Report of the project

Deriving Optimal Promotion Strategies for Increasing the Share of RES-E in a Dynamic European Electricity Market

Green-X

Analysis of Trade-Offs between Different Support Mechanisms

Project report – Work Package 4

within the 5th framework programme of the European Commission
supported by DG Research

Contract N°: ENG2-CT-2002-00607

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MARCH 2004

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Directorate-General for Research

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Printed in Austria

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Research project within the 5th framework programme of the European Commission, DG Research

Duration: October 2002 – September 2004

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Printed in Austria – March 2004

Photography (cover page) by Gustav Resch

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1 Introduction

1.1 The Need for Policy Instruments at the EU and Member States Level

The European Union recently ratified the Kyoto-protocol on greenhouse gas (GHG) reduction targets. Although there are by now no signs of more explicit breakthroughs towards a stronger international agreement on GHG reduction targets, GHG-issues are to an increasing extent at the core of the energy and environmental policies of the European Union and its member states. Looking back at the Kyoto protocol, the European Union has agreed on a common GHG-reduction of 8% during the period 2008-2012 relative to 1990. According to the agreed burden sharing within the EU, a number of countries are required to reduce their GHG-emissions considerably; for example, the reduction figure for both Denmark and Germany is 21% in the above-mentioned period of time.

In the implementation of these GHG-targets, the development of renewable energy resources is expected to play an important role. In its White Paper on a strategy for developing renewable energy, the EU-Commission has launched a goal of covering by renewable energy supplies, 12% of the European Union's gross inland energy consumption by 2010. These supplies would be mainly biomass, hydropower, wind energy and solar energy. Next to biomass, wind energy is foreseen to be the main future contributor (European Commission, 1997)[1]. The European Commission has in line with this launched a directive on the promotion of renewable energy technologies (European Commission, 2001a). This includes a proposal on the share of renewables in the electricity fuel mix in the individual member states in 2010, based on the percentage of each country's consumption of electricity. Although not binding, it seems by now that these targets are accepted by the EU Member States. Thus, the directive signals the need to include renewable energy technologies as one of the serious options in achieving the targets for GHG-reductions. Moreover, besides GHG-reduction, renewables are accompanied with a set of other benefits such as increasing security of supply, local employment and fostering the strength of European industries.

Currently, the renewable energy market in Europe is relatively protected and non-harmonised among their Member States. In future, due to evolution of important EU energy-related policies such as the EU Directive on Renewables or the fulfilment of the Kyoto target in combination with the liberalisation of the electricity market, the structure of the European electricity market, in general, and the conditions for RES-E, in particular, will be fundamentally reshaped. A number of different policy instruments are available for promoting renewable energy technologies as part of a GHG-reduction strategy, national as well as international. Among these are the most obvious ones to mention the introduction of a common EU framework for tradable emission allowances (TEA) and a tradable green certificate market (TGC), but, especially, a national instrument such as fixed feed-in tariffs has been very successful in implementing wind power in member states such as Germany, Spain and Denmark. Finally, other possibilities as investment subsidies and tendering procedures are also available. How such national and international instruments as those mentioned above interact with each other and with the national targets for reducing greenhouse gas emissions is not a trivial matter.

[1] The 12% target includes large-scale hydro, for which the potential for further exploration in the EU is very limited for environmental reasons.

1.2 The Objectives of Work Package 4 in the Green-X Project

The core objective of the Green-X project is to bring about a continuous and significant increase in the development of RES-E with minimal costs to European citizens. This objective is met by creating a dynamic toolbox GREEN-X integrating RES-E, CHP generation, conventional electricity and the most relevant demand-side activities. Moreover, the two important goals of increasing the share of RES-E (EU Directive on Renewables) and reducing GHG-emissions (Kyoto Agreement) will be linked in the toolbox GREEN-X, which will be designed in this project. An important part of the Green-X toolbox is the instruments available for supporting renewable sources and how these instruments act together and what this implies for the EU and national policies for implementing renewable energy technologies and in achieving GHG-reductions.

This last-mentioned issue is the core of Work Package 4 and this report, where the focus is interactions between instruments for supporting the renewable energy development. Quite a number of different instruments are available on the national and international scene in the attempt for the individual countries and the EU to support the development of renewable energy technologies and at the same time to reduce the emissions of greenhouse gases. The most important ones are mentioned below:

- Feed-In Tariffs (FITs)
- Investment Subsidy Schemes
- Tradable Green Certificate Schemes (TGCs)
- Tendering Systems
- Tradable Emission Allowances (TEA)

These policy instruments may be used individually or simultaneously either at the national level or at an EU level. Moreover, the Member States and the EU may want to achieve not only one but several targets in applying these instruments, as is the case for the indicative targets for the use of renewable energy and the national GHG-reduction targets. In most cases, the instruments are to be used in relation to electricity producing technologies and, therefore, also the organisational set-up of the power market is an important issue in relation to the mentioned policy-instruments.

But how these instruments interact with each other and with different targets is not a trivial matter to analyse. On the contrary, it turns out to be highly complex, theoretically and methodologically. The different instruments might influence a number of issues, the most important ones being:

- Prices at the power spot market;
- Consumer prices of electricity;
- The volume of implemented renewable power capacity;
- The national and international levels of emissions.

As an example, the introduction of a TGC-scheme leading to a higher deployment of wind power technologies will, in general, imply a lower price at the power spot market, because wind power has a low marginal production cost. The price to the consumers will, in general, rise, because they will have to pay for the green certificates as well (although this price reaction might be ambiguous as shown later in the report). Of course, a higher volume of wind power capacity will be installed and - depending on the organisation of the power spot market – because of this higher capacity emissions will be reduced nationally and/or internationally.

But if a TGC-scheme is already being introduced in parallel with a tradable emission allowance scheme (TEA), interactions start to arise. TEA will by itself increase the price at the power spot market – although the TGC-scheme will lower the spot price. The net result will presumably still be a total increase in the price, although ambiguity also exists here. If the national levels of emissions will be further lowered by the TGC-scheme than already observed with the TEA-scheme, then this is another ambiguity.

Thus, the major questions in relation to the supporting instruments and their interactions are:

- Will the instruments used be independent in their impact on price and markets or will they expose synergetic effects, or vice versa?
- Are some of the instruments mainly useful in national policies or can they be used simultaneously for national as well as international purposes?
- Are some of the instruments especially suited for achieving specific targets? And how do you determine the mix of different instruments to achieve more national and/or international targets?
- Will the instruments be sensitive to different barriers and how might this influence an optimal mix of instruments in policy use?

Many instruments do exist for the purpose of promoting renewable technologies and the interactions between these instruments are multiple. Thus, in this project it is not possible to investigate all issues within this field. Therefore, in an attempt to answer some of the above-mentioned questions, a number of relevant cases are chosen to be analysed in more detail in the following. These cases will cover both the needs and opportunities at the level of the national member states, but also those at the level of the EU. However, due to the character of these interactions, it has, of course, not been possible to discuss all problems within this field, but most of the important ones are hopefully treated in the following chapters.

2 Markets and Support-Schemes in the EU

Recently, winds of change in electricity from renewable energy sources (RES-E) and CO_2 emissions policy measures are leading to the setting up of targets and to the creation of new markets for environmental assets and technologies in Europe. The power sector will be affected by policy developments concerning RES-E and CO_2, which are taking place both at the EU and national levels.

On the one hand, the recently approved Directive on the promotion of RES-E initiated a transition process that may in the future lead to a community support framework for RES-E in EU-15, which substitutes (partially or totally) the current coexistence of national promotion schemes.

On the other hand, a CO_2 emission-trading system will be implemented at EU level following the prescriptions of the COM (2001) 581 Directive proposal (European Commission, 2001b). Participation will be mandatory for industry sectors (including the power sector), which jointly emit 46% of EU CO_2 emissions[2].

It is important to stress that these two sets of policy measures do not work independently from each other. Interactions between measures taken to support RES-E and to mitigate CO_2 emissions, but also between those policy developments and the structure and functioning of the power sector exist at the different levels (European and National). In order to analyse such interactions, which will be the focus of the following chapters, this chapter provides the main features of the interacting elements. The next subsection is dedicated to the physical power markets in the EU. Section 2.1 deals with the national level. It will provide a synthesis of how RES-E is being promoted by MS. Concerning CO_2, a brief summary of the two national emission trading systems working in EU-15 (U.K. and Denmark) will be given. Section 2.3. is dedicated to the very relevant policy developments taking place at the EU level. Some features and implications of both the RES-E Directive and the Emission Trading Directive will be discussed.

2.1 Physical Power Markets in the EU and Liberalisation of the European Electricity Market

2.1.1 Introduction

The European Commission is in charge of orchestrating the liberalisation of the electricity market in the European Union (EU). The Directive 96/92/CE concerning common rules of the internal market in electricity was adopted by the Council of Ministers on 19 December 1996, and came into force on 19 February, 1997. Member States (MS) had, in principle, two years to transpose it to national legislature and, although at different speeds, all countries have complied.

[2] The contribution of the power sector to CO2 emissions in the EU is 30% (as reported in the Green Paper, see European Commission 2000). The share of the power sector in the overall emissions of the industry sectors included in the trading regime is 65% (op.cit.). Therefore, the power sector is the main sector in the trading regime.

2.1.2 The Directive 96/92/CE

The Directive established new rules regarding the three most relevant areas of the electricity business: Generation, Transmission and Distribution.

2.1.2.1 Generation

There are two different procedures from which MS may choose for the construction of new generating capacity: (1) authorisation procedure and (2) tendering procedure.

In the authorisation procedure, MS shall set up criteria to grant authorisations. This criteria will be made public, may relate to safety and security of the electricity system installation and associated equipment, protection of the environment, land use and siting, use of public ground, energy efficiency, the nature of primary sources, characteristics particular to the applicant such as technical, economic and financial capabilities and public service obligations.

In the tendering procedure, MS or a competent body appointed by the State shall draw up an inventory of new capacity to be constructed, including replacement of old capacity. The procedure shall follow objective, transparent and non-discriminatory criteria. The specifications shall be published in the Official Journal of the European Communities at least six months before the closing date for tenders. The specifications shall contain a detailed description of the contract specifications. An exhaustive list of criteria governing the selection of tenders and the award of the contract shall also be included.

2.1.2.2 Transmission

Transmission is defined as the transport of electricity on the high-voltage interconnected systems. MS shall designate or require undertakings that own transmission systems to designate a system operator to be responsible for operating, ensuring the maintenance and, if necessary, for developing the transmission system in a given area and its interconnectors with other systems in order to guarantee security of supply.

The transmission system operator (TSO) is responsible for dispatching the generating installations in its area and for determining the use of interconnectors with other systems. For environmental reasons, a Member State may, however, require the TSO to give priority in the dispatching to electricity produced from renewables, waste and from combined heat and power. This is important as this allows Member States to ensure the sale of environmentally friendly electricity even in cases where the costs of this electricity exceed the costs of traditionally produced electricity. Priority in the dispatching can also be given to electricity produced using indigenous fuels, but only up to 15% in a calendar year of the overall primary energy necessary to produce the electricity consumed in the Member State.

2.1.2.3 Distribution

Distribution is defined as the transport of electricity on the medium-voltage and low-voltage interconnected systems.

As in the case for transmission, a system operator shall be designated to be responsible for operating, ensuring the maintenance and if necessary developing the distribution system in a given area and its interconnectors with other systems. The distribution system operator (DSO) is responsible for maintaining a secure, reliable and efficient electricity distribution system in its area with due regard to the environment. For environmental reasons, a Member State may require the DSO to give priority in the dispatching to electricity produced from renewables, waste and from combined heat and power. This is important as this allows Member States to ensure the sale of environmentally friendly electricity even in cases where the costs of this electricity exceed the costs of traditionally produced electricity. The operator must not discriminate between the system users and, in particular, not favour its subsidiaries or shareholders.

Besides these basic rules governing the three areas of the electricity business, the Directive tackles other issues:

- ✓ Unbundling – The idea is to maintain legally separated the three activities of the electricity business by imposing that each activity is undertaken by different companies so as to avoid discrimination, cross-subsidisation and distortion of competition.
- ✓ Access to the network – Member States can choose between negotiated or regulated third party access or the single buyer procedure when organising the access to the transmission and the distribution network.
- ✓ Direct lines - All electricity producers and electricity suppliers have a right to supply their own premises, subsidiaries and eligible customers through a direct line when the suppliers have the necessary authorisation.
- ✓ Public service obligations - The electricity market and all areas regulated in the Directive are subject to public service obligations, which Member States may impose, in the general economic interest on electricity undertakings in their market. The use of public service obligations will allow Member States to balance competition with public services where this is deemed necessary in the general interest of the society.
- ✓ Reciprocity - To avoid imbalance in the opening of electricity markets the Directive contains some possibilities of refusing access to customers from other Member States when the Member State itself opens a larger part of the market than the other states.

2.1.2.4 The Benchmarking Reports

Comparing the “First Benchmarking Report on the Implementation of the Electricity and Gas Directives”[3] and the “Second Benchmarking Report on the Implementation of the Internal Electricity and Gas Market”[4], both delivered by the Commission Staff, allows visualising the situation in terms of the liberalisation process in the EU.

The fundamental barriers identified in the first report were:

[3] European Commission (2001c)

[4] European Commission (2002)

- ✓ Excessively high network tariffs, which form a barrier to competition by discouraging third party access, and may provide revenue for cross subsidy of affiliated businesses in the competitive market;
- ✓ A high level of market power of existing generation companies combined with a lack of liquidity in wholesale and balancing markets which is likely to expose new entrants to the risk of high imbalance charges;
- ✓ Network tariff structures, which are not published in advance or subject to ex-ante approval. This may lead to uncertainty and create costly and time consuming disputes unless combined with full ownership unbundling;
- ✓ Insufficient unbundling, which may obscure discriminatory charging structures and lead to possible cross subsidy.

In the second report, recognition is given to advances in the market functioning of Germany, Austria and the Netherlands. However, some issues are still pointed out as "difficulties":

- ✓ Differential rates of market-opening continue to reduce the scope of benefits to customers from competition, leading to higher prices than otherwise to small businesses and households, and also promote distortion of competition between energy companies by allowing the possibility of cross-subsidies at a time when companies are restructuring themselves into pan-European suppliers;
- ✓ Disparities in access tariffs between network operators which, due to the lack of transparency caused by insufficient unbundling and inefficient regulation, may form a barrier to competition;
- ✓ The high level of market power among existing generating companies associated with a lack of liquidity in wholesale and balancing markets which impedes new entrants;
- ✓ Insufficient interconnection infrastructure between Member States and, where congestion exists, unsatisfactory methods for allocating scarce capacity.

The results of the analysis carried out in terms of the level of liberalisation in each country are summarised in Table 1, which takes both reports into comparison. As shown, the degree of liberalisation has advanced significantly in many countries. Belgium, Greece, Ireland, Netherlands, Portugal and Spain all declared improvements in their liberalisation processes. France, on the other hand, maintained its 30% level. In terms of "full opening dates", Italy sets 2004 for non-household customers, while the rest of the countries maintain more or less their initial commitments.

Regarding the "*Biggest three-generator share (%)*" a general but shy trend downward is seen in almost all countries, with the exceptions of Spain (going from 79 to 83%) and Sweden (going from 77 to 90%).

Table 2.1: Comparing results from Benchmark Reports

	First Benchmark Report (2001)			**Second Benchmark Report (2002)**			
	Declared Market Opening %	*Full Opening Date*	*Share of Three Biggest Generators (%)*	*Declared Market Opening (%)*	*Full Opening Date*	*Unbundling: Transmission System Operator*	*Biggest Three Generators' Share of Capacity (%)*
Austria	100	2001	68	100	2001	Legal	45
Belgium	35	2007	97 (2)	52	2003/7	Legal	96 (2)
Denmark	90	2003	75 (2)	100	2003	Legal	78
Finland	100	1997	54	100	1997	Ownership	45
France	30	none	98	30	-	Management	92
Germany	100	1998	63	100	1999	Legal	64
Greece	30	none	100 (1)	34	-	Legal\Mgmt	97 (1)
Ireland	30	2005	97 (1)	40	2005	Legal\Mgmt	97 (1)
Italy	45	none	79 (2)	45	nhh[2] in 2004	Own\Legal	69
Neth	33	2003	64	63	2003	Ownership	59
Portugal	30	none	85	45	2003	Legal	82
Spain	54	2003	79	55	2003	Ownership	83
Sweden	100	1998	77	100	1998	Ownership	90
UK	100	1998	44	100	1998	Ownership	36

Source: Adapted from 1st and 2nd Benchmark reports. (European Commission 2001c & 2002)

The degree of "switching" taking place among the different types of consumers gives an idea of the depth of the liberalisation process. Table 2 shows the percentage of customers switching suppliers in the EU countries. The majority of large eligible customers have explored the possibility of switching or renegotiating contracts, while the small commercial customers have done so to a much less extend.

Table 2.2: Switching estimates 1998-2001

	Large Eligible Industrial Users		**Small Commercial & Domestic**	
	Switch	Switch or Renegotiate	Switch	Switch or Renegotiate
Austria	20-30%	Unknown	5-10%	Unknown
Belgium	2-5%	30-50%	Not eligible	
Denmark	Unknown	>50%	Not eligible	
Finland	Unknown	>50%	5-10%	10-20%
France	10-20%	Unknown	Not eligible	
Germany	20-30%	>50%	5-10%	10-20%
Greece	nil.	nil.	Not eligible	
Ireland	10-20%	Unknown	Not eligible	
Italy	>50%	100%	Not eligible	
Luxembourg	10-20%	>50%	Not eligible	
Netherlands	20-30%	100%	Not eligible	
Portugal	5-10%	Unknown	Not eligible	
Spain	10-20%	>50%	Not eligible	
Sweden	Unknown	100%	10-20%	>50%
UK	>50%	100%	30-50%	n.a.

Source: Adapted from 2nd Benchmark report. (European Commission 2002)

As recognised in the 2nd benchmark report, there has been a general increase in the overall level of market opening, an improvement in the degree of unbundling of network operators, and greater clarity and transparency in regulation. Most Member States, notably Austria, Germany and the Netherlands, have seen an increase in consumer activity among eligible customers and price reductions have been recorded in Italy, Spain and the UK for large consumers in the past year. Meanwhile, prices for small businesses have fallen significantly in Austria. However, some of the outstanding issues since last year have not been resolved and key problems remain, particularly concerns about the degree of unbundling, the continuing position of market dominance in some countries and the lack of infrastructure to allow cross-border exchanges.

2.1.3 Other Issues Concerning Liberalisation

The European Commission, besides the work done by the staff, has been collaborating in the development of other independent studies on several ancillary issues that may arise as a result of the liberalisation process. An important effect that the Commission wanted to evaluate was that on employment. In this section, we reproduce the key conclusions emerging from the Study "The Effects of the Liberalisation of the Electricity and Gas Sectors on Employment"[5] :

✓ *The electricity industry has seen substantial reductions in employment over the last 10 years;*

✓ *As the gas market in many European countries is not yet mature, the gas sector has, in the main, witnessed an increase in employment over the last decade. One significant exception is the UK;*

✓ *It is difficult to disentangle the impact of restructuring, the introduction of new technology, etc. from the direct impact of market liberalisation, beyond saying that the latter has a role in accelerating the former. Our case studies revealed that restructuring was in many cases directly linked to the liberalisation agenda. The recent increase in merger activity can also be linked to liberalisation and the need to remain competitive. Merger announcements are often accompanied by further announcements of job losses.*

There are no direct links between the extent of strides taken towards liberalisation and the number of jobs lost. However, in the countries where liberalisation has been linked with privatisation (primarily in the UK), job losses have been greatest.

2.2 Markets and Support Schemes in the EU - The National Level

2.2.1 RES-E Support Schemes in EU Countries

MS have been promoting RES-E on the basis of their alleged positive externalities (environmental and otherwise) and on the consideration that support is crucial to allow renewables to penetrate the electricity market.

A wide array of support schemes is being used (and will be used) by the European countries in order to promote RES-E. It should be noted that, of course, not all promotion schemes have the same relevance for the promotion of RES-E. In general, promotions are based on three main mechanisms: feed-in tariffs, tradable green certificates (TGCs) and bidding/tendering systems. These are usually supplemented by other secondary instruments. A second group of relevant but complementary support measures (secondary support measures) includes investment subsidies, fiscal and financial incentives. Countries usually have one (at most, two) of the schemes in the first group (except Finland that does not have any). This is supplemented by a combination of measures pertaining to the second group. The main instruments (grouped in 6 categories) being applied in the EU-15 are the following:

- Feed-in tariff. They are subsidies on output in the form of guaranteed premium prices in combination with a purchase obligation by the utilities. They provide a great deal of certainty to the RES-E producer and the investor. Although by setting a price for RES-E and allowing the market to set

[5] Ecotec 2001

the quantity produced, they would not guarantee the deployment of a certain quantity of RES-E, reality shows that they have been quite effective in promoting RES-E (i.e, Germany, Spain and Denmark). However, only by chance, feed-in would be a cost-effective instrument in the deployment of RES-E. This would be the case when the feed-in tariff is set at the optimal level. Reality shows that they are usually set at a higher level than is socially optimal.

With some differences in the design of the system, feed-in tariffs are currently being applied in all MS except in Ireland, The Netherlands[6] and the U.K. Certain technologies may not benefit from feed-in tariffs in certain countries. In other countries, the following comments apply.

- The feed-in tariff in Finland is not an “orthodox” feed-in tariff. Electricity producers pay an annual electricity tax. The producers generally pass this charge on to their customers. These electricity taxes are returned back to renewable electricity producers, i.e., producers of electricity from certain renewable energy sources (wind power, small scale hydropower, wood and wood based fuels) are given a tax refund at the end of the year;
- Given that the expected low price of TGCs in Sweden may not be a sufficient incentive for wind energy promotion in Sweden, a transitional feed-in tariff (in addition to the TGC) applies to this energy source during 2003-2007.

- Tradable Green Certificates (TGCs). TGCs are certificates, which can be sold in the market allowing RES-E generators to obtain revenue, which is additional to the revenue from the electricity they produce, which is sold in the physical market. Therefore, two separate markets coexist: a physical market and a TGC market. In the later, supply of TGCs is based on their issuing for every specified amount of RES-E. The demand for TGCs can originate from an obligation (on consumers, suppliers or even producers), from voluntary demand or even from fiscal incentives (ecotax exemption). From the interaction of supply and demand, a TGC price emerges and generators and investors plan their production and investments accordingly. TGC schemes are, in theory, a cost-efficient instrument to deploy RES-E. This is especially true if certain conditions in the market for green certificates are met (wide markets, liquidity, etc.). Lack of experience with these systems makes their practical functioning still uncertain. Their interaction on a EU level and their design features are also sources of uncertainty. The Netherlands was the pioneering country in the implementation of TGCs (the 1998 Green Label system) based on a voluntary demand. Mandatory TGC-schemes have benn introduced in a number of countries, among these Belgium (two regional TGC systems, in Flanders and Wallonia), Italy, The Netherlands, Sweden and the U.K. Although there is a basic structure of these mandatory TGC systems, important differences between them in relation to certain features (i.e., penalty levels and quotas) exist. The obligation is generally put on the supplier on behalf of the consumer, except in the Italian scheme where it is put on the producer and the importer. In the Netherlands, the current system is one of TGCs with a voluntary demand stimulated by an energy ecotax exemption (REB). However, this system will not be maintained in the future. It is quite likely that a combination of TGCs, feed-in tariffs (MEP) and a (reduced) ecotax exemption will apply (see below).
- Tendering/Bidding Systems. Tenders are invited by a public body to compete either for a certain financial budget or a certain capacity of RES-E generation. Within each technology band, the cheapest bids per kWh are awarded contracts and receive the subsidy. The operator pays the bid

[6] The Netherlands is on the way to change the system.

price per kWh. The difference between this price and the market price of electricity is reimbursed by a fund, which is financed by a non-discriminatory levy paid by all electricity consumers. Competition between RES-E producers is stimulated by this system. Once bids are awarded, they give certainty to the generators/investors, as they work like a guaranteed feed-in system. However, the high administrative costs and the complexity of the procedures involved in a tendering system are important drawbacks of this system (Faber et al 2001; Uyterlinde et al 2003). Tendering/bidding systems are or have been applied in the U.K., Ireland, Denmark and France. The British NFFO system was abandoned some time ago. In Ireland, AER still applies, although the system is being questioned and it will probably be substituted by another system in the future. France still promotes wind-onshore electricity through a bidding system (the EOLE 2005 programme).

- Investment Subsidies. The subsidies can either be calculated as a percentage on the renewable energy output or on the installed capacity, the latter version is more common. Sometimes subsidies are awarded not on a percentage basis but for €/kWh or €/m2. Their use is widespread in all countries (except, apparently, in Italy and Ireland). The currently less economical technologies (i.e., PV) usually receive relatively higher levels of subsidy while technologies closer to the market profit from subsidies at lower levels. A problem with investment subsidies is that the generator does not have the incentive to operate the plant as efficiently as possible (Faber et al 2001).

- Fiscal and Financial Incentives. Fiscal incentives work via the tax system. These can be exemptions or rebates on (energy, corporate or income) taxes, tax refunds, lower VAT rates or attractive depreciation schemes. They might affect old and recent installations (generation-based incentives) or only the new ones (capacity-based incentives)(Uyterlinde et al 2003). Their use is widespread in the MS. Financial incentives in the form of reduced interest rates are applied in Austria, Germany, Luxembourg and Spain.

- Green Pricing/Green Funds. Under the voluntary instruments of Green Pricing electricity consumers pay a surplus on their electricity bill for the promotion of electricity from RES. Therefore, this system is based on a Willingness to Pay (WTP) for green electricity on the part of consumers. The extra costs of RES-E are covered by the surplus, which is received by the generator. An independent organisation guarantees that the electricity for which consumers pay a price has a renewable origin, if the green pricing option is independently labelled. There are currently green pricing schemes in Finland and Germany (the RWE Unweltariff).

Although the above comments may give the impression of uniformity in the schemes being applied, the reality is that the same generic scheme (i.e., TGCs) may show different design details in each country. Of course, the effective promotion not only depends on the type of instrument being used but also on the support provided by the scheme and on its design characteristics.

Of utmost relevance is also the time stability of the support instrument being used. For example, if this changes continuously, this will lead to further risks and uncertainties for the investor delaying or even prevent additional investments in RES-E from taking place. Some countries are currently substituting a support scheme by other types. Italy, Austria (small hydro), Belgium and the U.K. have recently changed to a TGC system. Since May 2003, a TGC system has been implemented in Sweden. In other countries, changes are expected to take place in the short/medium-term. Denmark considers the introduction of a TGC-scheme, but the introduction is postponed at least until 2004-2005. The application of a TGC scheme is expected in the Brussels region of Belgium (together with the TGC systems of Flanders and Wallonia). Ireland will probably move from AER (bidding system) to a market based mechanism or to feed-in tariffs. In the Netherlands, a new, complex system is expected in the short-term (MEP). It is based on a combination of a TGC system, a feed-in tariff and an ecotax exemption. In this system, the generator would obtain income from three different sources: the market price of electricity, the TGC price and the feed-in. A (reduced) ecotax exemption is applied to stimulate demand for TGCs. Under the MEP, the total level of operating support is determined by the sum of the feed-in tariff and the value of the ecotax exemption[7]. In general, a move from feed-in tariffs and bidding systems to TGCs can be observed in some countries. It is hard to predict what will be the policy support trend in the future. In any case, promotion schemes will continue to have a crucial role in RES-E deployment.

2.2.2 Emission Trading at the National Level - Denmark and the UK

In Europe, only Denmark and the UK have so far implemented a domestic emission trading system.

2.2.2.1 Danish Trading Programme for CO_2 Emissions from Power Plants

The Danish CO_2 Emissions Trading Programme went into effect at the beginning of 2001. It is a cap-and-trade programme. The allocation under the Danish programme is a grandfathering mechanism based on average emissions between 1994-1998. The number of firms included in the programme is small. A synthesis of the main features of the programme is provided below (Harrison and Radov 2002; Haites 2002, IETA 2002 and DEA 2003):

Compliance period. Programme is in effect from 2001-2003.

Sources included. All electricity producers in Denmark, excluding renewable generators and CHP plants with annual historical emissions under 100,000 tonnes CO_2. Currently, only 8 companies are required to participate[8]. More than 90% of the total CO_2 emissions from electricity (about 30% of total Danish GHG emissions).

Cap. The system tries to reduce national emissions from 22 $MtCO_2$ (2001) to 20 $MtCO_2$ (2003).

Allocation type. Emission allowances are grandfathered based on the average historical emissions in 1994-1998 of the participating companies (30.3 Mt CO_2 on annual average for the period[9]). Allowances are issued per company, and not per unit or plant. An adjustment for CHP exists. Allowance allocations for each unit are proportional to the unit's average historical emissions from electricity production during the period 1994-1998. Emissions are calculated based on standard emissions factors

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[7] The government guarantees this total level of support for a period of ten years after entering into operation. This means that future changes in the level of the ecotax exemption will be compensated by an equivalent adjustment of the MEP feed-in tariff such that the overall level of support remains the same for any single producer. For further details, see Van Sambeek and Van Thujil (2003).

[8] The cap covers emissions by about 500 electricity producers, most of which are very small combined heat and power plants, but emissions trading is limited to 8 firms. A "small plant" is one with emissions of less than 100,000 tonnes of CO_2 per year. Small plants do not receive allowances and are not subject to penalty in case of non-compliance. Allowances are allocated free to the eight participants based on their 1994-98 emissions. Two firms, Elsam and Energi E2 received 93% of the allowances allocated.

[9] Emissions are calculated by applying an emission factor to average fuel use (in 1994-1998).

for each fuel. Allocation follows a two-tiered process: all CHP units receive allowances first (up to their average 1994-1998 emissions); remaining allowances go to non-CHP units.

**Sanctions.* The penalty for non-compliance is set at 40 DKK per tonne CO_2 emitted in excess of the company's allowance. The revenue from any non-compliance fines is to be invested in energy savings initiatives.

**Banking.* Permits not used in one year can be banked for subsequent years, with technical limitations on banking in 2001 and 2002.

2.2.2.2 United Kingdom GHG Emissions Trading Programme

The UK Emissions Trading Scheme began in April 2002. The programme is currently a hybrid combination of a cap-and-trade, emissions reduction credit, and averaging system, although in later years it may switch to a pure cap-and-trade programme. For the first five years, the cap-and-trade portion of the programme will be voluntary, although strong incentives are awarded to participants. Sources can enter the programme in one of three ways (Haites 2002):

1) CCLA Participants. Through Climate Change Levy Agreements (CCLA), energy intensive sectors accept energy efficiency or emissions targets in return for an 80% discount of the Climate Change Levy[10]. Participants can earn tradeable allowances for CO_2 reductions computed in relation to the targets, i.e., targets can be achieved via trading.

2) Direct participants. Companies that met specified eligibility conditions may bid an absolute CO_2 emissions cap for a share of £30 million per-year after taxes, offered as an incentive by the Government for five years:

- Electricity generators are excluded from voluntary cap-and-trade programme;

- Facilities are accountable for indirect emissions to allow participants to reduce overall energy consumption, but without "outsourcing" of emissions, e.g., by moving on-site electricity production off-site to a non-participating firm;

- Allocations to participants will be a version of grandfathering that also incorporates the emission reductions that each participant commits to under its winning auction bids.

3) Project participants. Any UK company may carry out a project that results in verified emissions reduction credits, which are also tradable. The rules for project participation have not been devised yet.

**Year.* Trading in the system commenced in April 2002.

**Sources included.* Firms and industries can participate on a voluntary basis.

**Emissions covered.* CO_2 emissions.

**Cap.* It depends on participation, including auction results.

[10] The Climate Change Levy is an energy tax.

**Allocation type.* Auction is used initially (firms bid for emissions reduction credits below emissions baseline) but subsequent programme may grandfather. Firms that meet the reduction target for 2002, following verification in January-March 2003, will receive payments from the incentive fund in April 2003. The incentive funding was distributed through an auction in March 2002 where companies traded their emission reductions to the government for the period 2002-6. In such auction, participants bid reductions of about 4 $MtCO_2e$ for 2006 from their base year (1998 to 2000) emissions. The allocation is based on the following formula: Allocation = 1998–2000 Emissions – Emissions Reduction Obligation

**Targets.* Emission reductions in the UK scheme will be made against a 1998-2000 baseline. The targets were set through the auction for the UK of £215 mill. in incentive money held in March 2002. The overall target is set at 4,028,176 tonnes CO_2e reduction from baseline in 2006. Due to linear reductions from baseline, this results in a total overall reduction target of 12,084,528 tonnes CO_2e for the five-year period.

**Compliance period.* The first compliance period started on the 1 January, 2002 for the calendar year. Participants will have to deliver annual emission reductions. The system will run for a five-year period from 2002-2006.

**Sanctions.* In cases of non-compliance, there is a three-month reconciliation period after the end of the compliance period where participants can get back into compliance. The penalties for non-compliance with the absolute cap are non-payment of the incentive, possible clawing back previous years' payments with interest, and docking allowances for subsequent years at a rate of between 1.1 and 2 times the shortfall.

**Banking and borrowing.* There is no limit on banking from one year to another in the period 2002-2006. Banking of pre-2008 allowances for use during 2008-2012 is available to participants with absolute caps to the extent that they have over-complied with their targets (i.e., they cannot buy to bank)[11].

2.3 Markets and Support Schemes in the EU - The EU Level

2.3.1 RES-E Deployment: Towards a European Support Framework

2.3.1.1 Support of RES-E at the EU Level. The RES-E Directive

RES-E requires significant public support in order to penetrate the electricity market. This has been recognised at the EU level and by the individual MS. The latter have been promoting RES-E for years. At the EU level, renewable energy is, in general, considered to contribute to different objectives: security of supply, environmental protection, climate change mitigation, rural and regional development, employment, technological innovation. The justification for providing financial support to renewables is to level the playing field with respect to conventional electricity, to internalise those positive externalities of renewables in the decisions taken by economic actors and to allow renewables to

[11] The Government reserves the right to impose restrictions on banking of all other allowances and credits beyond 2007. Restrictions will be in the form of percentage-based cancellations applied to applicable holdings at the end of 2007.

penetrate the market. The White Paper on renewable energy sources (European Commission 1997) sets a specific indicative target: that at least 12% of energy consumption in 2010 comes from RES.

The White Paper also emphasises the need for a Community strategy for at least two reasons:

1. In order to mitigate the barriers to the penetration of renewables. As mentioned on page 7, technical progress by itself cannot break the non-technical barriers that prevent renewable technologies from entering the energy market.
2. In order to avoid distortions in the internal market.

Renewable electricity (RES-E) has a strategic role in renewable energy promotion. On the one hand, electricity, which accounts for 40% of gross inland consumption in the EU-15, represents by itself the most relevant energy subsector. On the other hand, several European studies (i.e., TERES) consider electricity generation as the easiest way to get renewables into the market.

This strategic role of RES-E within the 12% renewable energy target has been recognised by the RES-E Directive, which is a major policy initiative concerning RES-E support at the EU level (European Commission, 2001a). It sets main lines of legislation with the aim to promote investment in the medium-term in installations producing renewable electricity. The Renewable Electricity Directive sets targets for the deployment of renewable electricity by 2010. Its main lines are briefly summarised below.

2.3.1.2 Indicative Targets for RES-E

The 1997 White Paper target of 12% of gross inland consumption of energy coming from renewable energy sources (RES) was translated into a percentage share of electricity consumption in Europe being provided by electricity from renewable energy sources (RES-E) of 22%. This indicative target for the deployment of RES-E in Europe is specified in the Renewable Electricity Directive, which also sets indicative targets per MS (see table below).

Table 2.3: RES-E Directive indicative targets for RES-E (as share of gross national electricity consumption).

	RES-E 1997 (%)	TARGET 2010 (%)	RES-E 1997 (excl. large hydro) (%)	TARGET 2010 (excl. large hydro) (%)
Austria	70	78,1	10,7	21,1
Belgium	1,1	6	0,9	5,8
Denmark	8,7	29	8,7	29
Finland	24,7	31,3	10,4	18
France	15	21	2,2	8,9
Germany	4,5	12,5	2,4	10,3
Greece	8,	20,1	0,4	14,5
Ireland	3,6	13,2	1,1	11,7
Italy	16	25	4,5	14,9
Luxembourg	2,1	5,7	2,1	5,7
Netherlands	3,5	9	3,5	9
Portugal	38,5	39	4,8	14,9
Spain	19,9	29,4	3,6	17,5
Sweden	49,1	60	5,1	15,7
UK	1,7	10	0,9	9,3
EU-15	13,9	22	3,2	12,5

2.3.1.3 The RES-E Directive. Main Issues and Deadlines

1) *National Support Schemes and EU Community Framework*

Taking account of the wide diversity of promotion schemes between Member States, the Directive states that it is too early to set a Community-wide framework regarding support schemes. By 10/27/2005, the Commission should present a report on the experience gained with the application and coexistence of different support schemes in the Member States. The report may be accompanied by a proposal for a Community framework for RES support schemes (art.4.2). However, the directive also stipulates that such a proposal for a harmonised support framework should allow a transition period of at least 7 years (thereafter) in order to maintain investors' confidence and avoid stranded costs.

Thereby, the EU RES-E Directive has initiated some sort of transition period concerning support schemes, which will surely have an influence on renewable electricity deployment in the next years. The Directive sets a minimum framework for RES-E policy. However, it does not prejudge what the

RES-E policy scheme should be used for in the future. Not even if a common RES-E promotion scheme should be implemented. In line with the Principle of Subsidiarity, it allows each MS to choose the support scheme, which "corresponds best to its particular situation". Therefore, at least in the short/medium-term, national support schemes will continue to be used by MS to promote RES-E. In the future, some sort of combination of a community framework (harmonisation) and continuation of MS policies for new and existing capacity can be expected.

2) *Mandatory Guarantees of Origin (GOs)*

   By 10/27/2003 at the latest, MS shall ensure that the origin of RES-E can be guaranteed as such according to objective, transparent and non-discriminatory criteria laid down by each MS. They will issue a GO containing data about the energy source from which the electricity was produced (including dates and places of production). The explicit aim is to enable producers of RES-E to demonstrate that the electricity they sell is produced from RES. GOs will be mutually recognised by MS.

3) *Ensure Grid Access*

   MS shall take the necessary measures to ensure that transmission system operators and distribution system operators in their territory guarantee the transmission and distribution of RES-E.

4) Finally, the Directive sets *reporting obligations* for the Commission and for MS on success in meeting the national indicative targets, issuing of guarantees of origin for RES-E, etc.[12]

2.3.2 The Emission Trading Directive: Main Features

In October 2001, the European Commission adopted a proposal for a directive establishing a scheme for greenhouse gas emission allowance trading within the Community (European Commission 2001b). The EU emission trading Directive was formally adopted by the Council on 22 July, 2003.

The Directive establishes a compulsory greenhouse gas allowance trading scheme in all EU Member States from 1 January 2005 onwards[13]. It provides for the introduction of binding, absolute emission limits in 2005 for about 4000-5000 installations (power stations and industrial plants with high energy consumption). Allowances can be traded between the companies involved. It requires Member States

[12] The following reporting obligations apply to the European Commission: (1) Publication of a report assessing if MS have made progress towards achieving their national indicative targets (10/27/2004 and then every two years). (2) Presentation of a report on the implementation of the Directive (12/31/2005 and then every five years). On the other hand, MS will also have reporting obligations: (1) Publication of reports setting national indicative targets for the future consumption of RES-E for the next 10 years (10/27/2002 and then ever five years). (2) Publication of national reports on success in meeting the national indicative targets (10/27/2003 and then every two years). (3) Issuing a guarantee of origin of RES-E (10/27/2003). (4) Publication of a report evaluating the authorisation procedures for RES-E plants (10/27/2003).

[13] In the wording of the draft Directive, "allowances" are the papers that state the authorisation to emit a certain amount, while the permit is the general authorisation to take part in trading allowances.

to implement a domestic GHG trading programme. Some elements of the design are common to all the domestic programmes. Others are left to the discretion of the MS national governments.

* *Type of system.* It is a cap and trade, downstream system which covers absolute emissions comprising the total emissions of the companies concerned. The total quantity of allowances issued and their distribution to participants (sectors and companies) is largely left to MS, with each State having to submit a national allocation plan (NAP) in advance to the Commission on 31 March, 2004 at the latest.

**Sector Coverage:* The Annex I of the proposal includes the plants that will participate in the system. They will be plants from the following sectors:

- Power and heat generation (in plants with a thermal input capacity exceeding 20 MW)
- Mineral oil processing
- Coke ovens and metal processing
- Cement, lime production, other building material and ceramics
- Glass and glass fibres
- Paper and pulp production

These plants are responsible for 46% of the total CO_2 emissions in the EU[14].

**Greenhouse Gas Coverage.* Only CO_2 emissions will initially be included. These will be both emissions from the combustion of fossil fuels and process-related emissions.

**Allocation of Allowances.* This is proving to be the more controversial issue. At least 95% of the allowances have to be allocated free for the 2005-2007 period. This means that a MS can choose pure grandfathering, pure output-based allocation or a combination of both[15]. In the following periods, a 10% auction can be used to allocate some of the allowances. Other relevant criteria for allocation are included in Annex III.

**Surrender of Allowances.* By 30 April of each year, participants are required to surrender allowances equal to their actual emissions during the previous calendar year.

**Penalties.* Penalties for non-compliance have been definitively set at €100 (€40 during the 2005-2007 period) for each tonne of excess emissions plus the restoration of excess tons in the following year.

**Banking and Borrowing.* The proposal does not allow the borrowing of allowances. Banking is allowed.

**Opt-In/Opt-Out.* An opt-out clause has been included. Opt-in is not allowed.

* *Flexibility Elements.* Three elements providing certain flexibility to the system are worth mentioning:

1) A temporal exclusion of specific installations is allowed (in the 2005-2007 period)(art. 27).

[14] This represents 38% of all Kyoto gases (Gagelmann and Hansjürgens 2002).

2) Installation pooling is allowed (art.28).
3) MS may ask the Commission to allocate additional allowances to specific installations in case of force majeure.

*Links with Kyoto (project) Mechanisms. On 23 July, 2003, the Commission adopted a draft directive on the link between its recently adopted greenhouse gas emissions trading scheme and the flexible mechanisms foreseen in the Kyoto Protocol. The proposal suggests that EU companies shall be able to make use of certified emissions reductions (CERs; the CDM trading unit) and emission reduction units (ERUs) from JI project activities to comply with their obligations in the EU ETS from 2008 onwards, provided that the Kyoto Protocol will have entered into force.

[15] MS could use different alternatives for different sectors (European Commission 2003a). In reality, allocation to individual installations within sectors could be based on past emissions or on other activity data such as inputs of raw materials (e.g., heat) or output of products.

3 Policy Interactions at the National Level

A number of different instruments are available for the individual EU member states in their attempt to promote the development of renewable technologies and in parallel to reach their national emission reduction commitments. Some of the important ones of these instruments - a national tradable allowance scheme for CO_2-emissions, a national market for green certificates for a general promotion of renewable sources, a tendering procedure for a selective support of new renewables, CHP, and finally, DSM – are treated in this chapter.

In the analyses, special emphasis is put on the interactions between the three market instruments and the interplay with a liberalised physical electricity market, but only considered from a national policy perspective. Thus, consideration on how these three instruments are related to international promotion and reduction instruments, as a common EU tradable allowance scheme and other Kyoto instruments, will not be taken into account in this chapter. Later, in Chapter 4, the analyses are extended to an international arena.

3.1 The Relationship between Feed-In Tariffs, Tendering, TGCs and TEAs as Specific Support Systems for Promoting Renewable Technologies

Feed-in tariffs, TGC systems and tendering procedures are instruments that are designed to reach deployment or consumption goals of RES-E, whereas, TEA systems are designed to reach emission goals. However, both the goals and all four instruments are interrelated.

Therefore, in this section both the different instruments and the interactions between these instruments at the *national* level are looked at.

3.1.1 Price of Electricity

In order to make analytical studies of the effects of introducing TGC, TEA and feed-in systems, we assume that the equilibrium price of electricity is found in the market balance when net supply of electricity equals demand. In order to make a manageable discussion of the price, one can simplify the notation by specifying that the total electricity supply at a given price p is denoted $S(p)$, and the total electricity demand D. This is illustrated by a curve for the different prices in Figure 3.1 below, where the vertical line represents the prices in euros per MWh and the horizontal line the amount of MWh. Thus, the market based equilibrium price p_e is found at the point where the supply and demand curves intersect. In other words, p_e equals the marginal supply cost of electricity.

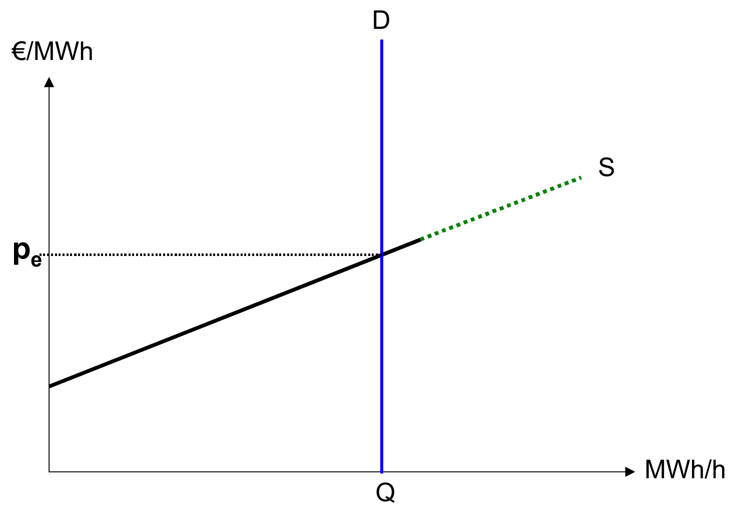

Figure 3.1: Equilibrium price of electricity in the base case

For simplification, we assume that the demand for power (*Q*) is constant. The dotted line in Figure 3.1 illustrates the supply of renewable energy. In the base case, it is assumed that renewable energy supply is too expensive to penetrate the market without support.

3.1.2 Tradable Green Certificates (TGC)

The main idea of a mandatory market for green certificates is to ensure a (politically) planned deployment of renewable energy technologies as effectively as possible. This is done in order to maintain low consumer prices for power and enable efficient renewable energy burden sharing. In particular, the existence of a large market for green certificates should make it increasingly desirable to invest in renewable energy technologies, and ensure that these investments are made in the most effective technologies and locations.

Compared with other methods that promote the development and deployment of renewable energy supplies, green certificates deal with energy that is actually produced rather than merely available capacity. Each time a green power producer sells electricity to the grid, he receives a corresponding number of green certificates. These certificates are financial assets and tradable. In addition to the physical power market, they can be sold in an organised, financial market established for green certificates and thereby realise an additional payment to the producer for his/her green power.

As a result of this, the price obtainable to the producer for the renewable-energy-based electricity will be the sum of the market-based settling price for physical power and the price of the tradable green certificates.

Competition between the producers of green power on the certificate market ensures that the supply price for green certificates reflects the actual price differential between “green” and “black” power.

Thereby, the market for green certificates has the important goal of giving key policy makers, industrial stakeholders, and consumers a price signal from the actual marginal renewable energy technology on the market. In addition, the green certificate system remunerates only the most efficient renewably based power producers compared with a politically mandated system where every power producer is obliged to produce a specified amount of renewably based power.

The demand for certificates in a mandatory scheme is often guaranteed by incurring a purchase obligation either on the producers and importers or on the consumers. On one hand, the system has character as a market-based PSO system if the obligation is incurred on the producers. On the other hand, the system has character as a market-based, demand-driven deployment system if the obligation is incurred on the consumers.

In other words, the introduction of a certificate system with producer purchase obligation is a natural development of the politically mandated system to a market-based deployment system. In contrast with that, the introduction of a certificate system with consumer purchase obligation is a much more radical change of system.

The EU liberalisation debate has focused on the electricity supply industry, and how to make it more effective by competition. Therefore, it is no surprise that the tradable green certificate system with consumer purchase obligation has gained support on political grounds.

In the EU, only Italy (so far) will implement a system with producer purchase obligation. Therefore, in this paper, we will focus on the demand-driven system since this is the most diversified system compared with the politically mandated system, and furthermore, this is the design that Denmark and other EU countries have chosen.

According to national or international (e.g., EU) energy plans, every consumer or distribution company is obliged to acquire a minimum number of green certificates. This corresponds to a percentage (quota) of their yearly consumption. Thus, in the long-term, this creates a financial market for green certificates via their demand for certificates.

The demand will subsequently contribute to the development of renewable-energy-based electricity production as the obligation to acquire green certificates increases yearly, depending on the energy plans, e.g., the EU goal of 22% renewable electricity by 2010.

The demand on the green certificate market is politically determined in terms of a minimum quota, a fixed percentage of the yearly power consumption. Therefore, the weighed price (final consumer price net of taxes) per kWh electricity consumed consists of the physical power price plus the price for certificates multiplied with the percentage defined in the green quota.

To the extent that consumers do not fulfil their purchase commitments for green certificates (green quota), they have to pay a penalty fine for the missing number of certificates, i.e., for each kWh for which they should have purchased green certificates but did not.

The size of this fine can either be variable or fixed. On one hand, a variable fine can, for example, be set at 200% of the market price of certificates. This implies that the fine is of minor importance, since the consumers will always try to fulfil the purchase obligation.

On the other hand, a fixed fine means that all actors on the market for green certificates know the penalty for not buying the yearly obligatory number of certificates. Therefore, the demand function has an upper bound, since no one will demand green certificates at a higher price than the penalty price. This ensures that fluctuations of the certificate prices are price cap regulated. This situation may lead to a non-realised deployment of (investment in) renewable energy technologies, however, when the market prices are lower than the actual marginal cost added together. As a consequence, the politically planned spread of renewable energy (green quota) may not be reached with the actual penalty price.

In this section, we will focus on a variable fine and assume that it is set so high that it is actually not used. In other words, we will exclude the fine altogether in order to make a more manageable analysis.

3.1.3 TGCs in Order to Reach a Certain Amount of RES-E Consumption

Both a TGC system and a feed-in system give priority rights to a certain amount of RES-E. This implies that the power market is split (divided) between a priority market and a "free" competitive market. Since an effect at one of the markets can counteract an effect at the other, the total effect is not always unambiguous. We will examine this below.

Firstly, we look at why the effect of introducing green certificates is ambiguous. Not only do both the demand and supply sides react, but there are also two market balances, both of which have to be fulfilled.

When introducing a green quota, K_c, this share of the physical market is given priority and do, therefore, not contribute to the determination of the equilibrium price, p_e. Thereby, the remaining share of the market, $(1\text{-}K_c)Q$, now determines the market price for power. This remaining share of the market can be interpreted as the "free" market. The other share of the total demand, K_cQ, can be interpreted as the green priority market determined by the green quota K_c. This is illustrated in Figure 3.2.

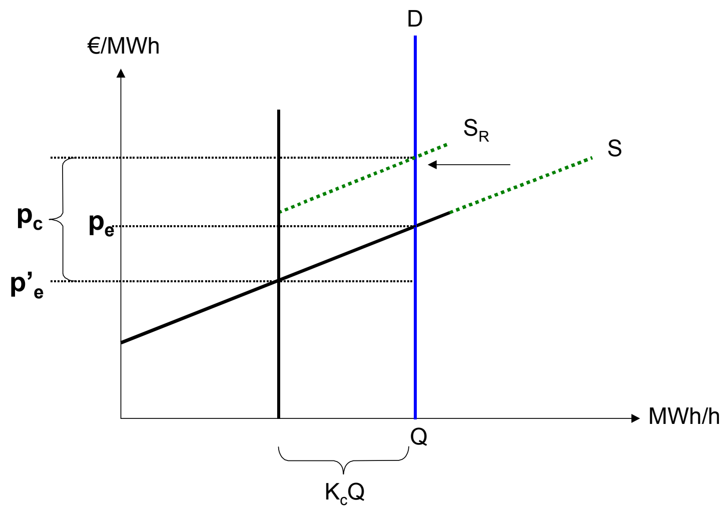

Figure 3.2: Change in prices when introducing a green quota

When the quota K_c in percentages is introduced, the corresponding amount K_cQ of renewable electricity displace the same amount of conventional power.

Thereby, the market based power price decreases from p_e to p_e'. The renewable power producers receive the sum of the power and certificate prices, $p_e' + p_c$, i.e., for them the decrease in the power price is counterbalanced with the positive price for certificates, p_c.

The change of the consumer price is ambiguous, it changes from p_e to $p_e' + K_c\, p_c$. In other words, the decrease in the power price is counterbalanced by the positive certificate price. However, the certificate price is weighed with the quota K_c. Therefore, the total consumer price may decrease even though the certificate price is high if the quota is low.

The example below illustrates this.

Example:

Assume a green quota K_c = 10%, a marginal RES-E cost of 3.4 EuroCent/kWh, and that the power price then changes from p_e = 2.1 EuroCent/kWh to p_e' = 1.8 EuroCent/kWh.

Then, the certificate price p_c = 3.4 – 1.8 = 1.6 EuroCent/kWh. This implies a consumer price of p_e' + K_c p_c = 1.96 EuroCent/kWh, which is a decrease compared with the base price p_e = 2.1 Euro-Cent/kWh.

The corresponding equilibrium consumption and supply of power can either be higher or lower than within a model without any certificates, a situation that is remarkable! It follows that the consumption effect of introducing green certificates is ambiguous.

Table 3.1 below summarises the different effects from introducing either a green certificate or a feed-in system into the base model.

3.1.4 Feed-In Tariffs in Order to Reach a Certain Amount of RES-E Consumption

Like the certificate system, a feed-in system also implies a split of the market by giving RES-E priority. The main difference between TGC and feed-in systems is that the quota is the regulation instrument in the TGC systems with a corresponding market based price. Whereas, the tariff (T) is the regulation instrument in the feed-in system with a corresponding cost based amount (K_TQ) of RES-E.

This is illustrated in Figure 3.3 below.

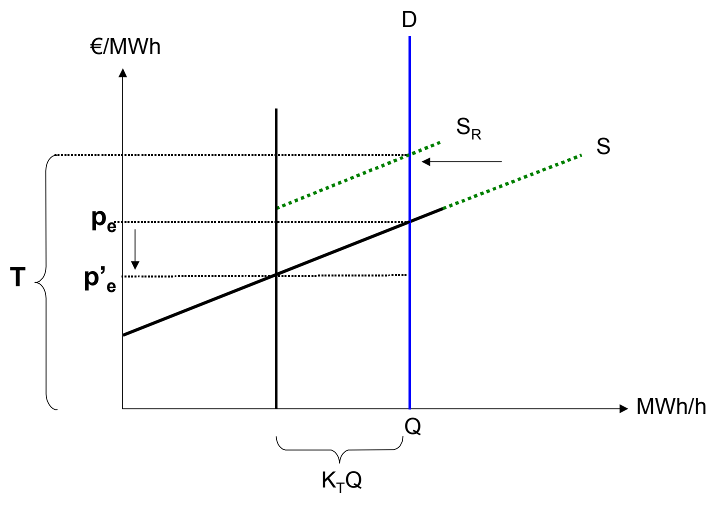

Figure 3.3: Change in prices when introducing a feed-in tariff

The feed-in tariff T implies a certain amount of RES-E is given priority, namely the amount of RES-E that has a supply cost that is lower or equal to the feed-in tariff, T. By using the notation K_TQ for this amount, it can be interpreted as a percentage, K_T, of the total electricity demand, Q.

The amount K_TQ of RES-E displaces the same amount of conventional power. This implies a decrease in the power price from p_e to p_e'. This is similar to the certificate case.

It is assumed that the RES-E deployment based on a feed-in tariff is paid by the consumers, corresponding to the demand. Thereby, the observations made for the TGC system are similar to the feed-in system. In that way, the percentage K_T, of the total electricity demand, Q is purchased at the priority market for RES-E to the price equal to the feed-in tariff. The rest of the demand, $(1- K_T)Q$, is purchased at the "free" market at the power price p_e'. Therefore, the average consumer price per unit of electricity is equal to $p_e' + K_T T$.

This is summarised in the table below.

Table 3.1: Comparative static effects on the power and consumer prices

	Power Price	Consumer Price
Green certificate	–	?
	Power Price	Consumer Price
Feed-in tariff	–	?

Thereby, the split of the power market has an ambiguous effect at the consumer price[16].

When the feed-in tariff is introduced, one could also split the tariff down to a stepwise feed-in tariff. This will (of course) only be beneficial for the consumers in the form of lower consumer prices. This can be expressed mathematically as

$$p_e' + K_T T \;>\; p_e' + K_{T1}T_1 + \ldots + K_{Tn}T_n, \text{ where } K_{T1} + \ldots + K_{Tn} = K_T \text{ and } T_1, \ldots, T_n <= T.$$

In the "real world", stepwise feed-in tariffs are mainly technologically determined feed-in tariffs that are made in order to avoid gold plaiting of cheep RES-E technologies. Likewise, it is possible to make technological specific TGC systems. However, making technological specified support systems has the disadvantage of technological lock-in and lock-out if one is not very good at benchmarking the different tariffs and quotas. Moreover, if separate, technology-specific TGC systems are applied in small countries, market volumes might appear to be too small, implying that no 'real trade' are to be expected.

When you have both a TGC and a feed-in system running parallel for different RES-E technologies, you will have a splitting of the total demand in three markets: a prioritised TGC market, a prioritised production with a market share determined by the feed-in tariff and the RES-E supply cost, and finally, a free competitive market for the conventional technologies.

It is also possible to mix the different system. For example, by letting some (less competitive-mature) RES-E technologies receive a feed-in tariff in addition to the TGC price. In other words, these technologies will get the political determined tariff instead of the power price. It is also possible to give these technologies a feed-in tariff in addition to the TGC and power prices, i.e., to make them more "competitive" at the TGC market.

16 If we had assumed a price elastic power demand, also the effect on consumption would be ambiguous!

In the case where the green quota K_c is unchanged compared to a TGC system without feed-in tariffs or other subsidies, the effect at the power price is unchanged. The introduction of additional feed-in tariffs only affects the TGC market. The TGC market is divided as in the above case for feed-in tariffs, i.e., the TGC price decreases and some of the RES-E technologies are replaced by the RES-E technologies that receive the feed-in tariff.

By that way, an introduction of feed-in tariffs interferes with the functioning of the TGC market. However, it is also a way of ensuring a political determined diversity of RES-E technologies, and thereby hinders lockout of promising RES-E technologies.

3.1.5 Tradable Emission Allowances (TEA)

Tradable emission allowances (TEAs) can also be used to advance the RES-E deployment, even though they are designed to reduce emissions. When introducing a TEA system, the conventional supply cost will increase. The most emitting plants will have a relative higher increase in supply cost than the low emitting conventional plants, i.e., the conventional plants shift places in the supply curve and at a higher level. Therefore, the supply curve for conventional plants will, in general, increase. This is illustrated as the vertical increase in Figure 3.4 below. The shift of order between the conventional plants is illustrated with a different slope between the old and new supply curve.

The vertical increase in the conventional supply curve implies a higher power price. This is a benefit for the RES-E technologies.

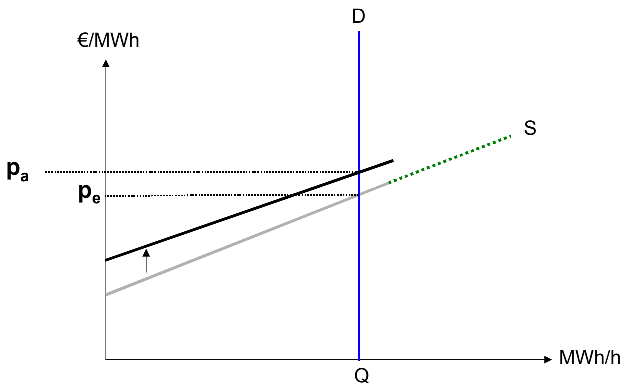

Figure 3.4: Change in prices when introducing a TEA system at a national spot market

If, in addition, a TGC system is introduced, we will see a market split as discussed above, but with the higher power price as the reference price. Thereby, a lower TGC price, p_c, is required compared to a case without a TEA system.

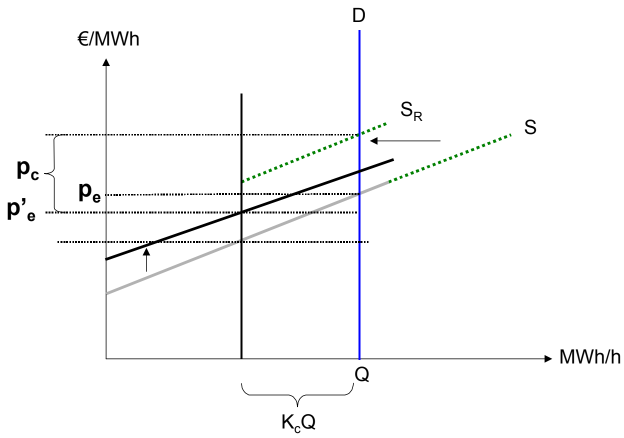

Figure 3.5: Change in prices when introducing national TGC and TEA systems at a national spot market

Since the TEA system implies a higher power price and the TGC system implies a lower power price, the total effect is ambiguous.

Table 3.2: Comparative static effects on the prices of introducing both TEA and TGC systems

	Power Price	Consumer Price
TEA	+	+
	Power Price	Consumer Price
TEA + TGC	?	?

Since TGC and feed-in systems have the same effects (see Table 3.1), similar observation could be made with respect to comparative static effects of TEA and feed-in systems.

3.1.6 Interaction between TGCs and TEAs in Reaching the Two Targets of Renewable Deployment and CO_2-Reduction

Since both TEA and TGC systems can be used to reach RES-E deployment goals and emission reduction goals, it is obvious to ask which of the instruments it is most efficient to use. In the sense that you look at the consumer prices we have got the following results.

An introduction of a TEA system alone will increase the power price and thereby also the consumer price, whereas a TGC system in some cases will lower the consumer prices. Thereby, it is always better, with respect to consumer prices, to use a TGC system to reach a RES-E deployment target.

In the case of reaching an emission goal the optimal choice of instruments depends on the correlation between the consumer price and the green quota. In the case with a negative correlation between the green quota and the consumer price, it is optimal to use the TGC. In the case with a positive correlation (the increase of the green TGC quota, K_c, implies a higher consumer price), it is optimal to use the TEA system.

In the case with two simultaneously goals for RES-E deployment and emission reduction, it is optimal to use both instruments in the case with a positive correlation between the green quota and the consumer price. If there is a negative correlation, only the green quota (TGC system) should be used to reach both goals! For more analytical discussions, see (Jensen and Skytte 2003).

3.1.7 A Green Certificate Market Combined with a Tendering Procedure

In this section, a green certificate market combined with a tendering procedure will be discussed. As mentioned above, a certificate market will only determine the additional support to the most economic attractive renewable technology compared to conventional ones. Thus, if it is a political wish, there might be a need to support other less developed technologies and, in this context, a tendering system could be relevant.

One of the important issues of the green certificate market is to stimulate the development of new renewable production capacity. Figure 3.6 below tries to explain this. The SRMCC is the supply curve for certificates from existing plants (Short Run Marginal Certificate Cost), while LRMCC is the certificate supply curve for new plants to be established during the year (Long Run Marginal Certificate Cost). The price of certificates is determined where the supply curve intersects the demand curve, at price P_{GC}. Thus, the “gap” between the supply from existing renewables and the obligatory demand has to be filled with green certificates from the ongoing development of new capacity to be established within the considered year. Thus, in order for the driving force in the certificate market to be operational, it is crucial that the prescribed quota always is above the established level of capacity – otherwise the capacity development will, of course, be brought to a halt.

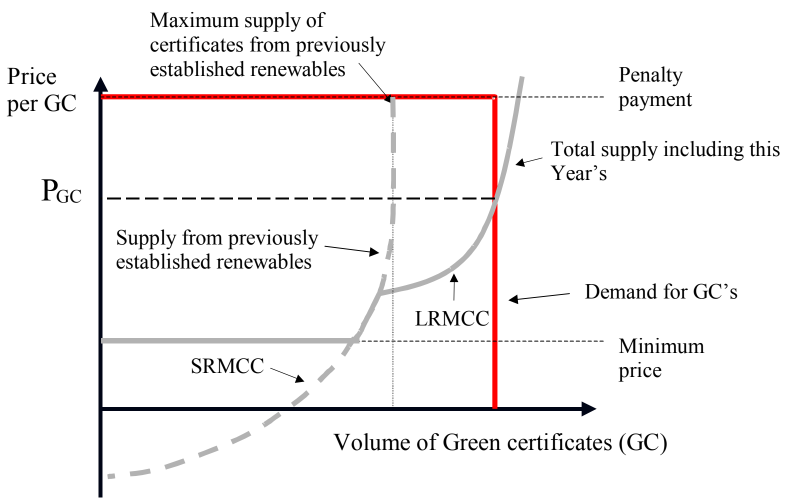

Figure 3.6: Demand and supply at a green certificate market

Although most renewable technologies are small scale in terms of size and capacity, they do take time to construct. There will be a considerable time lag in the development of new renewable capacity from the initial investment decision to when the plant is on stream. Even for on-land wind turbines, it might easily take a couple of years and for larger projects suitable for a tendering procedure as offshore wind farms, it is certainly expected to take considerably longer. Including planning procedures, environmental impact assessment, construction, etc., it might easily take 4-5 years.

With this planning horizon, the prescribed quotas at the green market are to be seen as signals to new investors in the renewable energy market of how the future long-run marginal price for certificates may develop given an expected development of the spot market electricity price. New potential investors have to base their investment decisions on the prices of electricity at the spot market and of green certificates realised in the past, adding the information to be found in the quotas specified by the authorities for some years ahead. For new investors to gain confidence in this information, it is important that the market is characterised by the following criteria:

- That there are a considerable number of actors on the market to achieve competition with no single actor being in a dominating role;
- That there is free entrance to establish new renewable plants;
- That the new capacity developed is established as a large number of marginal projects with no one alone filling a considerable part of the quota “gap”.

These criteria are widely fulfilled in respect of the development of smaller projects, individual wind turbines, roof-based photovoltaics or small-decentralised biomass plants. However, with regard to the development of larger project suitable for tendering, this might not be the case.

As an example, let us look at the development of offshore wind farms in Denmark. The first two offshore wind farms in Denmark are established by Danish power companies in agreement with the Danish government. But a tendering procedure is considered for the following. According to the preliminary conditions stated by a governmental offshore tendering committee[17], it should be possible to attract as large a number of bidders as possible, the major requirements focusing on the needs for competencies with offshore operations and wind turbine constructions, implying that a considerable number of actors should be on hand. Although, it is recommended by the Committee that specific sites for where to establish the future wind farms for tendering are chosen, implying that no free entrance will exist. Finally, the future wind farms to be established will expectedly be of the 150 MW-size, thus, having a considerable influence on filling the quota “gap” in a small country such as Denmark. Thus, if a small country is going to use a tendering procedure, together with a green certificate market, it should be done with caution. Otherwise the consequences might easily be that the price-determination at the certificate market is heavily influenced by the tendering projects, jeopardising the confidence of other actors at the market. Moreover, the tendering projects will gain little or no benefits by the certificate system, because the prescribed quotas cannot be the driving force behind the large tender-projects, these ones having to be planned and implemented outside the system anyway.

But if we turn to large countries, most renewable projects – even large offshore wind farms – will be marginal ones, not having any significant impact on filling the certificate quota. For these countries, a

[17] Set up by the Danish government to study the possibilities of tendering future offshore wind farms in Danish waters.

model combining a green certificate market and a tendering procedure including an investment subsidy is analysed below.

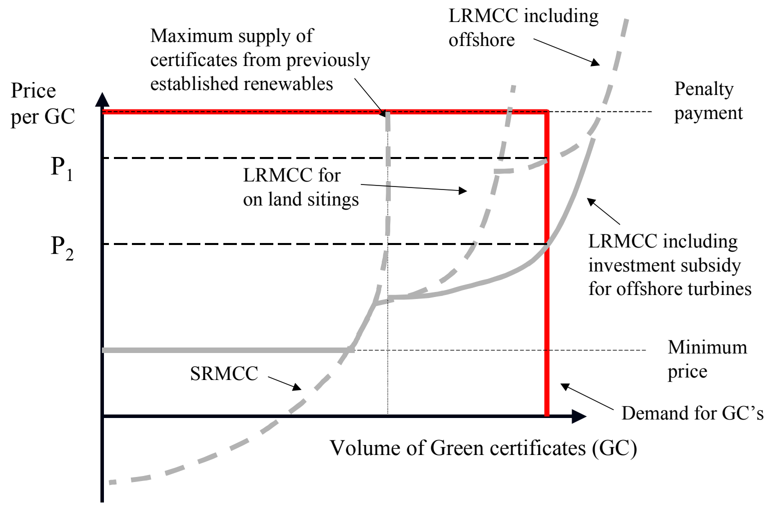

Figure 3.7: Demand and supply at a green certificate market combined with a tendering procedure including investment subsidy for offshore turbines

In Figure 3.7, the green market is supposed to regulate the development of large tendering projects (exemplified by offshore turbines) as is the case for other renewables such as in-land wind power. But the long-run marginal cost of offshore turbines is much higher than for on-land turbines. Thus, in the initial situation, the long-run marginal certificate cost (LRMCC) of offshore turbines is way above LRMCC for turbines sited on land – this is shown in Figure 3.7 as the two stippled curves for LRMCC. In this situation, the equilibrium price is P_1 showing a large expansion of fairly expensive on-land turbines and only a limited development of offshore turbines. If it is a political target to achieve a considerable development of offshore wind power this can be obtained by applying a tendering procedure including an investment subsidy to offshore turbines. Bidding among the competitors will determine the investment subsidy in an economic efficient way. The subsidy will lower the LRMCC of offshore turbines compared to on-land sited wind power and the total LRMCC supply curve may look like the one illustrated in Figure 3.7, where equilibrium is achieved at the lower price P_2 and with a much higher development of offshore wind power – of course, at the expense of a lower development of other RES-E technologies.

3.1.8 A Tradable Allowance Market Combined with a Green Certificate Market and a Tendering Procedure

A tradable allowance scheme will interact closely with the liberalised power market. To achieve CO_2 reductions in the power industry implies a cost increase in the power produced, which to a certain extent will be passed on to the liberalised power market. Thus, it is expected that the introduction of a tradable allowance scheme for the power industry will increase the spot market price of power. Therefore, in a tradable allowance market, the cost of CO_2-reduction will influence the economic viability of all available technological CO_2-reduction options.[18]

The following analysis will focus on the role of an individual power company and prices, etc., are to be seen from the company's perspective. Thus, a power company has three possibilities of fulfilling its tradable permit quota:

1. To reduce the emissions of CO_2, given the expected level of power production;
2. To reduce the production of electricity below the expected level;
3. To buy tradable allowance at the national market.

Finally, it has the possibility of paying the penalty for exceeding the quota. If this is profitable for the power industry will, of course, depend on the penalty size – if the penalty is adequately high, it will not be relevant to exceed the quota.[19]

How the three above-mentioned possibilities are utilised will depend on the cost conditions, both at the power spot market and at the companies' possibilities to reduce their CO_2 emissions. The three options are closely related. The trade of tradable emission allowance will ensure that the CO_2 reduction options are undertaken where it is most efficient in the power industry within the considered region. The power companies that have the most cost-effective options will undertake more reductions than needed to fulfil their own quota and will trade the surplus to companies that have reduction costs above average. The trade of allowances will ensure that the price of an emission allowance will be equal to the marginal cost of CO_2-reduction in the power industry.

To reduce power production below expected levels will be subject to the overall constraint, that total power demand in the region has to be covered by the power supply. Thus, if some companies decrease their production below the expected level, assuming that these expected levels of produced power add up to the total power demand, then some companies will have to increase their power production. But, of course, the production pattern between companies will expectedly change, as will export/import relations to other countries.

In the following, the possibilities of lowering the level of power production and of buying allowances from other producers are neglected, only concentrating on the power company's possibilities to undertake CO_2-reductions. Thus, in reality only two possibilities will exist for the company:

- Increased efficiency of conventional production achieved by renovating existing plants or establishing new ones;
- Fuel switching to fuels with a lower carbon content, e.g., from coal to natural gas or to renewable energy sources.

[18] Although energy-intensive industries might be included in a tradable allowance scheme (as is the case in the EU proposal), to simplify the analysis only power companies are considered in the following.

[19] In addition, in the proposed European greenhouse gas emission trading system, companies have to surrender missing allowance in the following year.

Which of these options will be utilised will depend on the economic conditions to be further discussed below.

If a green certificate market and/or a tendering system support renewable technologies, this will, of course, make these technologies more economically attractive as options for fulfilling the company's CO_2 quotas. How these two support schemes might affect the price of CO_2 reductions as seen by a power company and subsequently the price at the power spot market will be briefly discussed below.

The starting point in Figure 3.8 is one with only a TEA-market and neither certificates nor tendering. The three reduction options available to the power company are: Wood-chips combustion technology, straw combustion technology and conventional options (other options, i.e., increased efficiency and fuel switching to fossil fuels), which are all shown as the stippled curves in Figure 3.8[20]. Thus, in this case, the marginal cost of CO_2-reduction for the power company is determined by the "Only TEA" reduction supply curve, implying a price of P_1 per ton of CO_2-reduction. Only conventional options and the combustion plants burning wood-chips are contributing to CO_2-reductions.

But for a power company, the introduction of a green certificate market will in general shift downwards the marginal cost curve for CO_2-reductions obtained by renewable sources, thus, the curves for combustion of wood-chips and straw are both shifted down, implying that the reduction supply curve as seen by the company now is "TEA + TGC". The price of CO_2-reduction falls to P_2, wood-chips plants are contributing more to the required reduction on the expense of conventional options, due to reduced reduction-costs for the first-mentioned ones. But plants based on combustion of straw are still too expensive to be economically attractive as reduction options.

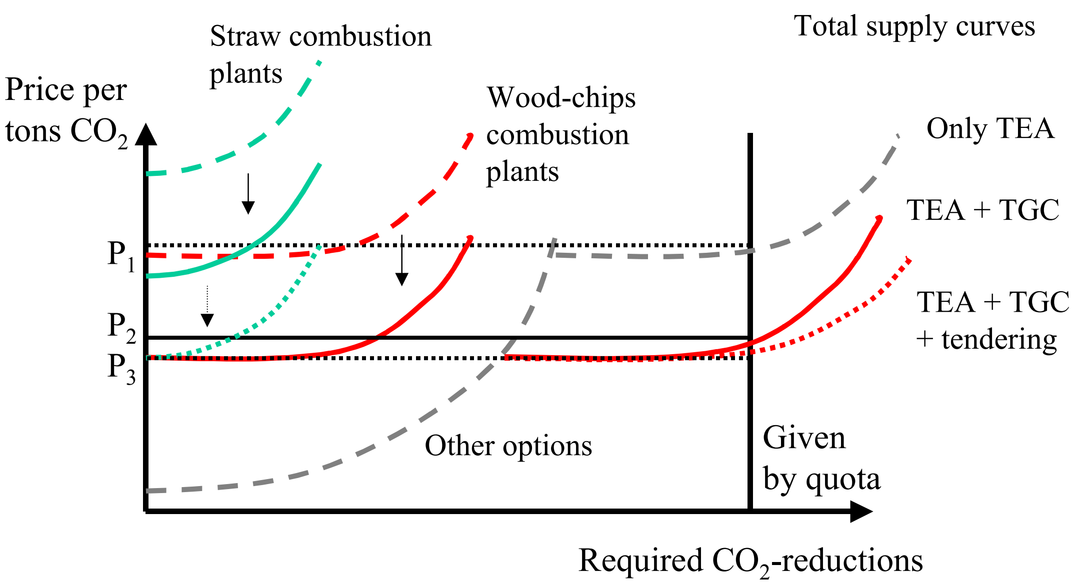

Figure 3.8: How support schemes as green certificates and tendering might influence the power companies' costs of CO_2-reduction in a tradable allowance scheme

Finally, by a tendering procedure, the marginal cost curve of CO_2 reductions for plants based on the combustion of straw is shifted further downwards (as seen by the power company) and by now, this

[20] Observe that only renewable sources that can replace the fuels on conventional plants are relevant in this case, e.g., biomass replacing natural gas or coal.

option becomes interesting for the company as well, although as can be seen from the reduction supply curve “TEA + TGC + tendering” only to a limited extent. In general, how much the reduction cost curves for combustion of wood-chips and straw are shifted downwards will be determined by the size of the TGC-quota, the possibilities for banking certificates and how much is being tendered.

But, in general, an introduction of a green certificate scheme and/or a tendering procedure will both tend to lower the costs of CO_2-reduction as seen by the power company, easing the companies in fulfilling the required volumes of CO_2-reduction as stated by the emission allowance scheme.

Switching to the market perspective, the introduction of the TEA-scheme will by itself raise the power price at the spot market, due to the costs of CO_2 reduction to be undertaken by the power companies. But how much the price will change is complicated to foresee, because the plants constituting the marginal cost curve of the power spot market most probably will change due to the introduction of the TEA-scheme. That is, an in-efficient but cheap coal-fired power plant might now change to be the marginal plant on the supply curve determining the power price, replacing an efficient but more expensive natural gas-fired plant.

How much the power price will decrease at the power spot market due to the introduction of TGCs and tendering in a market where a TEA-scheme already exists might neither be that easy to determine. The picture is complicated because the interplay with the physical power market has to be taken into account in this case as well. The marginal plant replaced at the power market will be the one to determine the decrease in price – thus, if it is a natural gas fired one, the additional cost related to CO_2-reduction will be considerably smaller than if it is a coal-fired one. Moreover, the introduction of TGCs and/or tendering will by itself tend to shift the ranking of power plants at spot market supply curve, because the production costs of eventually existing biomass plants will be lowered.

Finally, there does not seem to be any serious obstacles in combining a national tradable allowance market with the two promotion schemes for renewables, the green certificate market and the tendering system, either separately or in a combined way. The green certificate scheme will in general improve the economic competitiveness of renewables compared to other reduction options, while the tendering system will support specific renewable technologies.

3.1.9 Summary

At the national level the use of a TGC-scheme or a Feed-in tariff system have – under ideal conditions – almost identical impacts on prices, renewable capacity development and emissions:

- TGC and feed-in systems, which give priority to a certain amount of RES-E, will displace a corresponding amount of conventional power by lowering the demand for conventional power.
- Assuming increasing marginal cost of conventional power, the market price of power will decrease when support schemes for RES-E are introduced at the national markets (assuming no market power).

- If consumers have to pay for the increase in RES-E the effect on total consumer expenses is ambiguous: the increased costs for RES-E are counteracted by the decreased market price of conventional power.
- In a closed economy with no international power trading increased RES-E production will totally replace domestic conventional power and thus an equivalent emission reduction will be achieved.
- Applying differentiated tariffs or support prices to different RES-E technologies might decrease the cost of reaching a certain amount of RES-E due to different supply costs between the technologies, i.e. the cheaper technologies can be promoted by a lower tariff. Though in the case of a TGC-system the application of separate quotas for different RES-E technologies only makes sense if the market volume is big enough.

The use of a tendering system together with a green certificate scheme were also analysed and discussed in this section, giving the following conclusions:

- In a small country, the TGC-quota cannot be the driving force behind the development of large tender-projects. Such projects will not be small marginal ones compared with the quota, but will have to be planned and implemented outside the scheme. Otherwise the consequences might easily be that the price-determination at the certificate market is heavily influenced by the tendering projects, jeopardising the confidence of other actors at the market.
- In larger countries where tendering-projects are being considered marginal to the TGC-quota, it might be relevant to utilise the tendering-system to a selective promotion of those renewable being interesting in the long-term but presently not being economically attractive in a green certificate scheme.

In principle, there seems to be no major obstacles for combining the three markets for tradable allowance, green certificates and tendering. In general an introduction of a green certificate scheme and/or a tendering procedure will both tend to higher the contribution of renewables at the expense of conventional technologies.

Although mainly focusing on CO_2-reduction options in general, the introduction of a system of tradable emission allowances (TEA) at the national level will also have a positive effect on the promotion of RES-E technologies:

- The price at the power spot market will unambiguously increase because of the cost of reducing CO_2-emissions. The supply curve for power will be shifted upwards corresponding to the marginal costs of CO_2-reductions, that is to the emission allowance price. The resulting increase in the power price will depend on the price elasticity of power demand.
- Likewise, the consumer price will increase when a TEA system is introduced.
- The higher spot price will induce a stronger development of RES-E technologies, although RES-E will not be specifically favoured compared to other CO_2-reduction technologies like

fuel switching to less carbon intensive production or efficiency improvements on both the supply and the demand side.

- If a green certificate scheme and/or a tendering system is introduced into an existing TEA-scheme, this will tend to lower the price at the power spot market compared to a case without the RES-E support systems.
- For those companies and technologies covered by the emission trading system the CO_2-emissions will follow the determined quotas. For RES-E technologies outside the emission trading system the achieved volume of emission reductions is ambiguous. Either the RES-E power production will replace other conventional power production outside the TEA-scheme (for example small-scale natural gas fired CHP) and in this case national CO_2-emissions will be reduced. Or it will replace conventional power covered by the TEA-scheme, where in that case no reduction in CO_2-emissions will be achieved, because the conventional power plants still are emitting the allowed CO_2-quota.
- In a system with a tradable allowance scheme, the introduction of a TGC-scheme and/or a tendering system will make it easier for power companies to fulfil their CO_2 quota, giving them a chance to convert conventional fossil fuel fired plants to biomass at a lower production cost.

3.2 The relationship between CHP and TGCs/TEAs

Combined Heat and Power (CHP) saves primary energy and exhibits much lower CO_2-emissions than their separate production in fossil-fuelled power plants and boilers. These emission savings tend to be in the range of 20-50%. The EU, therefore, wants to increase the share of electricity from CHP from 9% in 1994 to 18% by 2010. Although the potential for CHP is substantial, market liberalisation in the electricity and gas markets has resulted in an economically difficult situation for CHP in most EU Member States. In addition, support programmes for electricity from renewable energy sources make RES-E more attractive relative to electricity generated by CHP plants (CHP-E). Thus, without support programmes for CHP, only few additional CHP-E may be produced in the near future. Likewise, whether the European Emissions Trading System (EU-ETS) will push or harm CHP-E cannot be predicted at this point in time and depends on the actual design of the system, in particular, on the treatment of CHP within the primary allocation of allowances (National Allocation Plans).

In this work package, we first analyse the effects of a TGC on CHP. Then, we explore the implications of a tradable quota system for CHP. The impact of simultaneous quota systems for both, TGC and CHP are also explored. Finally, the effects of a TEA on CHP are analysed. In the subsequent analyses, we do not discriminate between large and small, engine-driven CHP plants. Likewise, we abstract from differences in residential and industrial CHP.

3.2.1 The Relationship between CHP and TGCs

Figure 3.9 illustrates the effects of the introduction of tradable green certificates.[21] As usual, the price of electricity is shown on the vertical axis in EUR per MWh, while the quantity of electricity in MWh

[21] The analysis is similar to Jensen, S. G. and Skytte, K. (2003): Simultaneous attainment of energy goals by means of green certificates and emission permits, *Energy Policy* 31, 63-71.

is displayed on the horizontal axis. For simplicity, assume that power demand is constant. As represented by the vertical line D. Total supply (S_{Total}) is composed from the supply by conventional production technologies ($S_{Conv.}$), by CHP (S_{CHP}) and by renewable energy sources (S_R). Electricity produced by CHP (CHP-E) is considered to be more expensive than electricity generated by conventional technologies, but cheaper than electricity from renewable energy sources (RES-E). In the *base case*, equilibrium prices and quantities are given at the intersection of total supply and demand. Without TGCs, the equilibrium price for consumers and producers is P_e. Thus, in the base case, RES-E is too expensive, and without support, production of RES-E will be zero. The production of CHP-E in the base case is given by $Y_{CHP,\,0}$.

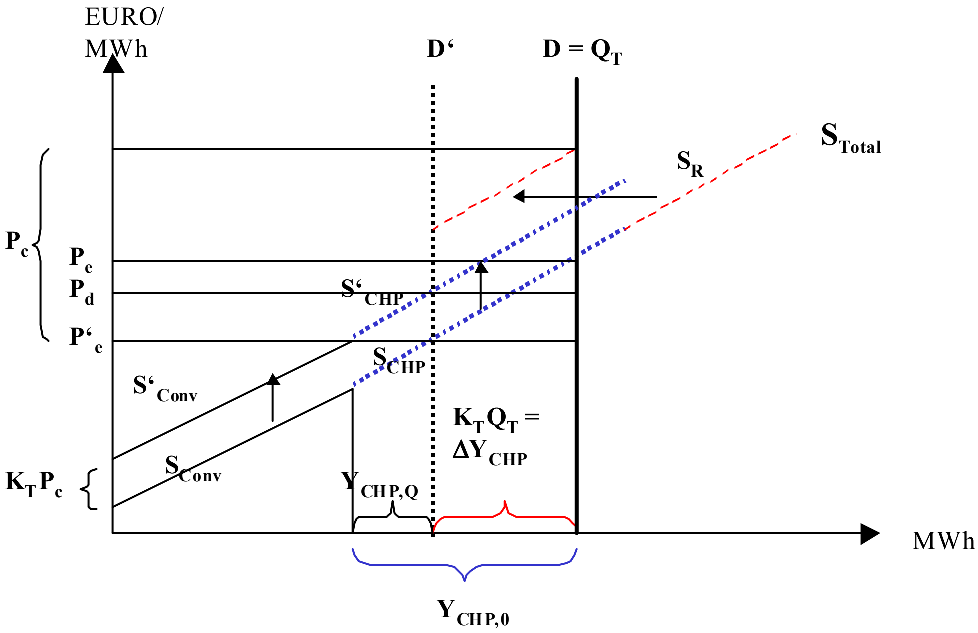

Figure 3.9: Effects of TGCs on CHP production, when RES-E share is based on total power production

Now we assume that in order to foster electricity from renewable energy sources, a quota for RES-E is implemented which can be traded across obliged parties. Two types of quota systems are considered which differ in the base for the RES-E quota. In the first case, it is assumed that the quota is defined such that the amount of RES-E corresponds to the *share of total electricity produced,* i.e., including CHP. In the second case, the quota for RES-E is based *on conventional electricity only*.

3.2.1.1 RES-E Quota Based on total Electricity Generation (Reference Case)

Assume that TGCs are introduced such that the amount of RES-E corresponds to a given *share of total electricity produced*, i.e., K_TQ_T, where Q_T stands for total electricity production and K_T is the quota for RES-E. D' may be interpreted as the residual demand (D - K_TQ_T) which has to be satisfied by conventional power production and CHP-E. So the power market is separated into a market for RES-E on the one hand and into a market for electricity from conventional sources and from CHP on the other hand. Since CHP-E is assumed to be the marginal producer, the additional electricity from renewable energy sources will crowd out an equivalent amount of CHP-E, i.e., $-\Delta Y_{CHP} = K_TQ_T$. Thus, under a TGC system only, $Y_{CHP,Q}$ will be produced. Conventional power producers and producers of

CHP-E receive P'_e , which is lower than P_e in the base case. By contrast, producers of RES-E receive the sum of P'_e and P_c. However, the additional costs from the TGCs will be levied on each MWh produced from conventional and CHP producers. This is reflected in the upward shift of the supply curves for conventional power and CHP-E by the amount of K_TP_c in Figure 3.9. The new consumer price (P_d) is given at the intersection of the residual demand curve D' and the new supply curve of the marginal supplier CHP-E. In general, the change in the consumer price is ambiguous, i.e., it can either be higher, the same or lower compared to the electricity price without a RES-E obligation in the base case (P_d >=< P_e). Given the magnitude of the quota and the resulting upward shift in the supply schedules in Figure 3.9, the new consumer price for electricity under TGCs turns out to be lower than in the base case. However, total costs of production will be higher than before, because RES-E was assumed to be more expensive than the power sources which were crowded out as a result of the TGCs.

For the analysis above, all CHP-E was considered to be produced using conventional fuels only. Alternatively, one may assume that part of CHP-E is based on biomass (CHP-E-RES). For example, a large part of CHP-E in Finland is based on biomass and stems from the pulp and paper industry. In this case, CHP-E-RES may also be eligible for TGCs. The implications are as follows. On the one hand, if in the base case, CHP-E-RES was more expensive than the marginal supplier, part of the SR curve could be interpreted as CHP-E-RES and the analyses would go through as presented. The introduction of TGCs would then increase the production of CHP-E-RES. On the other hand, if all CHP-E-RES were cheaper than the marginal supplier in the base case, p_c in Figure 3.9 would be smaller (assuming the same quota as before). In this case, the TGCs would generate wind fall profits to CHP-E-RES.

3.2.1.2 RES-E Quota Based on Conventional Electricity Generation

As an alternative, assume that – in order to avoid the negative effects on CHP - TGCs are introduced such that the share of RES-E no longer corresponds to the total share of electricity produced, but instead to *conventional electricity produced*, where, per definition, CHP-E is not included in conventional electricity production. The quota K_C stands for the share of conventional electricity generation that has to be produced by RES-E. This case is illustrated in Figure 3.10. The amount of RES-E production is now K_CQ_C, where Q_C stands for conventional electricity production. To allow for a consistent comparison with the previous case (termed *reference case*), RES-E generation must be the same, i.e., $K_CQ_C = K_TQ_T$ from above. Thus, it has to be the case that $K_C > K_T$. Likewise, it is assumed that the extra costs arising from the RES-E quota obligation are only levied on producers of conventional electricity. Thus, the lower the level of Q_C , the higher the share K_C has to be, so that $K_CQ_C = K_TQ_T$ still holds. In fact, the relationship between K_C and Q_C is hyperbolic: $K_C = K_TQ_T/Q_C$, where the numerator is constant. The elasticity between K_C and Q_C is minus one, i.e, a 1% decrease in electricity production from conventional power results in a 1% increase in the share of RES-E on conventional power production. The additional costs on conventional power are now K_CP_c, i.e., the marginal costs for conventional electricity is raised by K_CP_c. Producers of conventional power now receive P'_e which is lower than P_e. When the share of RES-E is based on conventional power only, P_c is higher compared to the case, where the share of RES-E is based on total electricity production. Producers of RES-E receive the sum of P'_e and P_c, which is the same as when the share of RES-E is based on total power production, since the same amount of RES-E production is required. Now, what happens to the production of CHP-E compared to the base case? In principle, three cases can be distinguished:

I. The additional costs imposed on conventional power are very high due to a high K_C and/or high marginal RES-E generation costs; in this case, conventional electricity will be substituted by RES-E production and CHP-E. As a special case, CHP-E may remain the same as without a TGC system.

II. The additional costs imposed on conventional power are medium; in this case, conventional and CHP-E will be substituted by RES-E production.

III. The additional costs imposed on conventional power are very low. In this case, only CHP-E will be substituted by RES-E production and conventional power production remains the same.

Compared to the reference case, CHP-E production will be higher in cases I and II. For illustration purposes, case I will be analysed graphically in Figure 3.10 and Figure 3.11. First note that the fact that the base for calculating the share of RES-E is no longer total electricity production, complicates matters, since K_C is now simultaneously determined with P_c and conventional power production under the TGC ($Y_{Conv,Q}$). Holding the total quantity of RES-E constant, one may choose an infinite number of combinations of K_C and Q_C, such that the target amount of RES-E which is K_TQ_T from the reference case, will be produced. In Figure 3.10 and Figure 3.11, the CC-line depicts all combinations of Q_C and P_cK_C such that (a) the target amount of RES-E is achieved, and (b) producers of RES-E receive their (long-run) marginal costs. As a starting point, in Figure 3.10 Q_C and P_cK_C are chosen such that total production of CHP remains unchanged compared to the base case (point A). That is, in this case, the introduction of the TGC based on conventional electricity results in the crowding out of conventional electricity only and CHP-E remains unchanged. The supply curve for conventional power (marginal costs plus additional costs for TGCs), which corresponds to the chosen combination of Q_C and P_cK_C in A is shifted upwards. Note that the shift does not make sense for the entire curve, but only for the part until the equilibrium level of conventional power production is achieved at $Y_{Conv,Q}$, because, in the new equilibrium, only that part will be hit by the additional costs. The supply curve for CHP-E remains unchanged (the parallel shift to the left in Figure 3.10 is only for illustration). The consumer price will be determined at the intersection of total demand and (in Figure 3.10 the original) supply for CHP, or, alternatively, at the intersection of the residual demand D' and the (left)shifted CHP-supply curve. Since CHP is still the marginal producer, and since the costs for CHP did not change from the introduction of a TGC system based on conventional power production, the consumer price will be determined by CHP-E. Since CHP-E remains at the same level as in the base case, consumer prices do not change either and remain at P_e.

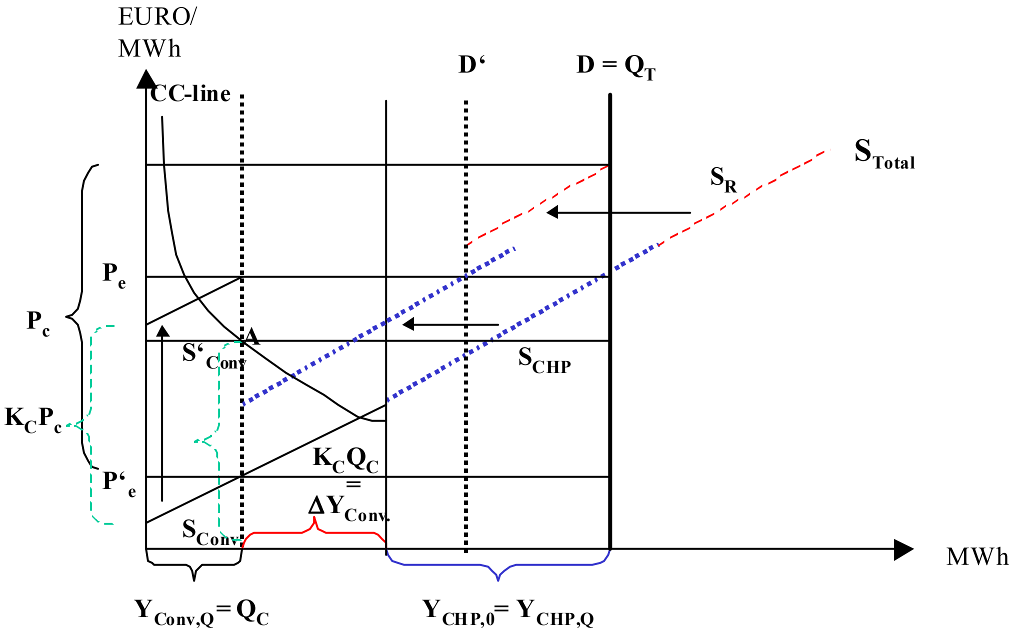

Figure 3.10: Effects of TGCs, when RES-E share is based on conventional power production and CHP-E remains the same

Note that, if a point to the North West of A on the CC-line is chosen (i.e., via a higher K_C), such as point B in Figure 3.11, the additional costs from the TGC on the production of conventional power are higher and the production of conventional power is lower compared to the case illustrated in Figure 3.10. So, some conventional power is substituted for CHP-E. CHP-E is still the marginal producer, but now more expensive CHP-E is employed, so the consumer price P_d is higher than P_e.

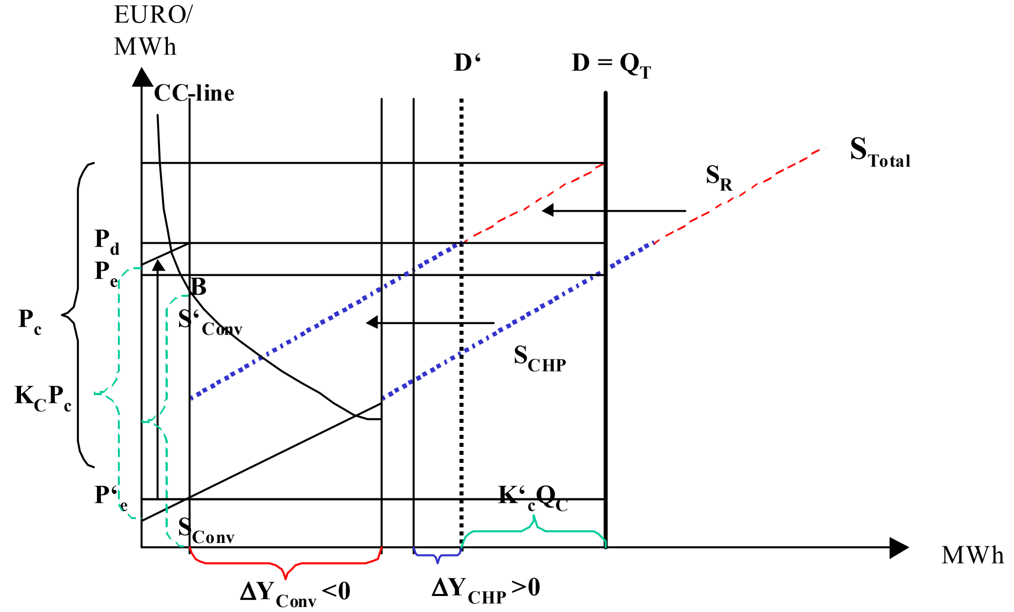

Figure 3.11: Effects of TGCs, when RES-E share is based on conventional power production and CHP-E increases

If we move along the CC-line to the Southeast of A, additional costs from TGC on the production of conventional power decrease continuously and CHP-E will start to be crowded out by RES-E. Eventually, TGCs only crowd out CHP-E and no longer conventional power. Since the marginal producer to satisfy residual demand D' becomes cheaper and cheaper, consumer prices also fall at points which lie to the Southeast of point A on the CC-line.

3.2.2 Effects of a CHP Quota

In this section, the effects of the introduction of a quota for CHP-E are firstly analysed. Secondly, the effects are explored when a quota for CHP-E and a quota for RES-E are introduced simultaneously.

In principle, the analysis is very similar to the analyses for TGCs. When introducing a quota for CHP-E (K_{CHP}), the power market is separated into a market for CHP-E on the one hand and into a market for conventional electricity on the other hand. The effects of the introduction of a quota on CHP-E are illustrated in Figure 3.12. For simplicity, assume – as before – that total demand for electricity is totally inelastic and can be displayed by a vertical line. Also assume that without any policy intervention, the entire market is supplied by conventional electricity, i.e., CHP-E, which is represented by the dotted line in Figure 3.12, is too expensive. In Figure 3.12, the equilibrium power price for consumers and producers is given by P_e .

Now, when the quota for CHP is introduced, the market is split and residual demand for conventional electricity is given in Figure 3.13 by D', where D' = D – ($K_{CHP}Q_T$). In the new equilibrium, the production of conventional power will be lower by an amount corresponding exactly to the quota for CHP-E which is $K_{CHP}Q_T$. The price, which producers of conventional power receive, drops from P_e to P'_e. Producers of CHP-E receive $P'_e + P_{CHP}$. The additional costs for the CHP-E quota are levied on conventional power producers, so that costs for conventional power supply increase by $K_{CHP}P_{CHP}$. In Figure 3.13, this cost increase is reflected in the upward shift of the supply schedule for conventional power from S_{Conv} to S'_{Conv}. The new consumer price is determined at the intersection of residual demand D' and the new supply curve for conventional power. In general, the change in the consumer price is ambiguous, i.e., it can either be higher, the same or lower compared to the electricity price without a CHP-E quota (P_d >=< P_e). For the upward shift in the supply schedule for conventional power in Figure 3.12, the new consumer price for electricity under a CHP-E quota turns out to be lower than in the base case. However, total costs of production will be higher than before, because CHP-E is more expensive than the conventional power, which is substituted by CHP-E.

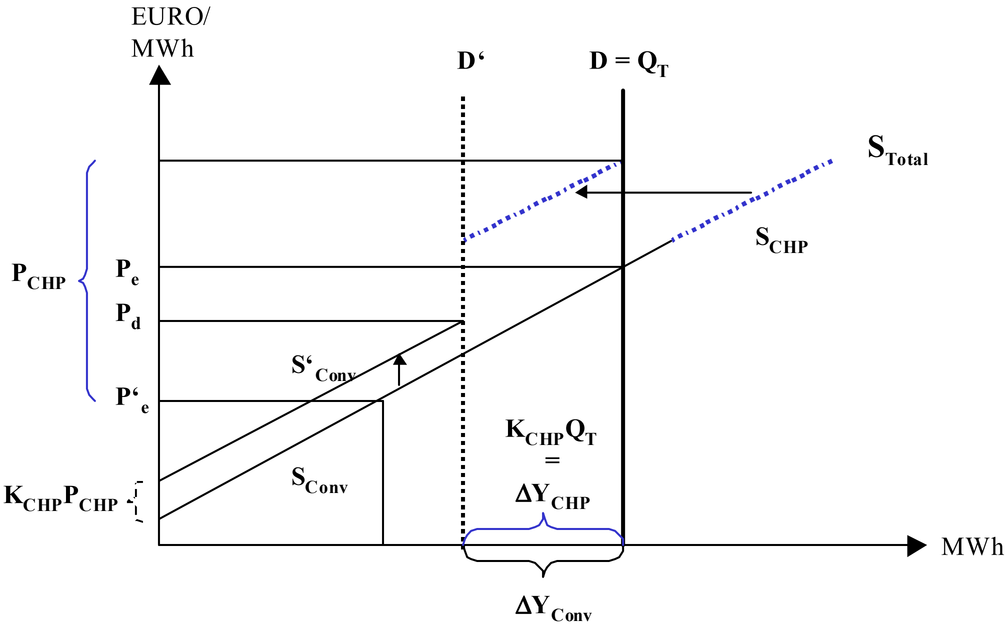

Figure 3.12: Effects of introducing a quota for CHP-E

Now, consider the case where a quota for CHP-E ($K_{CHP}Q_T$) and a quota for RES-E (K_CQ_T) are simultaneously introduced. In Figure 3.13, the residual demand is given by D' where D' = D – ($K_{CHP}Q_T$ + K_CQ_T). The market is split in a market for CHP-E, in a market for RES-E and in a market for conventional electricity production. In the new equilibrium, the production of conventional power will be lower by an amount corresponding exactly to the sum of the quota for CHP-E and for RES-E, i.e., $\Delta Y_{Conv} = K_{CHP}Q_T + K_CQ_T$. The price producers of conventional power receive drops from P_e to P'_e. Producers of CHP-E receive $P'_e + P_{CHP}$ and producers of RES-E receive $P'_e + P_C$. The additional costs for both quotas are levied on conventional power producers, so that costs for conventional power supply increase by $K_{CHP}P_{CHP} + K_CP_C$. In Figure 3.13, this cost increase is reflected in the upward shift of the supply schedule for conventional power from S_{Conv} to S'_{Conv}. The new consumer price is determined at the intersection of residual demand D' and the new supply curve for conventional power S'_{Conv}. In general, the change in the consumer price is ambiguous, i.e., it can either be higher, the same or lower compared to the electricity price without CHP-E and RES-E quotas (P_d >=< P_e). For the upward shift in the supply schedule for conventional power in Figure 3.13, the new consumer price for electricity under simultaneous CHP-E and RES-E quotas turns out to be lower than in the base case. However, total costs of production will be higher than before, because CHP-E and RES-E are more expensive than the conventional power, which is substituted by CHP-E and RES-E.

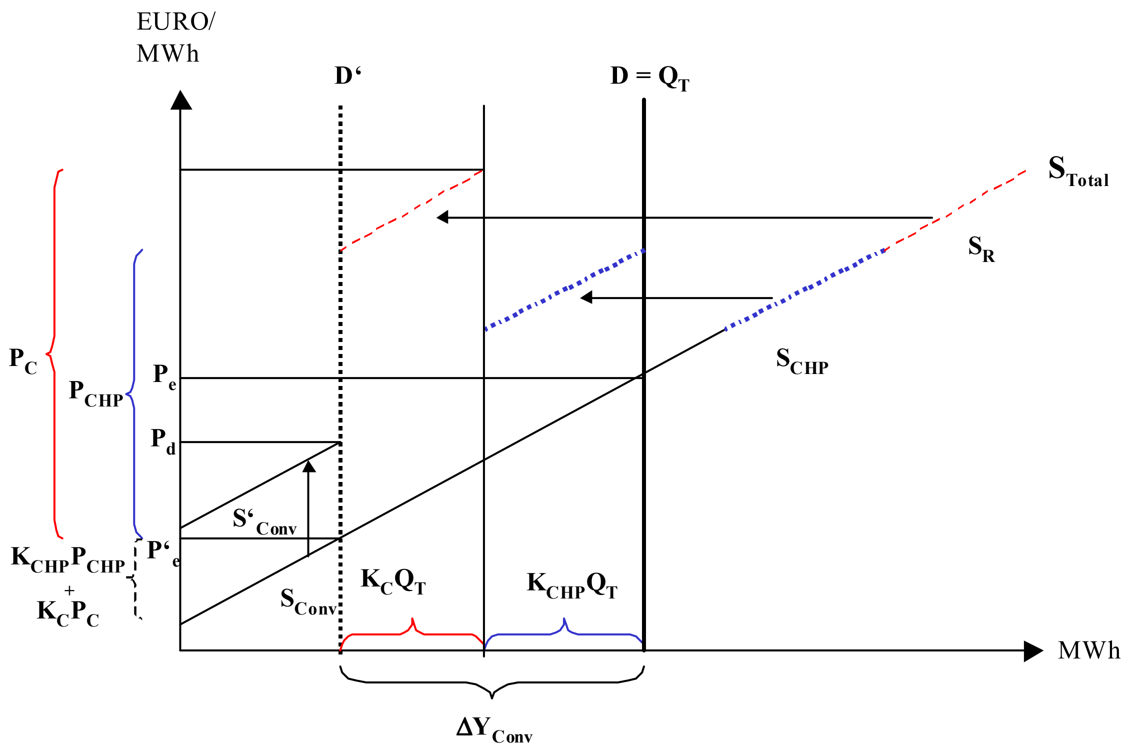

Figure 3.13: Effects of introducing a quota for CHP-E and a quota for RES-E

3.2.3 The Relationship between CHP and TEAs

According to the recent agreement of the EU-Council of Environmental Ministers from December 2002 (EU Council 2003) and the Second Reading of the European Parliament in July 2003, large installations from the energy industry and most other carbon-intensive industries will be part of an EU-wide CO_2 trading system (EU-ETS) commencing 2005. Installations to be covered by the emissions trading system are listed in Annex I of the directive proposal (COM (2001) 581, European Commission 2001b) and include combustion installations with a rated thermal input exceeding 20 MW (excepting hazardous or municipal waste) in the energy sector, mineral oil refineries, coke ovens, large installations in the production and processing of ferrous metals (steel) and the mineral industry (e.g., cement, lime, ceramic products) as well as installations for the production of pulp and paper. Thus, a large number of existing and future CHP plants will be subject to the European Union emissions trading system (EU-ETS).

The EU-ETS is a cap-and-trade allowance trading system and requires companies to submit for cancellation a number of allowances that corresponds to their actual annual CO_2-emissions. At the beginning of each year, participants receive allowances in the so-called primary allocation either for free or they have to buy them through an auction. According to the Parliament Decision, at least 95% of all allowances will be allocated free-of-charge for the years 2005-2007. For the first Kyoto commitment period, i.e., for 2008-2012, 10% may at most be auctioned off. Surplus allowances can be sold or, if allowed, they can be saved for future years. Failure to submit a sufficient amount of allowances results in sanction payments of 100 € per missing ton of CO_2-allowances. For the period 2005–2007, the penalty is only 40 € per missing allowance. In addition, companies have to surrender the missing allowances in the following year.

Whether CHP, which exhibits superior carbon efficiency compared to the separate production of heat and power, benefits from the EU-ETS depends crucially on the primary allocation of emission allowances. The primary allocation of allowances is – according to the subsidiarity principle - left to the individual Member States, which have to develop national allocation plans by the end of March 2004. Annex III of the Directive for the EU-ETS requires that national allocation plans have to specify how they deal with clean – including energy efficient – technologies. In a Position Statement, COGEN Europe fears that the EU-ETS may block the development of a large part of current CHP potentials, in particular, since they face a competitive disadvantage for the generation of heat compared to other systems which are not covered by the EU-ETS, such as small boilers.[22] To support CHP, it is suggested to allocate the number of allowances which would be necessary if heat and power were separately produced in a reference case.[23] If this was the case, CHP plants would receive more allowances than they actually need and could sell the excess allowances at a profit at the (secondary) allowance market.

So, in principle, it may be ambiguous whether CHP will benefit or loose from the planned EU-ETS relative to other power technologies. In Figure 3.14, the case where CHP-E looses from the introduction of a TEA system is displayed.

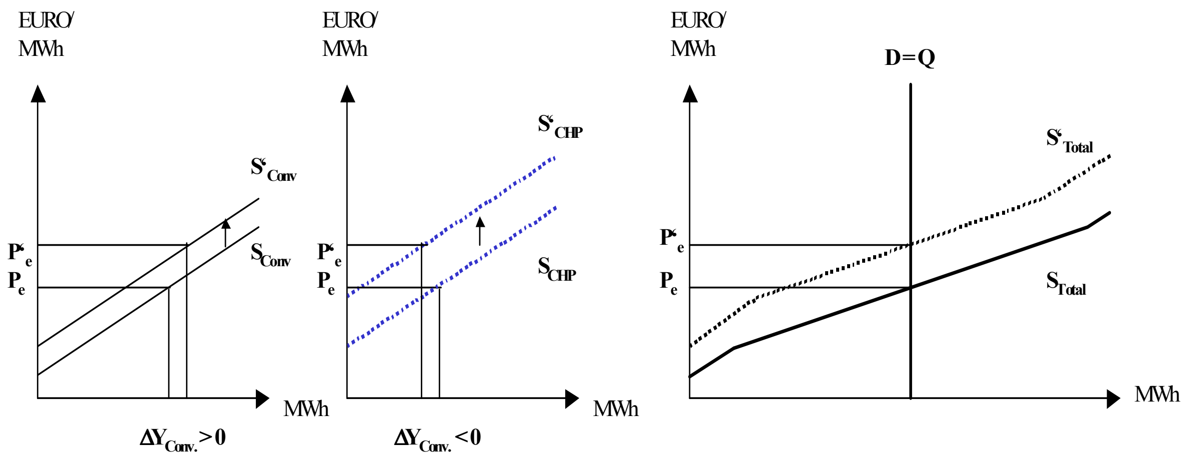

Figure 3.14: Effects of TEAs, when CHP looses compared to conventional power production

The first graph in Figure 3.14 shows the supply of conventional power, the second graph shows the supply of CHP-E and the third graph shows aggregate supply. Without intervention, the (partial) equilibrium market price at the intersection of (vertical) demand D and aggregate supply S_{Total} is p_e, production of conventional power and power from CHP are given at the intersections of the vertical dotted lines and $S_{Conv.}$ and S_{CHP} in the first and second graph in Figure 3.14, respectively. It is assumed that the introduction of a TEA system results in a relatively higher additional marginal costs for CHP-E compared to conventional power supply technologies. Thus, the upward shift in the conventional power supply schedule from $S_{conv.}$ to $S'_{Conv.}$ is smaller than the upward shift in the supply schedule for CHP-E from S_{CHP} to S'_{CHP}. The dotted line in the third graph in Figure 3.13 displays the new aggregate supply curve. Under the TEA system, equilibrium price is higher, conventional power production

[22] See COGEN (2002).

[23] See COGEN (2003).

is higher and power production from CHP is lower compared to the case without a TEA system. Since demand is totally inelastic, the increase in conventional power production corresponds to the decrease in CHP-E.

Since the case where CHP-E benefits from TEAs compared to other electricity production technologies is straightforward (just replace CHP and conventional power in Figure 3.14), it will not be further explored.

3.2.4 Summary

- The introduction of a TGC system where the share of RES-E is based on total electricity production will displace electricity produced from CHP, if CHP is the marginal power producer.
- The introduction of a TGC system, where the share of RES-E is based on conventional electricity production (without CHP-E) the effects on CHP-E are ambiguous. Thus, it is possible that the production of power from CHP will increase in response to the introduction of a TGC system.
- The analysis for the impact of a tradable certificate system for CHP-E alone is similar to the analysis for the TGC system. Similarly, a combination of tradable certificate systems for both RES-E and CHP-E increases RES-E and CHP-E at the expense of conventional power supply.
- The effects of a TEA system on CHP-E will depend crucially on the allocation of allowance. If the cost increase for CHP-E is higher compared to other production technologies, CHP-E will decrease. Likewise, if the cost increase for CHP-E is lower compared to other production technologies, the production of CHP-E will increase.
- Other support schemes for CHP, which could be combined with either TGCs or with TEAs include bonus systems or tradable certificates for CHP may result in an increase of CHP and may increase the production of CHP-E. Qualitatively, the effects of a bonus system would be similar to the analysis presented for the effects of TEAs on CHP, but CHP-E would be given a subsidy and thus, be better off compared to conventional power production.

3.3 The Relationship between DSM and TGCs/TEAs

In this subsection, the interactions of demand side management activities with the national power market and other policy goals such as the promotion of RES-E or the fulfilment of certain GHG-emission targets are investigated. To get a better understanding of the effects on elastic demand, the analysis starts with an investigation of the interaction of DSM measures on the power market and vice versa. Next, the relations between a quota obligation combined with tradable green certificates (TGC) and DSM are analysed, followed by showing the interactions between a feed-in tariff scheme and DSM activities. Finally, the relationships of a tradable emission permit scheme (TEP) with policies reducing the electricity demand are discussed.

3.3.1 Introduction / The Relationship between DSM and the Power Market (Base Case)

In contrast to the investigated cases in the subsectors previously described, it is assumed that customers can react on electricity price changes, i.e., the demand is not fully inelastic.[24] In more detail, two effects will be considered and analysed, which influences the demand (see also the left-hand side of Figure 3.15).

- Short-term price elasticity: The only possibility how costumers can react on the short-term electricity price fluctuations is to change the service level.
- Long-term price elasticity: In the long run, consumers are able to take measures to save electricity by replacing (parts of) their applications and technologies by some consuming less electricity.

Assuming a constant electricity price, in the short-term, no difference between an elastic and an inelastic curve exist. In the case where the electricity price changes, however, demand curve differs. Considering an elastic demand curve, a reduction of the electricity demand takes place if the price rises, and consumption increases assuming a drop in the electricity price by changing the service level. In the long-term, the possibility to shift the demand to the left exists by implementing demand reduction measures. A lower demand leads to a lower electricity price, which is given by the intersection of the demand with the supply curve.

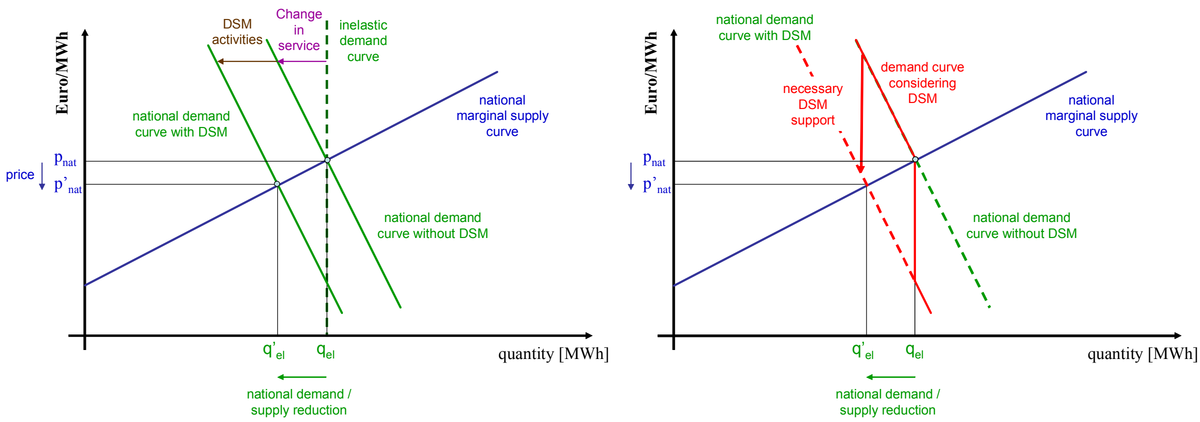

Figure 3.15: Interpretation of the demand curve: Left-hand-side: Schematic composition of the demand curve, right-hand-side: necessary support to impetus additional demand side activities

In practise, only those activities will be implemented, which are economically efficient. This means that the additional costs - per kWh electricity saved - necessary to implement the electricity saving technologies must be lower or at least equal to the (expected) electricity price level. This situation is depicted by the full line on the right-hand-side in Figure 3.15. To motivate consumer implementing, activities with higher specific reduction costs than the current electricity price incentives must be set. This means, by granting a certain (public or private) support demand can be dropped, leading to both a lower total electricity demand and a lower electricity price. In general, a higher price elasticity causes lower DSM costs.

The main general effects of the DSM support scheme within a national electricity system can be summarised as follows: DSM activities leads to

- A lower conventional market price;
- A lower national demand;
- A lower national electricity production;
- Lower national CO_2-emissions.[25]

In the following, the cost effect of demand side activities on both electricity producer and consumer are briefly described. With respect to the customers, a distinction between the group of consumer actually implementing DSM activities and the group of customers not directly implementing demand-side measurement must be made.

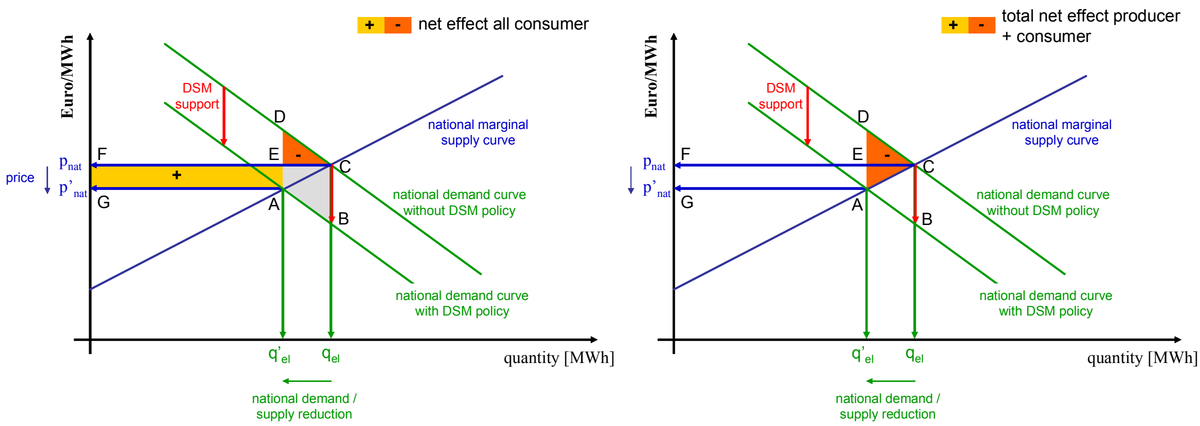

Figure 3.16 Effects of DSM activities on consumer and producer

The first group gains twice from DSM measure: Firstly, they reach the same service output by consuming less electricity and, secondly, due to the reduction of the electricity price.[26] The benefit for those customers not applying DSM measures is ambiguous. On the one hand, they gain from the electricity price drop – from p_{nat} to p'_{nat} in Figure 3.16. On the other hand, they co-finance the DSM support scheme.[27] The net effect for all customers due to DSM can be both, either positive or negative. The total effect depends on the supply and demand characteristic - compare the area [A-E-F-G] with the area [C-D-E] on the left-hand side in Figure 3.16.

[24] An inelastic demand is characterised by a vertical demand curve, see dotted line in Figure 3.15 (left-hand side).

[25] Of course, only under the assumption that the (marginal) substituted power plants are fossil ones.

[26] The total costs for DSM measures are given by the area [q_{el}-C-D- q'_{el}], see left-hand-side in Figure 3.16. The area [A-B-C-D] will be paid by all customers (or tax payers, depending on the support mechanism), hence consumer using DSM measures have to pay an adequate share of the costs ($1-q'_{el}/q_{el}$) of this area [A-B-C-D]. In addition, they have to pay the area [q_{el}-B-A- q'_{el}] by themselves. These costs, however, will be overcompensated by the benefit due to the electricity use, characterised by the area [q_{el}-C-D- q'_{el}] – i.e., the same service level (benefit from the electricity use) is reached applying energy saving technologies. Therefore, the net effect for the customers using DSM activities is given by the area ($1-q'_{el}/q_{el}$) * [A-B-C-D].

[27] The net gain is characterised in Figure 3.16 by the area [A-E-F-G] minus (q'_{el}/q_{el}) * [A-B-C-D].

Considering a national market, the net effects for national electricity generator is negative for two reasons: Firstly, due to the lower electricity demand (from q_{el} to q'_{el}), and, secondly, due to the drop of the electricity price. [28]

The total effect of DSM support measures for both - electricity producer and consumer - is negative. This means that the gains due to lower power price cannot fully compensate for the necessary additional financial support for implementing DSM activities. The welfare-losses are depicted by the triangle [A-C-D], see right-hand-side in Figure 3.16. Of course, this conclusion is only true if and only if external effects from the electricity generation and/or climate change targets are neglected.[29]

3.3.2 The Relationship between a TGC Market and DSM Activities

As already explained in the previous sector, a quota obligation combined with a tradable green certificate (TGC) system leads to a market separation. This situation is depicted in Figure 3.17 for the cases of an inelastic demand (left-hand-side) and an elastic demand (right-hand-side). K_C represents the quota obligation, Q, Q' and Q'' the actual electricity consumption of the different cases.

3.3.2.1 Interactions Inelastic Demand – Quota Obligation

The relationship between an inelastic demand and a TGC system is already discussed in Chapter 3.5.1.[30] The quota obligation splits the total electricity demand (curve) D_T into two parts. An "artificial" demand caused by the quota obligation ($D_R = K_C*Q$) and the remaining electricity demand that will be provided by the electricity spot market ($D_M = D_T - D_R = 1 - K_C*Q$). The effects due to the market separation can be summarised as follows (compare also Chapter 3.5.1).

- The premium price for TGCs (p_C) is characterised by the difference between the marginal generation costs from RES-E generation (S_R) and the power market clearing price (p'_e);
- The spot market price - characterised by p_e in the case of no quota obligation - decreases due to the market separation (from p_e to p'_e);
- The net effect for both, electricity generator and consumer is ambiguous, depending on the net price effect. In the case that $p_e > p''_e$[31], consumer gains from the introduction of a quota obligation. The reason is that the reduction of the conventional electricity price due to the market separation is higher than the additional RES-E costs that occur due to the quota obligation. For the producers, the reverse holds, i.e., they gain in the case that $p_e < p''_e$.

[28] The net losses are given the area [A-C-F-G] in Figure 3.16

[29] Note: A similar result occurs with respect to the promotion of RES-E technologies.

[30] Note: To be compatible with the other figures used in this chapter, a different Figure is used than depicted in Chapter 4.1.

[31] This means that the total electricity price including additional costs due to the RES-E support ($p''_e = p'_e + p_C*K_C$)[31] is lower than the initial power market price p_e.

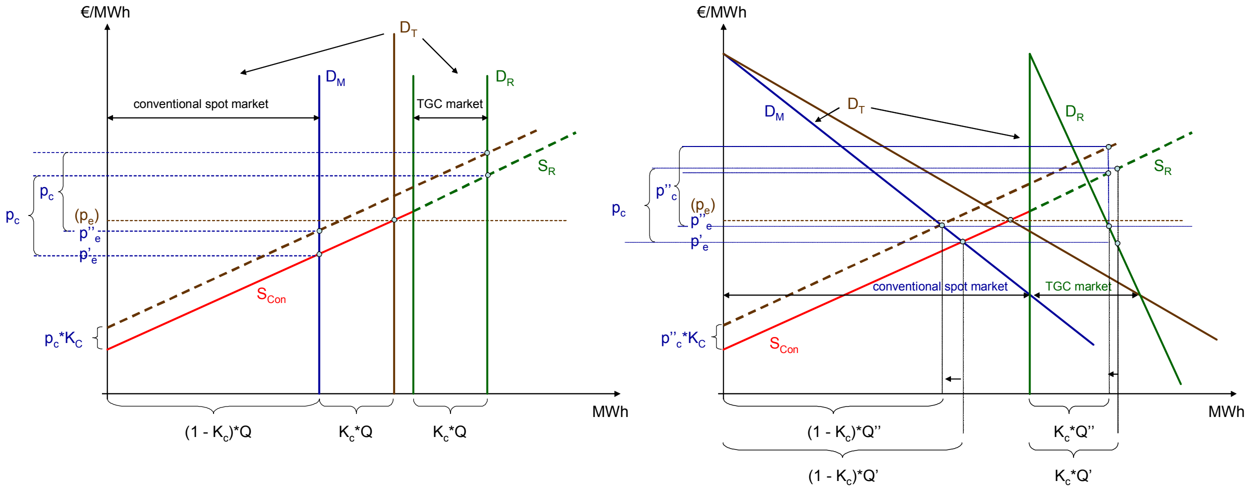

Figure 3.17 Effect of a quota obligation with TGCs on the spot market: left – assuming an inelastic demand, right – assuming an elastic demand

3.3.2.2 Interactions Elastic Demand – Quota Obligation

The interactions of a TGC system and the conventional power market assuming an elastic demand is depicted on the right-hand-side in Figure 3.17. Naturally, the main effects are similar to the case of an inelastic demand. This means that the net effect for both electricity generator and consumer is still ambiguous. Again, consumer gains if the total price (i.e., including additional costs due to the RES-E support) is lower compared to the case of no quota obligation.

However, and in contrast to the case of an inelastic demand, the types used to impose the additional costs on the consumer influence the effects of the TGC system.

- In the case where the additional costs are directly imposed on the electricity price, total electricity demand diminishes.[32] The total national electricity generation drops due to the lower demand. Hence, the total electricity generation from RES-E decreases too, because the ratio between RES-E and conventional power is defined by the quota obligation and is, hence, constant;
- In the case where the additional costs are paid by the public via general taxes and duties, the price signal of the electricity price is ever lower compared to the case of no quota obligation, $p'_e < p_e$.[33] The lower market price leads to a higher electricity demand and, hence, to a higher electricity generation from both conventional power and RES-E.

In other words, if the additional costs are not directly imposed on the electricity price, the total amount of RES-E generation increases. The conventional electricity production, and hence, the CO_2-emissions rises too.[34]

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[32] The additional costs are determined by the TGC price times the amount of the quota obligation, $p_C^{('')} * K_C$, see Figure 3.17. The final electricity price is characterised by p''_e

[33] Under these conditions, however, the lower (spot market) electricity price reflects not all costs for electricity generation.

[34] In addition, the following additional effects compared to an inelastic demand curve exist, assuming a lower (higher) total price $p''_e < (>) p_e$.

- Total demand increases (decrease) due to the lower (higher) electricity price;

3.3.2.3 Interactions Elastic Demand - Quota Obligation – DSM Measures

The situation where a DSM support is introduced in addition to a TGC scheme is depicted in Figure 3.18.

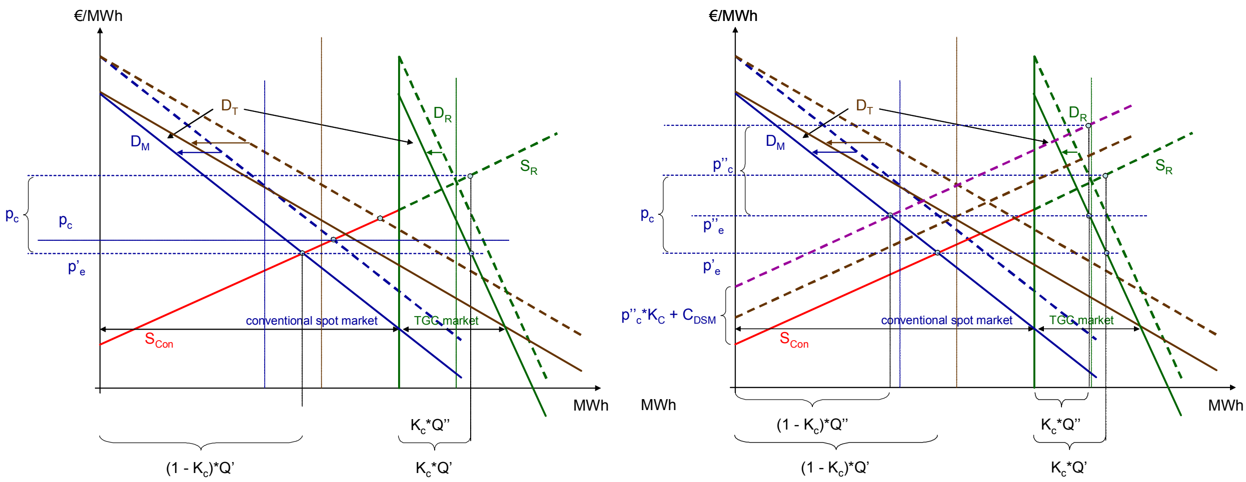

Figure 3.18 Interactions of a quota obligation with TGCs with DSM measures and the spot market: left – additional costs are not imposed on the electricity price, right – the electricity price reflects the additional costs due the policy schemes

The interactions between DSM measures, a quota obligation for RES-E and a national electricity market can be summarised as follows:

- DSM activities reduce the demand for conventional power and the demand for TGCs and hence, RES-E generation. High and effective DSM measures leads to a drop in the electricity generation. Besides this direct demand effect due to an active DSM policy, an indirect demand effect can be used. Namely, if all costs are directly imposed on the electricity price, demand diminishes due to the rise of the electricity price; see right-hand side in Figure 3.18.[35] In this case, DSM policy not only causes a reduction of the electricity demand due to long-term demand-side measures, but also causes a short-term reaction in service due to the change in the electricity price.
- It is ambiguous if the DSM activities in combination with the TGC system lead to lower total costs for the consumer or not. In the case where the additional costs caused by the DSM activities overcompensates the gains from the lower electricity price due to the demand reduction (DMS measures), consumer (not implementing the measures) looses.
- Producer ever looses from the introduction of the DSM policy - independently whether a RES-E quota exists or not - due to the lower electricity demand.

- The higher (lower) demand must be compensated by a higher (lower) national electricity generation. Hence, the total electricity generation from both RES-E and conventional power rises (drops). The share between RES-E and conventional power remains unreflected, as it is given by the quota obligation;
- A higher (lower) conventional electricity production ends in higher (lower) CO_2-emissions compared to the case of an inelastic demand curve.

[35]This means that the costs for both the TGC and the DSM measures will not be paid by (all) tax-payers without direct price-signal on the consumer. Compare previous subsection.

- The total national electricity generation drops due to the lower demand. Hence, the total electricity generation from RES-E decreases too. The reason is that the share between RES-E and conventional power is fix coupled by the quota obligation.
- A lower conventional electricity production causes less CO_2-emissions.
- The TGC price increases compared to the case of no DSM, i.e., $p''_C > p_C$. The reason is that due to the lower total conventional electricity generation, the economic efficiency of new RES-E technologies will be reduced, i.e., the gap between the conventional generation costs and RES-E costs increases. [36]

3.3.3 The Relationship between a Feed-In Tariff Scheme and DSM Activities

In the following, the interactions of an elastic demand with a feed-in tariff scheme and both a feed-in tariff scheme and DSM activities are analysed. The effects are schematically depicted in Figure 3.19.

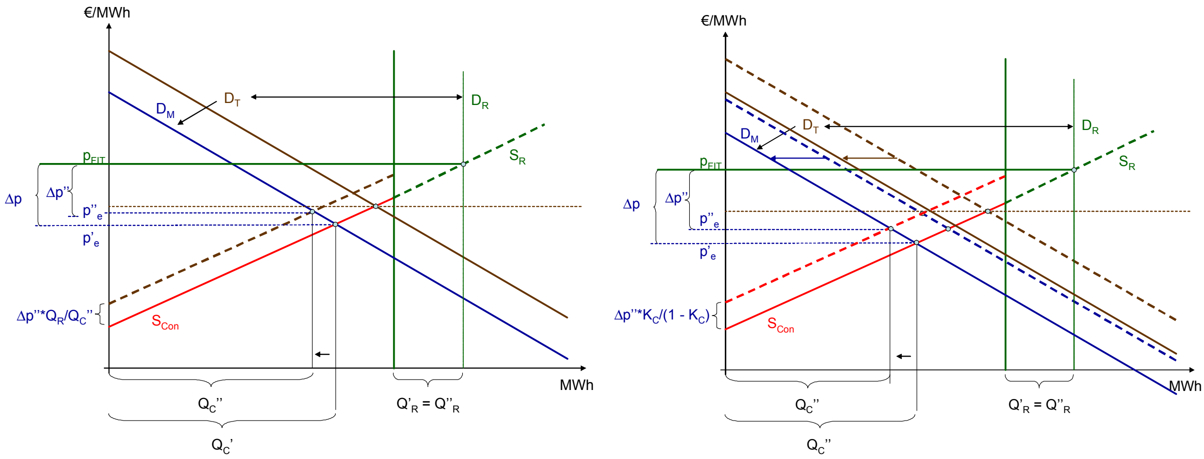

Figure 3.19 Interactions of a feed-in tariff for RES-E with a conventional power market: left – assuming an elastic demand, right – assuming an elastic demand plus DSM measures

3.3.3.1 Interactions Elastic Demand – Feed-In Tariff

Similar to the case of a quota obligation, a feed-in tariff scheme leads to a market separation; a protected market for RES-E and a remaining market for conventional (and not supported RES-E technologies) power occurs. As the feed-in tariff scheme, however, primarily affects the supply and not the demand, the amount of the RES-E demand is independent from the total electricity demand.[37] In other words, in contrast to the quota obligation, the RES-E support schemes split the market in two independent parts; a constant RES-E part and a spot power market, fully reflecting the given price elasticity. The consequences of the introduction of a feed-in tariff scheme are (compare also subsection 3.5.1):

[36] Assuming a linear demand curve, this is true as long as the quota obligation is less the 50%.

[37] Of course, only under the assumption that the share of RES-E is still lower than the total electricity demand, i.e., the total demand is higher than the RES-E supply.

- The RES-E demand depends only on the level of the guaranteed price – a high feed-in tariff entails a high demand.
- The demand for conventional power is more elastic than in the case of a quota obligation, due to the inelastic RES-E demand. Hence, the conventional power generation reacts more sensitive on price changes.
- Under the assumption that the additional costs are directly imposed on the electricity price, a change to the quota system occurs. Under a feed-in tariff regime, the additional cost can only be imposed on the spot market. Hence, the conventional power price increases more rapidly, leading to a higher demand decrease compared to a quota obligation[38].
- The net effect for both the consumer and the producer is ambiguous. In the case of lower total costs (= electricity costs plus additional costs due to the feed-in tariff) compared to the situation without RES-E support, consumer gains, and under the conditions of higher total costs, electricity producer profits from the introduction of a feed-in tariff scheme.

3.3.3.2 Interactions Elastic Demand – Feed-In Tariff – DSM Measures

If DSM measures are supported in combination with a feed-in tariff scheme the following effects exist:

- DSM activities fully reduce the conventional power generation. The reason is that the RES-E is only determined by the level of the feed-in tariff system, i.e., demand for RES-E is independent from the conventional electricity demand;
- Due to the reduction of the conventional power generation, the CO_2-emissions also drops (and more compared to the situation of a quota obligation);
- Similar to the case of a quota obligation, the net effect for the consumer is ambiguous;
- Producers lose from the introduction of a DSM policy.

3.3.4 The Relationship between a TEP Permit and DSM Activities

As already discussed in subsection 3.5.1. a CO_2 cap system combined with tradable emission permits (TEP) is an effective instrument to reduce CO_2-emissions in a cost-efficient way. When introducing a cap and trade system, costs for fossil electricity generation increase. Hence, due to the CO_2-free electricity production, such a system favours RES-E generation compared to conventional fossil power. In more detail, the specific CO_2-emissions of the electricity production must be considered in the generation costs. More CO_2-emitting plants (e.g., coal fired plants) entail higher premium costs than less CO_2-emitting plants (e.g., gas fired plants). The CO_2-premium costs are schematically depicted in Figure 3.20 by ΔpCO_2.

[38] The additional costs in the case of a feed-in tariff are determined by $\Delta p_C * Q_R/Q_C$, compared to $\Delta p_C * Q_R/(Q_C + Q_R)$ in the case of a quota obligation.

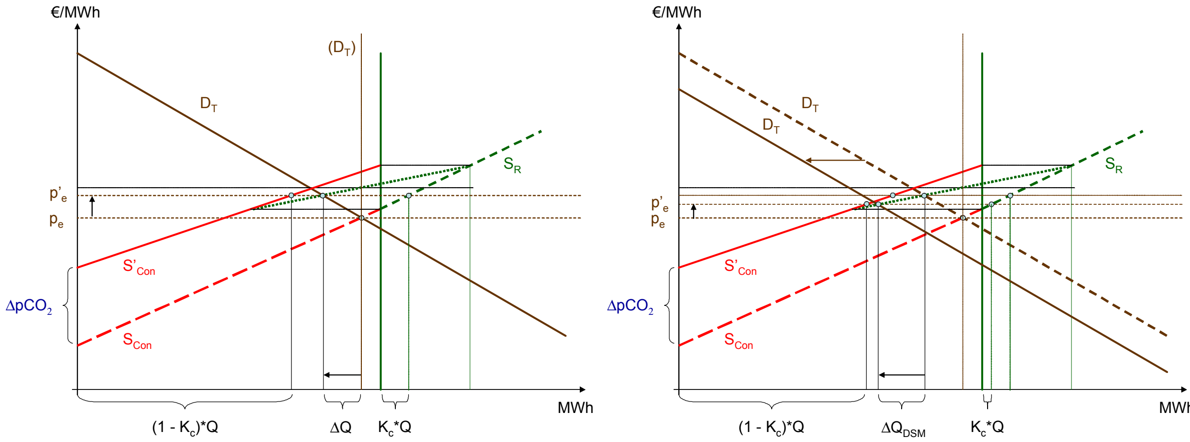

Figure 3.20 Interactions of a tradable emission permit scheme with a conventional power market and the RES-E deployment: left – assuming an elastic demand, right – assuming an elastic demand plus DSM measures

The consequences of the introduction of a TEP system, and hence of higher marginal conventional generation costs are:

- The cost efficiency of RES-E power production increases relatively;
- The amount of RES-E generation rise;[39]
- The power price increases;[40]
- If the price elasticity is high, the consumer reacts on the higher electricity price with a large reduction of the electricity demand. Due to the demand reduction, less conventional power must be used. This leads to a less scarcity of CO_2 and, hence, to a lower TEP price compared to the case of a less price sensitive demand. The lower TEP price, however, favours conventional power, so the share of RES-E drops too;
- As consumers are confronted with higher electricity prices, they generally loose (economically) due to the introduction of a TEP system;
- The situation whether the producer gains or looses due to the cap and trade system depends on the marginal conditions;
- CO_2-emission drops – they reach per definition the CO_2-level of the cap, (assuming that the penalty that has to be paid in the case of non-fulfilling the cap is greater than the TEP price);
- The marginal generation plants consist – in dependency of the CO_2-level – of a portfolio of fossil and RES-E power plants (see Figure 3.20). By introducing a DSM support scheme, the total electricity demand drops. Therefore, the marginal power plants (without DSM) will not produce electricity.[41] This means that DSM systems hinder the penetration of RES-E, because they will reduce

39 In the graphical illustration (Figure 3.20), the level Q will be reached.

40 In Figure 3.20 from p_e to p'_e.

41 More precisely, the marginal power plants will not be built in case the plants are still not implemented. Note, assuming that all plants are already built, a quite different situation occurs, because the STMC of RES-E plants are normally lower compared to fossil plants.

the CO_2-emission level, and, therefore, the requirement to shift a CO_2-less or CO_2-free electricity generation;

- TEP price drops by applying a DSM policy due to the lower demand and, hence, due to the less pressure to reach the CO_2-target.

3.3.5 Summary

Assuming a price-elastic power demand the use of DSM-activities can have significant impacts on power prices and thus on RES-E capacity development when different support instruments are introduced. DSM activities reduce both the demand for conventional power and the demand for TGCs and therefore also the demand for RES-E produced power if a green quota related to the power consumption determines this demand. Thereby, it is ambiguous if the DSM activities in combination with the TGC system lead to lower total costs for the consumer or not. In the case of a feed-in tariff scheme, the amount of RES-E generation retains unaffected from the introduction of a DSM policy

4 The EU/International Level of Interactions

4.1 National and international spot and TGC-markets

In Chapter 3.1 the effect of introducing a TGC system in closed markets was discussed, i.e. with national power and TGC markets. The introduction of a TGC system implies that priority is given to a certain amount of produced RES-E. This amount is measured as a share, $K_c\ Q$, of the total electricity demand. In a closed national system without import or export of power, this implies that an equivalent share of conventional power is forced out of the market. The power price that is determined at the conventional power market decreases from p_e to p'_e. This is illustrated in Figure 4.1 below.

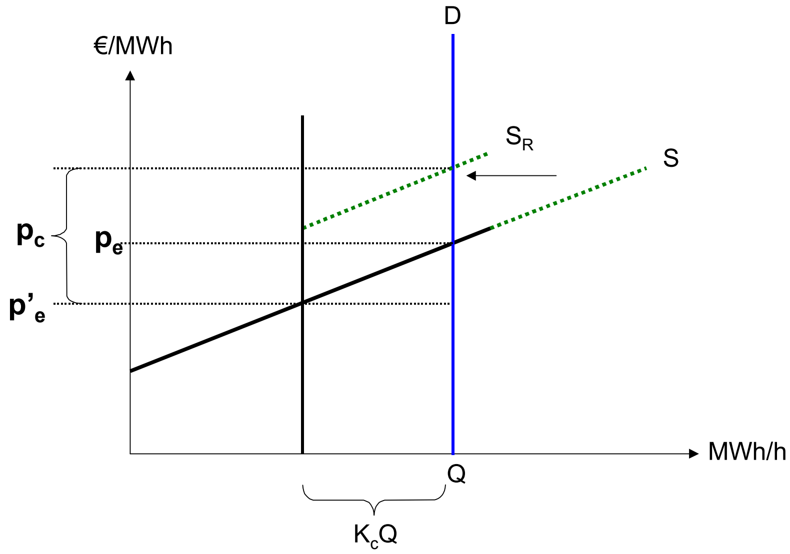

Figure 4.1 National TGC market and a national spot market

A lowering of the power price counteracted the introduction of a positive TGC price in away that the total effect on the consumer price, $p'_e + K_c\ p_c$, was ambiguous. It is interesting to see if this is only the case when we look at national markets. Therefore, this chapter extends the discussions from Chapter 3.1 to cover international markets.

If the national case is one extreme case, the other extreme case is when a small country acts on an international market and a national market for power and TGCs, respectively.

The later implies to two sub-cases:

A: Small country with international spot market and national certificate market.

B: Small country with national spot market and international certificate market.

Cases A and B are the cases where the largest effect will be seen. All other combinations of market openness and size of the countries can be found as a combination of these two cases and the national case.

If both the power and TGC markets are international markets, we will have the same effect as if we had one big national market.

An international TGC market can also be interpreted as an international fixed support price, e.g., a feed-in tariff, which is given in addition to the power price.

4.1.1 A: Small Country with International Spot Market and National Certificate Market

With a small country at an international power market, it can be assumed that the power price at the international market is unaffected by the power supply from the small country. In other words, we assume that the power price, p_e, is exogenously given at the national power market in the small country. We also assume that there is a small export, E, of power from the small country, i.e., the national marginal supply cost is lower than the international spot price at the national demand. This is illustrated below in Figure 4.2.

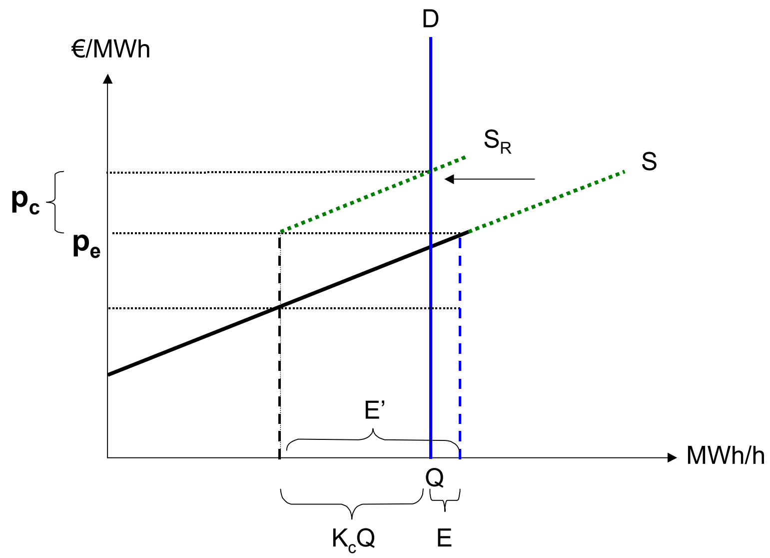

Figure 4.2 National TGC market and an international spot market (exogenous power price)

When a national TGC system is introduced, a certain share, K_cQ, of the national demand will be covered by the TGC system. Since the power price is determined at the international market, the power price is unaffected. This implies that the small country can export more – from E, without the TGC system, to E', with a TGC system.

The TGC price is determined according to the international power price, i.e., the TGC price, p_c, is equal to the marginal cost of RES-E minus the power price, p_e.

Since the power price is unaffected, the consumer price, $p_e + K_c p_c$, is higher than before the TGC system was introduced where the consumer price was equal to the power price, p_e.

Table 4.1: Comparative static effects on the power and consumer prices

	Power Price	Consumer Price	Export of Power	Export of TGC
Green certificate	0	+	+	0

4.1.2 B: Small country with national spot market and international certificate market.

The effect of introducing a TGC system changes, if we instead assume that the power price is determined at a national market for physical power, and the TGC can be traded at an international TGC market. This is the case for islands or other regions that are not connected with a physical grid, or which have a limited transmission capacity of power.

If the TGC price is determined at an international market, it is given exogenously to the small country, i.e., independently of green quota, K_cQ, and the RES-E marginal cost in the country. Introducing an exogenous TGC price, p_c, will give priority to some part of the RES-E supply and thereby displace the same amount of conventional produced power at the national power market. This is illustrated in Figure 4.3 below.

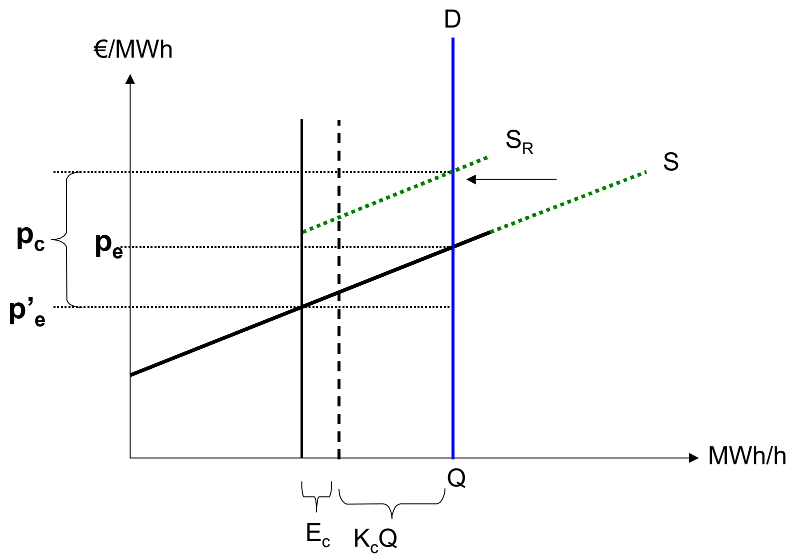

Figure 4.3 International TGC market and a national spot market (exogenous TGC price)

Since the power market is a national market, no import or export of physical power is permitted. Therefore, displacement of conventional power with RES-E will lower the national power price – from p_e to p'_e. The new power price, p'_e, plus the TGC price, p_c, determines how much RES-E that is produced in the country.

Export of TGCs is seen when the payment to the RES-E producers, p_e' + p_c, is larger than it would have been with a national TGC market, i.e., when the marginal supply cost of RES-E at the green quota is equal to the payment. There will be an export of TGCs if there is a higher national production of RES-E than the quota, K_cQ. This is illustrated with E_c in the figure. In this case, introducing an international TGC market implies a lower power price and a higher national RES-E production than in the case of a national TGC market. Since the power price is lower, then the certificate price is higher in the case with export compared to a case without international TGC markets or to the case with import.

Likewise, there will be an import of TGCs if there is a lower national production of RES-E than the quota, K_cQ. This would lead to *less* decrease in the power price and *less* national RES-E production than in the case of a national TGC market.

Since the power price is reduced in both the exporting and importing cases, the consumer price, p_e+ $K_c\ p_c$, can either be higher or lower than before the TGC system was introduced where the consumer price was equal to the power price, p_e. This is similar to the case with national power and TGC markets.

Table 4.2: Comparative static effects on the power and consumer prices

	Power Price	Consumer Price	Export of Power	Export of TGC
Green certificate	–	?	0	?

4.2 The Relationship between TGCs, TEAs and DSM Activities on International Level

The effects of introducing a tradable emission allowance (TEA) system in a national system were discussed in Section 3.1.5. This is summarised in Figure 4.4 below. In this section, the discussion is extended to deal with international systems and interaction with the other instruments.

The levels of the allowance price will most likely differ if the price is determined at a national allowance market compared to being determined at an international allowance market. However, it does not matter if the allowance market is national or international, as long as the power price is determined at a *national* spot market. The effect at the power price is the same; a positive allowance price increases the supply cost, which implies a higher market price at the spot market.

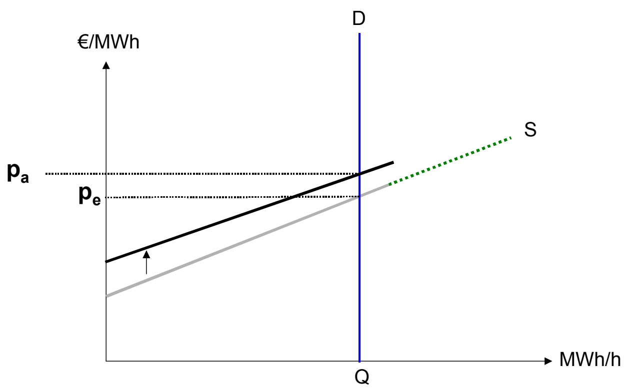

Figure 4.4 Change in prices when introducing a TEA system at a national spot market

The effect of introducing a TEA market is different when we look at a small country with international spot market and national allowance market. In this case, the power price will be given exogenously to the small country, and introducing a TEA in the country will not effect the power price. This is illustrated in Figure 4.5 below.

In the figure, it is assumed that the country has a small export before the TEA system is introduced. In other words, it is assumed that the marginal supply cost of power to cover the national demand, Q, is lower than the international given power price, p_e.

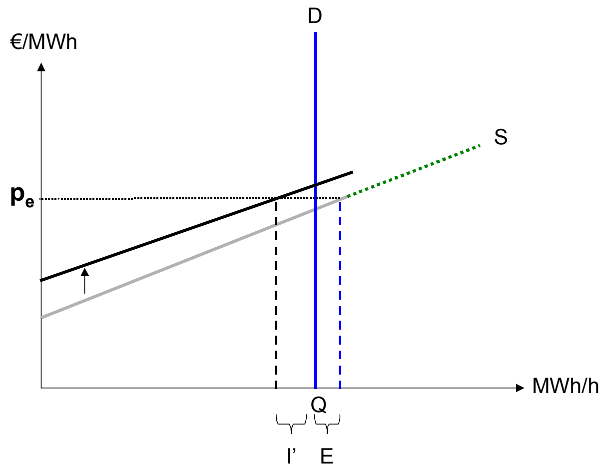

Figure 4.5 National allowance market and an international spot market (exogenous power price)

When the TEA system is introduced, the supply cost increases for thermal power. In the figure, it is assumed that the marginal supply cost to cover the national demand, Q, becomes higher than the international given power price, p_e. Thereby, the little country will become importer of power, compared to the export situation before the TEA system was introduced.

Table 4.3: Comparative static effects on prices and power export of introducing TEA

	Power price	Consumer price	Export of power
National spot	+	+	0
International spot	0	0	–

In general, introduction of a national TEA system will lower the international competitiveness of the thermal power supply sector in the small country.

4.2.1 Introducing TGC and TEA Systems Simultaneously

We now turn our attention to looking at an introduction of both TGC and TEA systems simultaneously. TGC and TEA prices are negatively correlated. Figure 4.6 below illustrates the effect in national systems. A large green quota, K_c, implies that an equivalent share of conventional power is forced out of the market. This should imply a lowering of the power price. However, the introduction of TEAs might counteract this. Therefore, the effects on power and consumer prices are ambiguous.

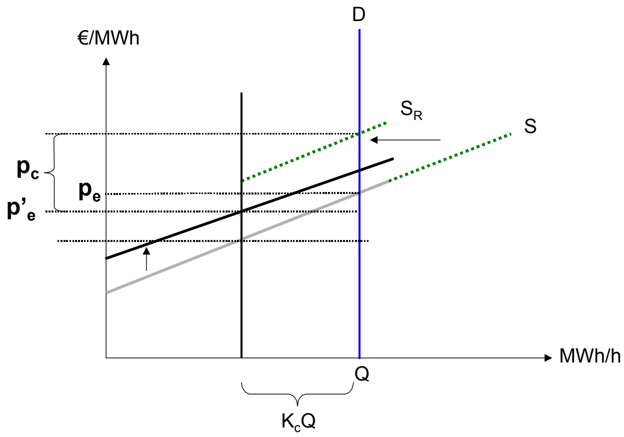

Figure 4.6 Change in prices when introducing national TGC and TEA systems at a national spot market

This might not be the case in an international system. In order to analyse this, we look at two cases for a small country. The cases are defined as in the previous section:

A: Small country with international spot market and national certificate market.

B: Small country with national spot market and international certificate market.

4.2.2 A: Small Country with International Spot Market and National Certificate Market

With a determination of the power price at an international spot market for power exchange, the power price is exogenously given to the small country. Therefore, introducing national TEAs increases the production cost, but do not influence the power price. Likewise, introducing national TGCs do not influence the power price. This is illustrated in Figure 4.7 below.

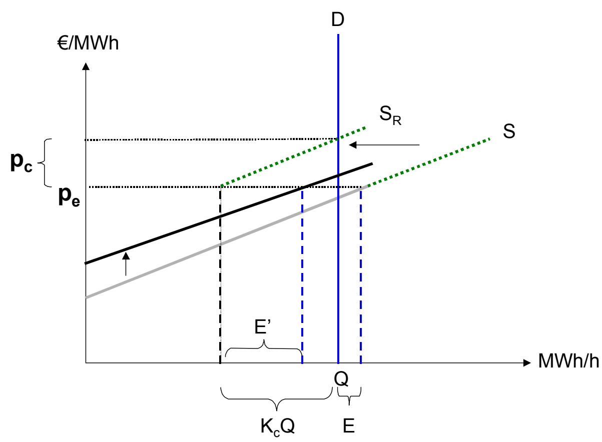

Figure 4.7 Change in prices when introducing national TGC and TEA systems at an international spot market

In order to illustrate the effects on export of power, it is assumed that there is a small export, *E*, before the introduction of the national TGC and TEA systems.

When introducing the TGC system, the national demand for conventional power is reduced to $(1 - K_C)Q$. Without an introduction of a TEA system, the export of conventional power would increase. However, the increase in export is limited due to the increase in production costs. In Figure 4.7 an increase from *E* to *E'* is illustrated. Import of power is seen, if the marginal production cost becomes higher than the international power price at $(1 - K_C)Q$. Therefore, the effect of simultaneously introduction of TEA and TGC systems is ambiguous.

The effects at the different prices and export are summarised in Table 4.4 below.

4.2.3 B: Small Country with National Spot Market and International Certificate Market

The introduction of TEA and TGC systems influence the power price when the spot market is national. The international determined TEA and TGC prices are both helping the RES-E deployment. This also implies that a larger export of TGCs is seen than in the case without a TEA market. This is illustrated in Figure 4.8.

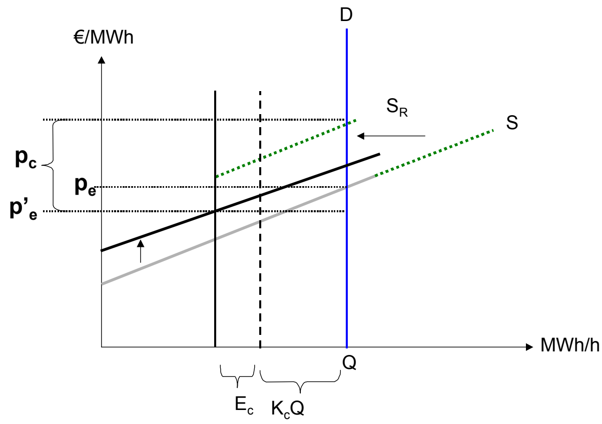

Figure 4.8 Change in prices when introducing international TGC and TEA systems at a national spot market

In the figure, it is assumed that a TGC amount corresponding to E_C of the national power demand, *Q*, is exported after the introduction of the TEA and TGC systems. The total amount of RES-E production, $E_C + K_CQ$, is a result of both an increased production cost for conventional power and the TGC price.

As can be seen from the above discussions, the two cases, A and B, differ with respect to the effect of introducing TGC and TEA systems simultaneously. This is summarised in Table 4.4.

Table 4.4: Comparative static effects on the prices and export

	Power Price	Consumer Price	Export of Power	Export of TGC	Export of TEA
National	?	?	..	..	..
Case A	0	+	?	..	..
Case B	?	?	..	?	?

4.2.4 Introduction / The Relationship between DSM and the International Power Market (Base Case)

In the following, the effects of DSM support measures on a liberalised electricity market are analysed.

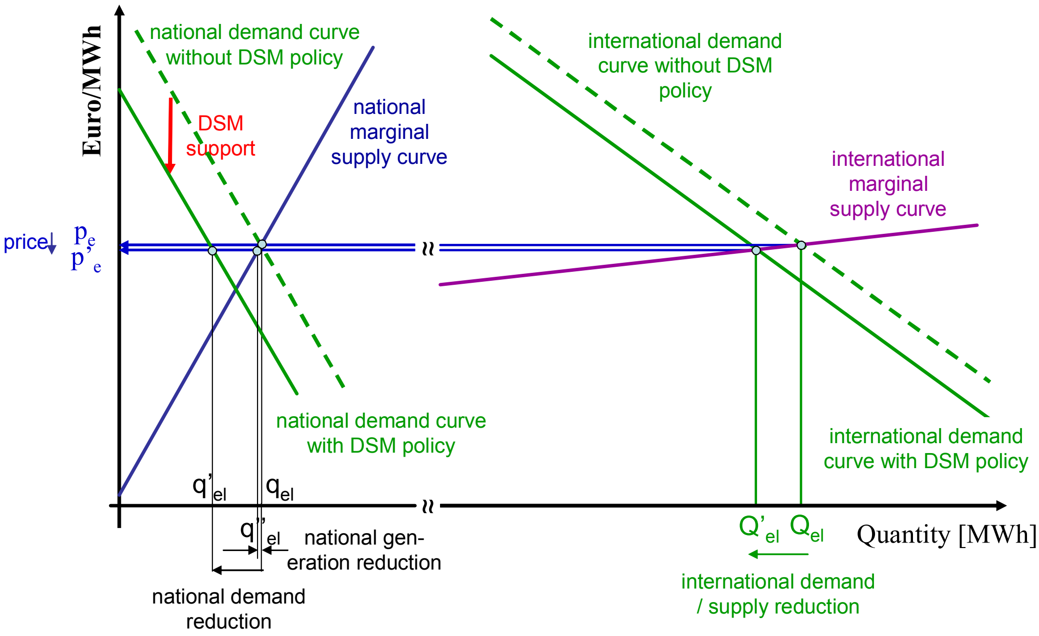

Figure 4.9: Interactions of DSM measures with an international power market

The interactions between national DSM activities and an international power market are depicted in Figure 4.9. Quite different consequences of DSM compared to a national market occur.

- The reduction of the international (and hence national) power market price is low, especially if DSM measures are only implemented in (some) small countries. The reason is that the international supply curve is flat compared to the national one (see Figure 4.9. This means that the demand reduction has less influence on the price structure;
- A higher national demand reduction occurs compared with the case of a national power market assuming the same financial support. The reason is that the lower power price reduction leads to less additional demand due to the price elasticity (=> higher service level, general rebound effect);
- National electricity production will be reduced only slightly compared to the case of a national market, i.e. the reduction of the national electricity generation is lower than the national demand reduction (see Figure 4.9. Hence, the share of exporting electricity increases and the share of importing electricity from abroad decreases, respectively. The reason is that the actual electricity generation in one country depends totally on the marginal electricity conditions at the spot market

and not on the distribution of the national demand relations; DSM measures have only little effects on national electricity generation;

- An international market leads to less national CO_2-reductions in the country implementing the DSM measures compared to the case of a national market. The actual reduction depends on the marginal conditions of the electricity generation structure. Hence, DSM measures are no adequate policy for national CO_2-reduction;
- On international level, however, CO_2-reduction takes place, most (or at least some) CO_2-reduction occurs in countries not initiating a demand reduction policy;
- Effects in the country implementing DSM activities are: consumers actually implementing the measure can gain, but can also loose; the actual effect depends on the share of the additional expenditures necessary to implement the measures; consumers not implementing the measure loose; the loss is higher than having a national power market, because the power price reduction is lower; the electricity generators loose compared to no activities, but gain compared to a national market. The reasons are, firstly, the power price remains higher, and, secondly, the national production level is higher (share of export increases);
- Effects in the country not implementing DSM activities are: all consumers abroad gain from the expenditures made in the country implementing the DSM activities. This means that this country subsidises the consumers in all other countries due to the (slight) lower power price; all producers loose a little due to the slight power price reduction.

From the national climate change perspective as well as from the consumer's point-of-view, a national power market is preferable compared to an international one. In practice, existing import/export restrictions lead to higher gains for the consumer and the national environment. In a liberalised market, DSM measures should be harmonised on an international level. Table 4.5 compares the effects of a national versus an international power market.

Table 4.5: Comparison of preferences national versus international power market:

Group	***National Power Market***	***International Power Market***
Consumer using DSM measurement	Indifferent - slightly favourite	
Consumer not using DSM measurement	Favourite	
All customers	Favourite	
Electricity producer		Favourite
Electricity producer and consumer		Favourite
Demand reduction		Favourite

4.3 Summary

In this chapter different RES-E support schemes, an emissions trading scheme and DSM have been analysed and discussed in an international context and the following results have been achieved.

Introducing an EU-wide TGC market will have the following effects:

- An international TGC-scheme will ensure that the RES-E deployment is made at locations where it is most efficient and profitable.
- The total conventional power demand is reduced according to the total green quota at EU level. The power price is reduced accordingly. If there is an EU-wide TGC market, the TGC price reflects the marginal RES-E production cost.
- As in a national system the development of RES-E technologies will lead to lower prices at the power spot market, assuming an increasing marginal supply costs for the conventional power plants and no market power.
- Even though the power price is determined at a common power market, the effect on consumer prices might differ between the Member States since the green quotas differ. Consumers in Member States with a relative small green quota, will enjoy the benefit of the decrease in the power price and only experience low extra costs of buying TGCs. Consumers in Member States with a relative large green quota, will also enjoy decreasing power prices, but will have a larger share of the TGCs price included in the consumer price. Therefore, it is likely, that the introduction of an EU-wide TGC market will lead to a reduction of consumer prices in Member States with small green quotas, and vice versa in Member States with large green quotas, i.e. the consumer prices will increase in these countries. Note that an equal burden sharing, that is the same relative quota in all countries, will lead to the same consumer price in all countries.

As for the national part, the effects of an international introduction of an EU-wide TEA is more straightforward than an international TGC-market, although some effects are ambiguous:

- The price at the power spot market will unambiguously increase because of the cost of reducing CO_2-emissions. The supply curve for power will be shifted upwards corresponding to the marginal costs of CO_2-reductions, that is the emission allowance price. The resulting increase in the power price will depend on the price elasticity of power demand.
- The new and higher level of the consumer price of power will be the same for all consumers within the liberalised power market.
- The higher spot price will induce a development of RES-E technologies in all countries, although RES-E will not be specifically favoured compared to other CO_2-reduction technologies. RES-E and conventional power production will be developed, where it is most efficient.

Pursuing an active national DSM policy in an international power market leads to less price reduction (especially if it is a small country). The national electricity generation decreases less than the demand reduction, as parts of the “free” electricity capacity will be used for exporting power. Hence, only parts of the CO_2-emission reductions due to the DSM activities remain in the country. Consumers in this country subsidies the consumers in all other countries due to the (slightly) lower power price.

Introducing an international TGC-system in addition to an international TEA-scheme will normally work out well, since the TGC’s be complimentary to the TEA’s. The TGC-system will favour the development of RES-E compared to other CO_2-reduction options, though the TGC-price will be lower than in a solitude TGC-system. But the pros and cons of the separate international TGC-scheme will still exist, although a strong coordination of the use of the two instruments will moderate the disadvantage of the emission reduction sharing of the TGC-system.

5 Modelling Analyses of Interactions

In this chapter, interactions are analysed applying a small medium to long-term model that includes a fully developed spot market for power and markets for international emission trading and green certificates. To analyse the international interactions between these three markets a small partial model is set up for four countries. In more detail, three important issues with respect to the integration of different renewable energy sources into the liberalised conventional electricity market and the international condition of GHG-reduction are investigated.

First, it will be analysed how most important promotion schemes for different renewable energy technologies for electricity generation – namely feed-in tariffs and quota systems with tradable green certificates - interact with the liberalised conventional electricity market.
Second, the linkage of different CO_2-targets with and the effects of the allocation of the corresponding tradable emission allowances on the liberalised power market will be investigated.
Third, the interactions of RES-E, conventional electricity generation and GHG-reduction with the three markets, for physical power, tradable green certificates and GHG emission allowances will be investigated, i.e., it will be evaluated how new environmental markets, such as an international market for GHG emission allowances may affect or overlap with the promotion of RES-E.

In the analysis, special concern is given in working out the consequences for the national GHG-reduction policy as well as the costs for the consumer pursuing the achievement of the goals. To facilitate the understanding, the investigation will be illustrated by a four countries/utilities example.

5.1 Model Assumptions and Conditions set in the Numerical Example

Before the interactions of different policies can be investigated, the main assumptions of the model are described. It is assumed that the following three general conditions are fulfilled.

- All considered countries have entrance to the same physical electricity market. In addition, there are no barriers for export/import of electricity between the countries.
- In the case of import/export of electricity GHG-emission adjustments are taken place.
- Electricity consumption is assumed to be constant and do not depend on the price level, i.e., the price-elasticity is zero.[42]

As already mentioned above, a numerical example considering four countries will be used to illustrate the consequences of a certain policy on both national and international level.[43] Used specifications with respect to the generation costs and the specific CO_2-emissions are summarised in Table 5.1. It is assumed that two big countries (country 1 and 2) and two small ones exist. For each country, three options to generate electricity by conventional fossil power plants and three options to generate electric-

[42] In reality, small negative price elasticity can be observed.

[43] Consider: By replacing the name 'country 1' by 'utility 1', etc, the influence of different policy schemes on regional and national level, respectively, can be show.

ity by RES-E are available. In addition, it is assumed that one big (country 1) and one small country (country 3) possesses a high(er) RES-E potential. Note that all data used in the numerical example are constructed, but especially with respect to cost curves, caution is taken to make these 'relatively' close to the observed reality.

Table 5.1: Model specifications in the numerical four-country example

	Country 1			Country 2			Country 3			Country 4		
	Demand: 110 TWh			Demand: 110 TWh			Demand: 40 TWh			Demand: 40 TWh		
	Generation costs	Potential	Specific CO_2-emissions	Generation costs	Potential	Specific CO_2-emissions	Generation costs	Potential	Specific CO_2-emissions	Generation costs	Potential	Specific CO_2-emissions
	€/MWh	TWh	tCO_2/MWh	€/MWh	TWh	tCO_2/MWh	€/MWh	TWh	tCO_2/MWh	€/MWh	TWh	tCO_2/MWh
Conv. 1	25,0	20	0,80	28,0	60	1,00	28,0	10	0,90	28,0	22	0,90
Conv. 2	28,0	30	1,00	31,0	38	0,40	29,0	14	0,85	32,5	22	0,38
Conv. 3	32,0	40	0,50	37,0	62	0,60	31,5	8	0,40	36,0	4	0,65
Conv. total		90			160			32			48	
RES-E 1	15,0	24	0,00	65,0	5	0,00	10,0	14	0,00	55,0	7	0,00
RES-E 2	65,0	24	0,00	70,0	6	0,00	68,0	22	0,00	69,0	14	0,00
RES-E 3	100,0	42	0,00	98,0	9	0,00	95,0	12	0,00	90,0	11	0,00
RES-E total		90			20			48			32	

National Conventional Electricity Market

Assuming, first, that the four countries are not connected by an international grid or import/export of electricity is (via political constraints) not possible.[44] Hence, each country has to fulfil the electricity demand by themselves. Obviously, depending on the national electricity supply structure, different national market prices occur. The average weighed electricity price is 33,83 €/MWh (see Table 5.2).

Table 5.2: National conventional electricity market

			Country 1	Country 2	Country 3	Country 4	Total
targets	electricity demand	[TWh]	110,0	110,0	40,0	40,0	300,0
electricity generation	conventional electricity	[TWh]	86,0	110,0	26,0	40,0	262,0
	RES-generation	[TWh]	24,0	0,0	14,0	0,0	**38,0**
	Import / Export (+/-)	[TWh]	0,0	0,0	0,0	0,0	0,0
	CO_2-emission	[Mt-CO_2]	64,0	82,4	21,7	26,6	**194,7**
market price	spot market price	[€/MWh]	32,00	37,00	31,50	32,50	
generation costs	conventional electricity	[M€]	2.492	3.302	749	1.201	7.744
	RES-E	[M€]	360	0	140	0	500
	generation costs	[M€]	2.852	3.302	889	1.201	**8.244**
effects on producer / consumer	producer surplus	[M€]	668	768	371	99	**1.906**
	consumer costs	[M€]	3.520	4.070	1.260	1.300	10.150
	consumer costs	[€/MWh]	32,00	37,00	31,50	32,50	**33,83**

[44] This case should be served as reference case.

Liberalised Conventional Electricity Market

By allowing international electricity trade between the suppliers among the different countries, one of the major energy goals of the EC can be pursued, namely the reduction of consumer prices. The consequence of an international market is that total generation costs in the considered countries can be reduced, due to a higher (and cheaper) available portfolio of generation units. Neglecting any existing import/export barriers electricity generation costs can be minimised.[45]

Table 5.3: Liberalised conventional electricity market

			Country 1	Country 2	Country 3	Country 4	Total
targets	electricity demand	[TWh]	110,0	110,0	40,0	40,0	300,0
electricity generation	conventional electricity	[TWh]	90,0	98,0	32,0	42,0	262,0
	RES-generation	[TWh]	24,0	0,0	14,0	0,0	**38,0**
	Import / Export (+/-)	[TWh]	-4,0	12,0	-6,0	-2,0	0,0
	CO_2-emission	[Mt-CO_2]	66,0	75,2	24,1	27,4	**192,7**
market price	spot market price	[€/MWh]	32,50				
generation costs	conventional electricity	[M€]	2.620	2.858	938	1.266	7.682
	RES-E	[M€]	360	0	140	0	500
	generation costs	[M€]	2.980	2.858	1.078	1.266	**8.182**
effects on producer / consumer	producer surplus	[M€]	725	327	417	99	**1.568**
	consumer costs	[M€]	3.575	3.575	1.300	1.300	9.750
	consumer costs	[€/MWh]	32,50	32,50	32,50	32,50	**32,50**

In most cases, the market extension leads to a cost reduction for the consumer too. This constrain, however, is not automatically guaranteed. While consumers in countries with an expensive generation bases and hence high prices, gain from the liberalisation, customers in countries with a cheap electricity production structure must expect that the electricity prices rises. Obviously, the total CO_2-emissions change too, due to the different portfolio. In which direction - increasing or decreasing - however depends only on specific CO_2-emissions of the operating plants, i.e., a liberalisation of the electricity market will not automatically lead to a reduction on GHG emissions! The results of the numerical example are summarised in Table 5.3.

5.2 Interactions between RES-E Generation and Liberalised Conventional Electricity Market

In this section it is assumed that the Government promotes RES-E generation to reduce (besides other goals) their national CO_2-emissions. More precisely, it will be discussed how the most important promotion schemes for different RES-E technologies, i.e., a feed-in tariff scheme and quota systems with tradable green certificates, interact with the liberalised conventional electricity market.[46] Special attention will be given to the reduction of the national CO_2-emissions as well as the costs associated with the different policies.

[45] In the real world, economic inefficiencies exists, due to insufficient grid extension among the countries.

[46] Interactions between the different RES-E policies are described in detail in Huber et al. (2001b).

5.2.1 Feed-in Tariff [47]

Non-Harmonised Feed-In Tariff and Liberalised Conventional Electricity Market

First, it should be assumed that the national governments will introduce national-specific feed-in tariffs to increase their national RES-E production.[48] This means that each country offers different, non-harmonised guaranteed prices for their RES-E generation. The results of these strategies are summarised in Table 5.4. The RES-E production increases totally from 38 TWh to 140 TWh.

Table 5.4: Effects of a guaranteed price for RES-E in a liberalised conventional electricity market to reach a 'relative' unit share of RES-E generation related to the national consumption

			Country 1	Country 2	Country 3	Country 4	Total
targets	electricity demand	[TWh]	110,0	110,0	40,0	40,0	300,0
electricity generation	conventional electricity	[TWh]	50,0	64,0	24,0	22,0	160,0
	RES-generation	[TWh]	72,6	20,0	26,4	21,0	**140,0**
	Import / Export (+/-)	[TWh]	-12,6	26,0	-10,4	-3,0	0,0
	CO_2-emission	[Mt-CO_2]	46,0	61,6	20,9	19,8	**148,3**
market price	spot market price	[€/MWh]	31,00				
	feed-in tariff for RES-E	[€/MWh]	100,00	98,00	68,00	69,00	
generation costs	conventional electricity	[M€]	1.340	1.804	686	616	4.446
	RES-E	[M€]	4.380	1.627	983	1.351	8.341
	generation costs	[M€]	5.720	3.431	1.669	1.967	**12.787**
effects on producer / consumer	producer surplus	[M€]	3.090	513	870	164	**4.637**
	consumer costs	[M€]	8.419	4.750	2.217	2.038	17.424
	consumer costs	[€/MWh]	76,54	43,18	55,42	50,95	**58,08**

Assuming that total demand is constant, any additional RES-E generation will substitute conventional electricity generation.[49] The reason is that a market separation of RES-E and conventional electricity takes place, due to the introduction of such a RES-E strategies. Consequently, an active RES-E policy leads to lower CO_2-emissions and to a lower spot market price for electricity.[50]

A lower conventional electricity price, however, does not mean that the consumer automatically gains from the introduction of a RES-E promotion scheme. The reason is that they have to bear the additional costs from subsidising RES-E generation. Jensen and Skytte (2003) show that it is ambiguous whether the additional cost is larger than the saved cost. Therefore, the consumer costs can either increase or decrease, as a result of introducing a promotion scheme. In practise, considering that the cost curve for conventional electricity is flat, an increase of the consumer prices can be expected.[51] The electricity prices in the single countries, however, differ significantly. Note that the electricity price level does not explicitly depend on the level of the feed-in tariff (compare country 1 and country 2) but also on the actual share of RES-E production. Premium costs are high in countries with a large

[47] To be able to compare the numerical results of with those of the other sections (140 TWh RES-E generation), it is assumed that the amount, which can receive a guaranteed feed-in tariff is restricted. Note, this assumption is only necessary due to the constant cost curve for the single technologies in the numerical example. In practice, observing continuously increasing costs, this condition is unnecessary.

[48] Feed-in tariffs permit RES-E producers to feed their electricity into the grid and to receive, therefore, a minimum price (the feed-in tariff), usually for specific period of time. Note: Similar results occur applying other price-driven promotion schemes like investment subsidies or tax-relief.

[49] In the case of price elasticity, the occurring substitution rate is a bit lower.

[50] In the numerical model CO_2-emissions drops from 192,5 Mt-CO_2 to 148,3 Mt-CO_2 or 23%. The spot market price decreases from 32,5 €/MWh to 31 €/MWh.

[51] In the four country example, average consumer prices rises from 32,5 €/MWh to 58,08 €/MWh.

share of RES-E and low in countries with a restricted RES-E generation. Summing up, a feed-in tariff set individually and uncoordinated by the national governments leads to distortions among the consumers in the countries.

Due to the higher share of RES-E production, total cost efficiency of the electricity supply drops, i.e. total generation costs rises.[52]

The situation for the producer is similar to those for the consumer. They can either win or lose from the introduction of a RES-E policy. Under the assumption that RES-E cost curve is step and conventional marginal generation cost curve is flat –as observable in practise – producer surplus will rise, too (compare Table 5.3 and Table 5.4).

In parallel with the change of the production structure, the import/export balances of the countries alter too. The distribution of the national conventional electricity reduction is independent from the total national RES-E generation. The reason is that the national conventional electricity production depends only from the conditions on the international spot market (marginal generation plant). [53] As CO_2-emissions are related to the power generation, the same conclusion is valid for the national CO_2-reduction: How the total increase in RES-E generation by itself is distributed upon the countries has no influence upon the realised CO_2-reduction in each of the countries. This is totally determined by the marginal cost conditions at the spot market and the specific CO_2-emissions of the substituted electricity (Morthorst, 2003).[54]

Thus, the main result with respect to national climate change policy is: Within a liberalised electricity market the deployment of RES-E generation as an important instrument for obtaining significantly national CO_2-reductions cannot be recommended by itself. In general, this result stems from the fact that national reduction targets for CO_2- emissions do not go well together with a liberalised power market.

The remaining question is: Can a harmonised promotion scheme improve the unsatisfactory situation for both distortions among the consumer costs and the actual national CO_2-reduction.

Harmonised Feed-In Tariff and Liberalised Conventional Electricity Market

The situation will now be investigated in which all countries agree to harmonise their guaranteed feed-in price for RES-E. Assuming that the same quantity of RES-E electricity will be generated – otherwise the cases cannot be compared - no change in both, the total and the national CO_2-emissions occurs. This means, despite a harmonised promotion scheme for RES-E, no homogenous (national) CO_2-reduction benefits among the countries can be expected. The only certain advantage of a harmonisation of the promotion system on the global level is that total generation costs are minimised.[55]

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[52] In the model, generation costs rise by approximately 56% to 12.787 Mio. €.

[53] E.g.: the conventional electricity generation in country 1 drops from 95 TWh to 50 TWh due to the lower demand for conventional electricity.

[54] A comparison of country 2 and 3 in the numerical example illustrates this fact. While an increase of the RES-E generation by 12,4 TWh in country 3 leads to a CO_2 reduction of only 3,2 Mt-CO_2, a rise in country 2 by 20,0 TWh results in a CO_2 reduction of 13,6 Mt-CO_2.

Note: In contrast to an international power market, separated non-opened national conventional electricity markets would lead to an appropriate domestic CO_2-reduction. However, under this condition, a higher and non-harmonised power price occur.

[55] In the numerical example, generation costs can be reduced by 3,6%.

The reason is that all RES-E technologies in all countries receive the same subsidy, so – similar to a trading scheme - only most ‘efficient’ technologies are used.

Table 5.5: Effects of a harmonised guaranteed price for RES-E / minimum guaranteed price for RES-E minimising generation costs in a liberalised conventional electricity market

			Country 1	Country 2	Country 3	Country 4	Total
targets	electricity demand	[TWh]	110,0	110,0	40,0	40,0	300,0
electricity generation	conventional electricity	[TWh]	50,0	64,0	24,0	22,0	160,0
	RES-generation	[TWh]	48,0	12,0	48,0	32,0	**140,0**
	Import / Export (+/-)	[TWh]	12,0	34,0	-32,0	-14,0	0,0
	CO_2-emission	[Mt-CO_2]	46,0	61,6	20,9	19,8	**148,3**
market price	spot market price	[€/MWh]			31,00		
	feed-in tariff for RES-E	[€/MWh]	98,00	98,00	98,00	98,00	
generation costs	conventional electricity	[M€]	1.340	1.804	686	616	4.446
	RES-E	[M€]	1.920	843	2.776	2.341	7.880
	generation costs	[M€]	3.260	2.647	3.462	2.957	**12.326**
effects on producer / consumer	producer surplus	[M€]	2.994	513	1.986	861	**6.354**
	consumer costs	[M€]	6.626	4.214	4.456	3.384	18.680
	consumer costs	[€/MWh]	60,24	38,31	111,4	84,60	**62,27**

The consequences for the producer are ambiguous. While producer in countries with increasing feed-in tariff gains compared to the previous non-harmonised case, producer with a lower harmonised tariff loss.[56] The impact of a harmonisation for the consumer is contrary to them for the producer. Here, consumers in countries with a reduction of the guaranteed feed-in tariff gain.[57] Note that a homogeneous promotion scheme among the countries must not necessarily lead to fewer distortions among the consumer costs in the different countries. High costs for the customers occur in those states with a high share of actual RES-E generation, i.e., in countries with large cheap RES-E potential.

Summing up, it can be concluded that - independently if the price driven RES-E promotion strategies are harmonised or not internationally - distortions in the RES-E generation and in the national CO_2 reduction occurs. In the following section it will be analysed if a market instrument, a quota system for RES-E generation in combination with TGCs, fits better in a liberalised electricity market reducing national CO_2-emissions.

5.2.2 Quota System

Assuming that a quota system with TGCs will be implemented, the following additional model conditions are made:

- Free international TGC trade is possible, i.e., it is assumed that all countries have accepted the same rules for TGC trading;
- No GHG-credits are attached to the green certificates, i.e., no tradable GHG emission allowances (TEA) must be provided with the TGCs.

The introduction of a quota system leads – similar to a feed-in tariff, where the electricity will be feet into the grid at a guaranteed price and is, therefore, not available for the conventional power market -

[56] In our example, the producer in country 3 and country 4 wins significantly.

[57] In practice, this situation will lead to conflicts pushing or hindering a harmonisation between producers and consumers.

to a market separation between conventional electricity production and RES-E generation.[58] While the demand for the RES-E market is determined by the total quota obligation for RES-E, the demand for conventional electricity yields by the difference between total demand and the total quota for RES-E. Hence, how the substitution of conventional electricity is split upon the single countries is determined by two factors, firstly, the total RES-E quota and, secondly, the marginal cost conditions at the spot market. This means, how the total RES-E quota by itself is distributed upon the countries has no influence upon the realised substitution of conventional electricity, which depends totally on the marginal cost conditions at the spot market. As the TGC-systems allow international trade of RES-E generation, the actual RES-E development within a country depends on the international TGC market price. In other words, the RES-E deployment in one country is fully determined by the total (aggregated) quota for all countries, i.e., it is independent from the national quota obligation. In addition, the joint TGC-market guarantees that only cost efficient RES-E technologies will be used.

Table 5.6: Effects of a non-unit and a unit quota system per consumption for RES-E generation in a liberalised conventional electricity market

			Country 1	Country 2	Country 3	Country 4	Total
targets	electricity demand	[TWh]	110,0	110,0	40,0	40,0	300,0
	RES-E target	[%]	46,7 / 60,0	46,7 / 36,4	46,7 / 75,0	46,7 / 10,0	46,7 / 46,7
electricity generation	conventional electricity	[TWh]	50,0	64,0	24,0	22,0	160,0
	RES-generation	[TWh]	48,0	12,0	48,0	32,0	**140,0**
	Import / Export (+/-)	[TWh]	12,0	34,0	-32,0	-14,0	0,0
	CO_2-emission	[Mt-CO_2]	46,0	61,6	20,9	19,8	**148,3**
market price	spot market price	[€/MWh]	31,00				
	TGC price	[€/MWh]	67,00				
generation costs	conventional electricity	[M€]	1.340	1.804	686	616	4.446
	RES-E	[M€]	1.920	843	2.776	2.341	7.880
	generation costs	[M€]	3.260	2.647	3.462	2.957	**12.326**
effects on producer / consumer	producer surplus	[M€]	2.994	513	1.986	861	**6.354**
	consumer costs	[M€]	6.849 / 7.832	6.849 / 6.090	2.491 / 3.250	2.491 / 1.508	18.680 /
	consumer costs	[€/MWh]	62,27 / 71,20	62,27 / 55,36	62,27 / 81,25	62,27 / 37,70	**62,27 / 62,27**

Most important results of the numerical example are summarised in Table 5.6 for two cases:

- Country specific obligations, i.e., countries, more ambitious in promoting RES-E (and reducing national CO_2-emissions) impose a higher quota than more modest countries;
- Unit quota obligation per electricity demand in all countries[59]

How independently the quota allocation looks like, the same generation structure and the same CO_2-emissions occurs as implementing a harmonised feed-in tariff, if the guaranteed price is set equal to the spot market price plus the TGC price. In the case where each country should fulfil the same RES-E target per consumption, distortions between the electricity consumers in the single countries can be

[58] In the case of investment subsides, tax relief or guaranteed premium prices for RES-E generation (= premium feed-in tariff system as implemented e.g., in Spain), no market separation takes place. Due to the subsidy, however, marginal generation costs for RES-E technologies will be reduced by this amount. RES-E must compete with conventional power generation at a joint electricity market. In principle, however, the same generation structures and costs occur than implementing a feed-in tariff.

[59] Observe to be able to compare the results, it is assumed that the total RES-E quota remains unchanged in the two sub-cases.

avoided.[60] Observe that the quota allocation has no influence on the producer surplus of the RES-E producer in the countries. The reason is that the quota allocation does not influence the actual RES-E generation in the countries.

As already mentioned, independently of the national quota allocation – observe that just the total quota for all countries is relevant – both conventional and RES-E generation are determined by their marginal cost conditions at their single market (spot price market and TGC market). This means that the amount of RES-E generation, the conventional power production and the national CO_2-emissions in one country are independent of the RES-E quota allocation in this country. Even in the case that one country increases the internationally agreed total quota autonomously, i.e., the total RES-E quota will be extended, only a certain share of both RES-E generation and national CO_2- reduction can be gained by this country. Thus, the main result of the ambitious RES-E quota setting in one country is that they have to share the actual additional RES-E generation as well as the achieved CO_2-reduction with the less ambitious countries.

Summing up, from the perspective of a national CO_2-reduction policy, a separate introduction of an international green certificate system into a liberalised electricity market cannot be recommended either, if the TGC-market is expected to contribute to achieving the national CO_2-reduction targets. But, of course, the development of RES-E production does, in general, contribute to the overall international GHG reductions.

Figure 5.1 compares the national CO_2 reductions, the additional national RES-E generation and the resulting specific national CO_2 reduction factors due to the substitution of conventional power for three cases:

- Non-harmonised feed-in tariff plus national electricity trade [61](left bars);
- Non-harmonised feed-in tariff plus international electricity trade (bars in the middle);
- International quota system (or equivalent harmonised feed-in tariff) plus international trade (right bars).

It can be seen that by allowing international electricity trade, no distinctions between a feed-in tariff and a quota system on a global level exist with respect to both the global CO_2-emissions and the specific CO_2-substitition factor; see bracket total in Figure 5.1. Observe that they are lower in this (specific) example compared to pure national electricity markets.[62] With respect to the country's specific emissions, huge differences occur. For example, country 2 gains significantly due to the additional

[60] Note: According to the 'RES-E' directive (European Commission 2001a), a EU-target of 22,1% must be fulfilled by 2010. The indicative targets for the single EU member countries are set, however, very different. This means, that - assuming an international TGC trading system will be introduced– the consumer in the countries are imposed with quite different additional costs for the fulfilment of the national targets. A simulation with the model El*Green* (Huber 2001a) shows that the premium price varies between 3,6 €/MWh in Belgium and 53,9 €/MWh in Austria. Assuming a unit quota allocation between the countries (each country has to fulfil a quota of 22,1%), the additional costs would be 15,0 €/MWh.

[61] This case is added to illustrate the interactions between the international electricity market and the countries. It assumes that a non-harmonised feed-in tariff (as described in the section before) will be granted. Due to the national market restriction all additional RES-E generation substitutes national conventional electricity production. Note that the turn back of the liberalisation process of the conventional electricity market is currently not realistic.

[62] Note: This is, however, not generally valid.

RES-E generation in the other countries as indicated by the high country-specific CO_2-reduction factor.

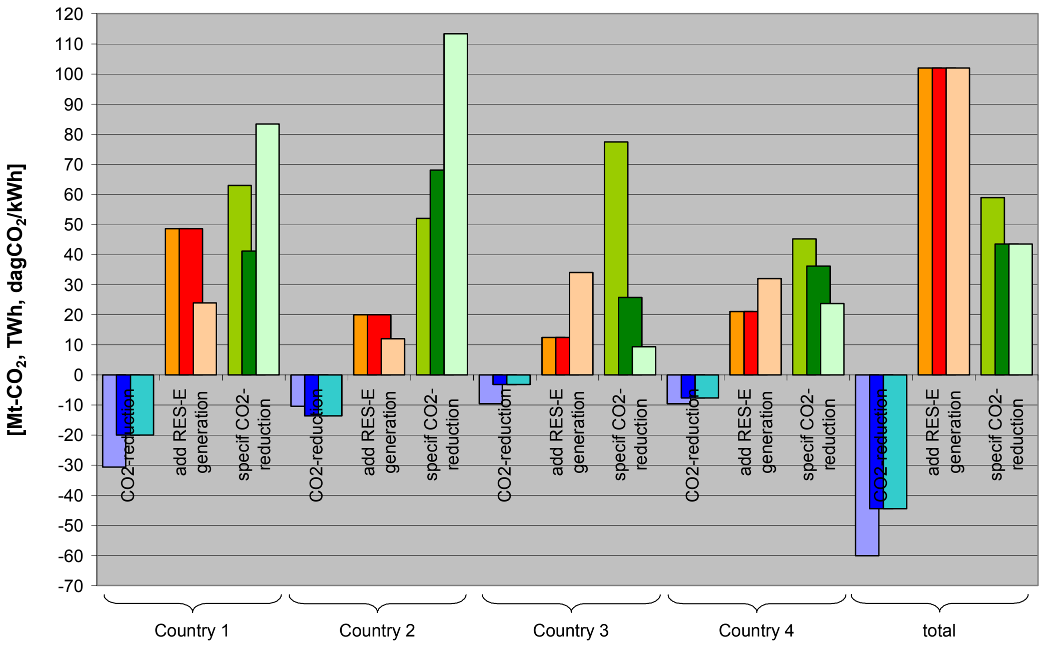

Figure 5.1: Comparison of national CO_2-reduction, additional national RES-E generation and specific CO_2-reductions for the cases no electricity trade and non-harmonised FIT (left), electricity trade and non-harmonised FIT (middle), and electricity trade and international quota system with TGC (right)

5.3 Interactions between a CO_2 Target and the Liberalised Conventional Electricity Market

In the previous section, it has been analysed that a RES-E strategy – both price-driven promotion schemes and a quota system with TGC – can not be adequately contribute to reduce national GHG-emissions. Thus, a general remedy has to be found. One solution is to introduce tradable GHG emission allowance (TEA) scheme as recently implemented by the European Commission (EC, 2001). The idea of a TEA scheme is to achieve reductions in GHG emissions from the power industry and other energy intensive industries by establishing a set of national quotas (allowances) that can be traded both nationally and internationally. Hence, GHG-reductions are carried out where it is least costly, because the TEA system will secure a cost-effective utilisation of GHG-reducing options within the industries covered by the scheme.

To simplify the analyses, the following additional assumptions are introduced:

- The TEA-scheme relates only to CO_2-emissions;

- The TEA-scheme covers only the power industry, i.e., other energy intensive industries are not included[63];
- Free international TEA trade is possible, i.e., it is assumed that all countries have accepted the same rules for TEA trading, e.g., consenting the rules developed in the EU trading scheme;
- Competitive market conditions, i.e., no distortions due to strategic behaviour of single players and/or allocations occur.

The TEA-system is characterised by two important framework conditions, namely:

- The distribution of the total CO_2-cap among the single countries, i.e., unit versus non-unit CO_2-target per electricity consumption;
- The allocation of the TEA to the single companies, i.e., free allocation of TEA (grandfathering) versus sale of the TEA via an auction.

In the following, the effects of these conditions on GHG emissions, the producer and consumer will be discussed.[64]

Country Specific, Non-Harmonised National CO_2-Target Setting

It is assumed that each country oblige a national-specific CO_2-targets, not relating to the actual electricity demand. More precisely, countries with a very ambitious environmental policy choose a low (harsh) CO_2-target, and countries with a modest interest agree to reduce their emission level less (high CO_2-target).[65] The consequences of this non-harmonised policy are summarised in Table 5.7 for two sub-cases - TEA are allocated sold (via an auction) and given for free (grandfathering system), respectively.

[63] Assuming that the power industry is dominant in terms of CO_2-emissions, the inclusion of other industries will not change results significantly.

[64] To illustrate the interactions of a TEA-system with the liberalised electricity market again, the numerical four country example is used. To be able to compare the results gained in the previous sections, it is assumed that the same total CO_2-emissions should be reached, i.e., the maximum CO_2 emission of all four countries is restricted by 148,3 Mt-CO_2.

[65] In the numerical example, total CO_2-emissions should be reduced by 23% compared to a liberalised power market without any environmental restrictions, compare Table 5.3. In the numerical example, the country specific distribution is very ambiguous: Country 1 agrees to reduce their emission by 54%, country 3 by 42%, country 4 by 11%, and country 2 increases their initial emission level by 6%.

Table 5.7: Effects of a GHG-target (CO_2 emissions < 148,3 Mt-CO_2; non-equal GHG-target per electricity consumption; TEA allocation via an auction / grandfathering system) for RES-E and conventional electricity generation in a liberalised conventional electricity market

			Country 1	Country 2	Country 3	Country 4	Total
targets	electricity demand	[TWh]	110,0	110,0	40,0	40,0	300,0
	GHG target	[Mt-CO_2]	30,0	80,0	14,0	24,3	148,3
	free allocation of TEA	[%]	0,0 / 100,0	0,0 / 100,0	0,0 / 100,0	0,0 / 100,0	0,0 / 100,0
electricity generation	conventional electricity	[TWh]	65,0	100,0	32,0	48,0	245,0
	RES-generation	[TWh]	34,0	0,0	14,0	7,0	**55,0**
	Import / Export (+/-)	[TWh]	11,0	10,0	-6,0	-15,0	0,0
	CO_2-emission	[Mt-CO_2]	41,0	52,4	24,1	30,8	**148,3**
market price	spot market price	[€/MWh]	65,00				
	TEA price	[€/t-CO_2]	37,00				
generation costs	conventional electricity	[M€]	1.921	3.472	938	1.475	7.806
	RES-E	[M€]	1.007	0	140	385	1.532
	generation costs	[M€]	2.929	3.472	1.078	1.860	**9.339**
effects on producer / consumer	producer surplus	[M€]	1.988 / 3.098	1.089 / 4.049	1.020 / 1.538	577 / 1.476	**4.674 / 10.161**
	consumer costs	[M€]	6.040 / 7.150	4.190 / 7.150	2.082 / 2.600	1.701 / 2.600	14.013 / 19.500
	consumer costs	[€/MWh]	54,91 / 65,00	38,09 / 65,00	52,05 / 65,00	42,52 / 65,00	**46,71 / 65,00**

Contrary to the cases investigated above, a CO_2-target leads to no-market separation of conventional electricity production and RES-E generation. This means that the total demand must be covered by one single market, including both conventional power plants and RES-E technologies. However, the marginal generation costs for fossil plants are influenced by the CO_2-restriction. The additional costs, characterised by the TEA price, are high for plants with high specific CO_2-emissions (e.g., coal) and low for technologies with low specific CO_2-emissions (e.g., gas). As the emissions refer to the electricity output, the energy efficiency of the plants is important too. Due to the consideration of the additional CO_2-costs, the spot market price for electricity rises.[66]

The total costs that the consumers, however, actually have to pay, depend on the allocation of the TEAs; see Figure 5.2.

Firstly, assuming that the allowances are allocated for free to the producer – as suggested, at least for 90% of the TEA in the EU-trading scheme – consumers have to pay the spot market price for their electricity.[67] As the market price is internationally given, the consumers in all countries are confronted with the same electricity price. Hence, no distortions between the consumers in the different countries occur. Observe that this type of TEA allocation, however, influences the producer surpluses in single countries. For more details, see next subsection.

Secondly, supposing that the producers have to purchase the TEA via an auction system, the state receives high revenue.[68] Assume that these revenues will be reimbursed to the customers, the electricity price can be reduced. The amount of the reduction depends on the national CO_2-target. Countries with a harsh emission goal receive less money from the sell of the TEAs, because the national amount of TEAs is low. Hence the benefit for the customers in these countries is lower compared to customers in countries with a weak CO_2-target.[69]

[66] In the illustrative example (with a high CO_2-restriction), spot market price increases from 32,5 to 65 €/MWh.

[67] In the example, consumers have to pay 65 €/MWh, which is more than using a RES-E system to reduce CO_2-emissions!

[68] In the numerical example, in total, 5487 Mio. € must be paid for the TEAs. This is equivalent to 58% of the total electricity generation costs.

[69] The electricity price in country 1 is 54,9 €/MWh compared to 38,1 €/MWh in country 2.

Due to the CO_2-restriction, total generation costs increases compared with the case of a pure liberalised market and no 'environmental' restrictions. The increase of total electricity production costs, however, is ever lower than it would be by reaching the same CO_2-target via applying a RES-E strategy. The reason is that all available options to reduce CO_2-emissions in the electricity supply sector can be used.[70] Normally, a certain increase of RES-E generation is part of the portfolio of CO_2-measures actually carried out. The level of the additional RES-E production indicates the efficiency of this type of measure compared with the other CO_2-reduction options. If this amount is high, the substitution of conventional electricity by RES-E is also an efficiency strategy reducing CO_2-emissions.

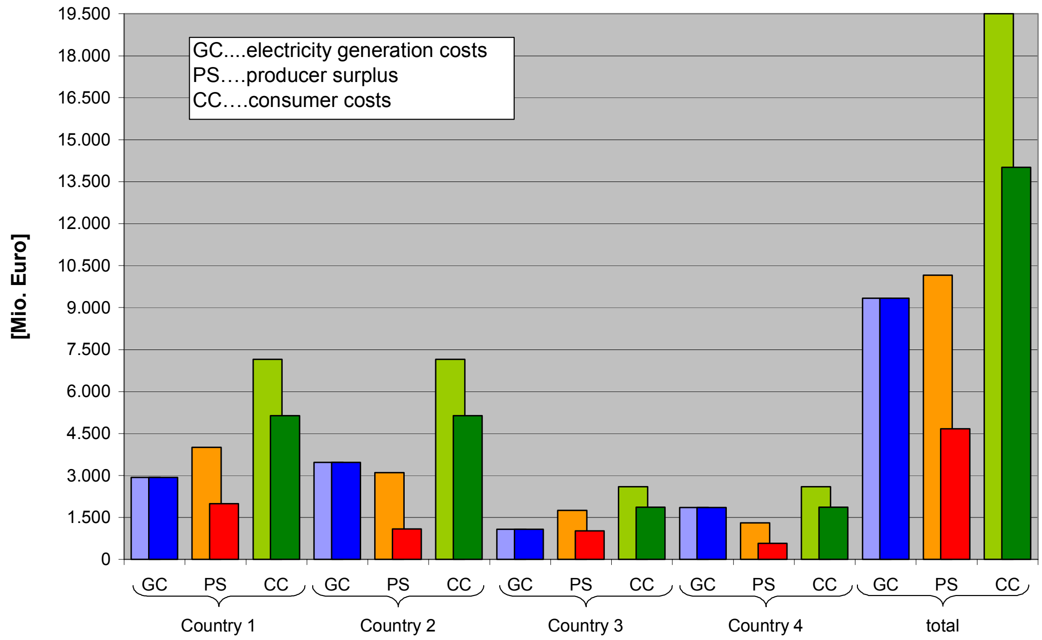

Figure 5.2: Effects of a non-equivalent GHG-target per electricity consumption assuming that TEA are allocated by grandfathering (left) and auction (right)

Harmonised CO_2-Target Setting

Now it is assumed that a joint CO_2-target – again 148,3 Mt-CO_2 in the numerical example – should be reached. The total CO_2-goal is broken down on the single country level according to the national electricity consumption.[71] Most important results are summarised in Table 5.8.

The distribution of the national CO_2-target has no influence on the actual national CO_2-emissions if the total CO_2-cap. In addition, again the marginal conditions at the spot market determine how the electricity generation – and hence the CO_2 emissions - is distributed among the countries. The distribution of the national CO_2-targets only influences the gains for the producers and consumers, respectively – see Figure 5.3.

[70] In more detail, these are: (i) energy efficiency improvements of conventional power plants, (ii) fuel switching to primary energy carrier with lower CO_2-content per energy output, e.g., a switch from hard coal to gas, and (iii) substitution of conventional electricity production by RES-E generation.

[71] Note: Setting the country targets according to the historical CO_2-emissions, as negotiated in international agreements, will not lead to a harmonised CO_2-burden for all consumers!

Table 5.8: Effects of a GHG-target (CO_2 emissions < 148,3 Mt-CO_2; equal GHG-target per electricity consumption; TEA allocation via an auction / grandfathering system) for RES-E and conventional electricity generation in a liberalised conventional electricity market

			Country 1	Country 2	Country 3	Country 4	Total
targets	electricity demand	[TWh]	110,0	110,0	40,0	40,0	300,0
	GHG target	[Mt-CO_2]	54,4	54,4	19,8	19,8	148,3
	free allocation of TEA	[%]	0,0 / 100,0	0,0 / 100,0	0,0 / 100,0	0,0 / 100,0	0,0 / 100,0
electricity generation	conventional electricity	[TWh]	65,0	100,0	32,0	48,0	245,0
	RES-generation	[TWh]	34,0	0,0	14,0	7,0	**55,0**
	Import / Export (+/-)	[TWh]	11,0	10,0	-6,0	-15,0	0,0
	CO_2-emission	[Mt-CO_2]	41,0	52,4	24,1	30,8	**148,3**
market price	spot market price	[€/MWh]	65,00				
	TEA price	[€/t-CO_2]	37,00				
generation costs	conventional electricity	[M€]	1.921	3.472	938	1.475	7.806
	RES-E	[M€]	1.007	0	140	385	1.532
	generation costs	[M€]	2.929	3.472	1.078	1.860	**9.339**
effects on producer / consumer	producer surplus	[M€]	1.988 / 4.000	1.089 / 3.101	1.020 / 1.752	577 / 1.308	**4.674 / 10.161**
	consumer costs	[M€]	5.138 / 7.150	5.138 / 7.150	1.868 / 2.600	1.868 / 2.600	14.013 /
	consumer costs	[€/MWh]	**46,71 / 65,00**				

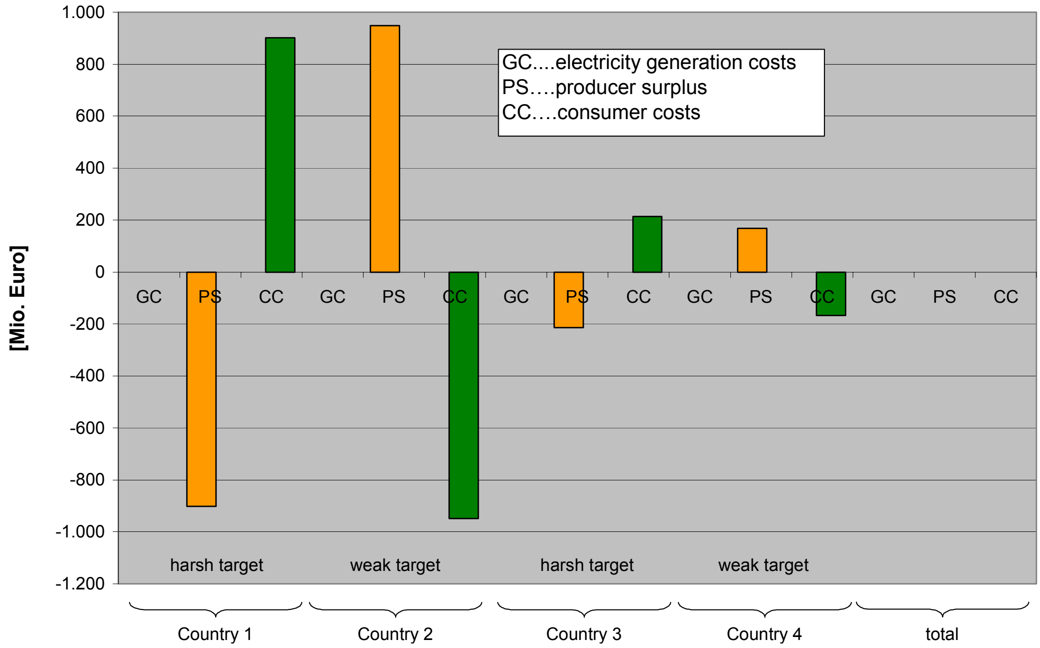

Figure 5.3: Comparison of non-unit and unit CO_2-target per electricity consumption assuming that the TEA are allocated for free (grandfathering – orange bars) and auction system (green bars)

With respect to the allocation of TEA, the following conclusion can be derived:

- The allocation of the TEA is important with respect to a harmonisation of international economic conditions for both producers and consumers;
- A free allocation (grandfathering system) of tradable GHG emission permits has no influence on the consumer costs, but leading to (large) advantages for electricity producers (in countries) with less restricted GHG targets compared to generators (in countries) with a more restrictive environmental goal. Hence, competitive distortions in the electricity sector occur implementing a grandfathering system.
- Applying an auction-system, total electricity costs are low for consumers in countries with a weak CO_2-target compared to consumers in countries with a more restrictive goal. The reason is that in the first case more revenues received from selling tradable GHG emission permits can be reimbursed (from the state) to the consumer. Hence, economic distortions between the consumers in different countries occur, which is especially important to the competitiveness of the industry. However, in contrast to a grandfathering system, an auction has no influence on the competitive situation in the electricity generator, because the additional costs due to the GHG restrictions are already included in the (rising) conventional electricity price. This means that the agreed quota of each country leads to no distortions within the electricity supply industry.

5.4 Interactions between a RES-E Market, a Tradable GHG Allowance Market and a Liberalised Power Market

In this section, the effects of the simultaneous use of two policy instruments, a RES-E quota and a GHG-target, both in combination with tradable certificate, i.e., TGCs for RES-E and TEA for GHG-reduction, on the reduction of CO_2-emissions will be investigated.[72] To be able to compare the results with those derived in the previous sections, the same model assumptions are used with respect to the liberalised electricity market, TGC-scheme and TEA-system, respectively. The cases described in the previous sections - i.e., applying a pure RES-E and a pure CO_2-target - can be understood as the border or corner solutions of the coincidental use of the two instruments. Table 5.9 summarises the results of a inner solution imposing a total RES-E quota of 80 TWh and a GHG-target of 148,3 Mt-CO_2.[73]

[72] Similar results arise implementing a feed-in tariff scheme instead of a RES-E quota.

[73] Furthermore, in the example, it is assumed that the total RES-E quota is distributes homogenously among the countries per national electricity consumption The effects of a non-uniform distribution are described in the section 3 and are in principle valid in this case.

Table 5.9: Effects of a RES-E quota (unit share per consumption, Q 1 = 29,33 TWh, Q 2 = 29,33 TWh, Q 3 = 10,67 TWh, Q 4 = 10,67 TWh) and a GHG-target (CO_2 emissions < 148,3 Mt- CO_2; equal GHG-target per electricity consumption; TEA are allocation via auction / grandfathering system) for RES-E and conventional electricity generation in a liberalised conventional electricity market

			Country 1	Country 2	Country 3	Country 4	Total
targets	electricity demand	[TWh]	110,0	110,0	40,0	40,0	300,0
	RES-E target	[%]	26,7	26,7	26,7	26,7	26,7
	GHG target	[Mt-CO_2]	54,4	54,4	19,8	19,8	148,3
	free allocation of TEA	[%]	0,0 / 100,0	0,0 / 100,0	0,0 / 100,0	0,0 / 100,0	0,0 / 100,0
electricity generation	conventional electricity	[TWh]	60,0	84,0	32,0	44,0	220,0
	RES-generation	[TWh]	48,0	5,0	20,0	7,0	**80,0**
	Import / Export (+/-)	[TWh]	2,0	21,0	-12,0	-11,0	0,0
	CO_2-emission	[Mt-CO_2]	36,0	60,0	24,1	28,2	**148,3**
market price	spot market price	[€/MWh]			50,50		
	TGC price	[€/MWh]			17,50		
	TEA price	[€/t-CO_2]			22,50		
generation costs	conventional electricity	[M€]	1.780	2.492	938	1.331	6.541
	RES-E	[M€]	1.920	325	548	385	3.178
	generation costs	[M€]	3.700	2.817	1.486	1.716	**9.719**
effects on producer / consumer	producer surplus	[M€]	1.784 / 3.007	414 / 1.637	948 / 1.393	348 / 793	**3.494 / 6.831**
	consumer costs	[M€]	4.845 / 6.068	4.845 / 6.068	1.762 / 2.207	1.762 / 2.207	13.213 /
	consumer costs	[€/MWh]			**44,04 / 55,17**		

Due to the RES-E quota obligation, total demand must be separated into two parts: Firstly, demand for RES-E generation, connected to the TGC-market, and, secondly, demand for conventional power, linked to the spot market. Equivalent to the case of a pure TEA-system, the additional CO_2-costs must be considered in the marginal supply curve for the conventional electricity. Now these costs depend on the RES-E obligation too. Generally, the additional CO_2-costs for conventional power decrease with an increasing RES-E quota obligation. The reason is that a higher share of conventional electricity is substituted by CO_2-free electricity production from RES-E. As the CO_2-target is independent from the RES-E quota[74], the fossil electricity production to cover the (lower) power demand can have higher average specific CO_2-emissions. In other words, the marginal generation costs for conventional electricity generation are a function of the RES-E quota.

A less ambitious RES-E policy favours plants with low specific CO_2-emissions. As the TEA price indicates, the scarcity of the commodity CO_2, the TEA market price is high under this assumption. Furthermore, as the marginal conventional electricity generation costs (including additional CO_2-costs) determine the spot market price, the spot market power price is also high. The reverse holds if the RES-E obligation is high, i.e., the TEA price and the spot market price are low. Figure 5.4 shows the progress of the TEA, the conventional power price as well as the TGC market price in dependency of the RES-E quota. Obviously, the TGC-price depends on the RES-E quota. The market price for TGCs rises with the (mandatory) RES-E demand for two reasons. First, a higher demand corresponds with higher marginal RES-E generation costs and, second, the TGC-price increases due to the reduction of the conventional electricity price; see Figure 5.4.[75]

[74] In the numerical example, the maximum CO_2-level is still 148,3 Mt-CO_2.

[75] Note: TGC-price is given by marginal generation costs minus conventional market price.

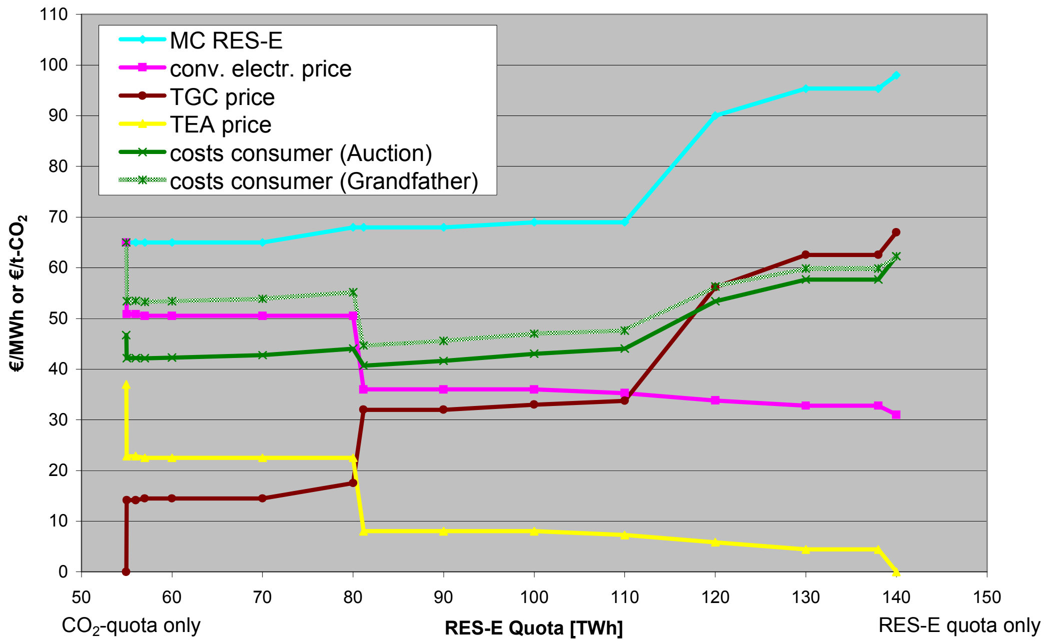

Figure 5.4: Development of the market prices for conventional electricity, TGC and TEA, the total end-user price (costs for consumer), and the marginal production costs of RES-E in dependency of the RES-E quota

The costs for the consumer consist of the conventional electricity price and the additional costs due to the RES-E obligation. One the one hand, the conventional electricity price decreases with a higher share of RES-E. On the other hand, the additional costs for the customers increase proportionally with the increase of the national RES-E obligation.[76] Hence, it is a priori not clear at which share of RES-E the total cost for the consumer will reach a minimum.[77] The TEAs do not directly affect the consumer costs. The CO_2-restriction, however, is internalised in a higher conventional electricity price. In addition, the allocation of the TEA influences the consumer costs. In the case of an auction system and a cost reimbursed from the sell of the TEAs to the customers, consumer costs are lower compared to a free allocation of TEAs (see Figure 5.4 and Figure 5.5). With respect to the allocation of TEAs, the reverse relates to the electricity producer. This means, a grandfather system leads to (much) higher surplus compared to an auction.

Total electricity generation costs increase with a higher share of RES-E. The reason is that – considering only the economic CO_2-reduction costs – more efficient options (such as efficiency improvement or fuel switching) will not be used adequately, due to the distorting promotion schemes.

However, besides the cost advantages for the customers that can occur due to the promotion of RES-E, renewables have other assets too.[78] In addition, in the long-run, RES-E generation may be a better

[76] Note in the case of a feed-in tariff, a higher national RES-E generation leads to higher consumer costs too.

[77] In the numerical example, the burden for the customers is at the lowest, imposing a RES-E quota of 82 TWh. Observe that the total electricity costs jump, in dependency of the marginal generation cost conditions at the spot market and the TGC market.

[78] For example: increased diversity of national power supply, increased security of supply, avoided pollution form "conventional" electricity generation, added value of developing new industries (e.g., new jobs, service skills, diversity of the rural employment, export and manufacturing capacity).

answer to the climate problem and to a sustainable energy system than the adaptation of conventional electricity plants. Hence, to secure the development of RES technologies, a separate promotion scheme for RES - besides pure climate change policy – makes sense.

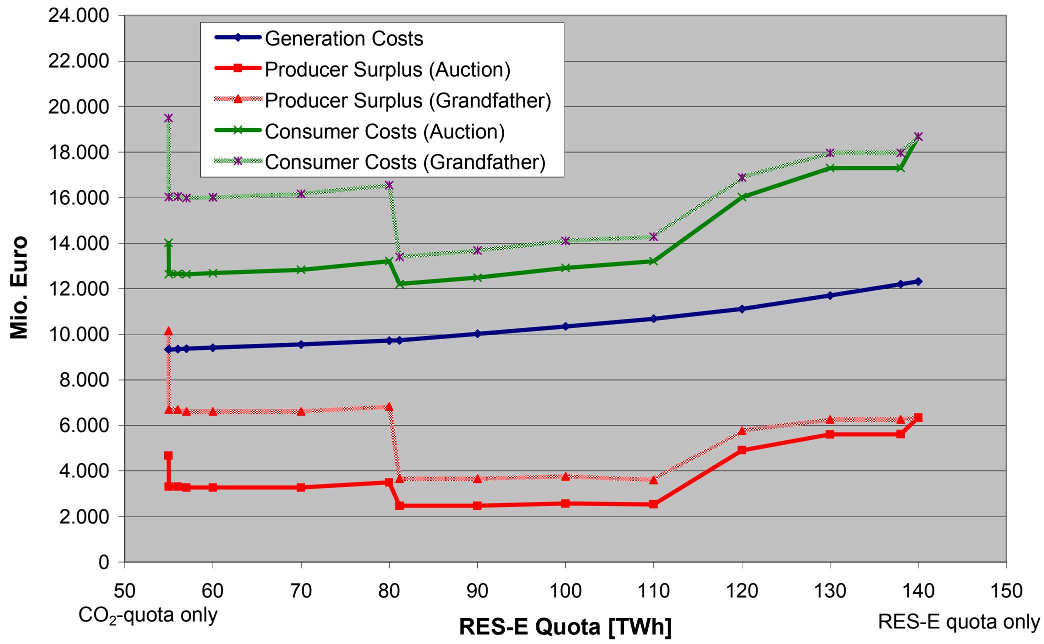

Figure 5.5: Development of the total generation cost, total producer surplus and total in dependency of the RES-E quota

5.5 Summary

This chapter has analysed the interactions of three markets, the conventional power market, a market for tradable green certificates (TGCs) and tradable emissions allowances (TEA) market in relation to a GHG-target. The investigations were focused on two aspects:

- Reduction of national CO_2-emission
- Cost effects for both producer and consumer

Most important conclusions with respect to national CO_2 emission reductions are:

- Independently from the design of the RES-E quota allocation, the same generation structure and the same CO_2-emissions occur as implementing a harmonised feed-in tariff, if the guaranteed price is set equal to the spot market price plus the TGC price.
- As part of a liberalised power market the domestically achieved emission reductions will depend on the marginal conditions at the power market. Thus the nationally achieved emission reductions will have to be shared among those countries participating in the power market. Thus if the main objective of the policy-goal is to reduce national CO_2-emission, neither the use of national price-driven RES-E support schemes nor the introduction of a TGC-system into a liberalised power market can be recommended. In a separated non-opened national power markets ambiguous RES-

E policy would lead to a corresponding domestic CO_2-reduction. However, in this case, a higher and non-harmonised power price would apply.

- Countries most ambitious in implementing RES-E technologies will only partly gain from the CO_2 reduction benefits themselves in an international environment – independently from the RES-E the support scheme. This means that the ambitious countries will support the less ambitious ones in achieving their GHG-reduction targets; e.g., in a TGC-system, the most ambitious countries will have to buy certificates from the less ambitious ones in order to fulfil their TGC-quotas, although this only contributes to achieving a national target for renewable development, not in reaching their national CO_2 reduction targets.
- A combination of a TEA market and a TGC system is seen to be efficient in contributing to achieving the national CO_2 reduction targets if a close co-ordination of the two instruments is undertaken at least at the national level: More precisely, when the RES-E production (of independent producers) is increased, the national CO_2 target (for the conventional power generators) should be decreased correspondingly. Thus, if it is a prerequisite that RES-E generation contributes to achieving national GHG-reduction targets, then the combination of these two markets might be the right solution. It should be mentioned that the achievement of the expected CO_2 reduction, however, might be expensive for the consumer and/or society.

The key conclusions with respect to generation structure, costs for producer and consumer, respectively are:

- A non-harmonised feed-in tariff usually leads to distortions among the additional costs imposed on the electricity customers in the different countries. A harmonisation of the feed-in tariff must, however, not necessarily lead to fewer economic distortions. High costs for the customers occur in states with a high share of actual RES-E generation, i.e., in countries with large cheap RES-E potential. One (certain) advantage of a harmonised promotion system (on global level) is that total RES-E generation costs are minimised;
- The distribution of the total RES-E quota influences the cost for customers. In countries with a high quota consumers are burdened with high additional electricity costs. In the case that each country fulfils the same RES-E target per national electricity consumption, distortions among the electricity consumer can be avoided. The quota allocation, however, has no influence on the producer surplus of the RES-E producer in the countries;
- A support scheme for RES-E can, but must not lead to higher total electricity costs (for the consumer). Due to the market separation, the conventional power price drops. If this gain is overcompensated due to the additional costs for RES-E generation or not depends on the marginal conditions of both conventional power and RES-E; in contrast, a GHG-target always drives the total consumer costs upwards;
- Under the assumption that a certain GHG-level must be reached, total consumer costs can be minimised by setting both a RES-E quota and a CO_2-target. By a simultaneous use of both instruments, the market prices for TGCs, TEAs and conventional electricity can be influenced in a way that the producer surplus can be reduced compared to both a pure GHG reduction scheme target and a pure RES-E policy, respectively, leading to lower total consumer costs;

- However, an introduction of an RES-E quota in addition to a given CO_2 restriction is counter-productive with respect to the total electricity generation costs. This means that a sole CO_2 target, neglecting any certain share of RES-E, minimises production costs for electricity generation. The reason is that by introducing an additional RES-E quota, the flexibility in choosing more cost-efficient CO_2 reduction measures is restricted;
- If the Member States have different quotas for CO_2-emissions the costs for power producers will be biased if the tradable emission allowances are grandfathered (distributed free of charge depending on historic emissions) to the companies covered by the TEA-system. The higher the quota compared to the available CO_2-reduction options the better off they will be. Thus, in countries where the government wants to achieve significant CO_2-reductions by means of the TEA-scheme (low quota for all installations), the power producers will be hurt economically, compared to companies in countries with less ambitious CO_2-reductions (high quota for all installations).
- If allowances are allocated via an auction there will be no bias between power producers, even when countries have different quotas for CO_2-emissions.
- An equal burden sharing among MS in determining the quotas (that is the same relative reduction compared to previous emission) will imply the same (relative) economic effects on power producers no matter whether a grandfathering or an auction scheme is used to allocate allowances.
- For those companies and technologies covered by the emission trading scheme, CO_2-emissions will follow the determined quota (adjusted for trade in allowances). For RES-E technologies outside the TEA-scheme, the achieved emission reductions are ambiguous. If RES-E is replacing conventional power not covered by the emission trading scheme (for example decentralised fossil-fuelled CHP) the achieved emission reductions will have to be shared among those countries participating in the power market and will depend on the marginal conditions of the power supply at this market. If RES-E is replacing conventional power covered by the TEA-scheme, no further emission reductions will be reached, because the conventional power plants are still emitting the allowed CO_2-quota.

Finally it should be stressed that:

- Other potential benefits related to the renewable development such as increased employment and industrial development will accrue to the country implementing the RES-E technologies independent of eventual RES-E quotas in the individual Member States.
- The development of a national RES-E industry requires a continuous RES-E policy.

6 Interactions with Kyoto Instruments - The Impact of CDM/JI on the Deployment of Renewable Electricity.

6.1 Introduction

International agreements have an impact on renewable electricity deployment. In this context, the effects of the Kyoto Protocol (KP) on the development of RES-E in Europe are worth analysing. This is the main aim of this chapter.

The KP sets an overall quota for the emission of GHG from industrialised countries ("Annex I Parties") which agreed to reduce the emissions from a basket of six greenhouse gases in 2008/2012 by 5,2% against 1990 levels. The EU accepted a legally binding emissions reduction target of 8% by 2008-2012. An agreement on differentiated burdens per Member State was also reached.

In order to help industrialised countries achieve those targets in a cost-effective manner, the KP allows industrialised countries to use three international "flexible mechanisms": International Emission Trading (IET), Joint Implementation (JI) and the Clean Development Mechanism (CDM). These instruments will allow Member States in Europe to cut their GHG emissions by means of transaction abroad.

The flexible mechanisms are different in nature, although they all share one basic aim: cost-effectiveness in reducing GHG emissions and stimulation of environment-friendly technologies. An additional goal, JI and CDM, is also to provide funds, new technologies and development opportunities to both developing and less developed countries, which will be the ones hosting the emission-reduction projects.

Joint implementation offers industrialised countries the opportunity to reach part of their Kyoto commitments by investing in GHG reduction projects in another industrialised (Annex I) country (primarily Eastern Europe and Russia).

CDM will enable industrialised countries to meet part of their commitments cost-effectively through projects in developing countries by means of capacity building and technology transfers.

Finally, IET allows industrialised countries to set up a market for buying and selling excess emissions credits among themselves.

Major legislative steps have already been taken to implement an emissions trading system of this sort in the European Union. Actually, a Directive creating a CO_2 emission-trading scheme in Europe was proposed in 2001. After going through the usual legislative procedure (Commission, Council and Parliament), the EU emission trading Directive was formally adopted by the Council on 22 July, 2003 and Member States are now expected to implement the provisions necessary to comply with the new emission trading scheme. The European Emission Trading Scheme (EU ETS) covers carbon dioxide emissions from large stationary sources including power and heat generators, oil refineries, ferrous metals, cement, lime, glass and ceramic materials, and pulp and paper. It is estimated that these sources will emit 46% of the Community's carbon dioxide emissions in 2010.

National authorities will issue site-specific greenhouse gas emission permits to installations setting requirements for monitoring and reporting emissions of greenhouse gases. Member States will allocate EU emission allowances to installations, based on a national allocation plan developed in accordance with common criteria[79]. Holdings of allowances will be recorded in a registry in each Member State, and four months after the end of each year, operators will be required to hand over to the national authorities allowances equivalent to the installation's emissions during the preceding year. Operators of installations will be free, if they so wish, to buy or sell their allowances. If an operator can reduce emissions, the excess allowances can be traded for a profit. The operator of an installation that increases its emissions beyond its allocation can acquire additional allowances in respect of those emissions from the market, thereby ensuring that the overall reduction target will be met. If an operator does not hold sufficient allowances, harmonised non-compliance penalties will apply. In this way, emission reductions can occur where it is most economically efficient for them to take place right across the EU.

Although the EU Directive marks a new initiative to put the EU-Kyoto commitment in an EU policy perspective, it does not specifically regulate the use of CDM/JI credits (Certified Emission Reduction units, CERs, and Emission Reduction Units, ERUs, respectively)[80]. In fact, one of the main criticisms to the Directive was that it provided an unclear link with the Kyoto Mechanisms. Not linking the allowance market with the Kyoto Mechanisms would create two markets, where two goods that are essentially identical (tCO_2 (eq)) would be traded at different prices. A number of other arguments why the two markets (the European allowance system and credits from CDM/JI) should be linked have been put forward.

First, formally separating allowance and credit markets is ineffective because both markets are yet, albeit indirectly, linked through the MS´ freedom with regard to their national climate policy design. Although the first commitment period only starts by 2008, this policy link between the allowance and credit market already exists as soon as any allocations of allowances would actually take place, not only because CDM crediting is already possible, but also JI crediting via early action. As soon as governments would start to allocate allowances to their national installations, it is perfectly rational for them to weigh their allocation system and the likely resulting allowance prices against the various alternative climate policy options, including using KP mechanisms. If Member States would allocate differently, this could result in one country through the ETS effectively making one transfer to another. There seems little incentive for individual governments to absorb a heavy burden in the allowance allocation (Jepma 2003, p.91).

On the other hand, if prices at the two markets differ, with allowance prices surpassing those of credits, then the allowance regime would crowd out JI crediting within the EU region.

[79] In the wording of the CO_2 Directive, "allowances" are the papers that state the authorisation to emit a certain amount of CO_2 (i.e., one ton), while the permit is the general authorisation to take part in trading allowances.

[80] The Directive states that "linking the project-based mechanisms, including Joint Implementation (JI) and the Clean Development Mechanism (CDM), with the Community scheme is desirable and important to achieve the goals of both reducing global greenhouse gas emissions and increasing the cost-effective functioning of the Community scheme. Therefore, the emission credits from the project-based mechanisms will be recognized for their use in this scheme subject to provisions adopted by the European Parliament and the Council on a proposal from the Commission, which should apply in parallel with the Community scheme in 2005. The use of the mechanisms shall be supplemental to domestic action, in accordance with the relevant provisions of the Kyoto Protocol and Marrakech Accords" (article 30, paragraph 3).

The largest gain, however, from combining both systems probably is that it will reduce the overall costs of compliance for the EU Members, and, therefore, would support the Member States' position at any future climate negotiations. Earlier calculations with the help of the PRIMES/POLES 2 model on behalf of the European Commission on the costs of an EU allowance-trading scheme with various trading options have made it clear that while the KP costs for the EU were projected at some 20 billion Euro for no trading options in 2010, those costs would come down to some seven billion under an allowance-trading regime without a link to the flexibility mechanisms, and to some 5 billion Euro if Annex B trading would be included in the system. Therefore, not linking the allowance and credit trading systems would involve future costs for the EU of several billion euros (op.cit.).

On 23 July, 2003 (only one day after the final adoption of the EU emissions trading Directive) the Commission adopted a draft directive on the link between its recently adopted greenhouse gas emissions trading scheme and the flexible mechanisms foreseen in the Kyoto Protocol. The proposal suggests that EU companies shall be able to make use of certified emissions reductions (CERs; the CDM trading unit) and emission reduction units (ERUs) from JI project activities to comply with their obligations in the EU ETS from 2008 onwards, provided that the Kyoto Protocol will have entered into force.

Even though the "linking directive" does not allow companies to use credits in the period 2005-2007 (a disappointment for many), the availability and cost of credits from JI and CDM projects will have a key impact on prices in the Kyoto period from 2008-2012 (Point Carbon 2003b). According to the present proposal, there will not be any *ex-ante* constraints on the amount of credits that companies may use for compliance purposes. However, a quantitative limit could be imposed for the remainder of the period were the amount of credits to exceed 6% of the total quantity of allowances allocated by Member States[81].

Of course, this draft directive will still have to be approved by the European Parliament and the Council of Ministers. For the reasons mentioned above, most players will eagerly await the final outcome of negotiations with these institutions.

The implications on renewable electricity deployment in Europe of this linking of the Kyoto Mechanisms with the EU trading Directive are worth exploring. In this context, CO_2 trading will interact with policy measures specifically aimed at RES-E promotion, such as tradable green certificates (TGCs). Actually, a European-wide TGC scheme might be implemented in Europe, following a report and a proposal from the European Commission. The interactions between those European instruments with different aims are also worth analysing.

Accordingly, this chapter is organised as follows. The following section will provide the theoretical framework for the analysis, including the assumptions being made. The effects of CDM/JI on renew-

[81] Somehow surprisingly, analyses by Point Carbon suggest that such a constraint would probably have little, if any, practical implications, largely for two reasons. First, the supply of credits is hampered by capacity and institutional constraints. Second, the price of EAUs could fall to a level resembling the marginal cost of JI/CDM projects, which could further impede project implementation. Notwithstanding these caveats, a recent analysis by Point Carbon suggests that carbon prices in year 2010 could drop by as much as 85% if the supply of credits reaches a limit of 6% compared to a situation without linking *(see The Carbon Market Analyst* , 2003, 'JI and CDM in the EU ETS').

able electricity will be shown in the following section. In the final section, the theoretical interactions between a hypothetical European TGC scheme and CDM/JI will be explored.

6.2 Renewable Energy and CO_2 Emission Schemes. Objectives, Methodology and Theoretical Framework

In this section, the basic theoretical framework and the methodology for the analysis of the impacts of CDM/JI on renewable electricity deployment are put forward.

6.2.1 Aim and Scope of the Study

An analysis the impact of CDM/JI on renewable electricity in Europe will be carried out. More specifically, we will look at the impacts on renewable electricity deployment as well as the effects on conventional electricity. The analysis will focus first on a situation where a Europe-wide TGC scheme has not been implemented. We will then look at the effects when a EU-wide TGC scheme has been implemented.

We will also analyse how the welfare of three types of actors involved in the electricity market will be affected:

- Renewable electricity producers
- Conventional electricity producers
- Consumers

The linking proposal leads to the following general economic effects:

- Reduction in compliance costs for the European Union Emission Trading System (EU ETS)
- Lower allowance price
- More market liquidity
- Some export opportunities for technology vendors (technology suppliers)

Since the "linking directive" does not allow companies to use credits gained in CDM/JI projects (CERs and ERUs, respectively) in the period 2005-2007, the analysis applies to the 2008-2012 KP period and after. The CO_2 cap per country translates into a CO_2 cap per installation/firm, which will have to hold enough allowances at the end of the period in order to cover its emissions. Of course, the KP cap and the European cap are equivalent. That means that a country complying with the EU ETS is also complying with the KP and vice versa.

6.2.2 Methodology and Main Assumptions

A one-country graphical analysis will be carried out. The main working assumptions can be grouped into three categories, each corresponding to the different type of markets involved:

Concerning the Electricity Market:

- A liberalised power market context is considered. We assume a perfect competition framework in the electricity market. The electricity price is set according to marginal costs, not to average costs.

- RES-E producers sell the physical electricity they generate competitively in the conventional electricity market.

Concerning the Allowance Market and the Credits from CDM/JI Projects:

- A system of CO_2 allowances is implemented in the period 2005-2007 at the European level in order to comply with the CO_2 Directive. For the period 2008-2012, both a European CO_2 market and a world CO_2 market to comply with the Kyoto Protocol targets exist.

- Since the "linking directive" does not allow companies to use credits gained in CDM/JI projects (CERs and ERUs, respectively) in the period 2005-2007, the analysis applies to the 2008-2012 KP period and after. Of course, an important (although relatively easy to accomplish) assumption is that the KP will have entered into force by then. Since only ratification by Russia is needed for this, we assume that Russia ratifies the KP[82].

- A CO_2 emissions reduction obligation exists (the Kyoto Protocol Annex I targets). Therefore, an emission quota exists. Countries use the Kyoto mechanisms (ET, CDM and JI) in order to reduce the cost of complying with the emission targets.

- We assume that CO_2 allowances in the European 2005-2007 market as well as in the World market are grandfathered. The reason is that the EU Directive only allows very limited bidding (maximum of 5% in the 2005-2007 period and 10% in the 2008-2010 period). Therefore, the system is basically one of grandfathering. Allowances are allocated freely to electricity producers according to their emissions in a base year (alternatively, they could be allocated based on input or output).

Concerning the TGC Market:

- A EU-wide TGC system is implemented with an obligatory demand (consumption quota) on renewable electricity. The 2010 indicative targets from the RES-E Directive are assumed to be mandatory for the EU as a whole as well as for individual countries. Thus, the obligation is put on different actors in the EU ETS and in the TGC scheme. In the former, it is electricity generators who are obliged. In the latter, the obligation rests on consumers (suppliers on their behalf). We have also assumed that no National TGC scheme was in place prior to the implementation of an European TGC market.

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[82] No assumption is really necessary about the ratification or non-ratification by the U.S. The reason is that if Russia ratifies, the KP enters into force and assuming ratification by the U.S. would only mean that the allowance market would be more liquid and would probably function better.

- We assume that no GHG credits are attached to certificates. This means that the development of renewables will add to GHG reductions only in those countries, where the plants are established, no matter what kind of tradable allowance scheme is adopted (see Morthorst 2001).

- Changes in the spot market price of electricity are reflected immediately and totally in the TGC price. Therefore, a reduction in the electricity price will lead to an increase in the TGC price and vice versa.

Trade in CO_2 allowances and TGCs takes place without major barriers. This means that there is a free flow of allowances and TGCs between the countries.

Other working assumptions are necessary in order to simplify the analysis. They will be made explicit in the text.

6.2.3 Renewable Energy and CO_2 Emission Schemes

In the following, we assume that a tradable emission allowance (TEA) system has already been implemented. In this section, we assume that a EU-wide TGC system has not been implemented.

Figure 6.1 provides the basic graphical framework that will be used to show the effect of introducing the possibility to use CDM and/or JI to comply with the CO_2 emission targets. It shows supply and demand in the electricity market. An inelastic demand curve for electricity has been assumed (although a small elasticity is probably more realistic). The supply curve has the typical increasing shape. It has three differentiated segments. The first one (leftmost part) represents cheap thermally produced power. We assume that some conventional power is cheaper than some renewable electricity sources, which correspond to the second segment in the supply curve. In turn, some of these RES-E (i.e., wind) is cheaper than some conventional power sources (third segment). Finally, the most expensive RES-E corresponds to the rightmost part of the supply curve.

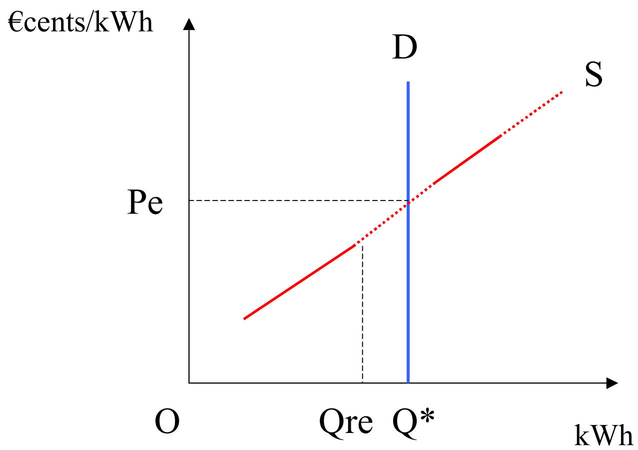

Figure 6.1: Supply and demand in the electricity market

The supply curve includes both the costs of producing electricity (renewable and conventional) and the costs of complying with the CO_2 target, i.e., both marginal costs of abating pollution and/or buying CO_2 allowances in the market. We have assumed that allowances are allocated mainly through grandfathering, although 10% of all allowances would be allocated by auction. If all allowances were grandfathered, the curve would be closer down to the right, since this would involve companies who would have lower costs because they receive all the allowances for free. If auctioning was the method chosen to allocate CO_2 allowances, the supply curve would move to the left (if revenues from the auction are not recycled back to bidders). An intermediate location would correspond to a combination of grandfathering and auction.

Of course, the intersection of demand and supply gives a market equilibrium corresponding to Pe and Quantity Q*. We can observe that all the thermally produced electricity would enter the market. But part of the cheapest renewable electricity segment would also penetrate the market (actually, by the amount Qre – Q*). Actually, a significant amount of renewable electricity would be too expensive in order to make it to the market. This is part of the second segment and the entire 4th segment.

In this situation, and compared to a situation without TEAs, RES-E is favoured because this source of electricity does not incur additional costs of reducing CO_2 emissions, since it does not emit greenhouse gases. However, the source of additional stimulus for the deployment of renewable electricity is different for independent generators producing renewable electricity than for companies that produce renewable as well as conventional electricity:

* Renewable electricity from independent producers. This is the case of RES-E generators entirely and exclusively dedicated to the generation of RES-E. That means they do not produce electricity from conventional sources. Thus, they do not have a CO_2 emission target to comply with and CO_2 allowances are not allocated to them under a grandfathering scheme nor they would have to buy allowances under an auction system either. However, these firms would benefit from a TEA system since they would receive a higher price for the electricity they sell in the market.

* Renewable electricity from conventional producers. Conventional electricity results in the emission of carbon dioxide. If a cap is put on those emissions, which is the case under a TEA scheme, conventional generators would have to give the pertinent environmental authority a quantity of CO_2 allowances at the end of the compliance period for every ton of CO_2 emission discharged. As renewable electricity does not emit CO_2, conventional generators do not have to keep allowances for the RES-E fed into the grid. In other words, by generating a combination of renewable electricity and conventional electricity, generators may provide the same amount of electricity to the market. But they would only have to hand allowances for the amount of electricity produced by conventional CO_2 emitting sources, not for the renewable electricity. This means that a lower amount of allowances is thus necessary. These extra allowances can be sold in the market getting revenues in return. Or it may mean that the conventional generator does not need to buy those allowances in order to comply with its CO_2 quota. It is quite clear that this benefits renewable electricity insofar as this electricity does not have to be covered by allowances. Also, since the conventional generator would have lower abatement costs if RES-E is deployed, this would be an attractive option (see figure 6.2).

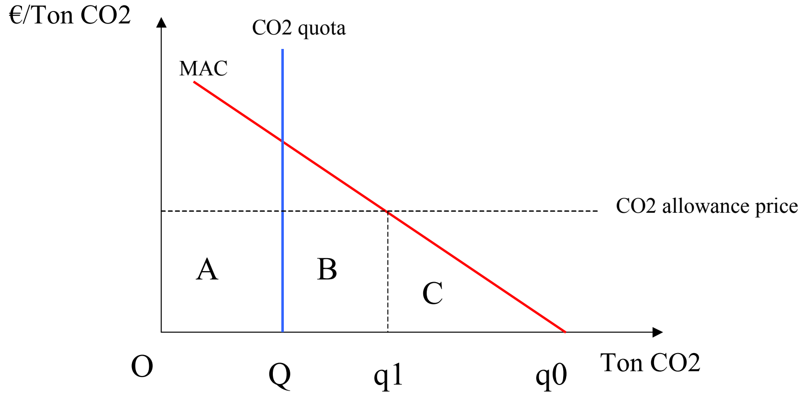

Figure 6.2: Complying with the CO_2 target. Case of conventional generator with no RES-E production. Where A represents the value of allowances allocated by grandfathering, B would be the costs of buying additional allowances in the market and C would represent total abatement costs. Note. We assume that only technical measures are used in order to reduce emissions. No reduction of production in order to reduce CO_2 emissions is considered.

Therefore, the conventional generator would incur the following direct costs when complying with the CO_2 target: B + C. Observe that A are not direct compliance costs, but opportunity costs instead (because the allowances allocated freely have a commercial value, which is not obtained when the generator uses them to comply with targets).

The costs for the generator would be lower if he substituted some of the production of conventional electricity by RES-E generation. If we assume a conventional generator decides to produce renewable electricity in the amount Q-q2 (see figure 6.3), this means that this generator would not have to buy allowances in that amount. The total direct costs would be B’ + C. A would still be opportunity costs. The generator would save costs in the amount A’ if he substituted some conventional electricity for RES-E. The more he substituted, the greater the cost savings in this respect. Therefore, a priori, under a TEA system, renewable electricity produced from conventional generators would also be stimulated to the point where the additional cost savings from not having to buy allowances are lower than the additional costs for deploying an additional kWh of RES-E.

Therefore, the cost saving mentioned above has to be compared with the additional costs of generating RES-E, because if these were very high, they could more than compensate the cost savings from purchasing less allowances (area A’). Assuming CO_2 allowances are auctioned would not change the picture greatly. Savings would be the same, although area A would not represent an opportunity cost, but a direct cost.

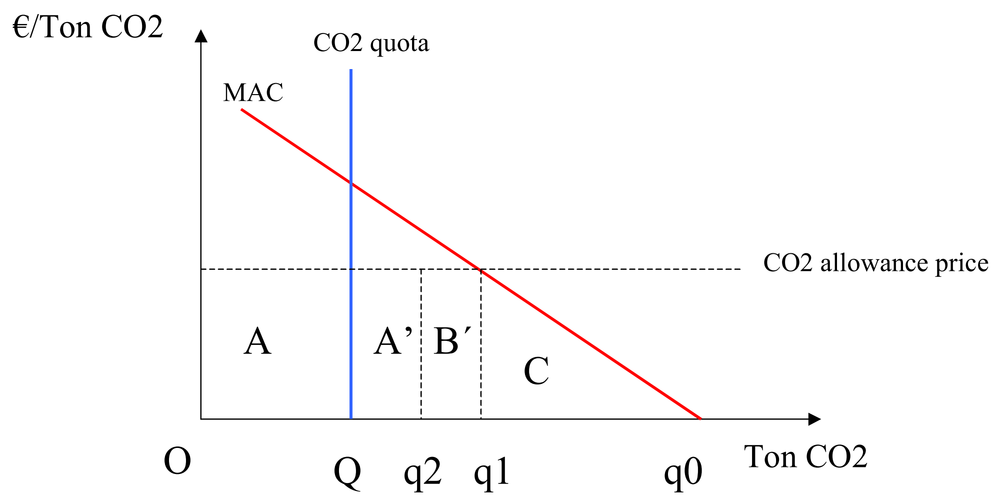

Figure 6.3: Complying with the CO_2 target. Case of conventional generator with some RES-E production

6.3 The Impact of Using CDM/JI on CO_2 Compliance

Once the implications of a TEA scheme for conventional electricity producers and RES-E generators have been identified, it would be interesting to see what happens when power utilities (and industrial installations as well) can use CDM/JI credits in order to comply with the CO_2 targets (for the 2008-2012 period and after) set up in both the EU Directive and the Kyoto Protocol.

According to the linking proposal, companies are not allowed to use credits (CERs and ERUs) in order to comply with the EU ETS in the 2005-2007 period. In other words, JI and CDM credits will not be available before 2008. ERUs and CERs could not come into existence until 2008 anyway (according to the Marrakesch accords)[83].

CDM/JI activities would affect the costs of complying with the CO_2 targets for electric utilities. This effect is both direct and indirect, the latter taking place through the impact CERs and ERUs would have on the CO_2 allowance price:

<u>* Direct effect</u>

Electric utilities in Europe may undertake CDM/JI projects in other countries. This might prove a cost-effective strategy, since both non-Annex I, Eastern European countries and Russia have a large low-cost CO_2 reduction potential. Electricity generators could invest money in renewable electricity projects in those countries (for example, an electricity generator from Germany may build a new renewable energy plant to produce electricity in Rumania), getting CERs and ERUs in return. How much CERs and ERUs would be obtained does not only depend on the amount of CO_2 saved by the project in question compared to the baseline scenario but also depends on how the host and investor countries and the actors involved agree on the sharing of those credits.

[83] An interesting difference, however, is that, in contrast to JI, the KP envisages a prompt start to the CDM, allowing CERs to accrue from projects from the year 2000 onwards for use in the period 2008-2012.

According to the draft linking proposal, those credits can be transformed into allowances for trade or compliance in the European scheme or be used directly in the emission trading market created from 2008 after the KP enters into force. It is highly likely that, since the costs of implementing RES-E projects in developing countries are relatively low compared to those costs in Europe, some companies will consider this option. This means that RES-E will be deployed in those countries and not in the European Union. While one may argue that a RES-E plant in Tanzania saves as much CO_2 as a RES-E plant of the same characteristics in Germany, the local benefits associated with the deployment of RES-E would remain in the host country.

The reason why a European conventional electricity generator would have an incentive to undertake RES-E projects in developing countries and not in Europe rests on the fact that these companies would not receive CO_2 allowances if renewable electricity was deployed in Europe (they would get TGC if a TGC market was set up), but they would get CERs and ERUs by carrying out CDM/JI projects. These CERs and ERUs can then be turned into CO_2 allowances, which have a commercial value and can be traded in the market, helping those companies comply with their CO_2 targets or allowing them to get revenue in return from their sale.

In general, it would be attractive for companies to deploy electricity from RES in a CDM/JI project up to the point where an additional kWh of RES-E costs more than the price of allowances (as CERs/ERUs are turned into allowances). If it costs more, it would not be profitable to produce an additional kWh because, it would then be more beneficial for the company to buy allowances in the market place.

<u>* Indirect effect</u>

Even if a European electric utility decides not to engage in a CDM/JI project, this company will still be affected by the existence of CDM/JI projects, i.e., by the possibility that other companies will carry out these projects. The reason is that the allowance price in the CO_2 market will go down. This in turn will tend to drive the electricity price down as well. Let us see why.

We have assumed above that the price of CO_2 allowances remains unchanged when firms have the opportunity to implement CDM/JI projects, but this is not realistic. The EU linking proposal allows CERs and ERUs to be transformed into allowances. Since the CO_2 targets are the same, the possibility to convert CERs/ERUs into allowances will lead to a downward pressure on the allowance price, both in the EU trading market and in the World market. The point is that this reduction in the price of CO_2 allowances would not be beneficial for renewable electricity[84]. The next figures show this.

[84] According to Criqui and Kitous (2003), taking into account the Acceding Countries in the EU trading scheme results in an allowance price of 26 €/tCO2e. Unrestricted opening of the EU ETS to JI and CDM credits would lead to an allowance price of around 5 €/tCO2e. A 6% limit on the import of credits done by the enlarged EU ETSe (meaning that 6% of the requested objective can be fulfilled by such credits obtained through JI and CDM) would result in an intermediate allowance price of 12 €/tCO2.

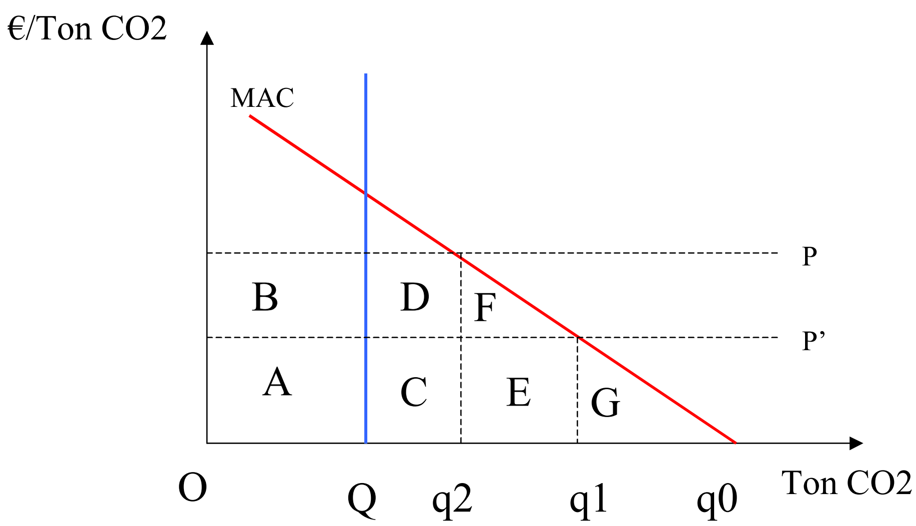

Figure 6.4: The effects of CDM/JI on the price of CO_2 allowances and on the compliance costs of the electricity generators

Figure 6.4 shows that when the price of allowances goes down, the costs of complying with a specific CO_2 target also go down (saving areas D and F). Assume that, prior to the implementation of a TEA system, the company emits q0 tons of CO_2. After the implementation of a TEA scheme, the company is allocated CO_2 allowances for free (i.e., the firm is grandfathered O-Q allowances). Then, at the allowance price P the company would reduce its level of emissions up to q2 and would buy allowances on the amount Q-q2. Reducing from q0 to q2 would cost the company areas C, D, E, F and G[85]. If the allowance price goes down to P' because CERs and ERUs are created in cheap mitigation projects, then the company would only reduce emissions up to q1 and would buy (Q-q1) allowances. So, in this case, the company would have total costs of areas G (abatement costs) and C and E (allowances purchased). Compared to the situation with an allowance price of P, it would save costs in the amount D and F. The company has less total abatement costs and although it buys more allowances, it does so at a much lower price than before. This means that, since compliance costs are reduced, the company has a lower incentive to engage in lower cost activities, i.e., it has a lower incentive to save costs. Intuitively, this involves the deployment of renewable electricity will be less attractive. This is shown in the next figure, which looks at the effects of a reduction in compliance costs in the electricity market. If allowances can be bought at a lower price in the market, then the conventional electricity supply curve will be shifted to the right.

[85] If allowances were grandfathered, areas A and B would represent opportunity costs, whereas they would be direct costs if allowances were auctioned.

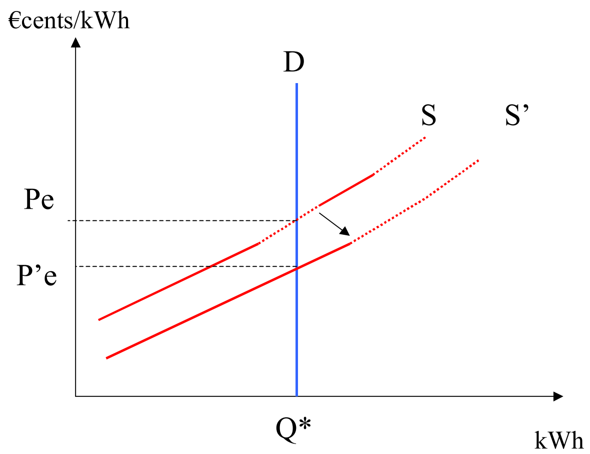

Figure 6.5: CDM/JI: effects in the electricity market caused by a reduction in the price of CO_2

The figure shows quite clearly what would be the effects of the reduction in the price of CO_2 allowances (triggered by the creation of CERs/ERUs in CDM/JI projects) on the electricity price, the deployment of renewable electricity, the deployment of conventional electricity and on CO_2 emissions. We also consider the effects on consumers.

* Price of electricity. Figure 5 shows that a reduction in compliance costs caused by a lower CO_2 allowance price put a downward pressure on the price of electricity. Since the costs of complying with the Kyoto and EU targets would be lower in a situation where CDM/JI projects can be used by electric utilities compared to a situation in which they cannot be used, the price of electricity would also tend to go down. The extent to which it will go down depends on the *market structure of the electricity sector* in question. The more competitive the market is, the more likely it is that a reduction in costs will drive down prices.

* Renewable electricity. A lower (or even non-existing) deployment of renewable electricity will result. The reason is that renewable electricity producers will be worse off under a lower electricity price[86]. They do not benefit at all from the reduction in the CO_2 allowance price, because neither they are neither allocated free allowances (under grandfathering) nor will they have to buy allowances in the market (auction). Therefore, their costs remain the same but, since the electricity price has gone down, their revenues are lower[87].

* Conventional electricity. A lower compliance cost for conventional electricity will boost cost-competitive technologies, allowing them to take a higher share of the electricity market. Only the very expensive conventional electricity (segment 4) would not enter the market. Conventional producers generating also renewable electricity might consider abandoning some RES-E plans. Of course, this

[86] If a national TGC market was in place, then renewable electricity producers would not necessarily be worse off after the reduction in the electricity price. The reason is that the TGC price would go up accordingly and the producer would still get the same amount of revenue.

[87] Note that, of course, there would still be more deployment of renewable electricity in Europe in a situation with a TEA market and CDM/JI projects than without these measures being implemented, the reason being that a TEA market with a target on conventional CO_2 polluting electricity provides a strong incentive for renewable electricity.

would depend on how they produce renewable electricity. The decision will be based on a comparison between the marginal costs of renewable energy deployment (which allows conventional generators to reduce CO_2 emissions) and the cost of CO_2 allowances. The higher the former and the lower the latter, the less attractive is the deployment of renewable electricity.

* Emissions. The effect on total CO2 emissions is neutral. Although more conventional electricity is produced in the country than before, the firms have contributed in the same amount to reduce CO_2 emissions by buying CO_2 allowances (formerly CERs abd ERUs) from CDM/JI projects). More CO_2 emissions would take place in the country but, since CO_2 is a global warming gas, it does not matter, because those additional emissions will be made up by the CDM/JI projects. Instead of reducing CO_2 emissions through a higher deployment of renewable electricity in the country, the company/country complies with their emission quota by buying allowances in the international market, stimulating thus the implementation of CDM/JI projects.

* Consumers/suppliers. Since consumers/suppliers pay the electricity price, and this goes down due to lower prices for CO_2 allowances, they benefit. These cost savings could be measured as the area between the y-axis, the former electricity price, the final electricity price and the demand line.

6.4 Effects of CDM/JI on RES-E Deployment when an International TGC Scheme has been Implemented

Let us consider what would be the effects of CDM/JI projects when a European-wide TGC system has already been implemented. Analysing this is very important, since policy trends in the EU point in the direction of coexistence between both instruments, as envisaged in the linking proposal and the RES-E Directive, respectively. Both instruments have different goals but mutual effects. One aims to reduce the costs of CO_2 mitigation and the other to reduce market distortions as well as the costs of complying with the 2010 RES-E Directive targets. Thus, the interactions between both instruments are worth analysing.

An EU-wide TGC system results in a uniform TGC price, which would account for the difference between the costs of producing RES-E and the lower costs of conventional electricity generation (see figure below). The marginal cost curve for producing RES-E in EU-15 would, of course, be the aggregation of the marginal cost curves per technology and Member State. An indicative quota of 21,7% of consumption from RES-E has been considered by the RES-E Directive. In this paper, we consider that an obligation has been put on consumers.

RES-E generators would have two sources of revenue. On the one hand, they receive the price of electricity. On the other hand, they receive a TGC for each kWh produced with RES. They can sell this in the TGC market. The TGC would cover the difference between the marginal costs of producing RES-E (MCre) and the price of electricity.

Assuming that a TEA market is in place and that electric utilities face an emission quota, what would be the effect on RES-E generators, conventional generators, emissions and consumers' welfare if CDM/JI projects can be undertaken?

* Prices. Compared to the situation described above (i.e., in Section 2), the possibility to carry out CDM/JI projects would also mean a reduction in the CO_2 compliance costs which would also result in a lower CO_2 allowance price. This would tend to put downward pressure on the costs of electricity

production and, therefore, on electricity prices. A reduction in the electricity price leads to an increase in the TGC price (because this is the difference between the marginal cost of producing RES-E minus the price of electricity at the quota level). To sum up, the use of CDM/JI leads to lower CO_2 allowance prices, lower prices of electricity and a rise in TGC prices.

Obviously, these changes have different effects on different actors. Let us analyse these impacts by using the graphical framework developed above (see figure 6.6). S is still the power supply curve, while D is the (inelastic) demand curve. In this situation, only a TEA scheme and an emission quota have been implemented. No TGC market exists at this point.

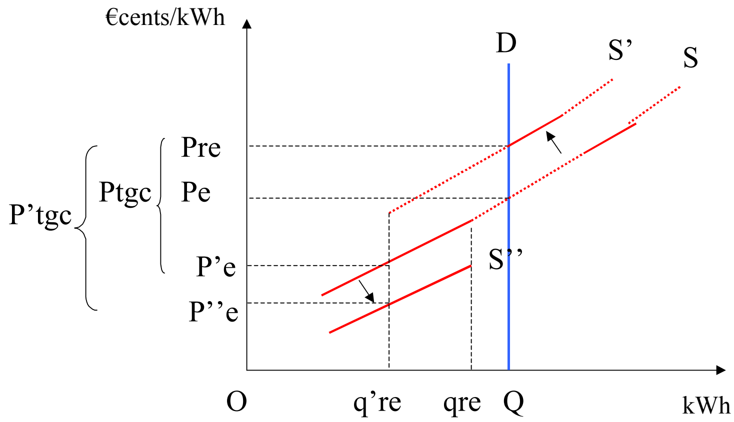

Figure 6.6: Effects of CDM/JI when an international TGC scheme has been implemented

We can see that a small amount of RES-E is deployed. Again, the reason is that, despite the high relative cost of RES-E, with a TEA market, some RES-E become cost-competitive with conventional power. The amount of RES-E in the electricity market is Q - qre, while qre is the amount of conventional electricity. However, if the Government decides that a higher amount of RES-E should penetrate the market, then it could implement a RES-E quota combined with a TGC market. Let us assume that the Government considers that Q - q´re of RES-E should penetrate the market. An amount of Q - q´re of RES-E is produced, while q´re would be the amount of conventional electricity generated. The new electricity price is P'e. The lower demand for conventional power drives the electricity price down. Renewable generators receive TGCs, whose price covers the difference between the costs of producing RES-E and the new electricity price. Therefore, the price of the TGCs would be Ptgc.

In this situation, with a TEA system (and a CO_2 quota) and a TGC system (and a RES-E quota), the possibility to carry out CDM/JI projects is considered. As mentioned in Section 6.2, there is no doubt that conventional producers would try to benefit from the low CO_2 cost opportunities offered by these flexible projects. This would lead to a shift of the conventional electricity supply curve to the right meaning that the same amount of conventional electricity can be produced at lower costs. This leads to a reduction in the electricity price, which would now be set at P''e.

This reduction in the electricity price leads to an increase in the TGCc price, which now would cover the difference between the marginal RES-E generators at the quota level minus the new electricity price P''e. Therefore, the new TGC price would be set at P'tgc.

Concerning possible changes in the quantities of RES-E and conventional electricity being produced, as we have assumed an inelastic demand, the total amount of electricity in the market would not change after the new conditions. It would still be Q. The split between conventional and renewable would also not change, since a quota on RES-E as a share of consumption has been set from the start and there has not been any change in electricity demand (again, because we have assumed inelastic demand). Therefore, (O – q're) kWh of conventional electricity and (q´re – Q)kWh of RES-E would result. The following tale summarises the final price and quantity implications of the existence of CDM/JI projects in the electricity and the TGC markets.

Table 6.1: Price and quantity effects

Price of TGCs	↑
Price of electricity	↓
RES-E generation	=
Conventional electricity generation	=

These price and quantity effects have a distinct impact on the different actors involved in both the electricity and TGC markets:

* RES-E producers. The carting out of CDM/JI projects leads at the end to a lower electricity price and, therefore, an increase in the TGC price for an unchanged quota[88]. This means that RES-E generators receive the same amount of revenue for the same amount of electricity fed into the grid.

* Conventional electricity producers. The possibility to buy cheaper CO_2 leads to a reduction in compliance costs for these actors. They would benefit from cost savings due to both a reduction in their abatement costs and a reduction in the price paid for the CO_2 allowances. However, as we have assumed inelastic demand and there is a quota on RES-E, conventional electricity will not gain any market quota at the expense of renewables.

* Consumers. The introduction of CDM/JI leads to a cost saving for consumers, which can be measured by the rectangle given by the area within P'e, P''e, q're and the y-axis. This cost saving is actually an increase in the consumer surplus, which is related to the reduction in the electricity price. Therefore, it is (q're)kWh times the difference between the former electricity price (before CDM/JI were used) and the new electricity price.

Table 2 summarises the impacts on actors due to the existence of CDM/JI projects. Summing up, the introduction of CDM/JI projects would have significant price effects on both the electricity and the TGC markets. Quantities would remain unchanged, however, since there is a quota on RES-E and we have assumed constant (inelastic) demand. However, in reality, an increase in electricity consumption

[88] In reality, it can be expected that a reduction in the electricity price tends to increase the European TGC price, which in turn would lead to a further stimulus for RES-E deployment in Europe (or at least, facilite compliance with RES-E targets).

as a result of JI/CDM activities could be expected. The reason is that, since CDM/JI activities tend to reduce compliance costs for thermal production technologies, then the price of electricity would also tend to go down. A lower price would result in a higher consumption when the demand curve is not inelastic.

This combination of changes in prices and constant quantities would have a positive impact (welfare improving) on all the actors considered (RES-E generators, conventional electricity generators and consumers).

Table 6.2: Impacts on the different actors

Actor	Positive (+) or negative (-) impact	Type of impact
RES-E generators	(=)	Unchanged
Conventional electricity generators	(+)	Cost savings
Consumers	(+)	Cost savings (increase in the consumers´ surplus).

6.5 Accounting for Direct Impacts

In this paper, mostly the indirect effects (due to changes in the allowance price) have been taken into account. However, direct impacts should also be considered. In this case, it is necessary to differentiate between firms in countries, which are host to JI projects (EU cannot be host to CDM projects, since MS are Annex I Parties) and investors in JI/CDM projects. Also, a different situation exists if only a TEA scheme exists than if a TEA system as well as a TGC scheme have previously been implemented. We will in the following consider the incentives to invest in CDM projects instead of investing in RES-E at home (we call this "crowding out") and the impact this would have on consumers.

At least 2 different cases are worth considering in this incentive-and-impact analysis[89].

6.5.1 CASE 1. JI/CDM Investors in the Context of a Pre-Existing International TEA (with CO_2 quota) but no TGC Scheme (and no RES-E Quota)

We should differentiate the incentives to invest in CDM/JI projects abroad between RES-E generators (which are not subject to any CO_2 target, but which can sell the CERs/ERUs they earn in JI/CDM projects) and conventional generators (which have a CO_2 quota and can reduce the costs of complying with that quota by investing abroad). RES-E generators also benefit from support from national RES-E policies.

[89] We only illustrate the cases when companies/countries are investors in CDM/JI projects but not hosts in JI projects. This latter case could be worth investigating.

Rather simplistically, RES-E generators would have an incentive to invest in CDM/JI projects abroad (including RES-E projects) if the following holds:

Value of credits earned (ERUs/CERs)[90] – Net cost of CDM/ JI project > revenue from RES-E support measures (feed-in tariffs, national TGC schemes, investment subsidies) + revenue from sale of electricity – domestic costs of deploying RES-E.

In the case where the first member of the inequality is greater than the second member, then investments in the JI/CDM project abroad would crowd out RES-E investments at home[91].

A conventional generator would also take into account the costs of buying allowances (the price of CO_2 allowances). Therefore, the incentives to invest in CDM/JI projects abroad instead of investing in RES-E projects in his country would be:

Value of credits earned (ERUs/CERs) + price of CO_2 allowances – Net cost of CDM/ JI project > revenue from RES-E support measures (feed-in tariffs, national TGC schemes, investment subsidies) + revenue from sales of electricity – domestic costs of deploying RES-E.

The conventional generator would invest in CDM/JI measures abroad instead of deploying RES-E at home (crowding out) if the following applies: the revenues from national RES-E support measures plus the price of electricity are very low, the value of the credit earned is high and the costs of carrying out the project abroad compared to the costs of deploying RES-E at home are low. If the price of CO_2 allowances is low, then the incentive to invest abroad in CDM/JI projects would be lower.

If the conventional generators reduce their compliance costs by investing abroad, then the effect on consumers would not be totally clear. Since more domestic RES-E deployment has an ambiguous effect on the consumer (see Jensen and Skytte 2003), it is also not unambiguous what would be the effects on the consumer of investing abroad instead of doing so at home. However, it could be expected that a slight reduction in the electricity price would result since utilities would reduce their compliance costs, which could put a downward pressure on the electricity price (under a perfect competition framework). Compared to this, the effects on the consumer would be ambiguous if RES-E deployment takes place at home, since, on the one hand, a reduction in the electricity price would be expected due to an increase in RES-E generation. However, consumers would also bear more costs because of the increase in generation, because that production would benefit from feed-in tariffs or TGCs, which at the end are paid by consumers (see Jensen and Skytte 2003). Since the effects on the consumer are less clear when RES-E takes place at home and since it seems more clear that an reduction in the elec-

[90] The value of credits earned is the amount of kWh produced by the CDM project additional to the baseline times the market value of CO_2 allowances.

[91] Note that crowding out could take place if national RES-E support measures plus the price of electricity are very low, the value of the credit earned is high and if the costs of carrying out the project abroad compared to the costs of deploying RES-E at home is low.

tricity price would probably follow from investing in CDM/JI, it could be expected that the consumers would be better off when companies invested abroad.

6.5.2 CASE 2. JI/CDM Investors in the Context of a Pre-Existing International TEA Scheme and a TGC Scheme (and a RES-E Quota)

When an international TGC scheme exists, the situation changes slightly. In this case, the incentives would be as follows:

RES-E generators would invest in CDM/JI projects abroad as long as:

Value of credits earned (ERUs/CERs) – Net cost of CDM/ JI project > revenue from the sale of TGCs + Revenue from selling the electricity– domestic costs of deploying RES-E.

Therefore, a RES-E generator has to compare the benefits of investing abroad with the benefits of investing at home. Of course, if the former are larger than the latter, he will invest abroad.

Therefore, the higher the value of the credits earned from a JI/CDM project, the lower the net costs of a CDM/JI project, the lower the sum of the revenue from the TGC price and the price of electricity. The higher the costs of deploying electricity at home, the higher the probability that the RES-E generator will invest abroad in CDM/JI projects instead of deploying RES-E at home.

For a conventional generator, a similar picture emerges, only that in this case he has to take into account the price of CO_2 allowances as well. The higher the price of CO_2 allowances, the higher the incentive to invest abroad in CDM/JI projects instead of investing at home.

If crowding out takes place, the effects for the consumers would be as follows. On the one hand, we can expect that a lower electricity price result from carrying out JI/CDM projects, since these activities are supposed to be cost-effective in complying with the CO_2 targets and they are carried out exactly for that reason. This would involve an increase in the consumer surplus. On the other hand, domestic deployment of RES-E when a TGC scheme is implemented has an ambiguous effect on consumers (again, see Jensen and Skytte 2003). Therefore, it can be expected that crowding out would be more welfare improving for consumers than when conventional investors decide to invest in RES-E at home (no crowding out).

6.6 Summary

The following main effects can be discerned:

1. Concerning crowding out, it is difficult to tell beforehand what would be the decision of both RES-E and conventional generators, both in the case of a TEA scheme only and in the case of a TEA scheme together with a TGC scheme. The reason is that many factors and variables, whose level and change cannot be predicted accurately at this moment (such as the price of CO_2 allowance, strict or lenient decisions of the CDM Executive Board on baselines, price of

electricity[92], price of TGCs, transaction costs in CDM/JI projects…), enter into the picture and lead to contradictory impacts.

2. Crowding out in the case of RES-E generators leads to an ambiguous effect concerning the costs to the consumer and compared to a no crowding out situation.
3. Crowding out in the case of conventional generators leads to a slight reduction in the cost for the consumers. This is true both when only a TEA scheme is implemented and when a TEA scheme together with a TGC scheme is applied.

It should be noted that the above discussion focuses on the effects of CDM/JI projects on RES-E deployment in Europe and also on the effects for the consumers. Of course, CDM/JI projects could be very beneficial for the deployment of RES-E in less developed countries (hosts). It could also have a beneficial effect for Annex I countries since these could export their RES-E technologies to the host countries finding a market for their technologies. The above discussion does not involve a negative general assessment of CDM/JI at all. Only some partial and geographically specific results are considered here.

[92] The electricity price depends on the marginal costs of the marginal producer. Therefore, the reduction in the electricity price depends on the measures taken by the marginal producer in order to reduce its compliance costs.

7 Conclusions

Even though there is a common agreement within the EU to increase the share of electricity from renewable energy sources (RES-E), it is not straightforward to agree upon how to do it. Different support mechanisms have been and still are used in different Member States. In addition, new instruments such as tradable green certificate and emission allowance systems are being designed in order to follow the trend of liberalisation.

The overall objective of the Green-X project is to analyse the possibility for a continuous and significant increase in the development of RES-E with minimal costs to European citizen. In order to make these analyses, it is important to understand the different policy instruments available for supporting renewable sources, how these instruments interact, and what this implies for EU and national policies for implementing renewable energy technologies and for achieving GHG-reductions.

In this report the focus is on interactions between instruments for supporting the renewable energy development. Quite a number of different instruments are available on the national and international scene in the attempt for the individual countries and the EU to support the development of renewable energy technologies and at the same time to reduce greenhouse gas emissions. The most important ones are mentioned below:

- Feed-in tariffs
- Tradable green certificates (TGC)
- Tendering systems
- Tradable emission allowances (TEA)
- Distributed combined heat and power (CHP)
- Clean development mechanism (CDM) and joint implementation (JI)

These policy instruments may be used individually or simultaneously either at the national level or at the EU level. Moreover, the Member States and the EU may want to achieve not only one but several targets in applying these instruments. For example, this is the case for the indicative targets for the use of renewable energy and the national GHG-reduction targets.

Analysing the interaction of these instruments with each other and with different targets is not trivial. By contrast, such analyses turn out to be highly complex theoretically and methodologically. The different instruments might influence a number of issues, the most important ones being:

- Prices at the power spot market
- Consumer prices for electricity
- The volume of implemented renewable power capacity
- The national and international emission levels;

These interactions and influences can be seen at both national and international levels.

7.1 Effects at the national level

The EU Member States might want to use different instruments in promoting RES-E technologies. The impact and interactions of using such national policy instruments are analysed at the national level, although international trade of conventional power is expected to take place within a liberalised market setup. Other instruments are assumed only to be used and have effect within a country's own borders.

At the national level the use of a TGC-scheme or a Feed-in tariff system have – under ideal conditions – almost identical impacts on prices, renewable capacity development and emissions:

- TGC and feed-in systems, which give priority to a certain amount of RES-E, will displace a corresponding amount of conventional power by lowering the demand for conventional power.
- Assuming increasing marginal cost of conventional power, the market price of power will decrease when support schemes for RES-E are introduced at the national markets (assuming no market power).
- If consumers have to pay for the increase in RES-E the effect on total consumer expenses is ambiguous: the increased costs for RES-E are counteracted by the decreased market price of conventional power.
- In a closed economy with no international power trading increased RES-E production will totally replace domestic conventional power and thus an equivalent emission reduction will be achieved.
- Applying differentiated tariffs or support prices to different RES-E technologies might decrease the cost of reaching a certain amount of RES-E due to different supply costs between the technologies, i.e. the cheaper technologies can be promoted by a lower tariff. Though in the case of a TGC-system the application of separate quotas for different RES-E technologies only makes sense if the market volume is big enough.
- Other potential benefits related to the renewable development such as increased employment and industrial development will accrue to the country implementing the RES-E technologies. The development of a national RES-E industry requires a continuous RES-E policy.

Introducing a tendering system alongside a feed-in tariff or a TGC-system will in large markets (or for small tendering schemes) not make up specific problems, the different systems interacting in a fairly straightforward way. The advantage of tendering is the ability to support specific technologies at specific points in time and thus this system in many ways are complimentary to more general support systems as feed-in and TGC's. Of course, to guarantee an effective RES-E development a tendering system – equal to a feed-in tariff or TGC – stop and go strategies must be avoided.

Depending on the design of the green power markets and instruments, promoting CHP might result in ambiguous effects on the consumer prices and on the volume of deployed RES-E and CHP. It is possible that the production of power from CHP will increase in response to the introduction of a TGC system. Actually, it is ambiguous if any emission reductions at all are achieved when supporting RES-E technologies in a CHP-system.

Assuming a price-elastic power demand the use of DSM-activities can have significant impacts on power prices and thus on RES-E capacity development when different support instruments are introduced. DSM activities reduce both the demand for conventional power and the demand for TGCs and therefore also the demand for RES-E produced power if a green quota related to the power consumption determines this demand. Thereby, it is ambiguous if the DSM activities in combination with the TGC system lead to lower total costs for the consumer or not. In the case of a feed-in tariff scheme, the amount of RES-E generation retains unaffected from the introduction of a DSM policy

Moreover, it is important to notice that the above-mentioned effects from the different instruments also exist when the policy instruments are combined.

Although mainly focusing on CO_2-reduction options in general, the introduction of a system of tradable emission allowances (TEA) at the national level will also have a positive effect on the promotion of RES-E technologies:

- The price at the power spot market will unambiguously increase because of the cost of reducing CO_2-emissions. The supply curve for power will be shifted upwards corresponding to the marginal costs of CO_2-reductions, that is to the emission allowance price. The resulting increase in the power price will depend on the price elasticity of power demand.
- Likewise, the consumer price will increase when a TEA system is introduced.
- The higher spot price will induce a stronger development of RES-E technologies, although RES-E will not be specifically favoured compared to other CO_2-reduction technologies like fuel switching to less carbon intensive production or efficiency improvements on both the supply and the demand side.
- For those companies and technologies covered by the emission trading system the CO_2-emissions will follow the determined quotas. For RES-E technologies outside the emission trading system the achieved volume of emission reductions is ambiguous. Either the RES-E power production will replace other conventional power production outside the TEA-scheme (for example small-scale natural gas fired CHP) and in this case national CO_2-emissions will be reduced. Or it will replace conventional power covered by the TEA-scheme, where in that case no reduction in CO_2-emissions will be achieved, because the conventional power plants still are emitting the allowed CO_2-quota.

7.2 Effects at an international level

Introducing the instruments in an international context might lead to different results, among other things because of trade among the Member States of for example green certificates and emission allowances.

Introducing an EU-wide TGC market will have the following effects:

- An international TGC-scheme will ensure that the RES-E deployment is made at locations where it is most efficient and profitable.
- The total conventional power demand is reduced according to the total green quota at EU level. The power price is reduced accordingly. If there is an EU-wide TGC market, the TGC price reflects the marginal RES-E production cost.
- As in a national system the development of RES-E technologies will lead to lower prices at the power spot market, assuming an increasing marginal supply costs for the conventional power plants and no market power.
- Even though the power price is determined at a common power market, the effect on consumer prices might differ between the Member States since the green quotas differ. Consumers in Member States with a relative small green quota, will enjoy the benefit of the decrease in the power price and only experience low extra costs of buying TGCs. Consumers in Member States with a relative large green quota, will also enjoy decreasing power prices, but will have a larger share of the TGCs price included in the consumer price. Therefore, it is likely, that the introduction of an EU-wide TGC market will lead to a reduction of consumer prices in Member States with small green quotas, and vice versa in Member States with large green quotas, i.e. the consumer prices will increase in these countries. Note that an equal burden sharing, that is the same relative quota in all countries, will lead to the same consumer price in all countries.
- As part of a liberalised power market the domestically achieved emission reductions will depend on the marginal conditions at the power market. Thus the nationally achieved emission reductions will have to be shared among those countries participating in the power market.
- The other benefits related to RES-E development of increased employment and industrial development will only be gained by those countries actually implementing the renewable technologies independent of the RES-E quotas in the individual Member States.

As for the national part, the effects of an international introduction of an EU-wide TEA is more straightforward than an international TGC-market, although some effects are ambiguous:

- The price at the power spot market will unambiguously increase because of the cost of reducing CO_2-emissions. The supply curve for power will be shifted upwards corresponding to the marginal costs of CO_2-reductions, that is the emission allowance price. The resulting increase in the power price will depend on the price elasticity of power demand.

- The new and higher level of the consumer price of power will be the same for all consumers within the liberalised power market.
- The higher spot price will induce a development of RES-E technologies in all countries, although RES-E will not be specifically favoured compared to other CO_2-reduction technologies. RES-E and conventional power production will be developed, where it is most efficient.
- If the Member States have different quotas for CO_2-emissions the costs for power producers will be biased if the tradable emission allowances are grandfathered (distributed free of charge depending on historic emissions) to the companies covered by the TEA-system. The higher the quota compared to the available CO_2-reduction options the better off they will be. Thus, in countries where the government wants to achieve significant CO_2-reductions by means of the TEA-scheme (low quota for all installations), the power producers will be hurt economically, compared to companies in countries with less ambitious CO_2-reductions (high quota for all installations).
- If allowances are allocated via an auction there will be no bias between power producers, even when countries have different quotas for CO_2-emissions.
- An equal burden sharing among MS in determining the quotas (that is the same relative reduction compared to previous emission) will imply the same (relative) economic effects on power producers no matter whether a grandfathering or an auction scheme is used to allocate allowances.
- For those companies and technologies covered by the emission trading scheme, CO_2-emissions will follow the determined quota (adjusted for trade in allowances). For RES-E technologies outside the TEA-scheme, the achieved emission reductions are ambiguous. If RES-E is replacing conventional power not covered by the emission trading scheme (for example decentralised fossil-fuelled CHP) the achieved emission reductions will have to be shared among those countries participating in the power market and will depend on the marginal conditions of the power supply at this market. If RES-E is replacing conventional power covered by the TEA-scheme, no further emission reductions will be reached, because the conventional power plants are still emitting the allowed CO_2-quota.

Pursuing an active national DSM policy in an international power market leads to less price reduction (especially if it is a small country). The national electricity generation decreases less than the demand reduction, as parts of the “free” electricity capacity will be used for exporting power. Hence, only parts of the CO_2-emission reductions due to the DSM activities remain in the country. Consumers in this country subsidies the consumers in all other countries due to the (slightly) lower power price.

Introducing an international TGC-system in addition to an international TEA-scheme will normally work out well, since the TGC’s be complimentary to the TEA’s. The TGC-system will favour the development of RES-E compared to other CO_2-reduction options, though the TGC-price will be lower than in a solitude TGC-system. But the pros and cons of the separate international TGC-scheme will still exist, although a strong coordination of the use of the two instruments will moderate the disadvantage of the emission reduction sharing of the TGC-system.

In addition to the above-mentioned instruments a number of so-called Kyoto-instruments exist, that might interact with those mentioned earlier, with regard to impacts on power and consumer prices, on the development of RES-E technologies and on the reduction of CO_2-emissions.

The Clean Development Mechanism (CDM) and Joint Implementation (JI) are both instruments expected to encourage the development of energy technologies with lower carbon emissions in the developing world. The interactions of CDM and JI with an EU tradable emission allowances scheme are summarized in the following:

- The acceptance of emission reduction units (ERU) and certified emission reductions (CER) as given by the CDM/JI-schemes to replace tradable emission allowances in the EU TEA-scheme will make it easier and cheaper for EU power producers to comply with the given EU emission quotas. Therefore the power spot price at the liberalised markets will go down, compared to a situation without the acceptance of CER/ERU.
- The lower spot power price will result in a lower development of RES-E technologies.
- If all renewable technologies are covered by an emission-trading scheme (TEA) the effect on global CO_2-emissions will be neutral, although it must be expected that CO_2-emissions within the EU will be higher (compensated by trade in ERUs/CERs). If a part of the renewable technologies is not covered by the TEA-scheme a slower RES-E development will imply a lower replacement of conventional power and thus a higher CO_2-emission.
- The lower spot power price will be beneficial for EU power consumers.

Finally, the interactions of CDM/JI are analysed with a combined EU TGC/TEA-scheme:

- As in the TEA-case the acceptance of ERU/CER will make it easier and cheaper for EU power producers to comply with the CO_2-quotas with a situation without ERU/CER replacing allowances and thus will imply a lower spot power price at the power market.
- The renewable quota will determine the development of RES-E and thus there will be no changes in the development of RES-E technologies compared to a situation without interactions with Kyoto-instruments.
- Due to the TGC-scheme the lower spot price will be compensated by a higher TGC-price.
- With an unchanged capacity of RES-E also the global emissions will be unchanged compared to a situation without Kyoto-instruments.

Many instruments exist to support renewable energy technologies and they interact at multiple levels. Although within the scope of this project it was not feasible to investigate all possible issues within this field, the cases analysed cover not only the needs and opportunities at the level of the national member states, but also those at the level of the EU. However, due to the character of these interactions it was, of course, not possible to discuss all problems within this field, but as shown above a number of the most important ones have been treated thoroughly.

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