated according to the start of operation.

2) Tariffs are differentiated according to plant size as well as to the start of operation.

3) Since 2011, the feed-in tariff for installations that started operation between in 2009 or 2010 is subject to a tax of 26%; exceptions from this tax apply for roof-top and facade-integrated plants whose capacity does not exceed 30 kW. For the feed-in premium a tax of 28% applies (again with an exception for small, roof-top and façade-integrated installations).

4) Tariffs are differentiated according to the type of biogas / biomass.

Source: Own elaboration based on RES LEGAL (2012a).

Investment subsidies

In the Czech Republic, three programmes for subsidising investments in renewable electricity generation are available (see RES LEGAL, 2012a): the ECO-ENERGY

25 Exceptions do, however, apply for plants for which the feed-in tariff is guaranteed for less than eleven years (see RES LEGAL, 2012a).

26 This adjustment of feed-in tariff does, however, not apply for biomass and biogas plants (RES LEGAL, 2012a).

Programme, the Operational Programme “Environment” and the EFEKT programme.

Under the ECO-ENERGY Programme, that is funded by the European Regional Development Fund (ERDF), investment grants (and loans) for RES-E projects are granted. The technologies eligible for the investment subsidy are specified in the respective calls for applications. However, generally all renewable electricity generation technologies can be subsidised under the ECO-ENERGY Programme. The level of the subsidies ranges between € 20,000 and € 4 million and depends on the project’s location as well as on the project parties (see RES LEGAL, 2012a).

The Operational Programme “Environment” also provides subsidies for renewable electricity generation. All technologies are in general eligible for the investment subsidy; with respect to hydro power, however, the subsidy is restricted to small plants, with respect to PV the subsidies are only available for roof-top or façade-integrated panels. The subsidy granted under the Operational Programme “Environment” must not exceed 20% of the eligible costs or € 2 million respectively (see RES LEGAL, 2012a).

The EFEKT Programme also, supports renewable electricity generation. In 2012, only small hydro-power plants with a capacity of up to 10 MW were eligible for an investment subsidy of this programme. The maximum subsidy is € 120,000 or respectively 40% of the eligible costs (see RES LEGAL, 2012a).

4.3 Renewable Electricity Generation in Hungary

4.3.1 Renewable Energies in Hungary: Status quo

In Hungary renewable energy sources currently account only for a small share in primary energy supply. While primary energy supply from renewable energy sources has been increasing from 50 PJ in 2005 to 83 PJ in 2010, the share of renewables in primary energy supply was still below 9% in 2010. Bioenergy (solid and liquid biomass as well as biogas) accounted for more than 90% of Hungary’s primary energy supply from renewables in 2010; geothermal energy accounted for more than 4%. The other renewables were of comparably low importance (see Figure 32).

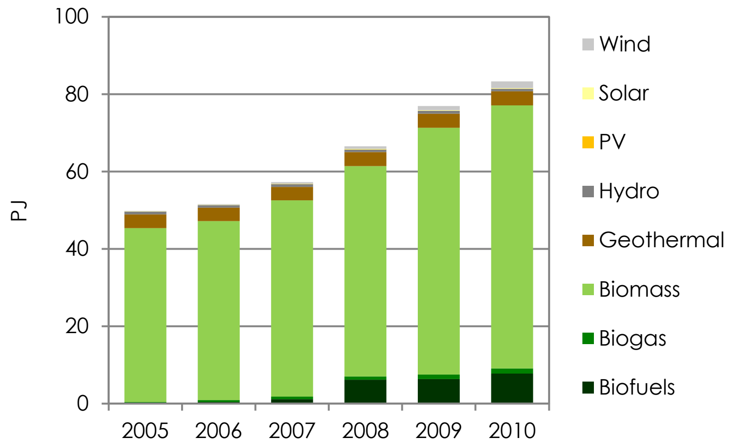

Figure 32. Development of primary energy supply from RES in Hungary by energy source, 2005 - 2010

Source: Own illustration based on Eurostat.

Renewable electricity generation in Hungary more than tripled in the period 2005 to 2010 (see Figure 33). Nevertheless, in 2010 only 7% of electricity generation has been based on renewable energy sources. Wind energy which has shown the largest increase between 2005 and 2010 is currently the most important RES-E technology in Hungary followed by hydro power and biomass based electricity generation.

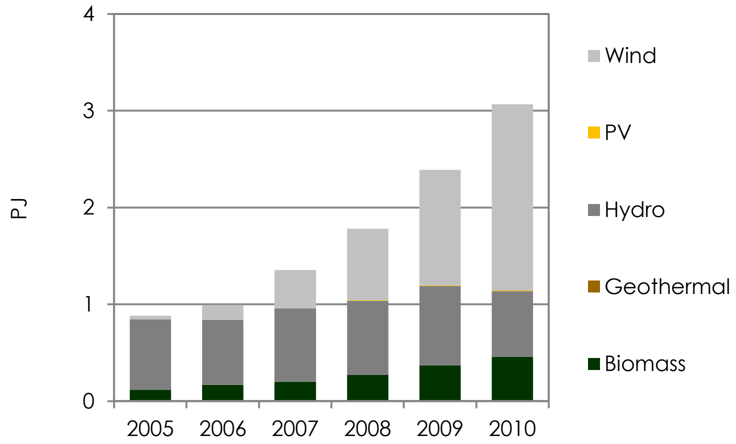

Figure 33. Development of renewable electricity generation in Hungary, 2005 - 2010

Source: Own illustration based on Eurostat.

4.3.2 Renewable Energies in Hungary: Potentials for 2030

Figure 34 provides a comparison of the electricity generation from renewable energy sources in the Hungary and the potentials for 2030 as identified by the Green-X model (see Resch et al., 2012). The largest expansion potentials are found for PV and biomass with 6.2 TWh and 5.1 TWh respectively. For biogas and wind power additional potentials of 3.0 TWh and 2.8 TWh are estimated. Expansion potentials for other renewable energy sources for 2030 range between 0.9 TWh and 1.4 TWh according to the Green-X model.

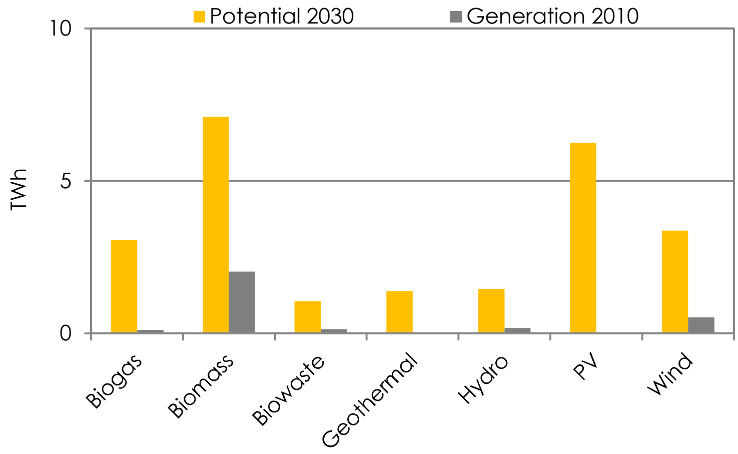

Figure 34. 2030 potentials for RES-E and RES-E generation in 2010 in Hungary by energy source

Source: Own illustration based on Green-X and Eurostat.

4.3.3 Renewable Energies in Hungary: Targets for 2020

In 2005 renewable energy sources contributed only 4% to gross final energy consumption in Hungary. As illustrated in Figure 35, between 2005 and 2010 the share of renewables almost doubled. According to Directive 2009/28, Hungary needs to further expand the share of renewables in gross final energy consumption until 2020; the target value as defined by the directive is 13%.

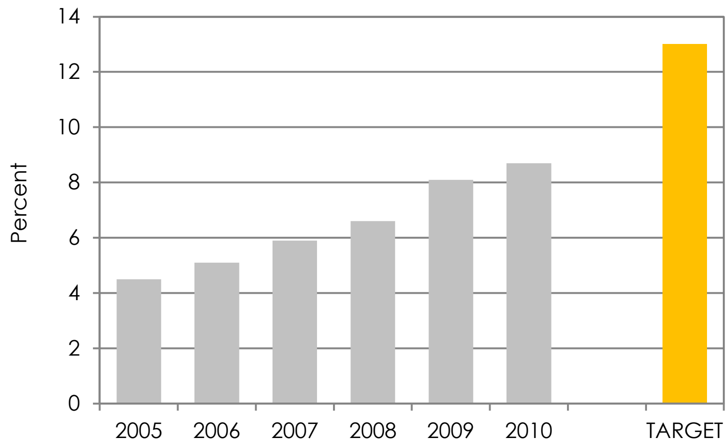

Figure 35. Development of the share of renewable energy sources in gross final energy consumption and 2020 target for Hungary

Source: Own illustration based on Eurostat.

Table 6 shows the target path for the share of renewable energy sources as defined in the Hungarian NREAP as well as the sectoral contributions to the increase in renewable energy sources. According to the NREAP, until 2020 gross final energy consumption of renewables should increase by 76 PJ (corresponding to 10 percentage points) compared to 2005. The sector ‘heating and cooling’ should expand the utilisation of renewable energy sources by 50 PJ (14 percentage points); the sectors ‘electricity’ and ‘transport’ should increase the use of renewable energy sources by 12 PJ (7 percentage points) and 13 PJ (10 percentage points) respectively compared to 2005.

For electricity generation from renewable energy sources, the Hungarian NREAP specifies the following detailed targets for 2020: Wind power capacity should be increased from 330 MW in 2010 to 750 MW. The capacity of plants based on solid biomass should increase by 140 MW compared 2010. For the other renewables increases between 15 and 86 MW respectively are planned (Figure 36).

Table 6. Target path for the development of RES in Hungary by sector

	2005	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
in % of gross final energy consumption												
Heating and Cooling	5.4	9	8.8	8.6	8.5	9.1	9.8	11.8	13.7	15.7	17.4	18.9
Electricity	4.3	6.7	6.5	6.9	7.5	8.6	8.1	7.1	8.6	10.2	10.7	10.9
Transport (incl. Electricity)	0.22	3.7	4.6	5	5	5.2	5.4	5.8	6.4	7.3	8	10
Total	4.2	7.4	7.3	7.4	7.5	8	8.3	9.3	10.7	12.3	13.4	14.65
in PJ												
Heating and Cooling	28	40	39	40	40	41	44	52	59	67	73	78
Electricity	8	10	10	11	13	15	14	12	15	18	19	20
Transport (incl. Electricity)	9	6	8	9	10	10	11	12	14	16	18	22
Total	45	56	58	60	62	67	69	77	89	101	110	121

Source: Own illustration based on the Hungarian NREAP.

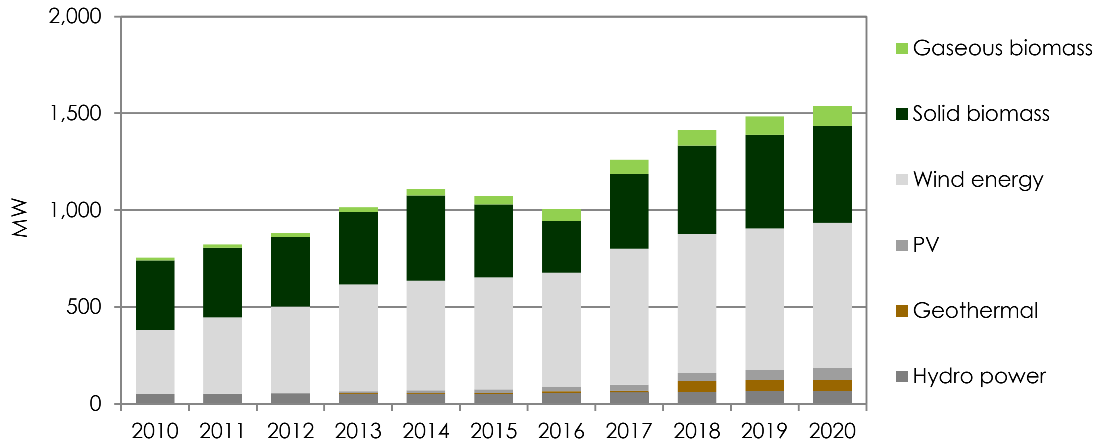

Figure 36. Target path for RES-E capacity in Hungary

Source: Own illustration based on the Hungarian NREAP.

Based on the capacity increases described above, electricity generation from renewable energy sources is estimated to increase by 10 PJ between 2010 and 2020 according to the Hungarian NREAP. The largest expansions are planned for wind power and solid biomass (+ 3 PJ each) followed by biogas (+ 2 PJ) and geothermal.

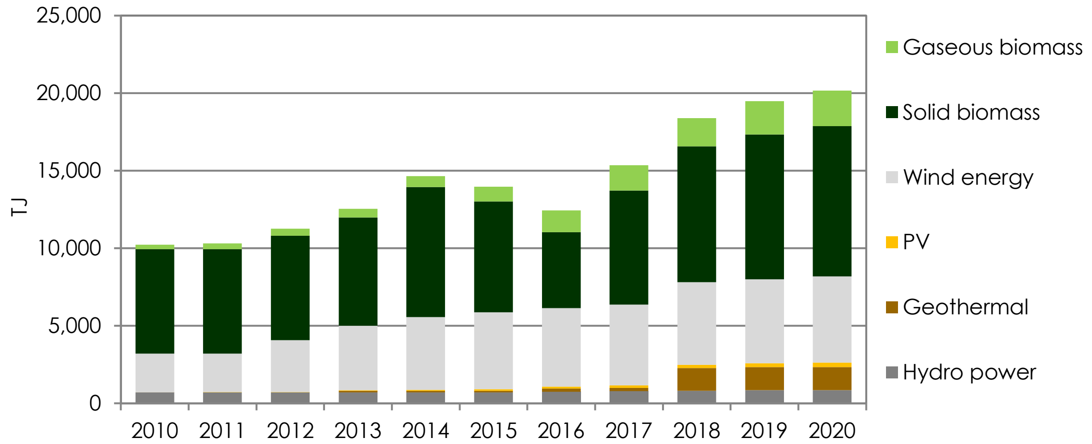

Figure 37. Target path for RES-E generation in Hungary

Source: Own illustration based on the Hungarian NREAP.

4.3.4 Renewable Energies in Hungary: Support Schemes

In Hungary the support of renewable electricity generation in based on a feed-in tariff system. Furthermore, subsidies are available to support renewable electricity generation. In general, all renewable electricity generation technologies are eligible for a feed-in tariff except for PV installations with a capacity below 50 kW (see RES LEGAL, 2012b).

Feed-in tariffs

In Hungary feed-in tariffs vary over the day differentiating between three time periods (peak time, mid-peak time, off-peak time) that are "defined by law, depend on the area the electricity is generated in and vary for weekdays and weekends/holidays as well as for summer and winter time" (RES LEGAL, 2012b).

The feed-in tariff furthermore depends on the electricity generation technology as well as on the plant size. Furthermore, the tariffs differ for plants approved by the Hungarian Energy Office before 2008 and for plants approved since 2008 (see RES LEGAL, 2012b).[27]

The level of the feed-in tariffs for the different technologies is defined by the Energy Office at the end of the year for the subsequent year. Table 7 summarises the Hungarian feed-in tariffs for renewable electricity generation in 2012. The tariffs are adjusted for inflation annually (RES LEGAL, 2012b).[28]

[27] With the exception of hydro power plants with a capacity of more than 5 MW and other renewables with a capacity of more than 50 MW (RES LEGAL, 2012b).

[28] For plants for which an application was submitted after 1 January 2008 each year the feed-in tariff will increase by the rate of inflation of the previous year minus 1%. For plants for which an application was submitted before the feed-in tariff will be adjusted by the total inflation of the previous year (RES LEGAL, 2012b).

Table 7. Feed-in tariffs in Hungary 2012 for plants approved since 2008

Technology	Capacity	Feed-in tariff (€-cent per kWh)		
		Peak time	Mid-peak time	Off-peak time
Wind energy	< 20 MW	12	10.7	4.4
	20 - 50 MW	12	10.7	4.4
	> 50 MW	7.5	4.8	4.8
PV	≤ 50 MW	10.7	10.7	10.7
	> 50 MW	7.5	4.8	4.8
Geothermal energy	< 20 MW	12	10.7	4.4
	20 - 50 MW	9.6	8.6	3.5
	> 50 MW	7.5	4.8	4.8
Biogas	< 20 MW	12	10.7	4.4
	20 - 50 MW	9.6	9.6	3.5
	> 50 MW	7.5	4.8	4.8
Biomass	< 20 MW	12	10.7	4.4
	20 - 50 MW	9.6	8.6	3.5
	> 50 MW	7.5	4.8	4.8
Hydro power	≤ 5 MW	12	10.7	4.4
	> 5 MW	7.5	4.8	4.8

Source: Own elaboration based on RES LEGAL (2012b) and an exchange rate of 1 HUF : 0.0035 € as of 29 October 2012.

Investment subsidies

Investments in renewable electricity generation are subsidised under the European Regional Development Fund's Environmental and Energy Operative Programme. Both the preparation and the realisation of renewable electricity projects are funded. Projects located in all districts except Buda and Pest are eligible for the subsidies. The total volume of the investments subsidies is limited to € 20.2 million (see RES LEGAL, 2012b).

In general, all renewable electricity generation technologies are eligible for investment subsidies. For most technologies, however, certain thresholds regarding the project size apply: To be eligible for an investment subsidy, the capacity of wind power and grid-connected PV projects must not exceed 50 kW and 500 kW respectively. For hydro power the capacity must not exceed 2 MW; for electricity generation based on solid biomass a limit of 20 MW applies (see RES LEGAL, 2012b).

The investment subsidies contribute at least to 10% of the eligible costs; the maximum contribution varies depending on the project's location and the project parties (see RES LEGAL, 2012b): For companies the investment subsidy ranges between 30% and 70% of total eligible costs (depending on the size of the company and the location of the project). For public bodies and NGOs the investment subsidies can cover up to 90% of the total eligible costs (depending on the project's location).

5 THE COSTS AND COMPETITIVENESS OF RENEWABLE ELECTRICITY GENERATION

In this chapter, the impact of the EU ETS on the long and short run marginal costs of fossil electricity generation, i.e. coal and gas based electricity generation, is analysed and changes in the merit order of fossil electricity generation and selected renewable electricity generation technologies (biomass and biogas, photovoltaics, wind and hydro power) resulting from the price signal established by the emissions trading scheme are examined (following Schwaiger et al., 2012 and Reinaud, 2003). It is then discussed whether and to which extent, i.e. for which technologies, changes in electricity prices triggered by the EU ETS could substitute renewable support schemes.

5.1 COST STRUCTURE OF THE SELECTED RENEWABLE ELECTRICITY GENERATION TECHNOLOGIES

In this section the cost structure of wind power, PV, small and large hydro power, biomass and biogas as well as of non-renewable reference technologies (coal, gas and nuclear) is analysed. The analysis is based on the following data sources: Data on renewable electricity generation potentials, investment costs and full load hours are taken from Green-X database (see Resch et al., 2012); with respect to the operating costs of renewable electricity generation technologies data from Resch et al. (2012) are used[29]. Cost data for the reference technologies are based on Hirth (2012); with respect to fuel costs price increases as assumed in the projections for 2030 (IEA, 2011) are applied. The efficiencies assumed for coal and gas plants in 2030 are based on IEA and ETSAP (2010a, 2010b); the full load hours for the reference technologies are derived from Kaltschmitt and Streicher (2009). Data on the depreciation rate as well as on the lifetime of all technologies are also based on Kaltschmitt and Streicher (2009)[30].

The cost assessment covers both long and short run marginal costs. Short run marginal costs include fuel costs and other variable costs and provide the basis for

29 I.e. for Austria values at the upper end of the range presented by Resch et al. (2012) are used. For Hungary and the Czech Republic, values at the lower end of the range are used.

30 The investment horizon is chosen corresponding to the technical lifetime of the plants.

daily decisions regarding plant operation: In a competitive electricity market, the price is determined by the short run marginal costs for serving electricity demand[31]. Those electricity generation technologies that exhibit the lowest marginal costs are hence first used to meet demand, while the plants with the highest marginal costs are the last to be brought onto the market covering peak load electricity demand. The ascending order in which electricity from different generation technologies is brought on the market according to the short run marginal costs is referred to as merit order.

Long run marginal costs in contrast to short run marginal costs do not only cover variable costs but also fixed costs, i.e. investment and capital costs (see e.g. Schwaiger et al., 2012). While short run marginal costs determine the dispatch order of existing plants, long run marginal costs determine in which renewable electricity generation technologies will be invested: Only if the price (market price or supported price) covers the long run marginal costs, electricity generation can be profitable.

In the comparison of renewable electricity generation technologies and reference technologies these two aspects need to be considered: A comparison of short run marginal costs indicates whether renewable electricity generation technologies can enter the market without privileged grid access. In order to assess whether investments in renewable electricity generation technologies will be made in order to substitute fossil and nuclear electricity generation the long run marginal costs of renewables need to be compared with the short run marginal costs of the reference technologies. Therefore, in the next sections the long and short run marginal costs of all technologies are examined. For the renewable electricity generation technologies two cost scenarios are calculated based on the Green-X database: costs in a default scenario (DS; moderate decrease in investment costs, moderate full load hours) and costs in an optimistic scenario (OS; more pronounced decrease in investment costs, higher full load hours).

31 If the price was set above the short run marginal costs, other generators would have the possibility to enter the market selling electricity at a lower cost.

5.1.1 WIND POWER

Table 8 shows the short and long run electricity generation costs for wind power in Austria, the Czech Republic and Hungary along with a summary of the input parameters for the calculations and cost positions. All values are reported for a unit capacity of 1 kW.

In the default scenario, the full load hours for 2030 range between 1,725 in Austria and 1,928 in the Czech Republic; in the optimistic scenario they range between 2,451 and 2,553. Based Kaltschmitt and Streicher (2009) an average investment horizon of 20 years is assumed for wind power. The investment costs range between € 1,281 and € 1,390 per kW in the default scenario and between € 1,230 and € 1,306 in the optimistic scenario. Assuming a discount rate of 4.5% (following Kaltschmitt and Streicher, 2009) for an investment horizon of 20 years, the investment annuity is between € 98 and € 107 in the default scenario and respectively between € 95 and € 100 in the optimistic scenario. O&M costs amount to € 30 to € 36.

Based on these assumptions the long run marginal costs of wind power amount to approximately € 75 per MWh in the default scenario and € 50 in the optimistic scenario; the short run marginal costs range between € 16 and € 17 per MWh in the default scenario and € 12 in the optimistic scenario.

In Figure 38 a sensitivity analysis of the long run marginal electricity generation costs of wind power with respect to changes in investment costs (IC), changes in operating and maintenance costs (OMC), changes in full load hours (FLH) and changes in the investment horizon (IH) is presented using data for Austria[32]. As indicated in Figure 38 the long run marginal costs of wind power show the highest sensitivity with respect to the full load hours assumed, hence the annuity depends on wind supply that is a decisive factor for electricity yields. The investment costs also strongly influence the long run marginal electricity generation costs. Changes in operating and maintenance costs as well as in the investment horizon are of minor importance.

[32] For the Czech Republic and Hungary analogue illustrations are provided in Appendix 1.

Table 8. Long and short run marginal generation costs of wind electricity in Austria, the Czech Republic and Hungary in 2030

		Austria		Czech Republic		Hungary	
		DS	OS	DS	OS	DS	OS
Rated capacity	kw	1.00	1.00	1.00	1.00	1.00	1.00
Full load hours	h p.a.	1,752	2,451	1,928	2,553	1,820	2,553
Electricity output	kWh/a	1,752	2,451	1,928	2,553	1,820	2,553
Investment costs	€	1,281	1,251	1,390	1,306	1,390	1,230
Investment horizon	years	20	20	20	20	20	20
Discount rate	p.a.	4.5%	4.5%	4.5%	4.5%	4.5%	4.5%
Capital recovery factor		0.077	0.077	0.077	0.077	0.077	0.077
Annuity	€ p.a.	98	96	107	100	107	95
Fuel costs	€ p.a.	0	0	0	0	0	0
O&M costs	€ p.a.	36	30	33	30	30	30
LRMC	**€/kWh**	**0.077**	**0.051**	**0.073**	**0.051**	**0.075**	**0.049**
SRMC	**€/kWh**	**0.021**	**0.012**	**0.017**	**0.012**	**0.016**	**0.012**

Source: Own calculations based on Green-X database, Resch et al. (2012) and Kaltschmitt and Streicher (2009).

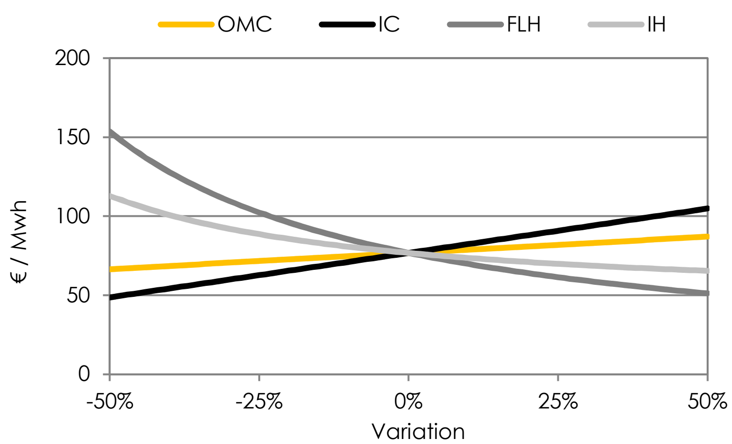

Figure 38. Sensitivity analysis of long run marginal generation costs of wind electricity generation in Austria in 2030

Source: Own calculations based on Green-X database, Resch et al. (2012) and Kaltschmitt and Streicher (2009).

5.1.2 PHOTOVOLTAICS

The short and long run electricity generation costs for PV in Austria, the Czech Republic and Hungary along with a summary of the input parameters for the calculations and cost positions are reported in Table 9. All values are again reported for a unit capacity of 1 kW.

For PV, the full load hours range between 807 and 944 in the default scenario and between 944 and 1,210 in the optimistic scenario. For the investment costs values between € 1,713 and € 1,898 per kW are assumed[33]. Assuming a discount rate of 4.5% and an investment horizon of 20 years, the investment annuity ranges between € 132 and € 146. O&M costs range between € 30 and € 39.

The long and short run marginal costs of PV considerably exceed those of wind power ranging between € 171 and € 209 per MWh in the default scenario and € 142 and € 173 in the optimistic scenario which reflects lower full load hours on the one hand and higher investment costs on the other hand. The short run marginal costs of PV range between € 32 and € 43 per MWh in the default scenario and € 25 to € 32 per MWh in the optimistic scenario.

Table 9. Long and short run marginal generation costs of PV in Austria, the Czech Republic and Hungary in 2030

		Austria		Czech Republic		Hungary	
		DS	OS	DS	OS	DS	OS
Rated capacity	kw	1.00	1.00	1.00	1.00	1.00	1.00
Full load hours	h p.a.	942	1,210	807	944	944	972
Electricity output	kWh/a	942	1,210	807	944	944	972
Investment costs	€	1,898	1,849	1,737	1,737	1,713	1,713
Investment horizon	years	20	20	20	20	20	20
Discount rate	p.a.	4.5%	4.5%	4.5%	4.5%	4.5%	4.5%
Capital recovery factor		0.077	0.077	0.077	0.077	0.077	0.077
Annuity	€ p.a.	146	142	134	134	132	132
Fuel costs	€ p.a.	0	0	0	0	0	0
O&M costs	€ p.a.	39	30	35	30	30	30
LRMC	**€/kWh**	**0.196**	**0.142**	**0.209**	**0.173**	**0.171**	**0.166**
SRMC	**€/kWh**	**0.041**	**0.025**	**0.043**	**0.032**	**0.032**	**0.031**

Source: Own calculations based on Green-X database, Resch et al. (2012) and Kaltschmitt and Streicher (2009).

A sensitivity analysis of the long run marginal electricity generation costs of PV with respect to changes in investment costs (IC), changes in operating and maintenance costs (OMC), changes in full load hours (FLH) and changes in the investment

[33] These are pessimistic estimates as module prices in Austria have already fallen below € 1,500 per kW (Biermayr et al., 2011).

horizon (IH) is provided in Figure 39 using data for Austria[34]. The long run marginal costs of PV show the highest sensitivity with respect to the full load hours assumed. The investment horizon as well as the investment costs have also a strong impact on the long run marginal electricity generation costs. Changes in operating and maintenance costs in contrast show only a minor impact.

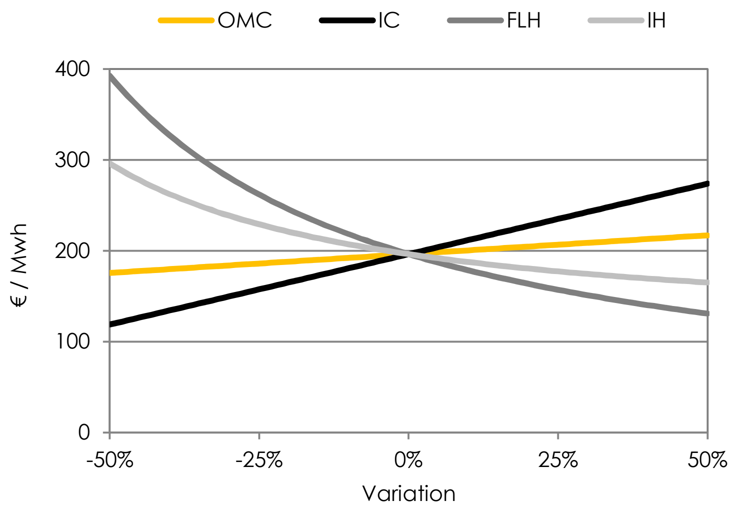

Figure 39. Sensitivity analysis of long-run marginal generation costs of PV in Austria

Source: Own calculations based on Green-X database, Resch et al. (2012) and Kaltschmitt and Streicher (2009).

5.1.3 Hydro Power

Table 10 shows the short and long run electricity generation costs for small and large hydro power in Austria, the Czech Republic and Hungary along with a summary of the input parameters and cost positions. All values are again reported for a unit capacity of 1 kW.

In Austria, for small hydro power 4,682 full load hours are estimated in the default scenario for 2030 and 5,150 full load hours are estimated for the optimistic scenario. For the Czech Republic and Hungary considerably lower full load hours are estimated that range between 3,451 and 3,796 in the Czech Republic and 2,627 and 2,625 in Hungary. Full load hours for large hydro power range between 1,427 in the Czech Republic and 4,692 for Austria.

[34] For the Czech Republic and Hungary analogue illustrations are provided in Appendix 1.

Based on Kaltschmitt and Streicher (2009) an average investment horizon of 40 years is assumed for hydro power plants[35]. The investment costs of hydro power are almost identical in the default and the optimistic scenario. For small hydro power, investment costs range between € 2,627 per kW in Hungary and € 3,419 per kW in Austria; for large hydro power investment costs range between € 1,017 per kW in the Czech Republic and € 2,147 per kW in Austria. Assuming a discount rate of 4.5% (following Kaltschmitt and Streicher, 2009) and an investment horizon of 40 years, the investment annuity is between € 143 and € 186 per kW for small hydro power plants and respectively between € 55 and € 117 for large hydro power. Annual O&M costs amount to € 36 to € 41 per kW for small hydro power and to € 33 to € 38 for large hydro power.

Based on the assumptions described above, the long run marginal costs of small hydro power amount to approximately € 40 per MWh in Hungary; for Austria and the Czech Republic average long run marginal costs are estimated € 45 and € 58 per MWh respectively. The short run marginal costs of small hydro power range between € 7 and € 9 per MWh. For large hydro power, long run marginal costs range between approximately € 30 per MWh in Hungary and € 60 in the Czech Republic; the short run marginal costs amount to approximately €8 per MWh in Austria and Hungary and to more than € 20 per MWh in the Czech Republic.

Figure 40 and Figure 41 present a sensitivity analysis of the long run marginal electricity generation costs of small and large hydro power with respect to changes in investment costs (IC), changes in operating and maintenance costs (OMC), changes in full load hours (FLH) and changes in the investment horizon (IH) is presented using data for Austria[36]. The figures show that the cost structure of small and large hydro power plants are similar. As indicated in Figure 40 and Figure 41 the long run marginal costs of hydro power show the highest sensitivity with respect to the full load hours assumed. The investment costs and lifetime of the plant also strongly influence the long run marginal electricity generation costs of hydro power. Changes in operating and maintenance costs are of minor importance.

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[35] This reflects the lifetime of the turbine. The lifetime of the construction is up to 80 years (Kaltschmitt and Streicher, 2009).

[36] For the Czech Republic and Hungary analogue illustrations are provided in Appendix 1.

Table 10. Long and short run marginal generation costs of hydro electricity in Austria, the Czech Republic and Hungary in 2030

		Austria		Czech Republic		Hungary	
		DS	OS	DS	OS	DS	OS
Small hydro power							
Rated capacity	kw	1.00	1.00	1.00	1.00	1.00	1.00
Full load hours	h p.a.	4,682	5,150	3,451	3,796	4,214	4,635
Electricity output	kWh/a	4,682	5,150	3,451	3,796	4,214	4,635
Investment costs	€	3,419	3,414	3,165	3,162	2,627	2,625
Investment horizon	years	40	40	40	40	40	40
Discount rate	p.a.	4.5%	4.5%	4.5%	4.5%	4.5%	4.5%
Capital recovery factor		0.054	0.054	0.054	0.054	0.054	0.054
Annuity	€ p.a.	186	186	172	172	143	143
Fuel costs	€ p.a.	0	0	0	0	0	0
O&M costs	€ p.a.	41	36	39	36	36	36
LRMC	**€/kWh**	**0.048**	**0.043**	**0.061**	**0.055**	**0.042**	**0.039**
SRMC	**€/kWh**	**0.009**	**0.007**	**0.011**	**0.009**	**0.009**	**0.008**
Large hydro power							
Rated capacity	kw	1.00	1.00	1.00	1.00	1.00	1.00
Full load hours	h p.a.	4,265	4,692	1,427	1,570	3,923	4,315
Electricity output	kWh/a	4,265	4,692	1,427	1,570	3,923	4,315
Investment costs	€	2,147	2,147	1,017	1,016	1,525	1,525
Investment horizon	years	40	40	40	40	40	40
Discount rate	p.a.	4.5%	4.5%	4.5%	4.5%	4.5%	4.5%
Capital recovery factor		0.054	0.054	0.054	0.054	0.054	0.054
Annuity	€ p.a.	117	117	55	55	83	83
Fuel costs	€ p.a.	0	0	0	0	0	0
O&M costs	€ p.a.	38	33	35	33	33	33
LRMC	**€/kWh**	**0.036**	**0.032**	**0.063**	**0.056**	**0.030**	**0.027**
SRMC	**€/kWh**	**0.009**	**0.007**	**0.025**	**0.021**	**0.008**	**0.008**

Source: Own calculations based on Green-X database, Resch et al. (2012) and Kaltschmitt and Streicher (2009).

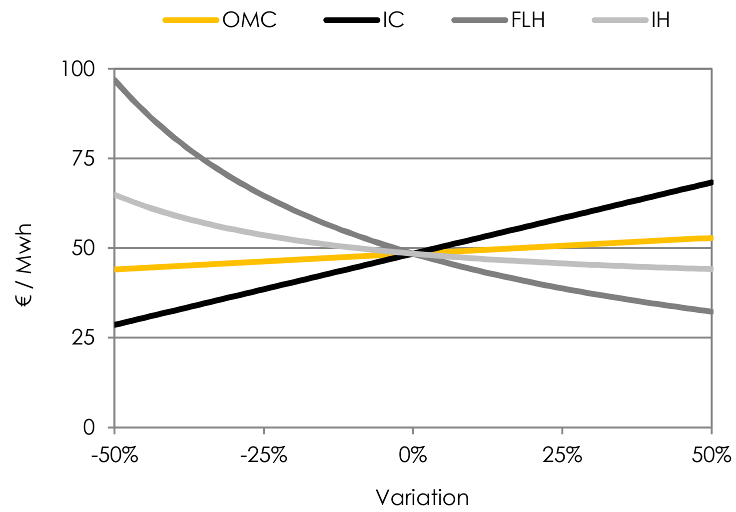


Figure 40. Sensitivity analysis of long run marginal generation costs of small hydro power plants in Austria

Source: Own calculations based on Green-X database, Resch et al. (2012) and Kaltschmitt and Streicher (2009).

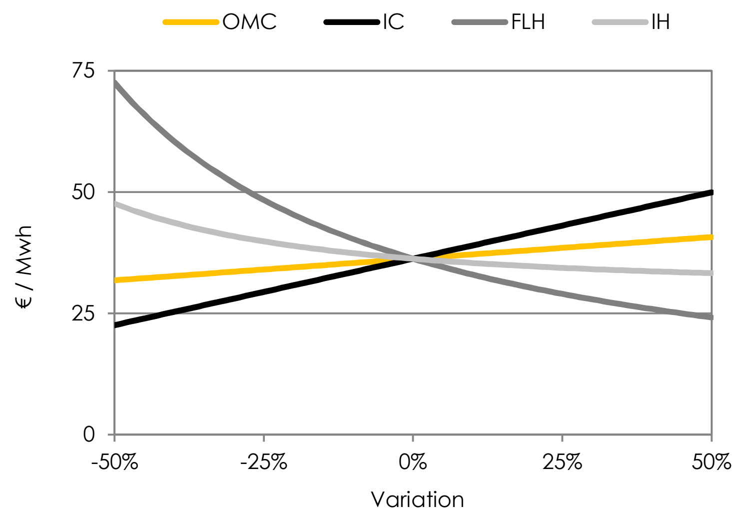


Figure 41. Sensitivity analysis of long run marginal generation costs of large hydro power plants in Austria

Source: Own calculations based on Green-X database, Resch et al. (2012) and Kaltschmitt and Streicher (2009).

5.1.4 Biomass and Biogas

Table 11 shows the short and long run electricity generation costs for biomass in the three Central and Eastern European case study countries as well as a summary of the central input parameters for the calculations and cost positions. All values are again reported for a unit capacity of 1 kW.

For the calculations, 5,000 full load hours are assumed for the default scenario and 5,500 full load hours are assumed for the optimistic scenario. Based on Kaltschmitt and Streicher (2009) an average investment horizon of 20 years is assumed. The investment costs range between € 2,017 and € 2,739 per kW in the default scenario and between € 1,658 and € 2,187 in the optimistic scenario. Assuming a discount rate of 4.5% for an investment horizon of 20 years, the investment annuities range between € 155 in the Czech Republic and € 211 in Austria in the default scenario and between € 127 and € 168 in the optimistic scenario. O&M costs range between € 86 and € 175. The fuel costs amount to € 357 in the default scenario and to € 223 in the optimistic scenario (assuming transformation efficiencies of 35% in the default scenario and 37% in the optimistic scenario and fuel prices of € 25 and € 15 per MWh_p respectively).

The long run marginal costs of biomass amount to approximately € 149 per MWh in the default scenario in Austria and to € 129 and respectively € 123 per MWh in the Czech Republic and Hungary; in the optimistic scenario long run marginal costs are in the range of € 79 to € 87 per MWh. The short run marginal costs range between € 89 and € 106 per MWh in the default scenario and € 57 in the optimistic scenario.

Table 11. Long and short run marginal generation costs of biomass based electricity in Austria, the Czech Republic and Hungary in 2030

		Austria		Czech Republic		Hungary	
		DS	OS	DS	OS	DS	OS
Rated capacity (net)	kw	1.00	1.00	1.00	1.00	1.00	1.00
Full load hours	h p.a.	5,000	5,500	5,000	5,500	5,000	5,500
Electricity output	kWh/a	5,000	5,500	5,000	5,500	5,000	5,500
Investment costs	€	2,739	2,041	2,017	1,658	2,235	2,187
Investment horizon	years	20	20	20	20	20	20
Discount rate	p.a.	4.5%	4.5%	4.5%	4.5%	4.5%	4.5%
Capital recovery factor		0.077	0.077	0.077	0.077	0.077	0.077
Annuity	€ p.a.	211	157	155	127	172	168
Fuel costs	€ p.a.	357	223	357	223	357	223
O&M costs	€ p.a.	175	97	131	86	86	86
LRMC	**€/kWh**	**0.149**	**0.087**	**0.129**	**0.079**	**0.123**	**0.087**
SRMC	**€/kWh**	**0.106**	**0.058**	**0.098**	**0.056**	**0.089**	**0.056**

Source: Own calculations based on Green-X database, Resch et al. (2012) and Kaltschmitt and Streicher (2009).

The short and long run electricity generation costs of biogas based electricity generation in Austria, the Czech Republic and Hungary as well as a summary of the central input parameters for the calculations and cost positions are reported in Table 12. All values are again reported for a unit capacity of 1 kW. As for biomass, for the default scenario 5,000 full load hours and for the optimistic scenario 5,500 full load hours are assumed in the calculations.

The investment costs of the biogas plants range amount range between € 3,474 and € 3,554 per kW in the default scenario; for the optimistic scenario investment costs are estimated to be in the range of € 2,975 to € 3,552[37]. Based on an investment horizon of 20 years and a discount rate of 4.5% (following Kaltschmitt and Streicher, 2009) the investment annuities are in the range of € 267 and € 273 in the default scenario and range between € 229 and € 271 in the optimistic scenario. The annual O&M costs amount to € 137 to € 182. The fuel costs amount to € 357 in the default scenario and to € 236 in the optimistic scenario (assuming a transformation efficiency of 35% and fuel prices of € 25 per MWh_p in the default scenario and € 15 per MWh_p in the optimistic respectively).

[37] For biogas plants, the investment costs differ considerably according to the fuel used (see Resch et al., 2012). The investment costs used here are based on a mix of sewage gas, landfill gas and agricultural biogas.

Based on the assumptions described above, the long run electricity generation costs of biogas plants range between € 153 per MWh in Hungary and € 162 per MWh in Austria in the default scenario. For the optimistic scenario long run marginal costs of € 109 to € 117 per MWh are estimated. The short run marginal costs of biogas based electricity generation are in the range of € 99 to € 108 per MWh in the default scenario and approximately € 66 per MWh in the optimistic scenario.

Table 12. Long and short run marginal generation costs of biogas based electricity in Austria, the Czech Republic and Hungary in 2030

		Austria		Czech Republic		Hungary	
		DS	OS	DS	OS	DS	OS
Rated capacity (net)	kw	1.00	1.00	1.00	1.00	1.00	1.00
Full load hours	h p.a.	5,000	5,500	5,000	5,500	5,000	5,500
Electricity output	kWh/a	5,000	5,500	5,000	5,500	5,000	5,500
Investment costs	€	3,554	3,346	3,474	2,975	3,522	3,522
Investment horizon	years	20	20	20	20	20	20
Discount rate	p.a.	4.5%	4.5%	4.5%	4.5%	4.5%	4.5%
Capital recovery factor		0.077	0.077	0.077	0.077	0.077	0.077
Annuity	€ p.a.	273	257	267	229	271	271
Fuel costs	€ p.a.	357	236	357	236	357	236
O&M costs	€ p.a.	182	118	160	137	137	137
LRMC	**€/kWh**	**0.162**	**0.111**	**0.157**	**0.109**	**0.153**	**0.117**
SRMC	**€/kWh**	**0.108**	**0.064**	**0.103**	**0.068**	**0.099**	**0.068**

Source: Own calculations based on Green-X database, Resch et al. (2012) and Kaltschmitt and Streicher (2009).

A sensitivity analysis of the long run marginal electricity generation costs with respect to changes in investment costs (IC), changes in operating and maintenance costs (OMC) and fuel costs (FC), changes in full load hours (FLH) and changes in the investment horizon (IH) is provided is provided in Figure 42 for biomass and in Figure 43 for biogas respectively using data for Austria[38]. The long run marginal costs of biomass and biogas again show the highest sensitivity with respect to the full load hours assumed. The investment horizon as well as the investment costs do also have a strong impact on the long run marginal electricity generation costs. In contrast to the other renewable electricity generation technologies, the operating and

[38] For the Czech Republic and Hungary analogue illustrations are provided in Appendix 1.

maintenance costs as well as fuel costs also significantly affect the long run marginal costs.

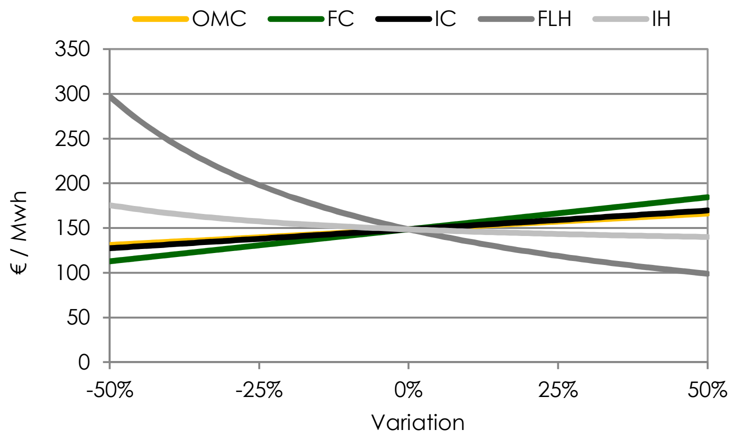


Figure 42. Sensitivity analysis of long-run marginal generation costs of biomass based electricity generation in Austria

Source: Own calculations based on Green-X database, Resch et al. (2012) and Kaltschmitt and Streicher (2009).

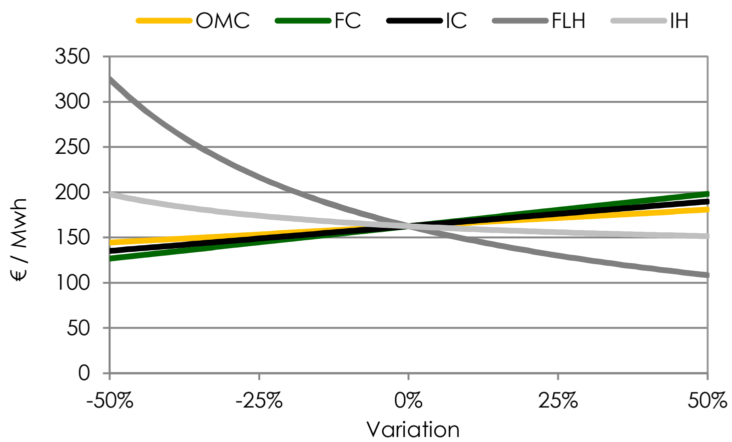


Figure 43. Sensitivity analysis of long-run marginal generation costs of biogas based electricity generation in Austria

Source: Own calculations based on Green-X database, Resch et al. (2012) and Kaltschmitt and Streicher (2009).

5.1.5 Reference Technologies

The short and long run electricity generation costs of the reference technologies (coal and gas based as well as nuclear electricity generation) as well as a summary of the central input parameters for the calculations and cost positions are reported in Table 13.

For the calculations 7,000 full load hours are for coal power plants (following Kaltschmitt and Streicher, 2009); for gas power plants and nuclear plants 6,000 and respectively 8,000 full load hours are assumed. Furthermore, the following efficiencies are used in the calculations: 39% for coal power plants, 48% for gas power plants and 33% for nuclear power plants (see IEA and ETSAP, 2010a, 2010b; Hirth, 2012).

Investment costs amount to € 1,000 per kW for coal, to € 1,600 for gas and to € 3,350 for nuclear power plants (Hirth, 2012). Assuming an investment horizon of 30 years and a discount rate of 4.5%, the investment annuity is € 98 for coal, € 61 and € 206 for gas and nuclear energy respectively. Fuel costs are estimated € 92 for coal, € 234 for gas and € 24 for nuclear power plants. Other O&M costs range between € 15 for gas power plants and € 53 for nuclear power plants.

The long run marginal costs of coal power plants amount to € 60 per MWh; for gas and nuclear power plants they are estimated € 80 and € 107 per MWh respectively. The short run marginal costs of coal power plants are € 33 per MWh, gas and nuclear power plants exhibit short run marginal costs of € 64 and € 29 per MWh respectively.

Table 13. Long and short run marginal costs of fossil and nuclear electricity generation

		Coal	Gas	Nuclear
Rated capacity	kw	1.00	1.00	1.00
Full load hours	h p.a.	7,000	6,000	8,000
Efficiency	%	52%	65%	33%
Electricity output	kWh/a	3,640	3,900	2,640
Investment costs	€	1,600	1,000	3,350
Investment horizon	years	30	30	30
Discount rate	p.a.	5%	5%	5%
Capital recovery factor		0.061	0.061	0.061
Annuity	€ p.a.	98	61	206
Fuel costs	€ p.a.	92	234	24
O&M costs	€ p.a.	29	16	53
LRMC	**€/kWh**	**0.060**	**0.080**	**0.107**
SRMC	**€/kWh**	**0.033**	**0.064**	**0.029**

Source: Own calculations based on Hirth (2012), IEA (2011), IEA and ETSAP (2010a, 2010b) and Kaltschmitt and Streicher (2009).

5.2 Effects of the EU ETS on Long and Short Run Marginal Costs

In the following section, changes in the merit order of the six renewable electricity generation technologies and the non-renewable reference technologies resulting from the price signal established by the emissions trading scheme are examined. In the analysis, a situation with a carbon price of € 36 and € 60 per ton of CO_2 emitted are compared with a situation without carbon pricing. A carbon price of € 36 corresponds to the price level assumed in the reference scenario of the EU's roadmap to a low carbon society[39]; a price of € 60 respectively corresponds to the price assumed in the most ambitious decarbonisation scenario without CCS.

The long and short run marginal costs of the non-renewable reference technologies with which the renewable electricity generation technologies are compared are summarised in Table 14 for the different carbon prices. At a carbon price of € 36 per ton of CO_2 emitted the costs of coal based electricity generation increase by € 24 (+71% of short run marginal costs); the costs of gas based electricity generation increase by € 11 (+17% of short run marginal costs). At a carbon price of € 60, the

[39] In this scenario, the long term climate targets of the European Union are not met.

cost increases are € 39 (+119%) and respectively € 18 (+29%). The costs of nuclear power plants are not affected by a carbon price.

Nuclear power plants exhibit the highest long run marginal costs and the lowest short run marginal costs. Without a carbon price, the short and long run marginal costs of coal plants are below those of gas plants. Due to the higher carbon content (and the lower transformation efficiency assumed), carbon pricing has a higher impact on coal power plants than on gas power plants. At a carbon price of € 36 both long and short run marginal costs of coal power plants are still below those of gas power plants. At a carbon price of € 60, the long run marginal costs of coal exceed those of gas while the short run marginal costs of coal are still lower[40].

Table 14. Long run marginal costs of coal and gas based as well as nuclear electricity generation for different carbon prices

CO_2 price (€ /t)	SRMC (€ / MWh)			LRMC (€ / MWh)		
	Coal	Gas	Nuclear	Coal	Gas	Nuclear
0	33	64	29	60	80	107
36	57	75	29	84	91	107
60	73	82	29	100	98	107

Source: Own calculations based on Hirth (2012), IEA (2011), IEA and ETSAP (2010a, 2010b) and Kaltschmitt and Streicher (2009).

5.2.1 EFFECTS OF THE EU ETS IN AUSTRIA

Changes in merit order in Austria are illustrated in Figure 44 for the different CO_2 prices. The figure shows that even without a carbon price the short run marginal costs of some renewable electricity generation technologies (wind power, small and large hydro power, and in the optimistic scenario also PV) are lower than the short run marginal costs of coal and gas power plants. At a carbon price of € 36 per ton of CO_2, wind power, hydro power and PV exhibit lower short run marginal costs than the reference technologies. At a carbon price of € 60, the short run marginal generation costs of biomass and biogas plants still exceed those of the reference technologies in the default scenario; in the optimistic scenario in contrast all renewable electricity generation technologies exhibit lower short run marginal costs

[40] Given the assumptions described above, the long run marginal costs of coal exceed those of gas at a CO_2 price of € 56. At a CO_2 price of € 88, the short run marginal costs of gas are also lower than those of coal.

than coal and gas power plants (see also Appendix 2). With respect to daily operation decisions, some renewable electricity generation technologies are hence already competitive compared to fossil electricity generation.

The long run marginal costs of the considered renewable electricity generation technologies in Austria are summarised in Table 15 for the default and the optimistic scenario. Assuming no carbon price, hydro power (and wind power in the optimistic scenario) exhibit lower long run marginal costs than the reference technologies, while the costs of the other renewable electricity generation technologies are still higher. At carbon prices of € 36 and € 60, the long run marginal costs of biomass are below those of the gas power plants in the optimistic scenario. For PV and biogas, the long run marginal costs exceed those of coal and gas even at a carbon price of € 60 (see also Appendix 2).

Table 15. Long run marginal costs of renewable electricity generation in Austria in 2030

	LRMC (€ / MWh)					
	Wind	**PV**	**Hydro S**	**Hydro L**	**Biomass**	**Biogas**
Default scenario	77	196	48	36	149	162
Optimistic scenario	51	142	43	32	87	111

Source: Own calculations based on Green-X database, Resch et al. (2012) and Kaltschmitt and Streicher (2009).

Comparing long run marginal costs of the renewable electricity generation technologies with the short run marginal costs of the reference technologies for Austria, shows that at a carbon price of € 36 per ton CO_2 small and large hydro power become competitive against the incumbent reference technologies in the default scenario, i.e. the long run marginal costs of the renewable technologies are below the short run marginal costs of the reference technologies. In the optimistic scenario, also wind power becomes competitive at a carbon price of € 36 per ton CO_2. The same is true for a carbon price of € 60 independent of the scenario. Biomass, biogas and PV do not become competitive against the incumbent reference technologies.

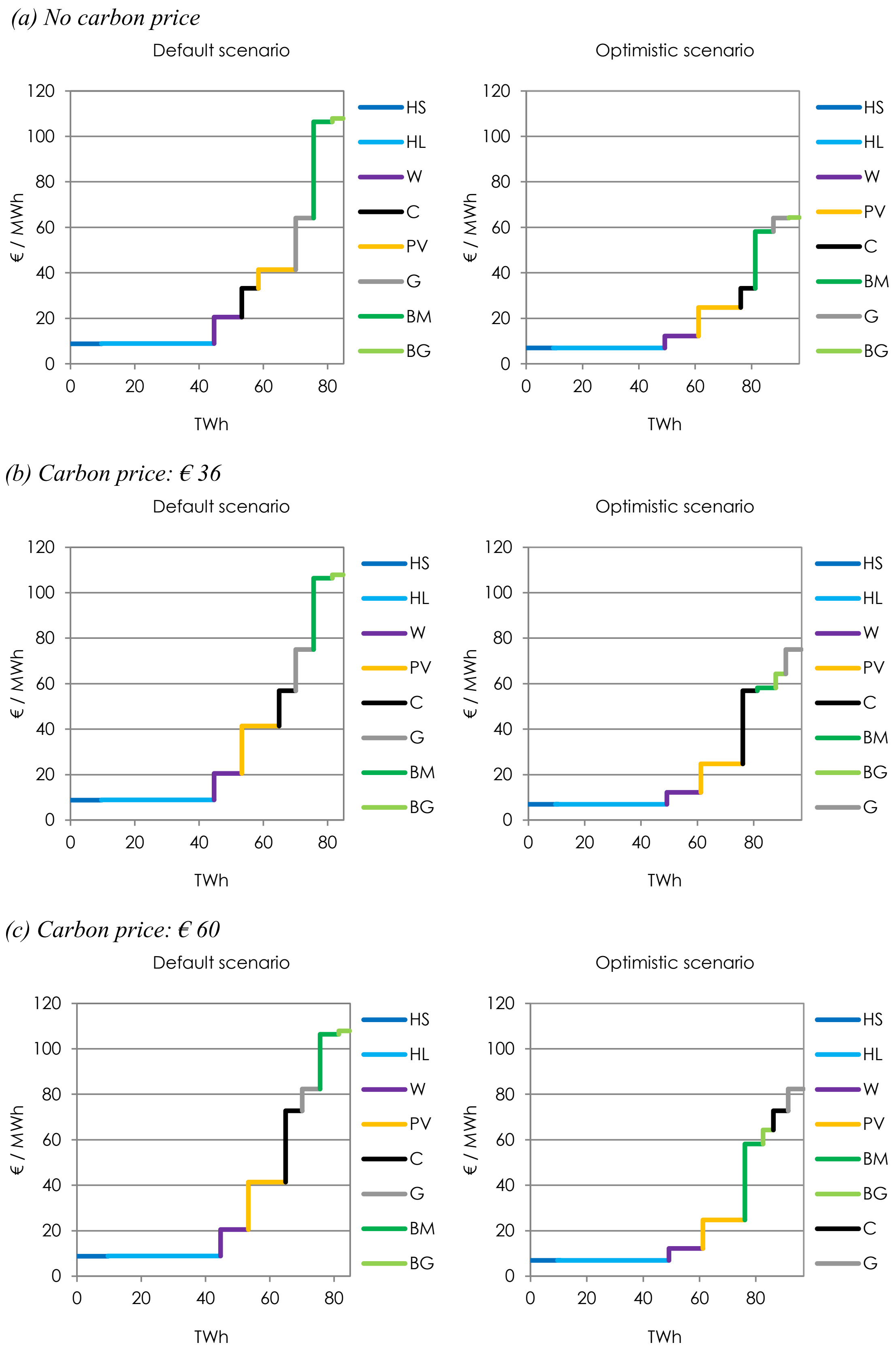


Figure 44. Merit order curve in Austria in 2030

Source: Own calculations based on Green-X database, Resch (2012), Kaltschmitt and Streicher (2009), Hirth (2012), IEA (2011) and IEA and ETSAP (2010a, 2010b).

5.2.2 EFFECTS OF THE EU ETS IN THE CZECH REPUBLIC

Changes in the merit order in the Czech Republic are illustrated in Figure 45 for different CO_2 prices. As for Austria, the figure shows that even without a carbon price the short run marginal costs of hydro power and wind power are lower than the short run marginal costs the reference plants in both scenarios. At a carbon price of € 36, PV does also exhibit lower short run marginal costs than coal and gas plants in the default scenario; in the optimistic scenario also the short run marginal costs of biomass plants are below those of coal and gas power plants. At a carbon price of € 60 per ton of CO_2 also biogas plants exhibit lower short run marginal costs than coal and gas power plants (see also Appendix 3).

Table 16 shows the long run marginal costs of the considered renewable electricity generation costs in the Czech Republic in the default and the optimistic scenario. Without a carbon price, hydro power exhibits lower long run marginal costs than the reference technologies in the default scenario; in the optimistic scenario also wind power exhibits lower long run marginal costs. At a carbon price of € 36, also the long run marginal costs of biomass are below those of coal and gas power plants. The long run marginal costs of biogas and PV exceed those of coal and gas power plants also at a carbon price of € 60 per ton CO_2 (see also Appendix 3)[41].

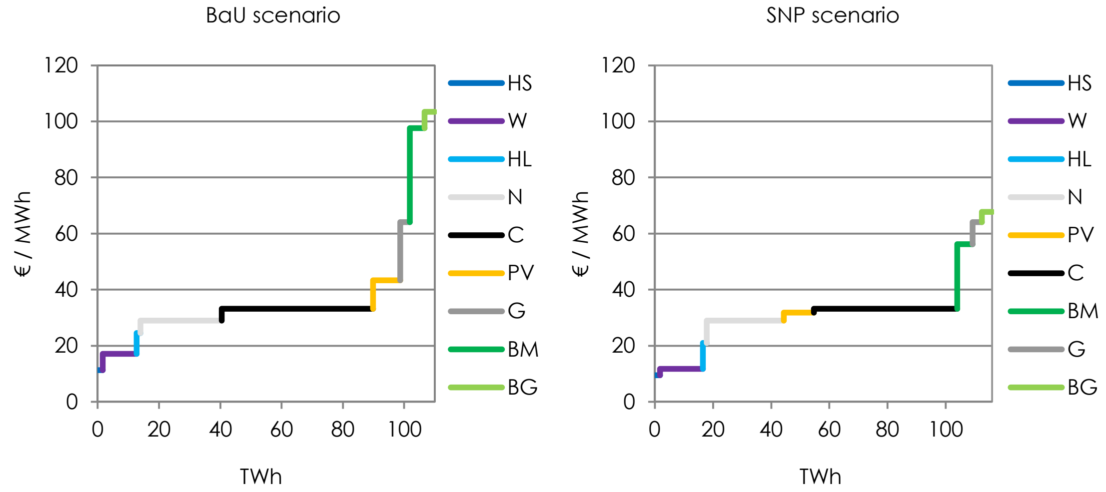
Table 16. Long run marginal costs of renewable electricity generation in the Czech Republic in 2030

	LRMC (€ / MWh)					
	Wind	**PV**	**Hydro S**	**Hydro L**	**Biomass**	**Biogas**
Default scenario	73	209	61	63	129	157
Optimistic scenario	51	173	55	56	79	109

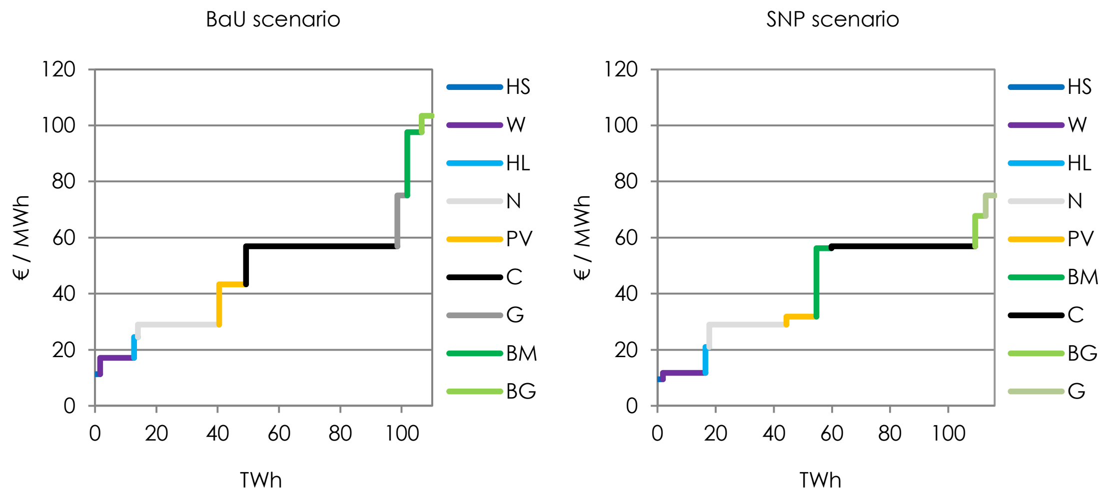
Source: Own calculations based on Green-X database, Resch et al. (2012) and Kaltschmitt and Streicher (2009).

[41] The long run marginal costs of PV even exceed those of nuclear power plants in the default and in the optimistic scenario.

(a) No carbon price



(b) Carbon price: € 36



(c) Carbon price: € 60

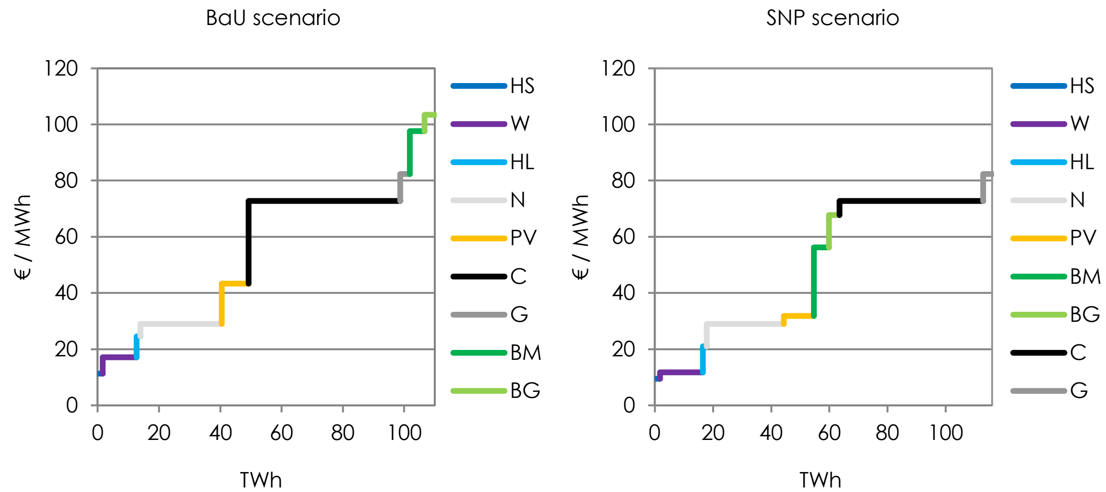


Figure 45. Merit order curve in the Czech Republic in 2030

Source: Own calculations based on Green-X database, Resch (2012), Kaltschmitt and Streicher (2009), Hirth (2012), IEA (2011) and IEA and ETSAP (2010a, 2010b).

Comparing the long run marginal costs of the renewable electricity generation technologies with the short run marginal costs of coal, gas and nuclear power plants for the Czech Republic, shows that at a carbon price of € 36 per ton CO_2 hydro power becomes competitive against incumbent coal and gas power plants in the default scenario, i.e. the long run marginal costs of the renewable technologies are below the short run marginal costs of these reference technologies; under the optimistic scenario also wind power becomes competitive at a carbon price of € 36. At a carbon price of € 60 also biomass becomes competitive against gas in the optimistic scenario.

5.2.3 EFFECTS OF THE EU ETS IN HUNGARY

Changes in the merit order in Hungary for different carbon prices are illustrated in Figure 46. In contrast to Austria and the Czech Republic, the short run marginal costs of PV are already below those of coal and gas power plants without a carbon price. Nuclear power plants exhibit lower short run marginal costs than PV, but higher costs than wind and hydro power. At carbon price of € 36 (€ 60), the short run marginal costs of biomass (and biogas) are also lower than those of coal and gas power plants in the optimistic scenario (see also Appendix 4).

A comparison of the long run marginal costs of the reference technologies (see Table 14) and the renewable electricity generation technologies in Hungary (see Table 17) shows the long run marginal costs of small and large hydro power even without a carbon price are below those of the reference technologies both in the default and in the optimistic scenario; in the optimistic scenario also the long run marginal costs of wind power are below those of the reference technologies. At a carbon price of € 60 per ton of CO_2 the long run marginal costs of biomass are also lower than those of coal and gas power plants (see also Appendix 4).

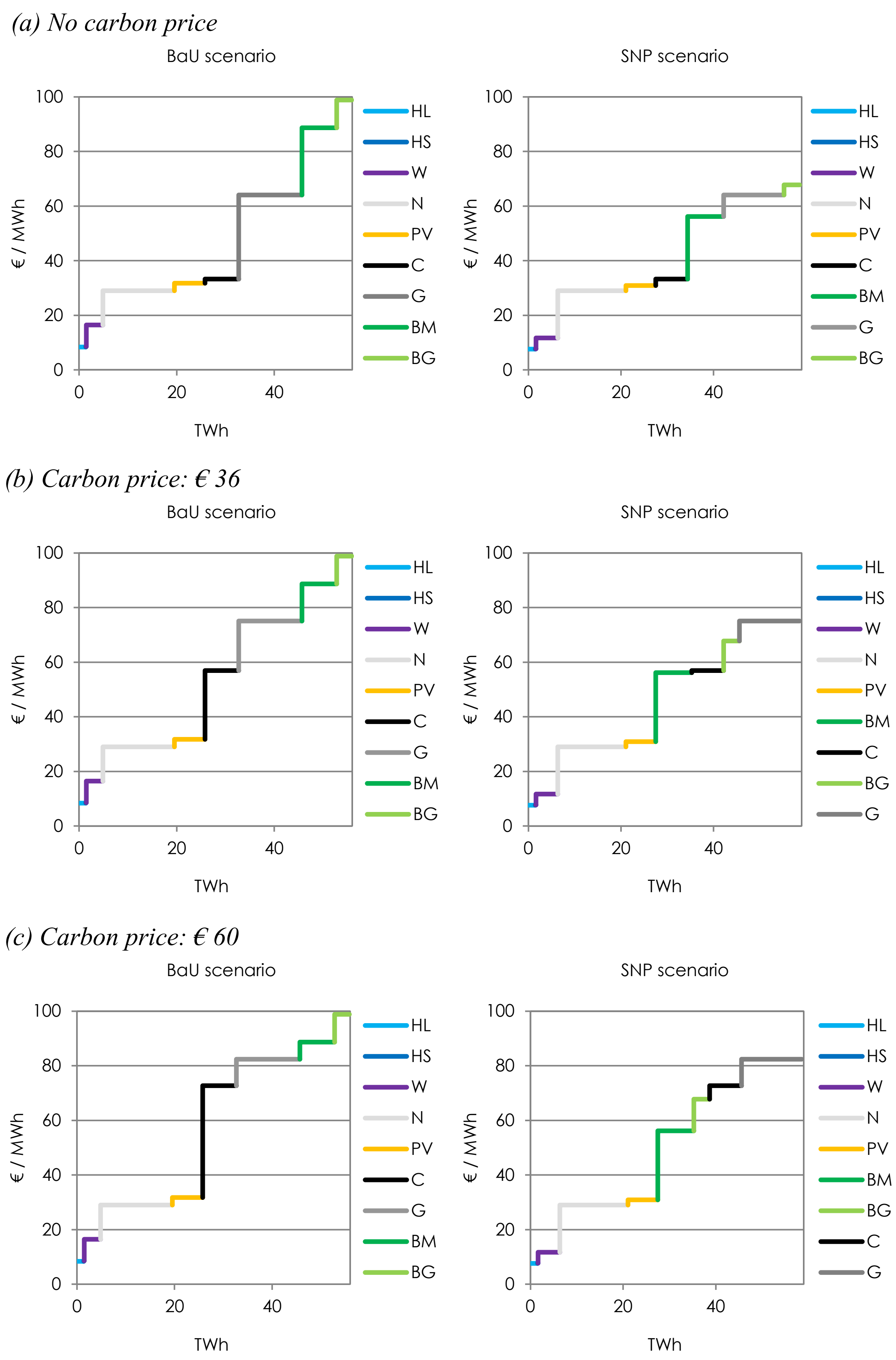


Figure 46. Merit order curve in the Hungary in 2030

Source: Own calculations based on Green-X database, Resch (2012), Kaltschmitt and Streicher (2009), Hirth (2012), IEA (2011) and IEA and ETSAP (2010a, 2010b).

Table 17. Long run marginal costs of renewable electricity generation in Hungary in 2030

	LRMC (€ / MWh)					
	Wind	**PV**	**Hydro S**	**Hydro L**	**Biomass**	**Biogas**
Default scenario	75	171	42	30	123	153
Optimistic scenario	49	166	39	27	87	117

Source: Own calculations based on Green-X database, Resch et al. (2012) and Kaltschmitt and Streicher (2009).

Comparing long run marginal costs of the renewable electricity generation technologies with the short run marginal costs of the reference technologies for Hungary, shows that at a carbon price of € 36 per ton CO_2 hydro power becomes competitive against incumbent coal and gas power plants in the default scenario; under the optimistic scenario also wind power becomes competitive at a carbon price of € 36.

6 SUMMARY AND CONCLUSIONS

The increase of renewable energy sources and a reduction of greenhouse gas emissions are central policy targets in the European Union. While often considered isolated, inter-linkages between policies aiming at emission reductions and an increasing share of renewable energy sources prevail: On the one hand, a carbon price generated e.g. by the EU ETS might increase the competitiveness of low carbon fuels such as renewables. On the other hand, an increasing share of – carbon neutral – renewables that is not taken into account in the definition of the GHG emission cap might undermine incentives for implementing other emission reductions options.

Focussing on electricity generation, this thesis investigated to which extent the EU ETS has supported in the past and might support in forthcoming years the use of renewable energy sources in Austria, the Czech Republic and Hungary. Based on a simple numerical framework following Schwaiger et al. (2012) it has been analysed whether and for which technologies changes in electricity prices triggered by the EU ETS could substitute or would allow a change in current renewable support schemes.

The cost assessment covered both long and short run marginal costs. Short run marginal costs include fuel costs and other variable costs and provide the basis for daily decisions regarding plant operation. Long run marginal costs in contrast to short run marginal costs do not only cover variable costs but also fixed costs, i.e. investment and capital costs. While short run marginal costs determine the dispatch order of existing plants, long run marginal generation costs determine in which renewable electricity generation technologies will be invested.

In the comparison of renewable electricity generation technologies and reference technologies these two aspects need to be considered: A comparison of short run marginal costs indicates whether renewable electricity generation technologies can enter the market without privileged grid access. In order to assess whether investments in renewable electricity generation technologies will be made in order to substitute fossil and nuclear electricity generation the long run marginal costs of renewables need to be compared with the short run marginal costs of the reference technologies.

Using two carbon price scenarios (€ 36 and € 60 per ton CO_2) and two renewable policy scenarios (default scenario; optimistic scenario), the competitiveness of renewable electricity generation technologies (wind power, small and large hydro power, PV, biomass and biogas) compared to non-renewable reference technologies in 2030 has been analysed.

Without a carbon price the short run marginal costs of (small and large) hydro power and wind power are generally lower than the short run marginal costs of coal and gas power plants. At a carbon price of € 36 per ton of CO_2, also PV exhibits lower short run marginal costs than coal and gas power plants in the case study countries. Biomass and biogas do only exhibit lower short run marginal costs than coal and gas in the optimistic scenario and assuming a carbon price of € 60 per ton CO_2.

With respect to long run marginal costs, hydro power does also exhibit lower costs than the reference technologies even without carbon pricing. At a carbon price of € 36, the long run marginal costs of all reference technologies do also exceed those of wind power. In the optimistic scenario, the long run marginal costs of biomass plants are also lower than those of the reference plants at a CO_2 price of € 60.

Comparing the long run marginal costs of the renewable electricity generation technologies with the short run marginal costs shows that at a carbon price of € 36 per ton CO_2 wind power and hydro power become competitive against the incumbent reference technologies in the optimistic scenario, i.e. the long run marginal costs of the renewable technologies is below the short run marginal costs of the reference technologies. The same is true for a carbon price of € 60 independent of the scenario.

Whether investments in renewable electricity generation technologies will occur, depends, however, on the expected electricity price and non-monetary factors. At a stable electricity price that is determined by the short run marginal costs of coal or gas power plants, some renewable electricity generation technologies (wind power as well as small and large hydro power) will not require a feed-in tariff or other support measures due to the higher market price resulting from pricing CO_2 emissions of fossil electricity generation. For end users such a situation would, however, not imply a cost reduction as reduced renewable electricity support would be set off by higher electricity prices.

When renewable electricity generation technologies do gain in importance, spot market prices will, however, tend to decline as renewable electricity generation technologies exhibit lower short run marginal costs than fossil electricity generation. Furthermore, the fact that variable renewable electricity generation technologies (wind power, PV) in times of (full) in-feed might deteriorate the prices on electricity markets, and hence receive a lower income than suggested by average market figures. In such a situation, the market price might not be sufficient for the expansion of renewable electricity generation.

In order to ensure a broad diversification of renewable electricity generation technologies, the EU ETS should be complemented by additional instruments (e.g. additional support for technologies that are not yet competitive like PV). A broad implementation of (variable) renewable electricity generation technologies furthermore needs to be integrated into a comprehensive reform of electricity markets in which the price formation mechanism is adapted both to renewable electricity generation technologies and the required electricity storage systems.

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Appendix

Appendix A.1: Sensitivity Analysis of Electricity Generation Costs of Renewables in the Czech Republic and Hungary

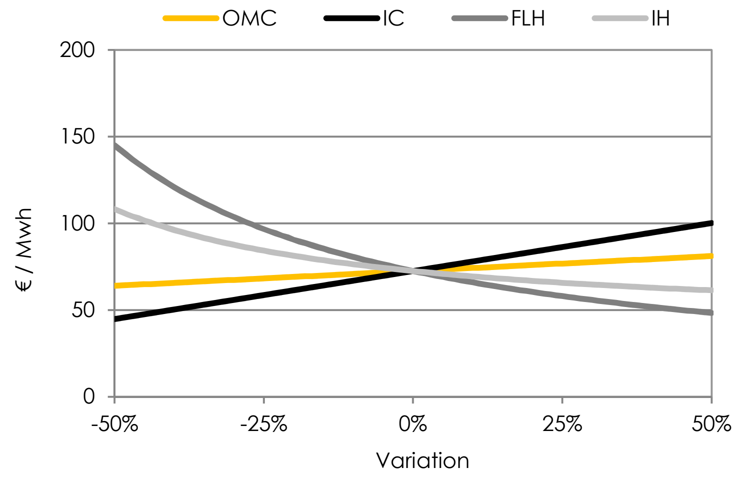

Figure A - 1. Sensitivity analysis of long run marginal generation costs of wind electricity generation in the Czech Republic in 2030

Source: Own calculations based on Green-X database and Resch et al. (2012).

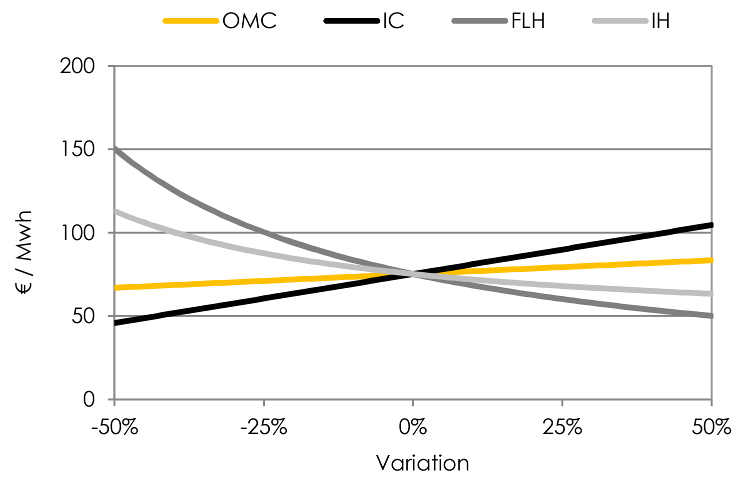

Figure A - 2. Sensitivity analysis of long run marginal generation costs of wind electricity generation in Hungary in 2030

Source: Own calculations based on Green-X database and Resch et al. (2012).

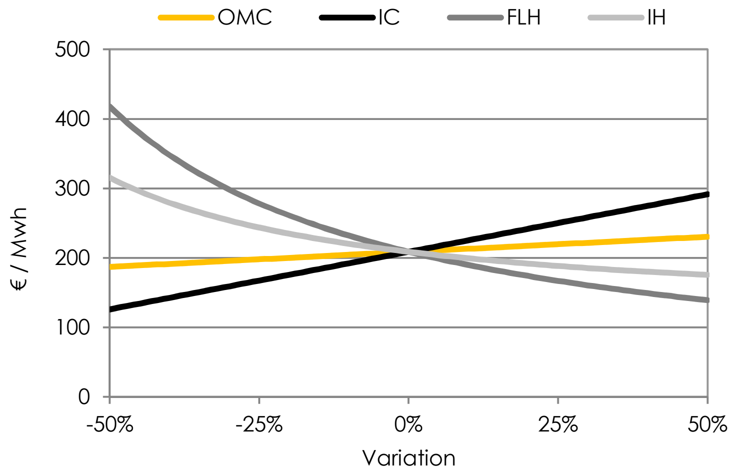

Figure A - 3. Sensitivity analysis of long run marginal generation costs of PV in the Czech Republic in 2030

Source: Own calculations based on Green-X database and Resch et al. (2012).

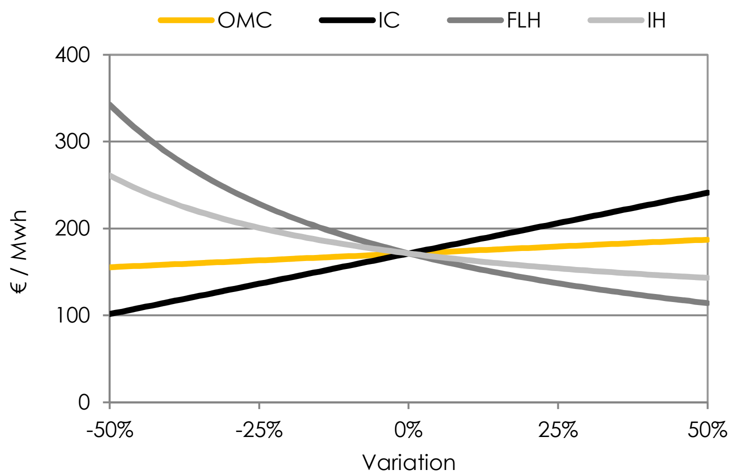

Figure A - 4. Sensitivity analysis of long run marginal generation costs of PV in Hungary in 2030

Source: Own calculations based on Green-X database and Resch et al. (2012).

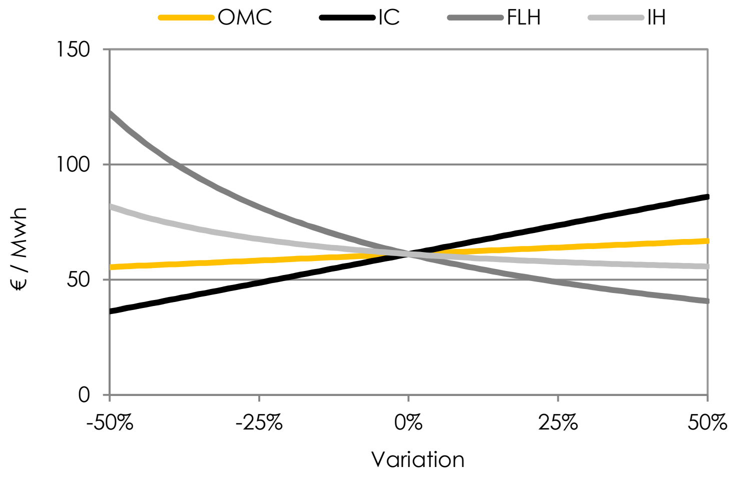

Figure A - 5. Sensitivity analysis of long run marginal generation costs of small hydro power in the Czech Republic in 2030

Source: Own calculations based on Green-X database and Resch et al. (2012).

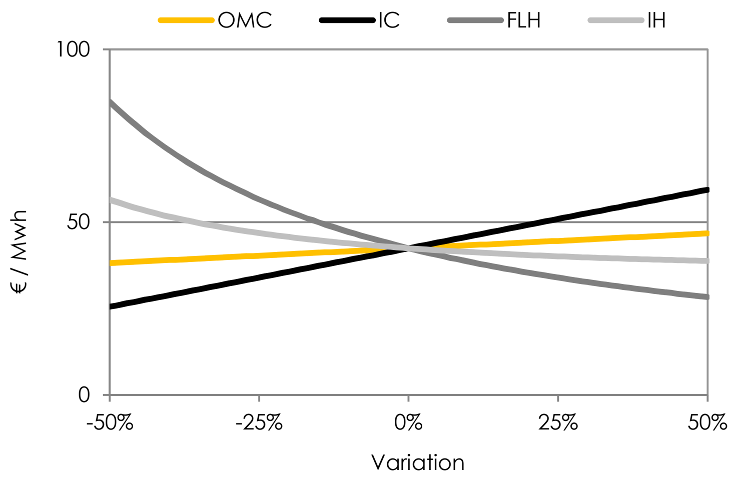

Figure A - 6. Sensitivity analysis of long run marginal generation costs of small hydro power in Hungary in 2030

Source: Own calculations based on Green-X database and Resch et al. (2012).

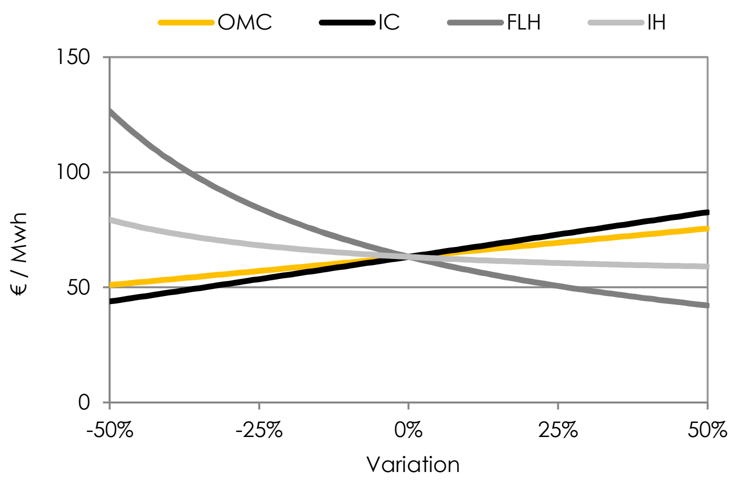

Figure A - 7. Sensitivity analysis of long run marginal generation costs of large hydro power in the Czech Republic in 2030

Source: Own calculations based on Green-X database and Resch et al. (2012).

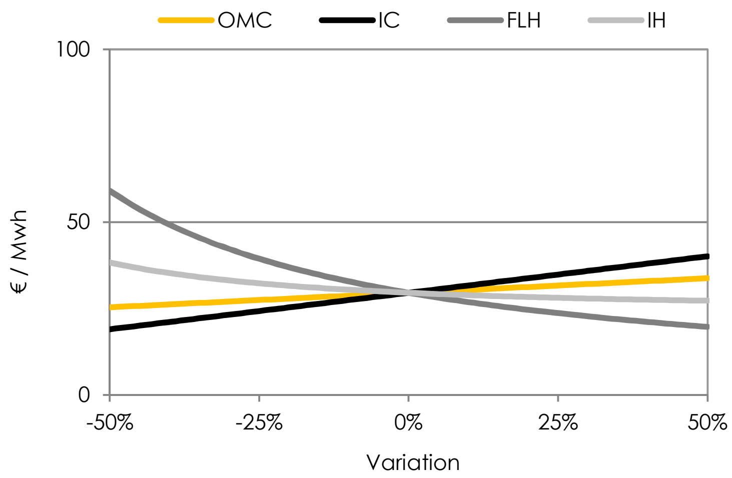

Figure A - 8. Sensitivity analysis of long run marginal generation costs of large hydro power in Hungary in 2030

Source: Own calculations based on Green-X database and Resch et al. (2012).

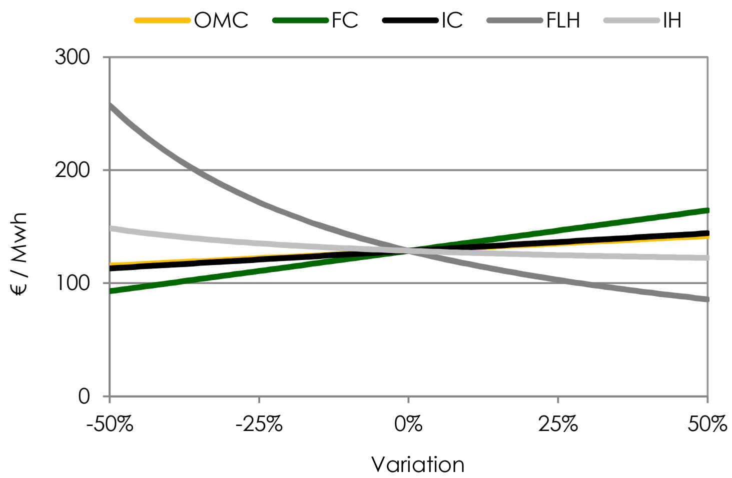

Figure A - 9. Sensitivity analysis of long run marginal generation costs of biomass in the Czech Republic in 2030

Source: Own calculations based on Green-X database and Resch et al. (2012).

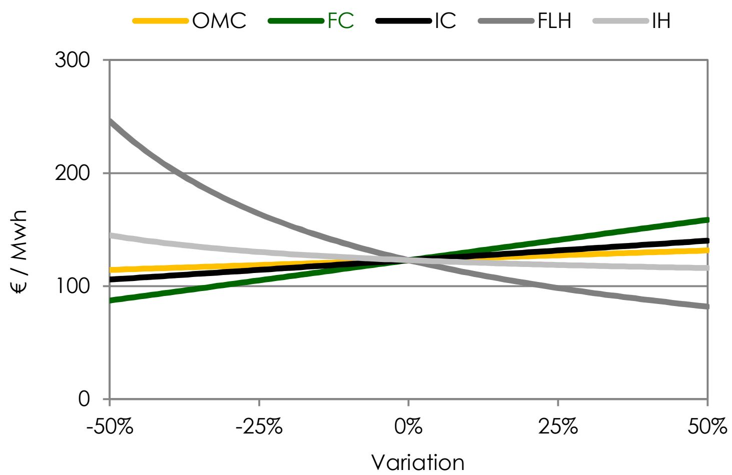

Figure A - 10. Sensitivity analysis of long run marginal generation costs of biomass in Hungary in 2030

Source: Own calculations based on Green-X database and Resch et al. (2012).

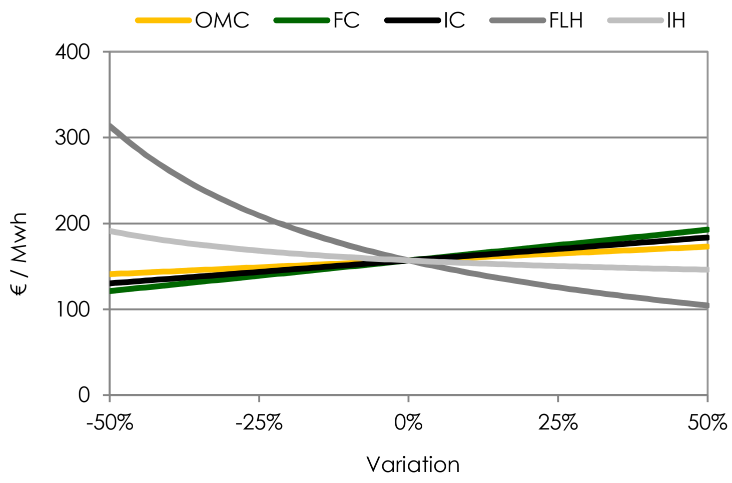

Figure A - 11. Sensitivity analysis of long run marginal generation costs of biogas in the Czech Republic in 2030

Source: Own calculations based on Green-X database and Resch et al. (2012).

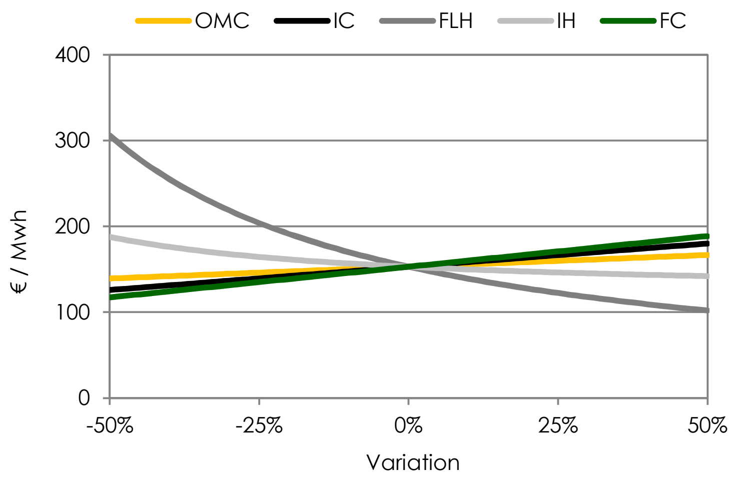

Figure A - 12. Sensitivity analysis of long run marginal generation costs of biogas in Hungary in 2030

Source: Own calculations based on Green-X database and Resch et al. (2012).

Appendix A.2: Comparison of Long and Short Run Marginal Costs in Austria

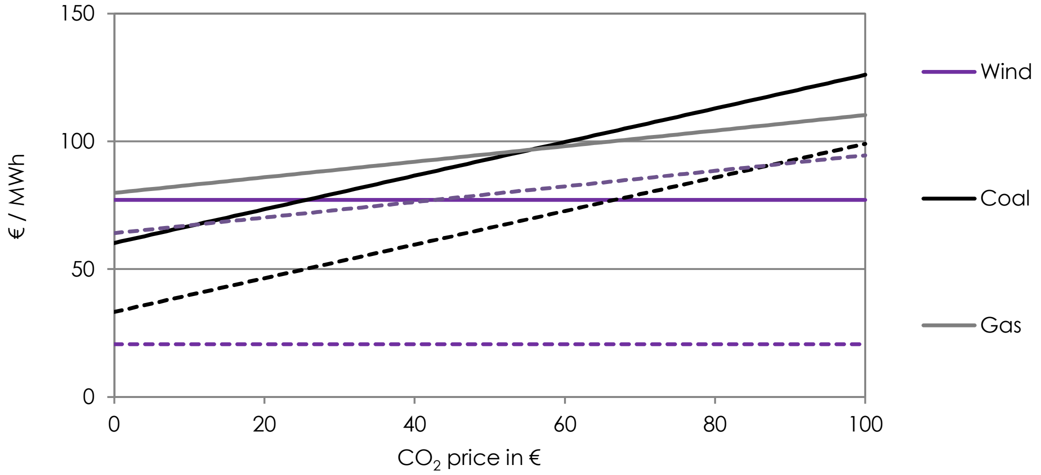

Figure A - 13. Long and short run electricity generation costs in Austria in the default scenario for 2030: Wind power vs. fossil electricity generation

Source: Own calculations based on Green-X database, Resch (2012), Kaltschmitt and Streicher (2009), Hirth (2012) and IEA (2011), IEA and ETSAP (2010a, 2010b). Dashed lines represent short run marginal costs; solid lines represent long run marginal costs.

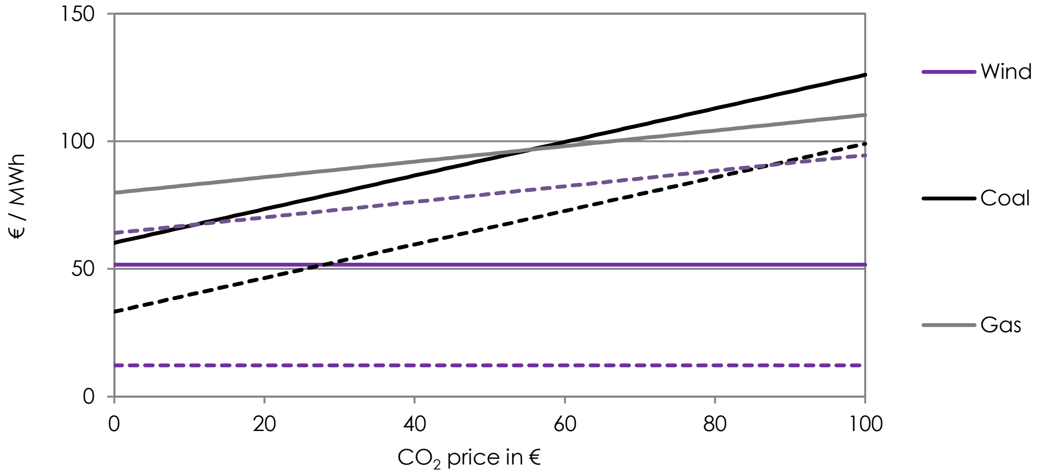

Figure A - 14. Long and short run electricity generation costs in Austria in the optimistic scenario for 2030: Wind power vs. fossil electricity generation

Source: Own calculations based on Green-X database, Resch (2012), Kaltschmitt and Streicher (2009), Hirth (2012) and IEA (2011), IEA and ETSAP (2010a, 2010b). Dashed lines represent short run marginal costs; solid lines represent long run marginal costs.

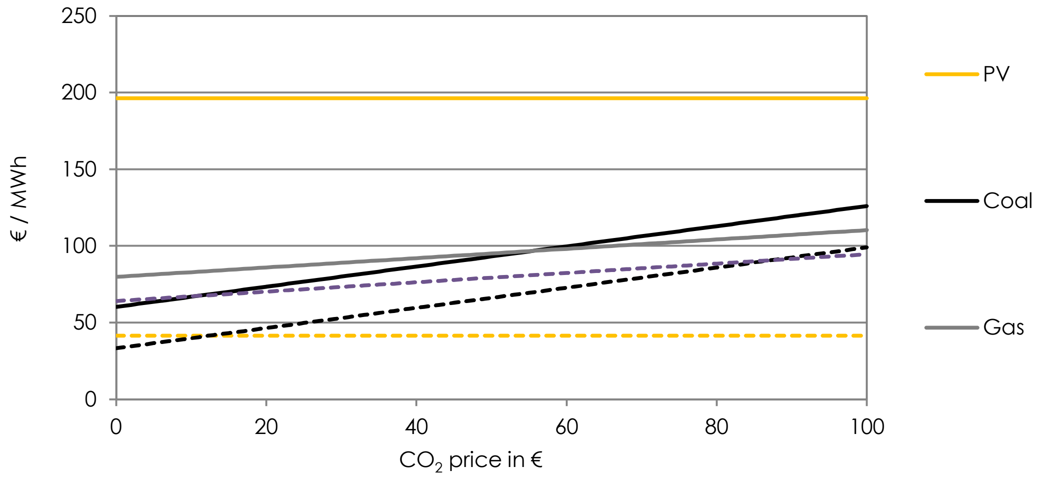

Figure A - 15. Comparison of long and short run electricity generation costs in Austria in the default scenario for 2030: PV vs. fossil electricity generation

Source: Own calculations based on Green-X database, Resch (2012), Kaltschmitt and Streicher (2009), Hirth (2012) and IEA (2011), IEA and ETSAP (2010a, 2010b). Dashed lines represent short run marginal costs; solid lines represent long run marginal costs.

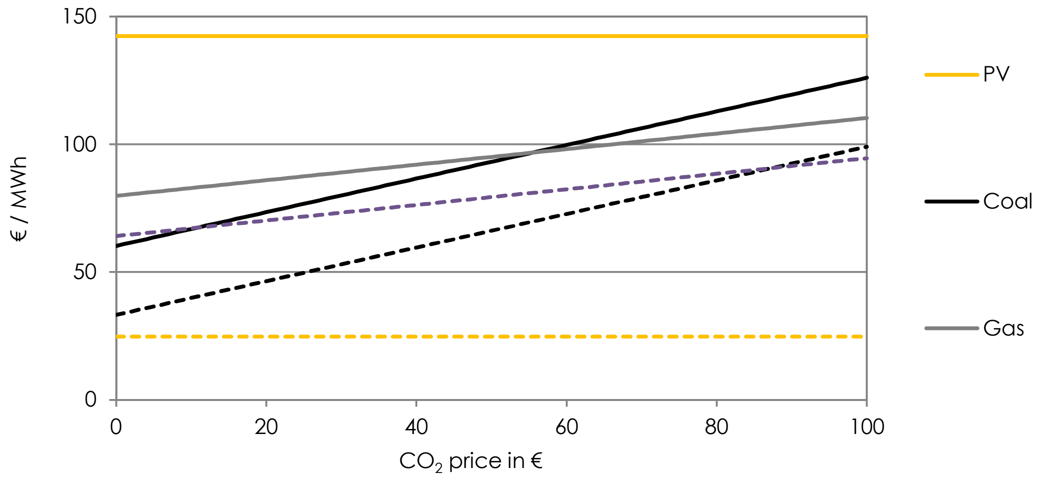

Figure A - 16. Comparison of long and short run electricity generation costs in Austria in the optimistic scenario for 2030: PV vs. fossil electricity generation

Source: Own calculations based on Green-X database, Resch (2012), Kaltschmitt and Streicher (2009), Hirth (2012) and IEA (2011), IEA and ETSAP (2010a, 2010b).

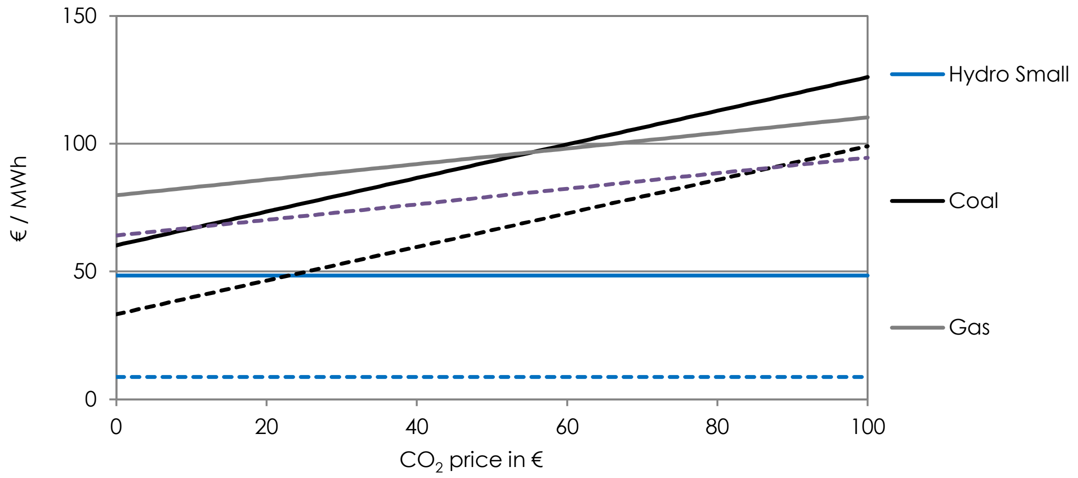

Figure A - 17. Comparison of long and short run electricity generation costs in Austria in the default scenario for 2030: Small hydro power vs. fossil electricity generation

Source: Own calculations based on Green-X database, Resch (2012), Kaltschmitt and Streicher (2009), Hirth (2012) and IEA (2011), IEA and ETSAP (2010a, 2010b). Dashed lines represent short run marginal costs; solid lines represent long run marginal costs.

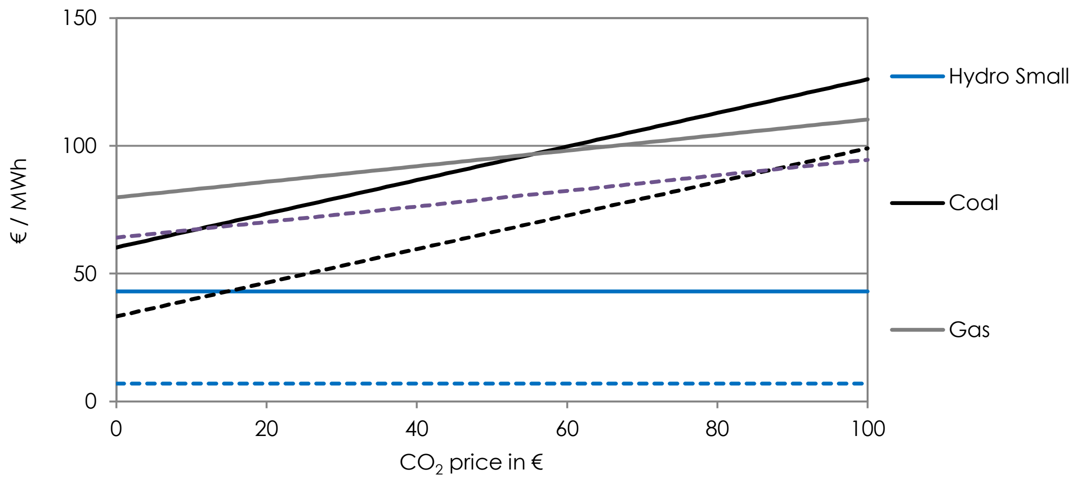

Figure A - 18. Comparison of long and short run electricity generation costs in Austria in the optimistic scenario for 2030: Small hydro power vs. fossil electricity generation

Source: Own calculations based on Green-X database, Resch (2012), Kaltschmitt and Streicher (2009), Hirth (2012) and IEA (2011), IEA and ETSAP (2010a, 2010b). Dashed lines represent short run marginal costs; solid lines represent long run marginal costs.

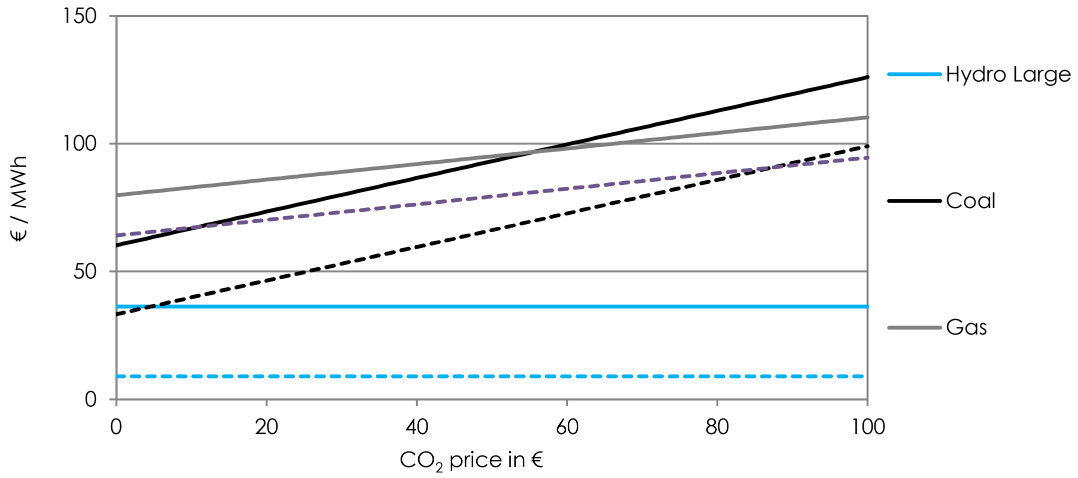

Figure A - 19. Comparison of long and short run electricity generation costs in Austria in the default scenario for 2030: Large hydro power vs. fossil electricity generation

Source: Own calculations based on Green-X database, Resch (2012), Kaltschmitt and Streicher (2009), Hirth (2012) and IEA (2011), IEA and ETSAP (2010a, 2010b). Dashed lines represent short run marginal costs; solid lines represent long run marginal costs.

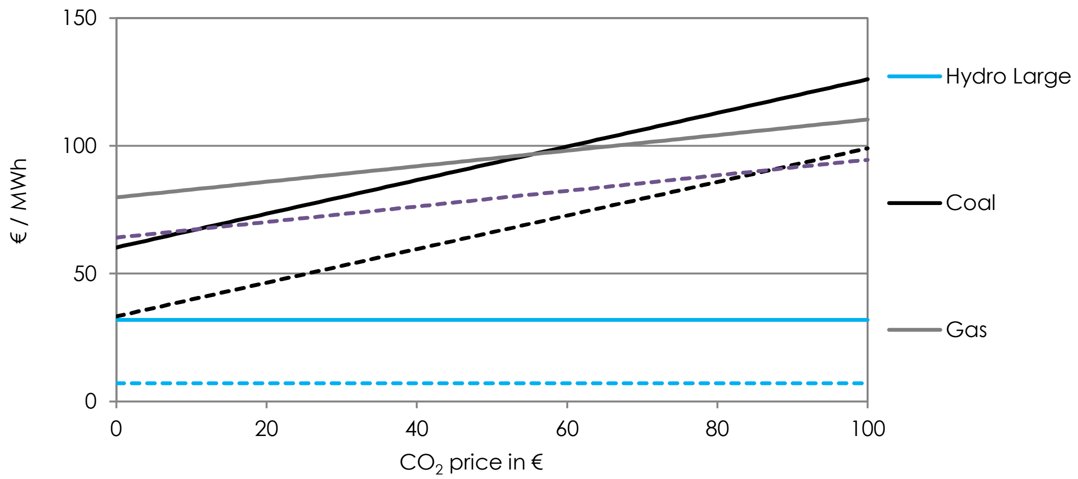

Figure A - 20. Comparison of long and short run electricity generation costs in Austria in the optimistic scenario for 2030: Large hydro power vs. fossil electricity generation

Source: Own calculations based on Green-X database, Resch (2012), Kaltschmitt and Streicher (2009), Hirth (2012) and IEA (2011), IEA and ETSAP (2010a, 2010b). Dashed lines represent short run marginal costs; solid lines represent long run marginal costs.

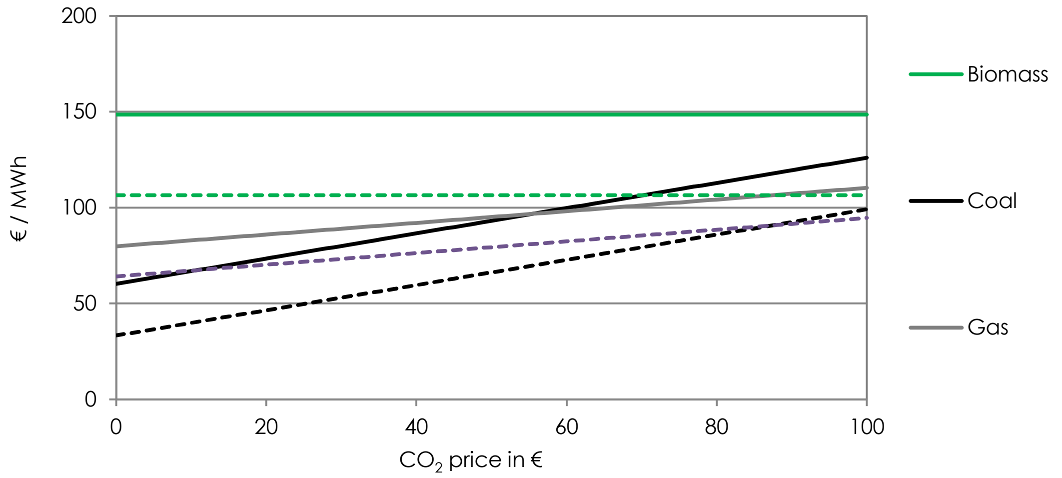

Figure A - 21. Comparison of long and short run electricity generation costs in Austria in the default scenario for 2030: Biomass vs. fossil electricity generation

Source: Own calculations based on Green-X database, Resch (2012), Kaltschmitt and Streicher (2009), Hirth (2012) and IEA (2011), IEA and ETSAP (2010a, 2010b). Dashed lines represent short run marginal costs; solid lines represent long run marginal costs.

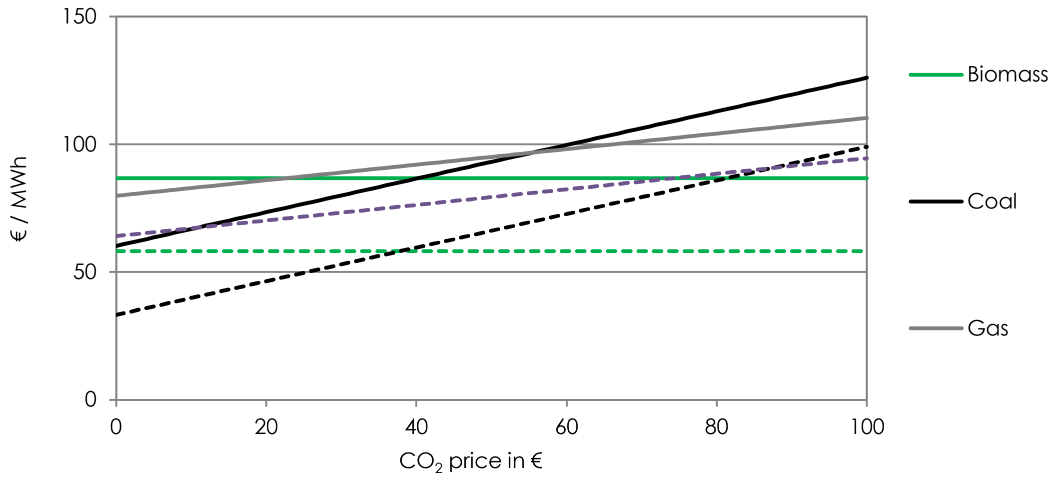

Figure A - 22. Comparison of long and short run electricity generation costs in Austria in the optimistic scenario for 2030: Biomass vs. fossil electricity generation

Source: Own calculations based on Green-X database, Resch (2012), Kaltschmitt and Streicher (2009), Hirth (2012) and IEA (2011), IEA and ETSAP (2010a, 2010b). Dashed lines represent short run marginal costs; solid lines represent long run marginal costs.

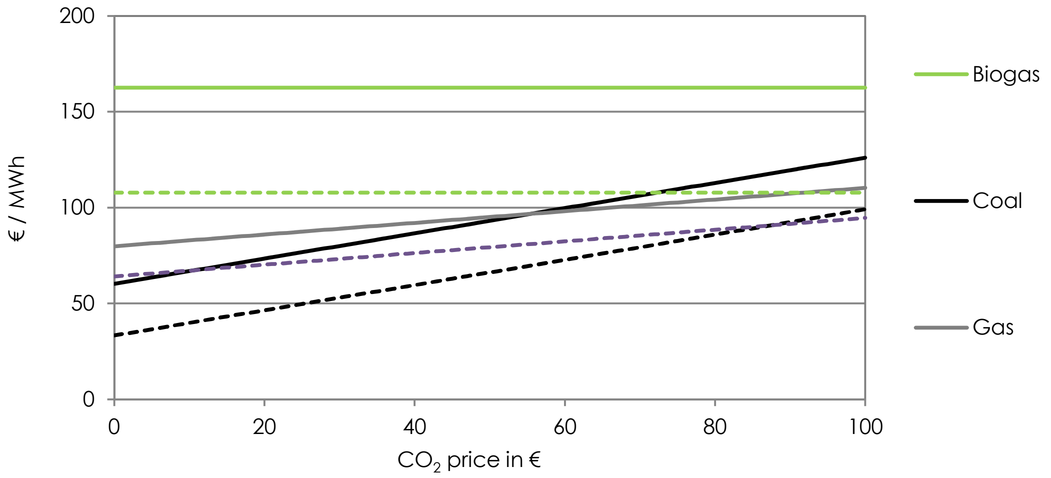

Figure A - 23. Comparison of long and short run electricity generation costs in Austria in the default scenario for 2030: Biogas vs. fossil electricity generation

Source: Own calculations based on Green-X database, Resch (2012), Kaltschmitt and Streicher (2009), Hirth (2012) and IEA (2011), IEA and ETSAP (2010a, 2010b). Dashed lines represent short run marginal costs; solid lines represent long run marginal costs.

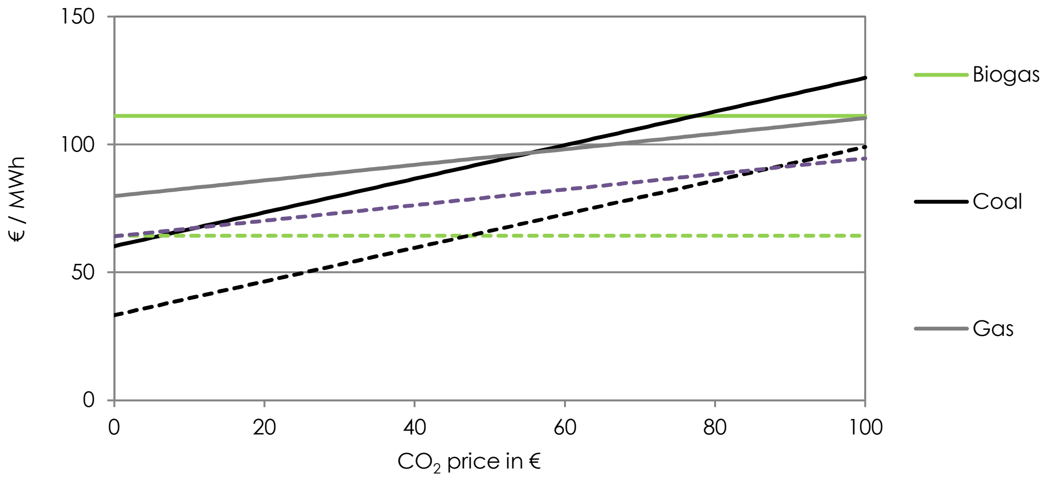

Figure A - 24. Comparison of long and short run electricity generation costs in Austria in the optimistic scenario for 2030: Biogas vs. fossil electricity generation

Source: Own calculations based on Green-X database, Resch (2012), Kaltschmitt and Streicher (2009), Hirth (2012) and IEA (2011), IEA and ETSAP (2010a, 2010b). Dashed lines represent short run marginal costs; solid lines represent long run marginal costs.

Appendix A.3: Comparison of Long and Short Run Marginal Costs in the Czech Republic

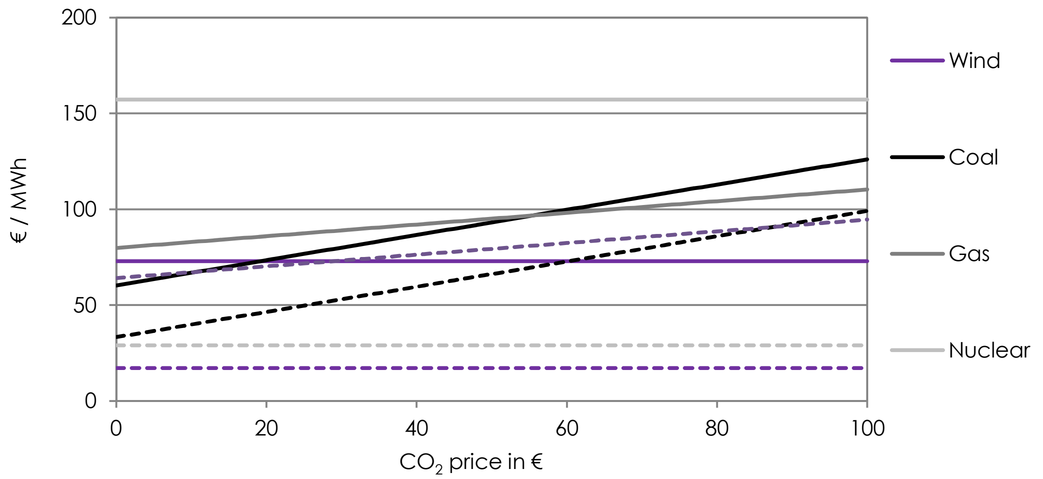

Figure A - 25. Long and short run electricity generation costs in the Czech Republic in the default scenario for 2030: Wind power vs. fossil electricity generation

Source: Own calculations based on Green-X database, Resch (2012), Kaltschmitt and Streicher (2009), Hirth (2012) and IEA (2011), IEA and ETSAP (2010a, 2010b). Dashed lines represent short run marginal costs; solid lines represent long run marginal costs.

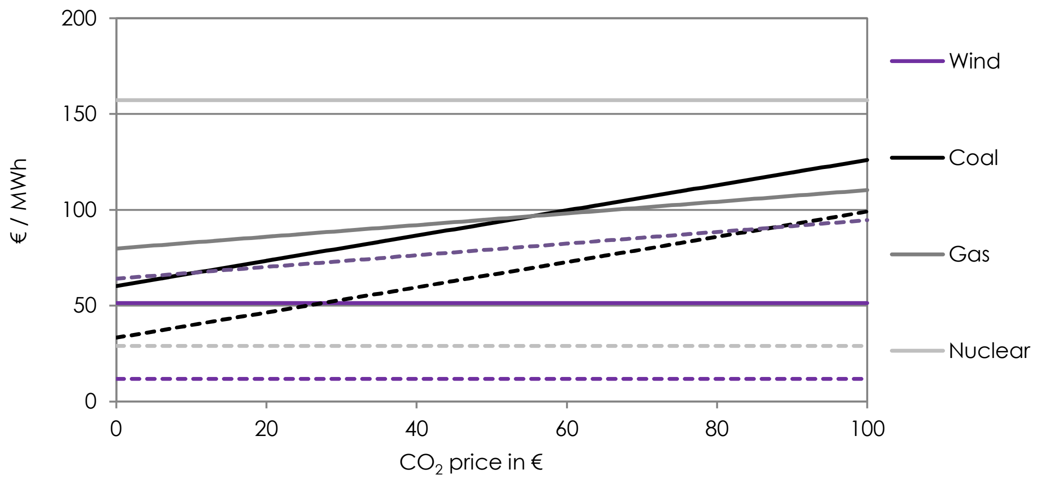

Figure A - 26. Long and short run electricity generation costs in the Czech Republic in the optimistic scenario for 2030: Wind power vs. fossil electricity generation

Source: Own calculations based on Green-X database, Resch (2012), Kaltschmitt and Streicher (2009), Hirth (2012) and IEA (2011), IEA and ETSAP (2010a, 2010b). Dashed lines represent short run marginal costs; solid lines represent long run marginal costs.

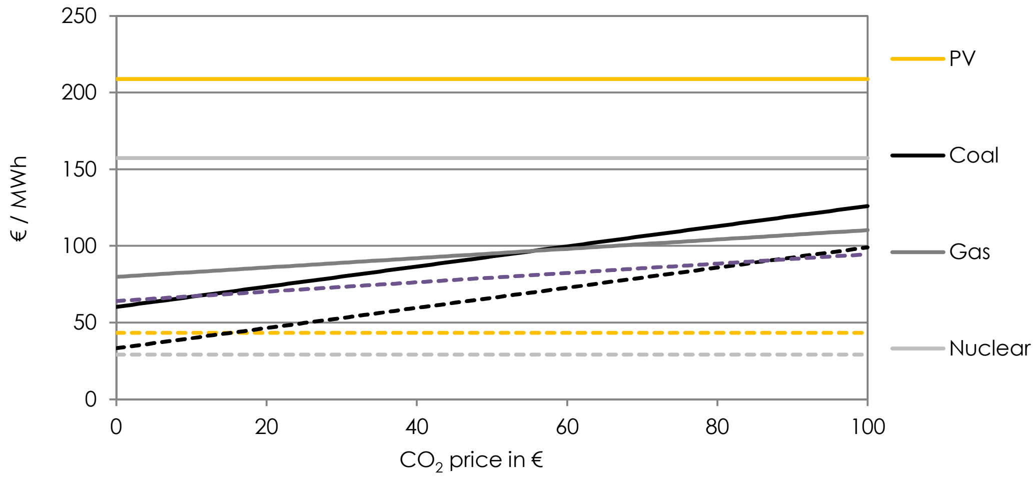

Figure A - 27. Comparison of long and short run electricity generation costs in the Czech Republic in the default scenario for 2030: PV vs. fossil electricity generation

Source: Own calculations based on Green-X database, Resch (2012), Kaltschmitt and Streicher (2009), Hirth (2012) and IEA (2011), IEA and ETSAP (2010a, 2010b). Dashed lines represent short run marginal costs; solid lines represent long run marginal costs.

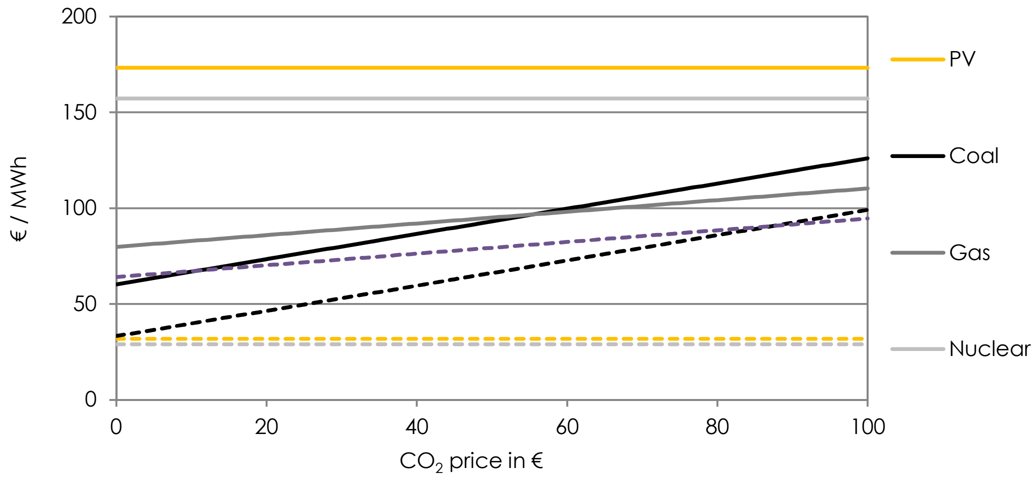

Figure A - 28. Comparison of long and short run electricity generation costs in the Czech Republic in the optimistic scenario for 2030: PV vs. fossil electricity generation

Source: Own calculations based on Green-X database, Resch (2012), Kaltschmitt and Streicher (2009), Hirth (2012) and IEA (2011), IEA and ETSAP (2010a, 2010b). Dashed lines represent short run marginal costs; solid lines represent long run marginal costs.

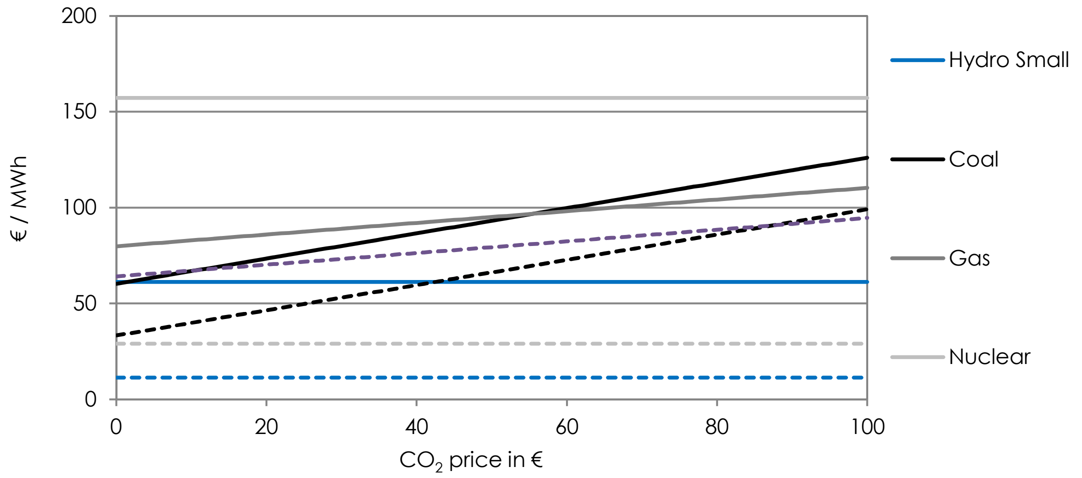

Figure A - 29. Comparison of long and short run electricity generation costs in the Czech Republic in the default scenario for 2030: Small hydro power vs. fossil electricity generation

Source: Own calculations based on Green-X database, Resch (2012), Kaltschmitt and Streicher (2009), Hirth (2012) and IEA (2011), IEA and ETSAP (2010a, 2010b). Dashed lines represent short run marginal costs; solid lines represent long run marginal costs.

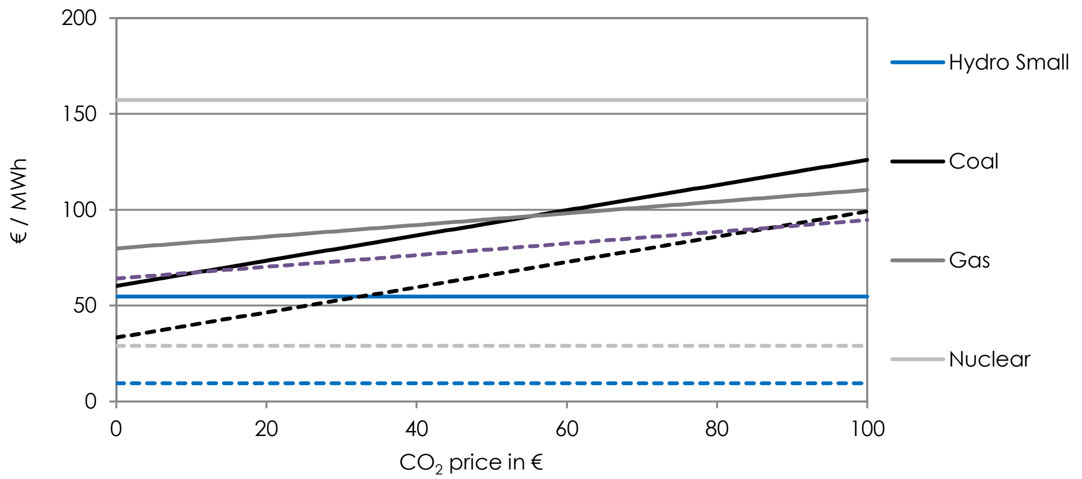

Figure A - 30. Comparison of long and short run electricity generation costs in the Czech Republic in the optimistic scenario for 2030: Small hydro power vs. fossil electricity generation

Source: Own calculations based on Green-X database, Resch (2012), Kaltschmitt and Streicher (2009), Hirth (2012) and IEA (2011), IEA and ETSAP (2010a, 2010b). Dashed lines represent short run marginal costs; solid lines represent long run marginal costs.

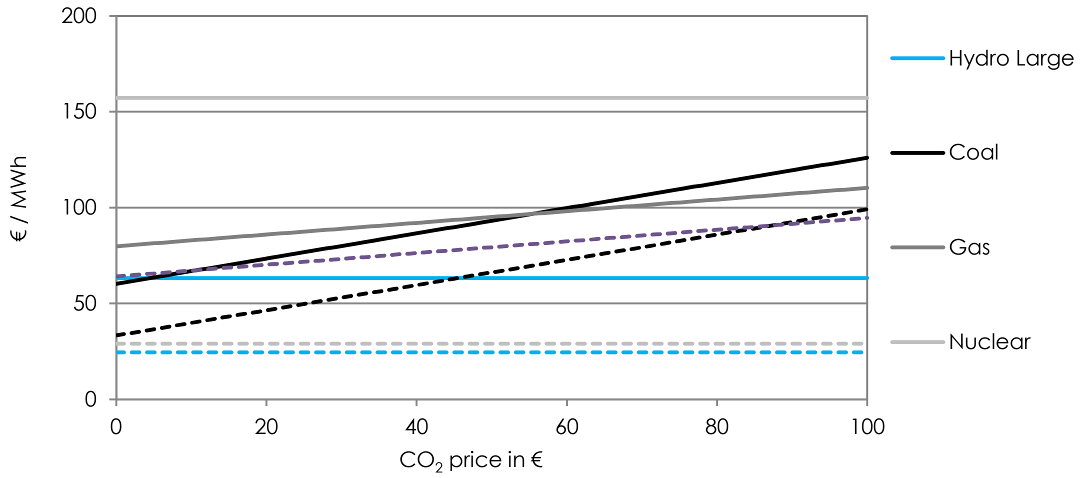

Figure A - 31. Comparison of long and short run electricity generation costs in the Czech Republic in the default scenario for 2030: Large hydro power vs. fossil electricity generation

Source: Own calculations based on Green-X database, Resch (2012), Kaltschmitt and Streicher (2009), Hirth (2012) and IEA (2011), IEA and ETSAP (2010a, 2010b). Dashed lines represent short run marginal costs; solid lines represent long run marginal costs.

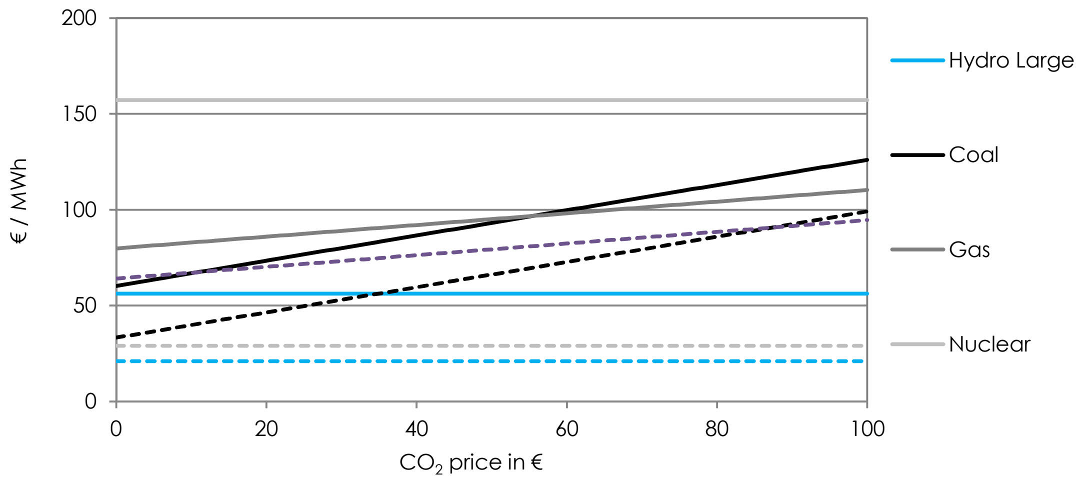

Figure A - 32. Comparison of long and short run electricity generation costs in the Czech Republic in the optimistic scenario for 2030: Large hydro power vs. fossil electricity generation

Source: Own calculations based on Green-X database, Resch (2012), Kaltschmitt and Streicher (2009), Hirth (2012) and IEA (2011), IEA and ETSAP (2010a, 2010b). Dashed lines represent short run marginal costs; solid lines represent long run marginal costs.

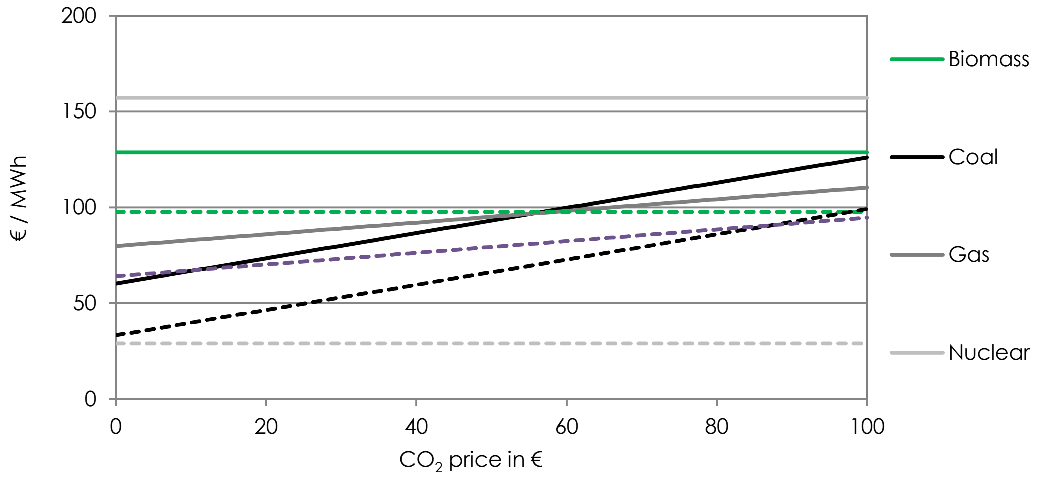

Figure A - 33. Comparison of long and short run electricity generation costs in the Czech Republic in the default scenario for 2030: Biomass vs. fossil electricity generation

Source: Own calculations based on Green-X database, Resch (2012), Kaltschmitt and Streicher (2009), Hirth (2012) and IEA (2011), IEA and ETSAP (2010a, 2010b). Dashed lines represent short run marginal costs; solid lines represent long run marginal costs.

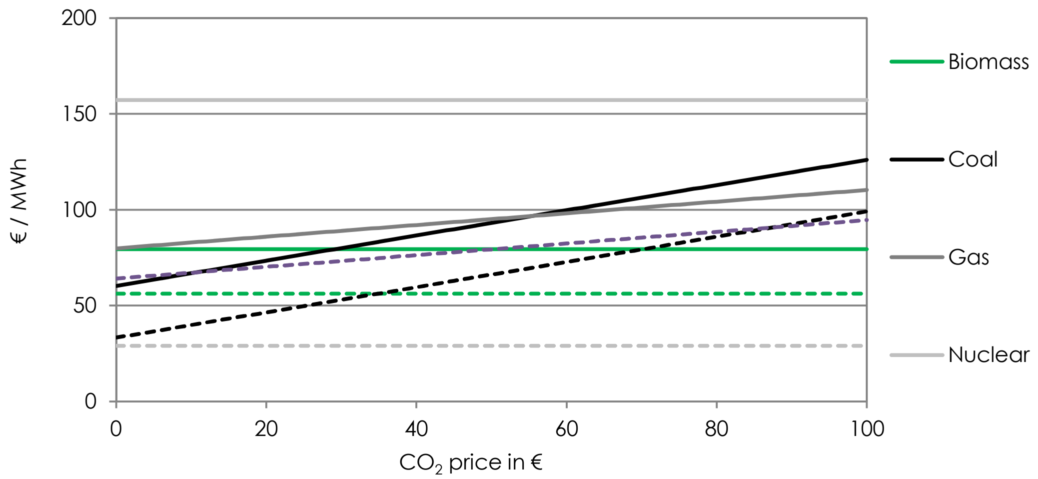

Figure A - 34. Comparison of long and short run electricity generation costs in the Czech Republic in the optimistic scenario for 2030: Biomass vs. fossil electricity generation

Source: Own calculations based on Green-X database, Resch (2012), Kaltschmitt and Streicher (2009), Hirth (2012) and IEA (2011), IEA and ETSAP (2010a, 2010b). Dashed lines represent short run marginal costs; solid lines represent long run marginal costs.

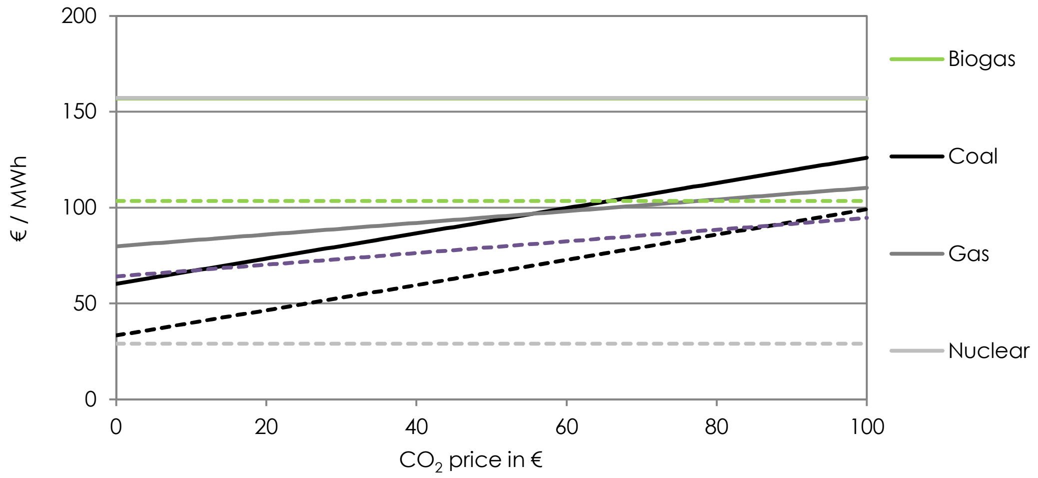

Figure A - 35. Comparison of long and short run electricity generation costs in the Czech Republic in the default scenario for 2030: Biogas vs. fossil electricity generation

Source: Own calculations based on Green-X database, Resch (2012), Kaltschmitt and Streicher (2009), Hirth (2012) and IEA (2011), IEA and ETSAP (2010a, 2010b). Dashed lines represent short run marginal costs; solid lines represent long run marginal costs.

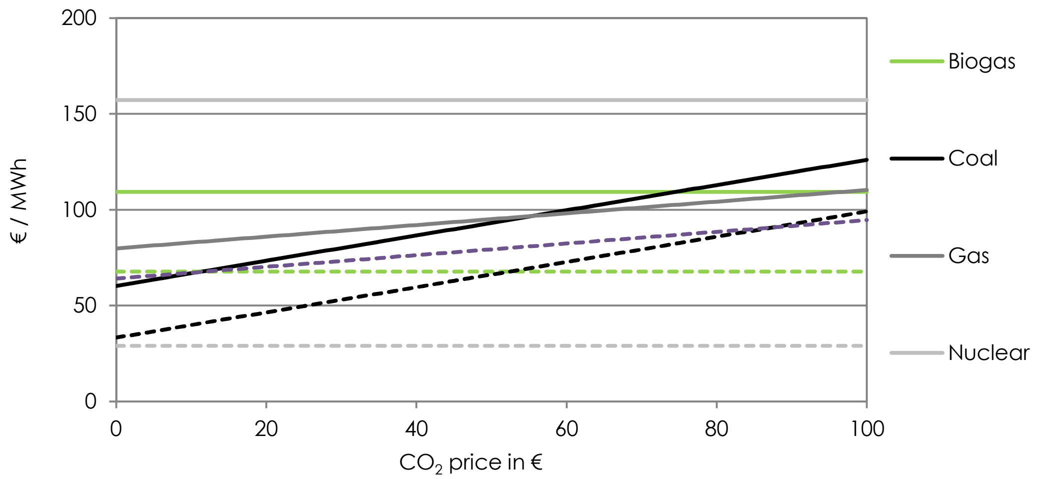

Figure A - 36. Comparison of long and short run electricity generation costs in the Czech Republic in the optimistic scenario for 2030: Biogas vs. fossil electricity generation

Source: Own calculations based on Green-X database, Resch (2012), Kaltschmitt and Streicher (2009), Hirth (2012) and IEA (2011), IEA and ETSAP (2010a, 2010b). Dashed lines represent short run marginal costs; solid lines represent long run marginal costs.

Appendix A.4: Comparison of Long and Short Run Marginal Costs in Hungary

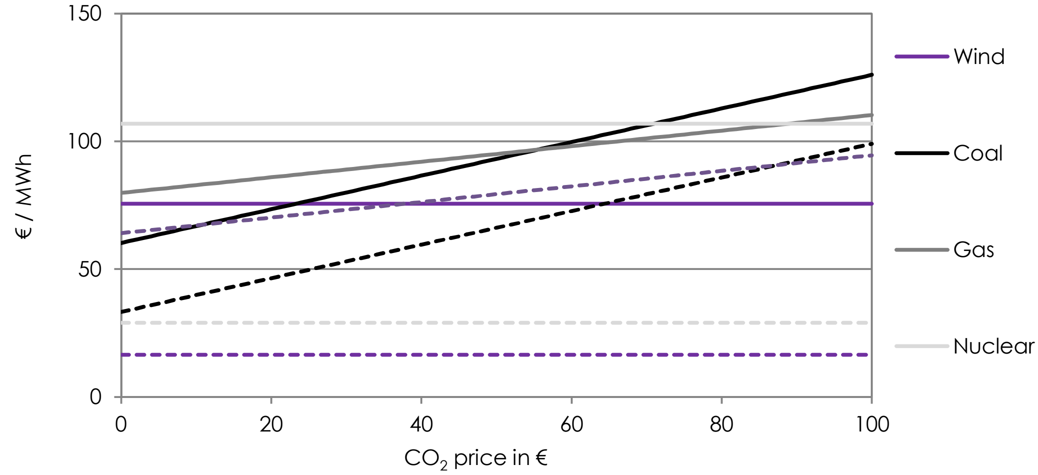

Figure A - 37. Long and short run electricity generation costs in Hungary in the default scenario for 2030: Wind power vs. fossil electricity generation

Source: Own calculations based on Green-X database, Resch (2012), Kaltschmitt and Streicher (2009), Hirth (2012) and IEA (2011), IEA and ETSAP (2010a, 2010b). Dashed lines represent short run marginal costs; solid lines represent long run marginal costs.

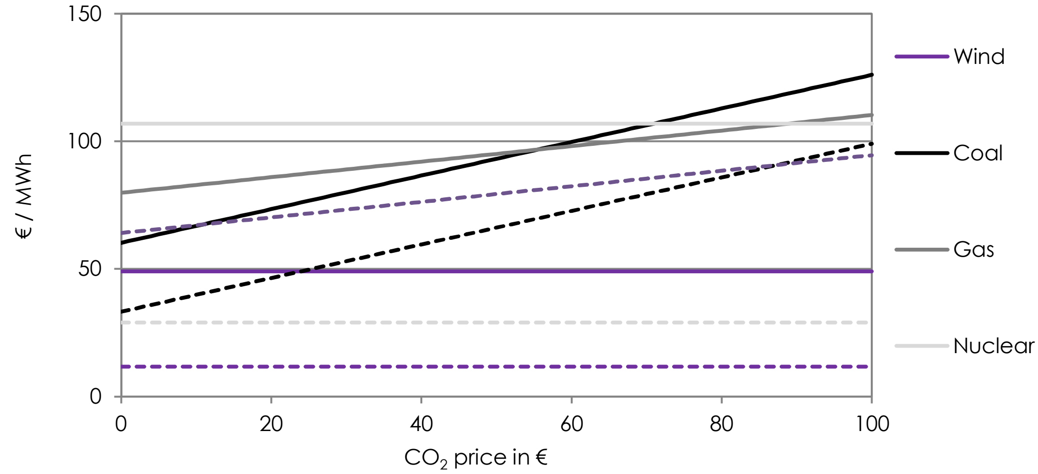

Figure A - 38. Long and short run electricity generation costs in Hungary in the optimistic scenario for 2030: Wind power vs. fossil electricity generation

Source: Own calculations based on Green-X database, Resch (2012), Kaltschmitt and Streicher (2009), Hirth (2012) and IEA (2011), IEA and ETSAP (2010a, 2010b). Dashed lines represent short run marginal costs; solid lines represent long run marginal costs.

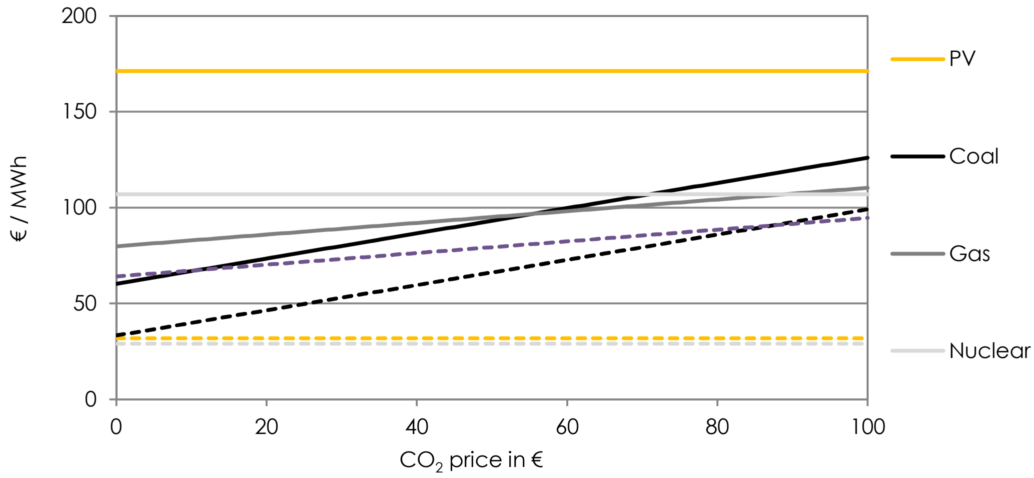

Figure A - 39. Comparison of long and short run electricity generation costs in Hungary in the default scenario for 2030: PV vs. fossil electricity generation

Source: Own calculations based on Green-X database, Resch (2012), Kaltschmitt and Streicher (2009), Hirth (2012) and IEA (2011), IEA and ETSAP (2010a, 2010b). Dashed lines represent short run marginal costs; solid lines represent long run marginal costs.

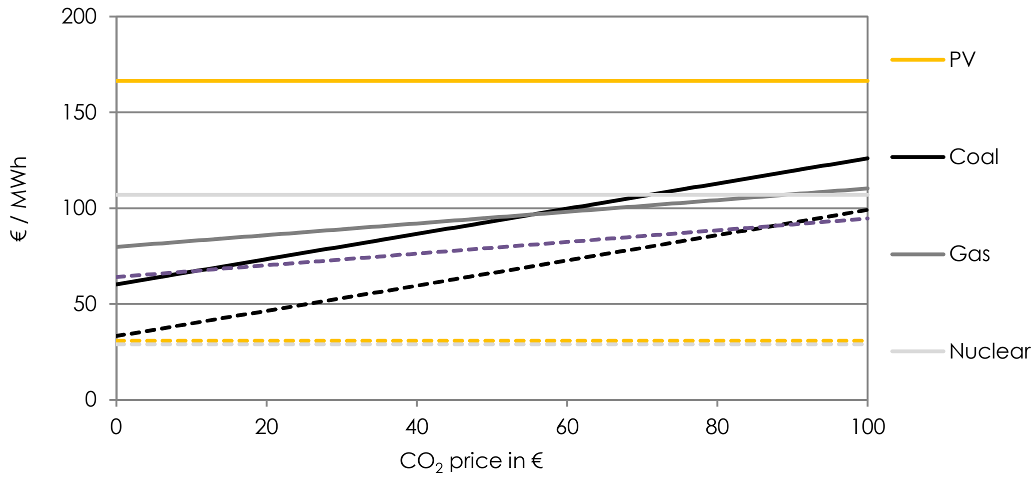

Figure A - 40. Comparison of long and short run electricity generation costs in Hungary in the optimistic scenario for 2030: PV vs. fossil electricity generation

Source: Own calculations based on Green-X database, Resch (2012), Kaltschmitt and Streicher (2009), Hirth (2012) and IEA (2011), IEA and ETSAP (2010a, 2010b). Dashed lines represent short run marginal costs; solid lines represent long run marginal costs.

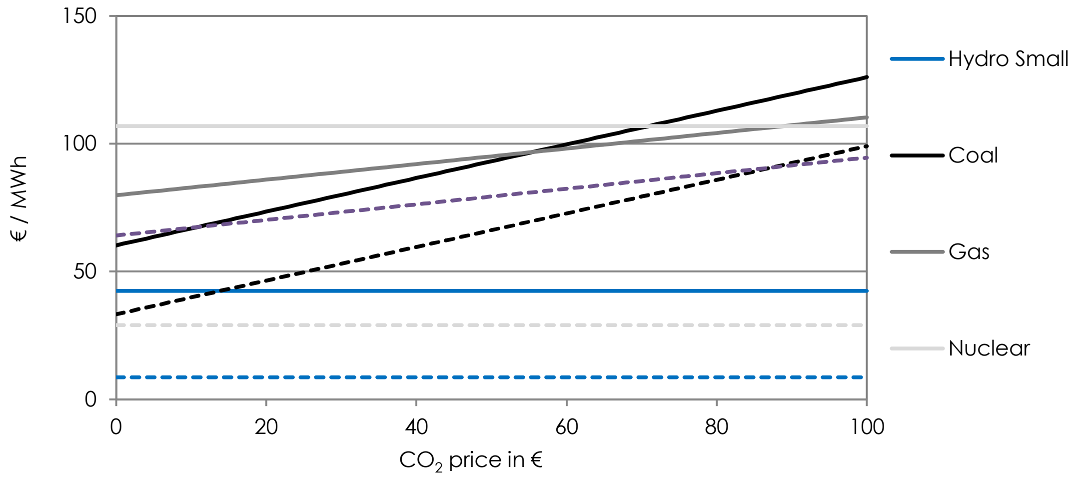

Figure A - 41. Comparison of long and short run electricity generation costs in Hungary in the default scenario for 2030: Small hydro power vs. fossil electricity generation

Source: Own calculations based on Green-X database, Resch (2012), Kaltschmitt and Streicher (2009), Hirth (2012) and IEA (2011), IEA and ETSAP (2010a, 2010b). Dashed lines represent short run marginal costs; solid lines represent long run marginal costs.

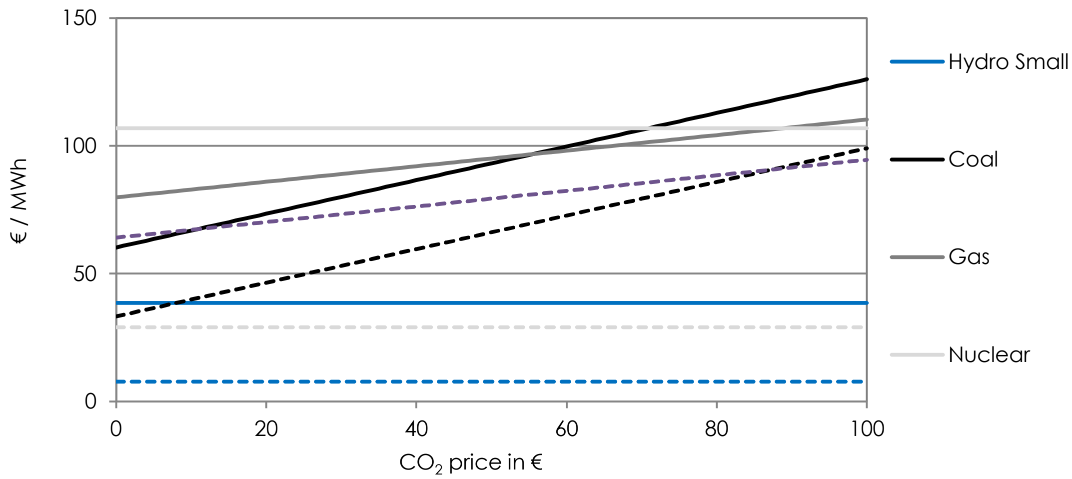

Figure A - 42. Comparison of long and short run electricity generation costs in Hungary in the optimistic scenario for 2030: Small hydro power vs. fossil electricity generation

Source: Own calculations based on Green-X database, Resch (2012), Kaltschmitt and Streicher (2009), Hirth (2012) and IEA (2011), IEA and ETSAP (2010a, 2010b). Dashed lines represent short run marginal costs; solid lines represent long run marginal costs.

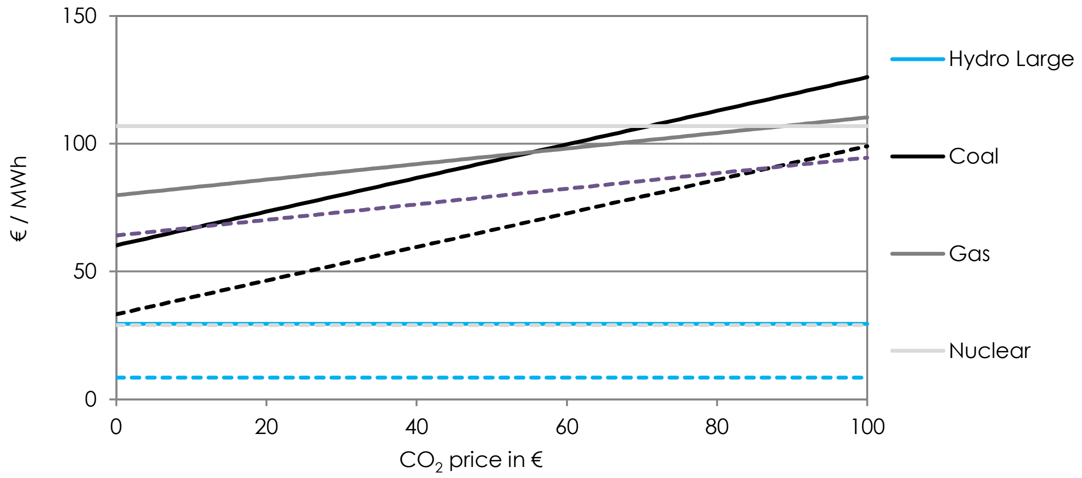

Figure A - 43. Comparison of long and short run electricity generation costs in Hungary in the default scenario for 2030: Large hydro power vs. fossil electricity generation

Source: Own calculations based on Green-X database, Resch (2012), Kaltschmitt and Streicher (2009), Hirth (2012) and IEA (2011), IEA and ETSAP (2010a, 2010b). Dashed lines represent short run marginal costs; solid lines represent long run marginal costs.

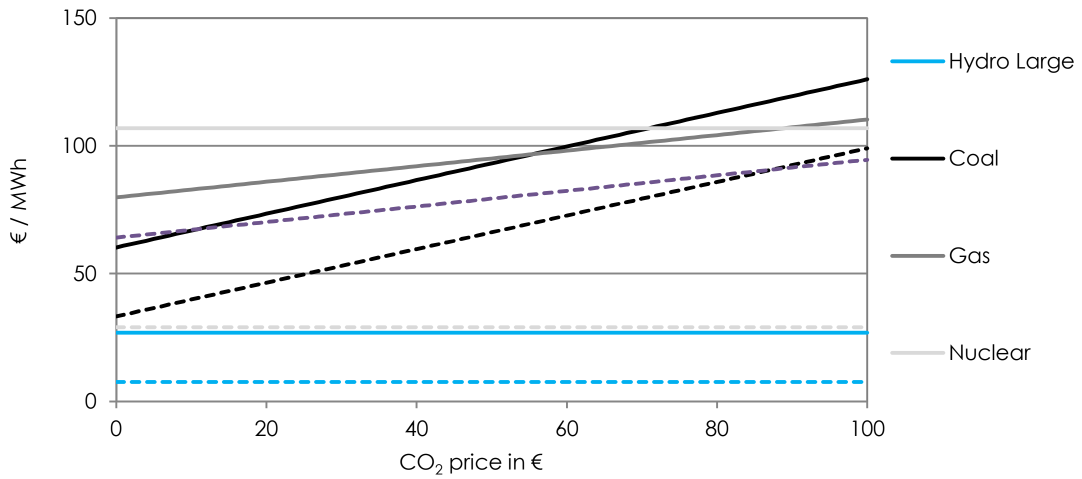

Figure A - 44. Comparison of long and short run electricity generation costs in Hungary in the optimistic scenario for 2030: Large hydro power vs. fossil electricity generation

Source: Own calculations based on Green-X database, Resch (2012), Kaltschmitt and Streicher (2009), Hirth (2012) and IEA (2011), IEA and ETSAP (2010a, 2010b). Dashed lines represent short run marginal costs; solid lines represent long run marginal costs.

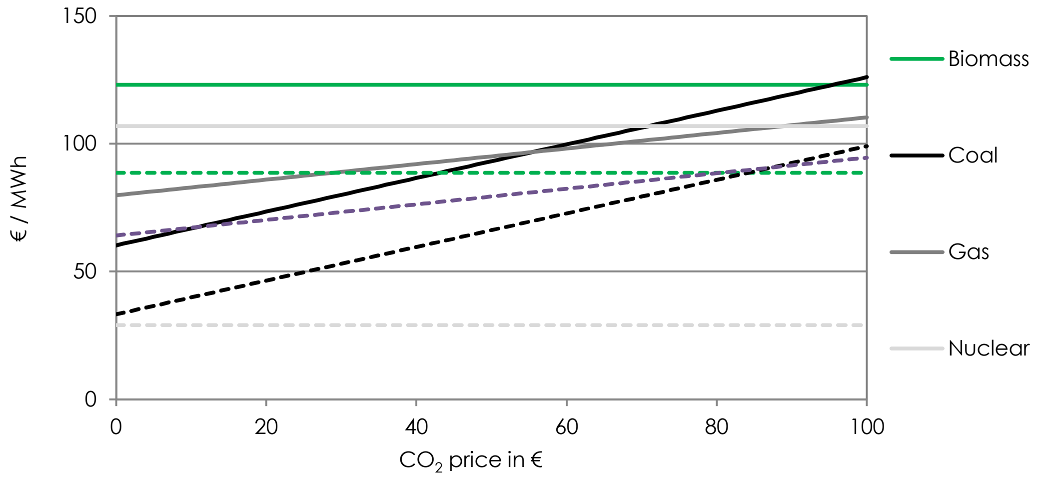

Figure A - 45. Comparison of long and short run electricity generation costs in Hungary in the default scenario for 2030: Biomass vs. fossil electricity generation

Source: Own calculations based on Green-X database, Resch (2012), Kaltschmitt and Streicher (2009), Hirth (2012) and IEA (2011), IEA and ETSAP (2010a, 2010b). Dashed lines represent short run marginal costs; solid lines represent long run marginal costs.

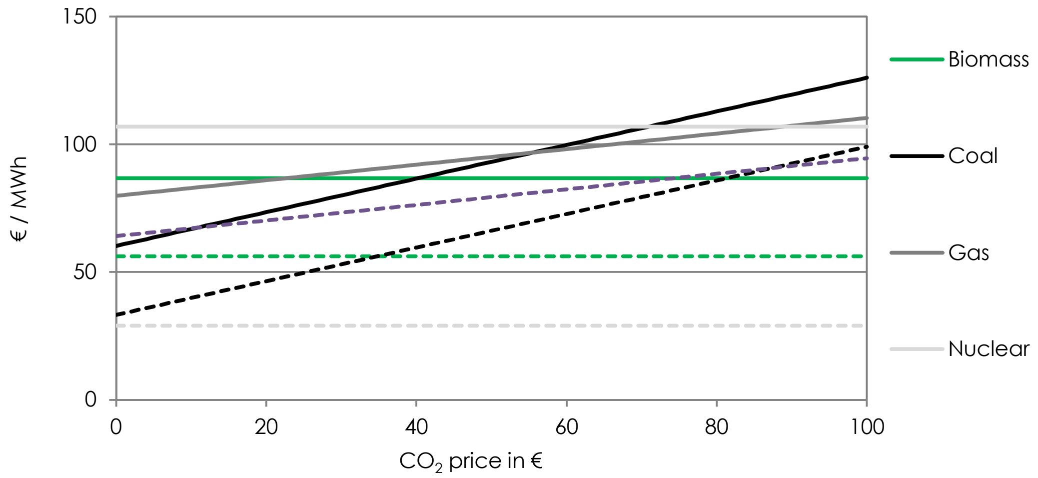

Figure A - 46. Comparison of long and short run electricity generation costs in Hungary in the optimistic scenario for 2030: Biomass vs. fossil electricity generation

Source: Own calculations based on Green-X database, Resch (2012), Kaltschmitt and Streicher (2009), Hirth (2012) and IEA (2011), IEA and ETSAP (2010a, 2010b). Dashed lines represent short run marginal costs; solid lines represent long run marginal costs.

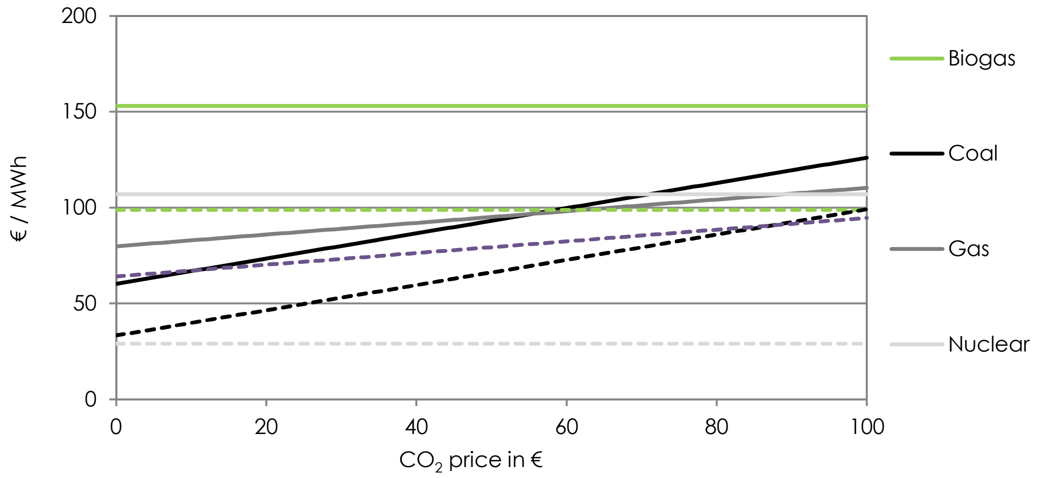

Figure A - 47. Comparison of long and short run electricity generation costs in Hungary in the default scenario for 2030: Biogas vs. fossil electricity generation

Source: Own calculations based on Green-X database, Resch (2012), Kaltschmitt and Streicher (2009), Hirth (2012) and IEA (2011), IEA and ETSAP (2010a, 2010b). Dashed lines represent short run marginal costs; solid lines represent long run marginal costs.

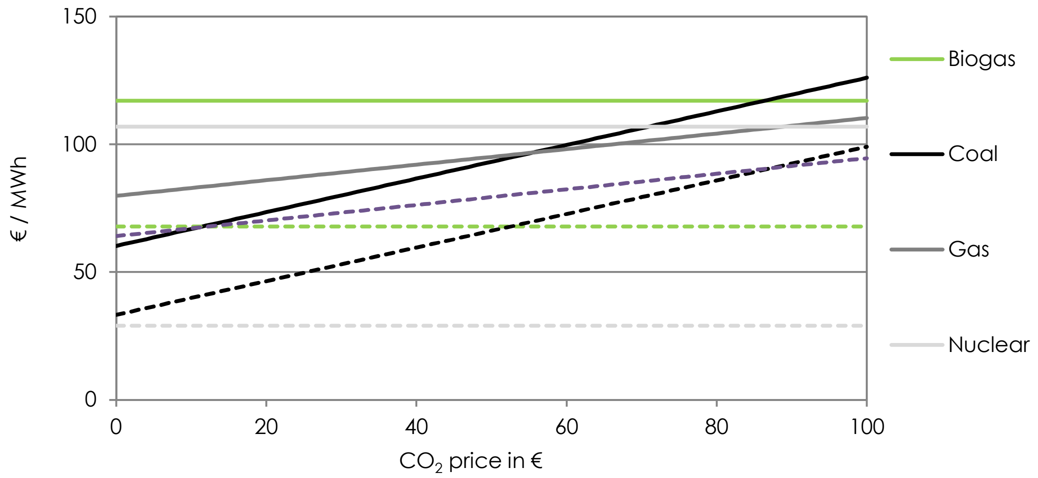

Figure A - 48. Comparison of long and short run electricity generation costs in Hungary in the optimistic scenario for 2030: Biogas vs. fossil electricity generation

Source: Own calculations based on Green-X database, Resch (2012), Kaltschmitt and Streicher (2009), Hirth (2012) and IEA (2011), IEA and ETSAP (2010a, 2010b). Dashed lines represent short run marginal costs; solid lines represent long run marginal costs.