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The Implications of Tradable Green Certificates for the Deployment of Renewable Electricity

Mid-Term Report

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Abstract

The issue of green certificates has received much attention in the recent year. In a system of green certificates, producers of renewable electricity receive a certificate for each pre-defined unit of electricity produced. Such a certificate represents the 'greenness', or in more general terms the 'societal value' of the production of electricity from renewable sources. By issuing green certificates two different markets are created for producers of renewable electricity: the market of physical electricity, on which they have to compete like any other electricity producer, and the market of green certificates. Demand for green certificates can originate from several sources. There might be a voluntary demand of consumers (e.g. by green pricing). Demand can also be imposed by the government on consumers or other actors in the electricity supply chain (generators, distributors, suppliers) via an obligation to generate, transmit, deliver or buy a certain amount of green certificates. The government itself can also act as a buyer of green certificates, e.g. by securing a minimum price or by a tendering procedure. In practice demand might come from a combination of these sources. Most current discussions and analyses on this issue take demand from an obligation as a starting point. This is also the case in this report. Proponents of a green certificate system regard it as an important incentive scheme for renewables in a liberalised market. Since many questions on the appropriate design of a green certificate system and the impacts on the deployment of renewable electricity sources are, as yet, unanswered, the EU decided to support a project to investigate these issues. In this report the results of the first six months of this project 'The Implication of Tradable Green Certificates on the Deployment of Renewable Electricity '(Altener Contract XVII/4.1030/Z/98-037) are summarised. Aspects of tradable green certificate systems that have been investigated include: The similarities and differences of green certificate systems that currently exist or are discussed within the several Member States; the effects of interaction with other incentive schemes for renewables; and the effects of interaction with possible climate change policies. Some preliminary conclusions can be drawn. The issue of green certificates is receiving increasing attention in several Member States (the Netherlands, Denmark, Belgium, Germany, Italy, Finland and the UK) from the side of the Government as well as the industry. Practical issues that are relevant for national systems are widely discussed and tackled in these countries. International trading is prepared by a group of utility companies from several Member States. Interaction with other incentive schemes is possible, but green certificate systems should be carefully designed to avoid unintended consequences, on the national level as well as on the international level. Interaction with climate change policy is an important issue. If the external value of the generation of renewable electricity is reduced to its value to avoid climate change, the tradability of green certificates is justified, and it can be expected that green certificate systems will be transformed and incorporated into a system of tradable climate change emission quota. However, this will not do justice to the remaining external values of renewable electricity. Part of these remaining values (e.g. emission of acid, job creation, diversification etc.) are related relatively more to the location of production than the benefit of avoiding climate change emissions. A question is whether making these values tradable all over Europe is justified.

CONTENTS

1. INTRODUCTION

In the first decade of the 21st century, global energy markets will be confronted with two issues that have increasingly dominated the international energy agenda during the last decades of the 20th century. These two issues are the liberalisation of energy markets on the one hand and the fulfilment of environmental targets put forward in the international policy arena on the other hand. The best known example of the latter is the Kyoto-agreement on the reduction of CO_2 and other greenhouse gas emissions. Another example is the indicative target that has been put forward in the White Paper on Renewable Energy of the Commission of the European Union. The White Paper states that 12% of the gross energy consumption in the European Union should come from renewable energy sources in 2010, a doubling compared to the 6% level of 1995. For electricity production this means that the share of renewables have to expand from the current 14% to about 23% (European Commission, 1999).

To realise environmental targets in a liberalising market, the design and implementation of policy measures and incentive schemes have to be in accordance with liberalised market principles. Current incentive schemes, most of which have been established in the pre-liberalisation situation, might not be able to fulfil this requirement. This emphasises the need for new policy measures, which are more in coherence with the new market.

A recently proposed new market-conform incentive scheme is known as the 'green certificate system'. The major characteristic of a green certificate system is that electricity produced by renewable sources is certified. These certificates have two purposes. It functions as an accounting system to verify whether demand has been met or, when there is no demand, to measure the amount of electricity produced from renewable energy sources (RES-E). Second, green certificates facilitate the creation of a green certificate market that functions independently from the market of electricity as a commodity.

First experiences with a green certificate system have taken place in the Netherlands. Denmark has agreed to introduce such a system starting in the year 2000. Other Member States are also interested. The European Commission considers this system as an option to reduce market distortions due to different state-aid schemes for renewables in the emerging internal electricity market. In order to get a better understanding of the consequences of such a system at a European level, the European Commission decided to support a study that investigates various aspects of a Tradable Green Certificate (TGC) system, including interaction with other incentive schemes, and interaction with climate change policy.

The project 'The Implication of Tradable Green Certificates on the Deployment of Renewable Electricity' consists of 4 phases. Phase 1 (January-February 1999) has been aimed at making an inventory of the state of the art of the current deployment of renewables, the renewable energy policies and degree of liberalisation in each of the 15 Member States. The purpose of Phase 2 (March-June 1999) has been to perform a set of analyses of a TGC system. During Phase 3 (July-October 1999) different possible designs of a TGC system will be investigated. A fourth phase (November-December 1999) is added to make sure that the results are disseminated appropriately. This report covers the preliminary results of the first two phases.

During the first phase 15 Inventory Papers have been written. Most emphasis has been put on the home countries of the team members (UK, Germany and the Netherlands). A bit less, but still substantial emphasis has been given to three other countries that are relatively active in renewable energy policy (Sweden, Spain and Denmark). More brief papers have covered the remaining EU countries. Chapters 3 and 4 will give a summary of the main similarities and differences between the Member States and the status of TGC systems in the Member States, which emerge from these Inventory Papers. The Inventory Papers themselves will become available in a separate report.

In Chapters 5 and 6 systematic analyses will be given of the possible ways a TGC-system can interact with other incentive schemes at a national and an international level, as well as with different ways of implementing climate change policy. Chapter (7) will round off the report by a summary and conclusions.

2. GREEN CERTIFICATES: INTRODUCTION AND DESCRIPTION

2.1 General features of a green certificate system

The main objective of a system of tradable green certificates is to stimulate the penetration of green electricity into the electricity market. In a green certificate system, certification serves two purposes. It functions as an accounting system to verify whether demand has been met or, when there is no demand, to measure the amount of electricity produced from renewable energy sources (RES-E). Secondly, it facilitates trade; through the establishment of green certificates (GCs) a separate market for the renewable characteristic of the electricity will originate besides the market for physical electricity.

2.1.1 Supply and demand of green certificates

Green certificates are created by the producers of electricity. Producers receive a certificate for each pre-defined unit of electricity produced from renewable energy sources that is put on the grid. Demand for green certificates can originate from several sources. There might be a voluntary demand of consumers (e.g. by green pricing). Demand can also be imposed by the government on consumers or other actors in the electricity supply chain (generators, distributors, suppliers) via an obligation to generate, transmit, deliver or buy a certain amount of green certificates. The government itself can also act as a buyer of green certificates, e.g. by securing a minimum price or by a tendering procedure. In practice demand might come from a combination of these sources.

For the sake of simplicity we will assume in the following analysis that demand originates from an obligation. In that case consumers of electricity are allotted with targets for the consumption or sale of electricity from renewable sources[1]. In order to show that they meet their targets, these consumers have to hand over certificates at a given point in time. Penalties are set if they are not able to fulfil their obligations. Therefore, consumers have an incentive to buy certificates from the producers and the certificates become valuable. It is expected that competition between producers will lead to declining costs of RES-E generation and increasing supply of green certificates. In this respect, the green certificate system is considered as a cost-effective way to meet the renewable energy target.

2.1.2 Green certificate market

Consumers will pay a price for the certificates in order to meet their target. The price will depend on the market, i.e. on demand (which is fixed by the target) and supply. With low supply of green certificates, the price will be high, which will be an incentive for new producers to provide renewable electricity. Moreover, in theory renewable energy will be provided in an efficient way because those producers who can provide renewable electricity at the lowest price will be able to sell their certificates. Figure 2.1 shows how the market for certificates will work. MC renewables is the marginal production cost curve of electricity from renewable energy sources. The target is set at Q, with corresponding marginal cost mc*. Given a market price (including general taxes) for electricity of P_E, the certificates will be sold for $P_C = mc^* - P_E$. Given the market price for electricity as drawn here, P_E, part of the renewable energy (up to A) would be produced even without a green certificate system, because it is already profitable. For these

[1] Here, consumers are those economic agents subject to the green certificate obligations (e.g. end consumers, distributors or generators). In Section 2.2 it will be discussed which economic agents might be subject to the obligation.

producers, the green certificate system will create extra profit (the difference between mc* and P_E. Total profit for renewable producers from the sale of electricity and the green certificates is equal to the area between the mc* line and the marginal cost curve, MC renewables.

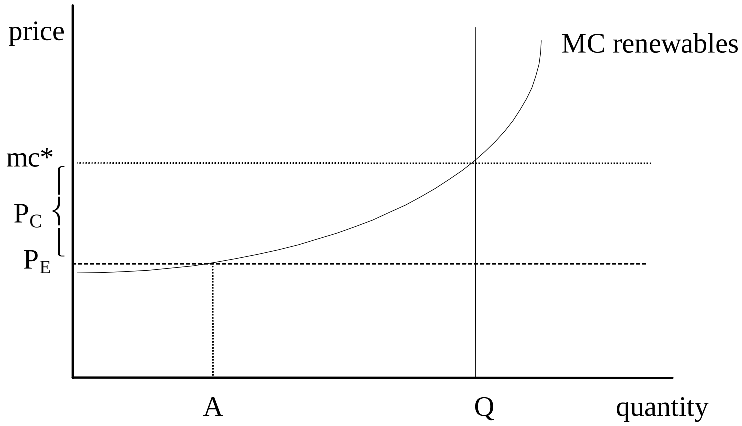

Figure 2.1 *Green certificates market*

It is expected that both a spot market and a forward market will develop for green certificates. On the spot market, consumers or distribution companies will trade green certificates that have been issued in the past. This market will be used to buy certificates to fulfil their obligation. On the forward market consumers or distribution companies can negotiate about long-term contracts i.e. they trade in green certificates that will be issued in the future. The forward market will be used to hedge for price risks, therefore securing investments into renewable electricity projects.

2.1.3 Functions and issues in implementing green certificates

We can identify six different functions in the institutionalisation of a green certificates system (see Niermeijer and Benner, 1999):
1. Issuing certificates,
2. Verification of the issuing process,
3. Registration of certificates and trade,
4. Exchange market,
5. Accounting of the certificates,
6. Withdrawing of certificates from circulation.

Green certificates are issued at the moment that actual green electricity is registered at the kWh-meter. Each certificate should be unique and separately identifiable. A paper certificate can represent it. Certificates may get a unique number, representing codes to identify the type of renewable energy source, the date of production, the owner of the green certificate, etc. The certificates are withdrawn from circulation at the moment that a customer accounts for his obligation by presenting the certificates to the registration authority. Certificates are also withdrawn if their period of validity expires. Between issuing and withdrawing green certificates, the certificates are accounted and can be traded. Accounting and trading of green certificates could be done by the owner of the certificates, but also by a ‘bank’, for example an energy utility or an association of producers. The organisation of the green certificate exchange could be coupled to e.g. the electricity exchange. All these activities require proper registration and verification.

Apart from these institutional functions, there are many other issues that have to be addressed in order to make a system of tradable green certificates work properly. Here we discuss four of them: the definition of renewables used, the time aspects of the obligation, the penalty for not reaching the target and the parties that should be obligated.

First, there should be an agreement on which energy sources are regarded as renewable, i.e. for which renewables green certificates are valid. For example, in documents of the EU it is assumed that electricity generated by large hydro plants is, in general, competitive and is therefore excluded from the scope of support. Clearly, this definition is based on cost and not on the principle of hydro being a renewable source. Furthermore, there is large controversy about the renewable value of waste. In this respect, it should also be clear what the renewable value of imported electricity is. Hence, the accreditation, verification and auditing of electricity generated from renewable sources are important issues.

Second, the targets, the point in time when the obligations will have to be met and the time validity of the certificates should be determined. These two aspects largely influence the stability of the system. In Section 2.3 a further discussion on appropriate setting of targets and time validity of certificates is given.

Third, if there is no penalty for failing to meet the target, a green certificate system will not work. The penalty should be higher than the market price of green certificates. There are different possibilities to set up a sanctioning system. For example, the penalties for actors with a deficit could be paid to the fiscal administrator or to a fund that stimulates projects in the field of renewable electricity. In the Netherlands, actors with a deficit will be forced to buy green certificates from actors with a surplus[2]. Van der Tak (1998) describes the problems that may arise in such a system.

Finally, it should be clear for which actors targets are set. The obligations regarding the minimum share of electricity from renewable energy sources could be put either on the distributors or on the consumers of electricity. The next section will deal with this question. In this respect the dimension of a green certificate is also important; if the obligation is put on the household level, the size of a green certificate should be smaller. Besides, consumers might voluntarily buy green certificates to stimulate renewable energy. In that case, the issue remains whether this part of renewable electricity generation should be additional to the obligations or whether it may contribute to reach the obligation.

2.2 Different models of a green certificate system with obligation

We may distinguish between different models of a green certificates system, according to the level at which the obligations are put and who pays the higher price for green electricity.

Demand for certificates originates from a voluntary business target, from an obligation from the government or from voluntary consumers' demand. Distribution companies or utilities may face an obligation for electricity generated from renewable energy sources. Thus at the date of settlement, the utilities have to show the proper amount of green certificates. The price of green certificates could be passed on to the consumers of electricity in the form of a general price increase. However, the price of green certificates may also be passed on to those consumers who have agreed to support renewable electricity, and therefore to pay a higher price. This system, however, does not seem to be sustainable, once consumers have found out that they are paying for something a utility is obliged to do anyway.

The obligation for renewable electricity can also be put on the consumers of electricity. At the date of settlement, consumers have to show the proper amount of certificates, which they have to buy from the utilities. Here, the price for electricity and the price of green certificates (green electricity) are strictly separated.

[2] Having a surplus of certificates seems irrational. However if banking is possible or if the certificate is still valid, actors may anticipate a target for the next period.

In order to structure the analysis of 'who to obligate', four different links in the electricity supply chain are considered: generation, wholesale, retail and consumers (Figure 2.2).

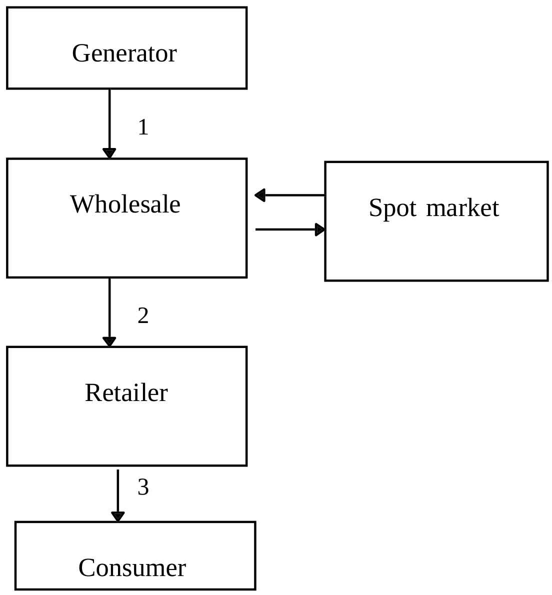

Figure 2.2 *Electricity supply chain (Hunt and Shuttleworth, 1996)*

In the choice of 'who to obligate' in a green certificate system some problems may arise. For ease of reference, the level of wholesales and retail will be combined as supply, since there is no distinction in the analysis between the two.

When the obligation is put on the supply companies (wholesale or retail) or on the generators, a green certificate system would lead to unfair competition for these companies vis-à-vis their foreign competitors that do not face a green certificate obligation. Under the current EU legislation, national Governments cannot enforce an obligation with respect to production methods on foreign companies entering the national market.

In a liberalised electricity market, customers are free to choose their supplier. When the obligation is put on suppliers, their supply cost increase. This will give (large) customers an incentive to by-pass the supplying company and buy their electricity directly from the spot market or from independent generators and thus avoid the green certificate obligation. When a green certificate system is introduced EU-wide, the different stages of market liberalisation in the different EU countries is also of importance. Utilities in a more protected market would have an advantage above utilities in an open market, since they can pass the extra cost to their captive customers.

Obligating generators

If a green certificate system is implemented nationally, and targets are put on the generators, the threat of unfair international competition does not seem to be relevant if the green certificate system is introduced at the European level, since the European electricity market can be considered as a closed system. At the same time, the problem of consumers by-passing the obligated supply companies does not seem to be relevant, since generators are at the top of the supply chain. However, the problem of different protection measures existing within the different countries could create unfair competition among generators.

Obligating suppliers

Obligating suppliers in a European context seems the least attractive option, since it would create unfair competition and also the problem that consumers can by-pass the suppliers would still prevail. However, this could be dealt with by a strict national licensing system requiring that every delivery of electricity is performed by a nationally licensed enterprise (which can be given to foreign companies as well). Such a license would include the obligation that a certain percentage of electricity supply should come from renewable sources. Since licensing procedures are different in the Member States, this option is not appropriate in all situations.

Obligating consumers

Putting the obligation on consumers dissolves the problems of international disadvantages of the electricity sector and bypassing by consumers. Unfair competition from countries with a high level of protection would still be possible, as in the case of generators. However, since consumers have the obligation for green certificates and supply or generation companies are not obliged directly, unfair competition seems to be minor problem in this situation. A disadvantage in this case could be the complexity and bureaucracy needed to check all consumers whether they have fulfilled their obligation. In practice this might be less problematic than it seems at first sight. It can be expected that most consumers obtain their supply through a licensed supplier and may pass on their obligation to the supplier of electricity, who, in turn, transfers the extra cost to the consumer.

From these arguments it can be concluded that the obligation for renewable electricity in a green certificate system should be put at the level of the end-consumers of electricity because it is the least distortive option. Table 2.1 summarises the considerations. In some cases putting the obligation on the suppliers could also be an option.

Table 2.1 *Market distortions per level of obligation*

Level of obligation	Green Certificate system introduced at national level only	Green Certificate system introduced European-wide with varying degrees of liberalisation
Generator	International competitive disadvantages because other countries have no target obligation.	International comparative disadvantage because of varying degrees of liberalisation.
Supply	Possibility of consumers to by-pass the obligated level.	Possibility of consumers to by-pass the obligated level.
	International competitive disadvantages because other countries have no target obligation.	International comparative disadvantage because of varying degrees of liberalisation.
Consumer		(International comparative disadvantage because of varying degrees of liberalisation).

Note that in a situation with different assumptions, e.g. if some customers will still be captive or if exchange in certificates is connected to the physical flow of the renewable electricity, conclusions might be different. See e.g. the UK Consultation Paper ‘New and Renewable Energy; Prospects for the 21st Century’, 1999.

2.3 Conditions for a stable green certificate system

A number of market imperfections may occur with respect to the implementation of the green certificate system. In this section the conditions required for a properly functioning green certificate system are analysed.

The intention of a green certificate system is to meet a renewable energy target in a cost- effective way using competitive market forces. The introduction of market forces will stimulate generators to incorporate cost into their decisions and operate in an efficient manner. As is known from general economic literature, for markets to work competitively, a number of conditions have to be fulfilled, such as:

- Sufficient suppliers and demanders to ensure that a single participant cannot influence the price and to ensure market liquidity.
- Market transparency and equal access to relevant information for all participants.
- No entry barriers and negligible transaction cost.

These general requirements will not be further discussed here. Instead, the focus will be on those conditions unique to a (government) created market, like the green certificate market. The first focal point of the analysis is price determination on a green certificate market as described the previous section. The next is to see how the specific nature of renewable energy systems will influence the supply of green certificates. The last part concentrates on the choices for the government in setting up a green certificate system.

2.3.1 Price volatility

When the green certificate system is accompanied by an obligation on utilities or consumers, demand for renewable electricity – and thus for green certificates – is fixed, except for voluntary (additional) demand. Supply of green certificates is determined by the installed capacity of RES-E. With a general characterisation of high fixed cost and low variable costs, renewable electricity suppliers will continue their production until the price is close to zero. When targets are to be met at a certain date and the certificates or the obligation is not transferable to the next period, the price of the green certificates is characterised by high volatility.

In case of under capacity, there will either be a strong upward pressure on installation of new capacity or (if the time period is too short for new installations) non-complying utilities or consumers will have to pay the penalty. In both cases, the price of green certificates is high. In case of over capacity, the supply of green certificates is higher than demand and competition among suppliers will lead to a strong downward pressure on the price of green certificates to nearly zero.

A number of options are available to prevent this price volatility. They can be divided into two categories:

1. Improve the flexibility of renewable electricity generators.
2. Improve flexibility on the demand side by changing the rules of the game.

Examples of both options are discussed below.

2.3.2 Validity of certificates

If green certificates are only valid in the year of issuing, the certificates produced in a certain year are worthless once all distribution companies have settled their obligation for that year. When in general the supply of green certificates is larger than the targeted demand, the price of certificates will decrease. Given this situation, the prices will even reduce to zero at the end of the target year. To stabilise the system, the validity of green certificates should be extended.

Each limitation to the validity of green certificates would mean that they would become more heterogeneous, which might lead to price differentiation and thus to a lower liquidity of the markets. Therefore, it is recommended to extent the validity of green certificates, i.e. to make banking of certificates possible.

Besides extending the validity of certificates to subsequent years, the validity of green certificates could be extended to meet targets before actual production of the green certificate has taken place, i.e. borrowing of certificates. This means that the expected green certificates to be generated in the next period (which can be purchased through forward contracts) can be used to meet today's obligations. This measure would also enhance supply side flexibility on the green certificate market in a number of ways. First, in case of shortage, the price will not reach the penalty rate, but instead market participants will purchase forward contracts to meet their obligations. Second, this measure will automatically correct for stochastic climate factors that increase the uncertainty in supply of green certificates. In case of a year with little wind, future green certificates can be used. Over the time span of the wind turbine, the produced green certificates will match with the targets for which its electricity was sold. Third, the extra demand for forward contracts resulting from this set-up, will help renewable energy developers to secure finance from finance institutes. It seems reasonable to restrict borrowing to a specified time period.

2.3.3 Financial and institutional barriers

External factors can cause the inability to expand capacity of renewable energy. Such inability could be based on the limitation in potential (biomass, onshore wind), or on financial and institutional barriers. In the Netherlands for instance, the expansion of onshore wind power is barred by the unwillingness of local governments to grant licenses for developing wind energy. Note that the Danes agreed to adjust the commitment to purchase certificates if supply development falls short.

A specific market barrier well known in renewable energy development is the access to finance. The renewables NFFO in the United Kingdom is the first example in Europe to support renewable energy in a competitive environment. With regard to obtaining finance, the NFFO experience has learned that market-based renewable energy development meets some difficulties. These problems are due to the newness but also to specific characteristics of renewable energy technologies, which do not match the requirements of the private sector financial system (Mitchell, 1995).

One of these aspects is the relative high proportion of initial investment required for renewable energy technologies. To reduce risk for investors and facilitate the access to credit, contracts are demanded to ascertain purchase of electricity. See Hunt and Shuttleworth (1996), for further reference on contractual relations to cover producer risk. Thus, the challenge for a renewable energy developer will be to find a market party who is willing to purchase all green certificates produced by the generator. The forward market with long term contracts could play a role in a green certificate system.

Another instrument is the use of financial options. For instance, through the issuance of put-options with a guaranteed price for which generators may, but do not have to, sell their electricity (Van der Tak, 1998). Crucial for these instruments is that counterparts can be found who are willing to take up the risk of a long-term green certificate obligation. Future expectations of the green certificate price are important in this regard.

If a green certificate system is only introduced nationally, the general condition of a sufficient number of suppliers and demanders cannot always be met. An international market will contribute to meeting the condition. It will also help to spread the risk of external factors or other barriers coming up in one country. In that case the supply needed to fulfil demand can come from other countries.

2.3.4 The role of the government

Implementing a green certificate system will help the government to meet its long-term renewable energy objectives. These long-term renewable energy objectives have to be translated into clear long-term targets, which do not change during the course of the years (due to the election of a new government, different priorities, etc.). This is an important condition to convince market participants that they will be able to recover their investments through the green certificate market. If market participants have the perception that the government might change the rules, they will try to anticipate such changes in their decisions (Van der Tak, 1998), leading to market distortions.

Clear consistent government policy is therefore an important condition for a stable green certificate system. One way to achieve this is to agree on a time frame in which the government stipulates the rules and required targets and will not further intervene in the green certificate system. The Government of the Netherlands has acknowledged this principal and has announced that in case a governmentally initiated green certificate system will be implemented the green certificate target will be announced for five succeeding years. The question remains whether five years is sufficient to give investors the investment security they wish.

Having a long-term time frame would in principle make a green certificate market work. Consumers can bank their purchased certificates until the withdrawing of certificates at the time of the obligation settlement. However, to keep markets liquid, it seems appropriate to bridge the time from the long-term targets, by translating them into intermediate targets set every year, or even every six months.

3. RENEWABLE ENERGY INCENTIVES IN A LIBERALISING EUROPEAN MARKET

3.1 Introduction

The purpose of this Chapter is to identify the differences and similarities of the renewable energy approaches (either implemented or discussed) in the various EU countries. First a general description will be given of the structures of EU-15 electricity sectors before the Electricity Directive 96/92/EC. A description of the current developments and future paths of liberalisation of these markets after the adoption of the Directive follows next. A description of the different renewable policies, including an analysis of the discussions on green certificate systems concludes this Chapter.

3.2 European electricity structure

To give a description of the structure of the electricity markets in Europe is difficult, because of the diversity between the various countries. Especially since the different countries are in transition to a new electricity market. However, Cross (1996) gave a useful historical review of electric utilities in Europe. He distinguished two groups of structural systems:

- centralised systems,
- decentralised systems.

In centralised electricity systems, one government-owned vertically integrated utility dominates the national electricity production and transmission, as well as a large part of the distribution sector. Centralised systems dominate in France (EdF), Ireland (Electricity Supply Board), Greece (Public Power Corporation) and Italy (ENEL). Belgium also has a centralised system (Electrabel), but it is mainly in private ownership. Traditionally, for these countries security of supply has been an important reason for choosing a centralised system, partly because of a poor indigenous energy resource base in those countries.

As Cross (1996) states it: ‘The basic system in each of these countries, excluding the Belgian anomaly for the moment, is that the dominant utility produces most of the country’s electricity needs, purchases surplus power from other domestic producers for resale, and transmits this power primarily on its own supply network. The dominant utility also controls imports and exports and in most cases has an exclusive statutory right over imports and exports. The relevant network operators are not obliged to offer access to ‘third parties’, and customers cannot seek different suppliers. The governments of these countries have accepted a view of electricity supply as a public service subject to central planning, not as a commodity to be subjected to a competitive market structure.’

A decentralised system is characterised by a variety of utilities in the electricity sector. The electricity supply can be under public, private or mixed ownership. In Denmark and the Netherlands, the utilities were developed bottom-up by local and regional governments or institutions. State intervention and privately owned utilities have been prevented in those countries, for reasons of large population density and small geographic areas (allowing the early utilities to quickly establish market dominance) and the lack of sites for hydro generation (that could have induced state intervention). In Germany and Spain complex mixed ownership structures have developed in electricity supply. Service territories demarcated the influences of decentralised monopolistic electricity companies in Germany.

‘Most of the decentralised systems have developed co-operative pooling mechanisms in order to gain the economic benefits deriving from larger interconnected power systems. National pooling systems have been developed in the Netherlands, Spain, Sweden, and England and Wales. Denmark has two separate power pools, operated by the grid companies Elkraft and Elsam, while Finland has several transmission grid operators. Germany never developed a national power pool, but instead operates on a regional basis.’ (Cross, 1996).

In the absence of legislation, co-operative pooling arrangements were established by the producers in the Netherlands and Denmark. Power producers were required to sell their electricity to the central grid operator, which then averages the costs to determine a standard price. Standard cost systems are used in Spain to provide an incentive for improved performance. Sweden has traditionally relied on the price-regulating effect of the state-owned utility Vattenfall. Instead of a co-operative power pool, the UK operates a day-ahead spot market for electricity.

In general, access to the electricity networks is regulated in the decentralised systems. The UK, Finland and Norway impose broad obligation for using the network system, while in Germany, Spain and the Netherlands specific legislation on network access exists. Luxembourg opposes third party access because of fears that foreign suppliers take over the market.

The electricity network systems are mostly interconnected in continental Europe and they are in parallel operation at the frequency of the Union for the Co-ordination of Production and Transmission of Electricity (UCPTE). In England, Wales and Scotland the National Grid Company operates the power pool. The grids of the Nordic countries Norway, Sweden, Finland and Denmark (eastern grid) are synchronous with each other (Nordel).

Table 3.1 *Characteristics of the electricity sector of the Member States before the Directive*

Country	Central/ Decentral	Ownership	Price regulation and exchange
Austria	Central	Public	
Belgium	Central	Private	Public recommendation
Denmark	Decentral	Mixed	Two power pools (Nord pool)
Finland	Decentral	Public	(Nord pool)
France	Central	Public	Monopolistic/governmental approval
Germany	Decentral	Private	Regional
Greece	Central	Public	Monopolistic/governmental approval
Ireland	Central	Public	Monopolistic/governmental approval
Italy	Central	Public	Monopolistic/governmental approval
Luxembourg	Decentral	Public	
Netherlands	Decentral	Public	National pool
Portugal	Decentral		
Spain	Decentral	Private→public	National pool
Sweden	Decentral	Public	National pool (Nord pool)
United Kingdom	Decentral	Public, regional authorities	National pool with day ahead spot market

3.3 Electricity market liberalisation arrangements

On 19 December 1996, the Council of Ministers adopted Directive 96/92/EC on the internal electricity market. Two months later on 19 February 1997 the Directive entered into force. By 19 February 1999, Member State should have the Directive implemented in national regulation. Belgium and Ireland are allowed one year of delay. Greece has been allowed a two-year delay.

The Directive establishes common rules for the generation, transmission and distribution of electricity. Its basic elements are described in the following (see also DG XVII, Guide to the Electricity Directive). For all the elements it is required that they are in line with objective, transparent and non-discriminatory criteria.

Generation
For the construction of new generating capacity, Member States may choose between the authorisation procedure and the tendering procedure. In the tendering procedure the Member State sets up an inventory of the need for future generating capacity, including the demand for electricity, based on estimations. In the authorisation procedure, applications that conform to the criteria for granting an authorisation should be authorised. Lack of demand is not a valid reason for refusal.

Transmission (the transport of electricity on the high-voltage interconnected systems)
Member States shall designate or require undertakings which own transmission systems to designate a system operator to be responsible for operating, ensuring the maintenance and if necessary 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, the TSO may give priority in the dispatching to electricity produced from renewables, waste and from combined heat and power (CHP). Priority can also be given to electricity produced using indigenous fuels but only up to 15% in a calendar year of the overall primary energy.

Distribution (the transport of electricity on the medium- and low-voltage interconnected systems)
A distribution system operator shall be designated who is responsible for maintaining a secure, reliable and efficient electricity distribution system in its area, with due regard to the environment.

Unbundling
The aim of unbundling is to avoid discrimination, cross-subsidisation and distortion of competition. Therefore, integrated electricity undertakings must in their internal accounting keep separate accounts for their generation, transmission and distribution activities.

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 distribution network.

- Negotiated third party access (nTPA) is characterised by the fact that producers and consumers of electricity will contract supplies directly with each other, but that they will have to negotiate access to the network with its operator. Such negotiations will deal with transport tariffs and other conditions. The operator may refuse access in case of lack of capacity. To promote transparency and facilitate negotiations for access to the system, system operators must publish indicative prices for the use of the transmission and distribution systems.
- In case of regulated third party access (rTPA) producers and consumers also contract directly with each other for supply. However, the price for the use of the transmission and distribution system can not be negotiated. The eligible customers have a right to access on the basis of published tariffs. For both nTPA and rTPA dispute settlement procedures should be set up.
- The *single buyer* is a legal person who is responsible for the unified management of the transmission system and/or for centralised electricity purchasing and selling. The single buyer would normally also be the TSO. The single buyer is obliged to purchase the electricity contracted by an eligible customer from a producer at a price that is equal to the sales price offered by the single buyer minus the price for the use of the network.

In either case, Member States shall take measures to enable producers and electricity suppliers to supply their own premises, subsidiaries and eligible customers through a direct line.

Market opening
The Directive provides for a gradual market opening in three steps. First, on 19 February 1999, final consumers with an annual consumption exceeding 40 GWh (corresponding to about 26% of each national market), are free to choose their electricity supplier. In the second step, on 19 February 2000, the threshold is reduced to 20 GWh (about 28%). Eventually, on 19 February 2003, the threshold is further reduced to 9 GWh (33%). Each Member State shall open the market such that they respect at least this minimum market opening. They define the eligible customers to participate in the market opening. However, very large final consumers of over 100 GWh and distributors responsible for the volume of electricity consumed through their distribution network by other final eligible customers must be included in the definition of eligible customers.

Public service obligations (PSOs)
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. The obligations shall fall into one of the following categories: security of supply, regularity, quality and price of supplies and environmental protection. PSO will allow Member States to balance competition with public services, where this is deemed necessary in the general interest.

Reciprocity
To avoid imbalance in the opening of electricity markets, the Directive contains some possibilities of refusing access for customers from other Member States when the Member State itself opens a larger part of the market than the other Member States.

Most of the EU Member States have already implemented basic national legislation liberalising their electric power markets (Tables 3.2 and 3.3 give an overview of the relevant legal acts). A few countries are still in the middle of the implementation process. The choices made by the Member States are generally aimed to be those that are most beneficial for effective competition to develop (Unipede/Eurelectric, 1999; European Commission DG XVII, 1999):

- Nearly all have adopted a system of access to the electricity transport network on the basis of regulated published tariffs (rTPA). Germany and Greece are the exception with negotiated Third Party Access (nTPA). Italy and Portugal opted for the single buyer.
- With regard to potential new producers and production plants, all but one Member State have chosen for an authorisation procedure. Portugal has chosen for a tendering procedure for the public system.
- With regard to transmission, almost all Member States have opted for the creation of legally separated transmission operators. Only in Germany, France, parts of the UK, part of Denmark and Austria the transmission system operator (TSO) will remain part of the vertically integrated electricity company.
- Almost all Member States have set up regulators independent of governments.
- Almost all Member States have chosen to liberalise more quickly and further than required by the Directive. Austria, France, Greece, Ireland and Portugal open their markets more or less in line with the minimum required by the Directive.

However, a number of operating rules that are crucial for an EU-wide market to function still has to be put in place. Instead of one single market for electricity currently there seem to be 15 fully or partially liberalised markets.

Table 3.2 *Legislation applying in each Member State*

	Name of law	Date of law/entry into force
Austria	Elektrizitätswirtschafts- und –organisationsgesetz (ElWOG)	18 August 1998
Belgium	Law on the organisation of the electricity market	29 April 1999
Denmark	• Energy Law, L486 • Political agreement on new Energy Law. • Bill on CO_2 quotas for electricity production	June 1996 March 1999 2 June 1999
Finland	Electricity Market Act	June 1995
France	Government bill on modernisation and development of the public electricity service	2 March 1999
Germany	• Gesetz zur Neuregelung des Energiewirtschaftsrechts (New Energy Act) • Stromeinspeisungsgesetz (Tariffs for RES-E)	29 April 1998 Changed 5 March 1998)
Greece	• Electricity Law • Law 2244/94 on RES-E • Draft law	1985 1994 1998
Ireland	Electricity Regulation Bill	1 December 1998
Italy	• Guidelines for the new Regulation of the National Energy System • Tariffs for Dispatch and Distribution of Electricity • Quality of Service of the Electricity Distribution Market • Legislative Decree (implementation of Directive)	1997 1998 1998 31 March 1999
Luxembourg	Draft Bill	
Netherlands	Elektriciteitswet (Electricity Act)	1 August 1998
Portugal	• 313/95 (IPP and autoproducers law) • 182/95-185/95 (Framework law, production, distribution, transport)	24 Nov. 1995 14 March 1997
Spain	• 2366/1994 (RES-E) • Electricity Act 54/1997 (special regime)	9 Dec. 1994 27 Nov. 1997
Sweden	Electricity Trade Act	1 January 1998
UK	Electricity Act	1989

Table 3. 3 *Implementation of the Electricity Directive*

	Production: type of system	Transmission: type of system	Distribution: type of system	Market opening	Eligible customers	Dispatch priority for indigenous fuels	Reciprocity	PSO	Stranded cost	Regulator	TSO	Transmission charges
Austria	Authorisation	rTPA SingleBuyer?	rTPA Single Buyer?	1999: 27% 2000: 2003: 50%	>40 GWh >20 GWh >9 GWh (distributors subject to higher thresholds)	none	yes, authorisation by minister	equal treatment of all consumers, general obligation to connect supply, duties in general interest, dispatch priority renewables, CHP, waste	8.7 bn ATS (632 mn Euro), some are large hydro plants	Ministry	Concession	
Belgium (+1 yr)	Authorisation	rTPA, nTPA for transit	rTPA	2000: 33% 2006: 40% 2010: 100%	>100 GWh	will be determined	yes	standard tariff for captive customers, security/quality of supply, social measures	yes	CREG for captive customers, Electricity Regulation Commission for open market	Daughter company of the existing companies	?
Denmark	Authorisation	will be determined	will be determined	90% new Act 2000: 2001: 2003: 100%	>100 GWh also for distributors >10 GWh >1 GWh all	none	no	obligation to maintain security of supply, consumer protection (connection and supply on equal terms), small scale CHP and renewables, CHP for district heating	yes	Electricity price committee and Gas and Heat price committee (new Energy Supervisory Board)	ELTRA? (ELSAM), ELKRAFT	postage stamp
Finland	Authorisation	rTPA	rTPA	100%	all	none	no	obligation to supply electricity at reasonable prices to captive customers	no	Electricity Market Authority	Fingrid (Finnish Power Grid)	postage stamp
France	Authorisation	rTPA	rTPA	1999: 25% 2003: 33%	>100 GWh	will be determined	will be determined	EdF	yes	Independent Electricity Commission	Independent part of EdF	postage stamp
Germany	Authorisation	nTPA	nTPA, optional transitional local SB	100%	all	lignite in East Germany	yes	obligation to connect captive customers, priority dispatch of CHP and renewables	network access restrictions in East Germany	Ministry of Economics/Cartel Office	several	postage stamp plus distance related if over 100 km
Greece (+2 yr)	Authorisation	nTPA	nTPA	2001: 23%	>100 GWh	lignite	yes	consumer and environmental protection to be further defined	yes	Regulatory authority	Independent body	
Ireland (+1 yr)	Authorisation	rTPA	rTPA	28%	>100 GWh consumers of >4 GWh under some conditions	peat, approx. 12%	yes	priority dispatch for CHP, renewables and peat, regulated tariff for captive customers	yes	Independent body for elec. And gas	New State owned company	

Italy	Authorisation	SingleBuyer + rTPA	?	30% 2002: 40%	>30 GWh included consortium	coal from Sardinia	no	obligation of connection, priority dispatch for CHP and renewables, equalisation of tariffs	yes	Independent authority for elec. And gas (AEEG)	Independent body	postage stamp with distance correction
Luxembourg	Authorisation	rTPA	rTPA	45%	>100 GWh	none	yes					
Netherlands	Authorisation	rTPA	rTPA	1999: 33% 2002: 62% 2007: 100%	>2 MW distributors for their eligible consumers	none	yes, authorisation by minister	obligation to provide captive customers at maximum prices, renewables schemes	3 bn FL	New unit of Ministry of Economic Affairs: DTE	Transmissio n and Dispatch company: TenneT	postage stamp and point tariff
Portugal	public system: tendering private system: authorisation	SingleBuyer + rTPA	SingleBuyer + rTPA	at least 26%	>40 GWh distributors eligible for 8% of consumption	none	yes	obligation to supply captive customers	yes	Entidade Reguladora: ERSE	REN	postage stamp
Spain	Authorisation	rTPA	rTPA	30% 2007: 100%	>15 GWh	coal, financial support	yes, authorisation by minister	guarantee of supply for all customers, levy to compensate for extra costs on islands, territorial supplements, refusal of access for lack of capacity, renewables schemes, 'special system'	1988.561 bn PTS	Ministry of Industry/Electric System National Board	Part of REE	postage stamp
Sweden	Authorisation	rTPA	rTPA	100%	all	none	no	holder of supply concession must sell electricity at regulated price and purchase from small producers, renewables schemes	yes	NUTEC	Svenska Kraftnat	postage stamp
UK	Authorisation	rTPA	rTPA	100%	all	none		financial help for customers in difficulties, services for aged and chronically ill, advice on efficient use of energy, NFFO	yes	OFFER	National Grid Company	connection, transportation and security charges

Sources: Unipede/Eurelectric (1999), European Commission DG XVII (1999), Country inventory papers.

3.4 Renewable energy activities and policies

3.4.1 Renewable energy activities

Political and historical background

The history of renewable electricity development, the current size of installed capacity and the mix of technologies varies widely between the EU Member States. The key factors driving the development of renewables have changed over the years. For almost all countries, the oil shocks of the 1970s added tremendous impetus to the development of renewables, primarily as a means to achieve more security of energy supplies. Later, other concerns began to dominate the development of renewables. Environment concerns began to manifest themselves during the 1970s. Policies and legislation geared towards promoting renewables to address the environment began to appear during the 1980s. Environmental concerns remain the most potent source of support for renewables in Europe today, although other concerns, such as regional development, opening energy markets to smaller players, exports and employment have grown in importance (The REALM research group, 1999).

One common theme amongst all countries has been, and continues to be, the predominant role played by electricity utilities as a mechanism for achieving social and political targets. That is, EU governments have chosen to use electricity utilities as instruments of their renewable energy policy. Consequently the utilities have proven to be one of the most important, the fastest and the most dynamic means for bringing on large amounts of renewable energy relative to any other sector or economic actor. Most legislation regarding renewables in the EU countries focuses primarily on the electricity sector. This seems likely to continue. However, it is not at all clear that this reliance on electricity utilities to meet national renewable energy targets can continue to achieve desired results in an open, liberalised electricity market, certainly not without substantial government support and intervention (REALM, 1999).

The definition of renewables

The definition of renewable or green electricity varies a lot between different countries. Electricity generated with wind turbines, solar cells and small hydro plants are generally considered to be green. Controversy exists about large hydro, imported green electricity and waste incineration. It is often the case that the definition of renewables is strict in countries where renewables already play an important role in electricity generation. For example, Austrian renewable electricity production is dominated by large hydro plant and in the new framework of promoting renewable energy, hydro (even small) is not included. Thus, it is important to make a distinction between existing and new renewable electricity generating techniques.

Table 3.4 *Electricity generated from RES in % of total electricity consumption*

	incl. Large hydro		excl. Large hydro	
	1996	1997	1996	1997
Austria	66.0		8.7	
Belgium	1.1	1.0	0.9	0.9
Denmark	6.3		6.3	
Finland	24.1		9.2	
France	15.5		2.2	
Germany	4.4	4.5	2.3	2.4
Greece	10.0	8.6	0.4	0.4
Ireland	4.0		1.1	
Italy	16.5	16.0	4.7	4.5
Luxembourg	1.6		1.6	
Netherlands	2.8	3.5	2.8	3.5
Portugal	44.6		4.7	
Spain	23.8		4.0	
Sweden	38.2		5.3	
UK	1.6	1.7	0.7	0.9
Total	13.5		3.0	

Source: European Commission, 1999.

The only renewable source of energy that has been exploited on a significant scale in the EU before 1990 has been large hydro. Since then, growth has been significant for all new renewables, between 15-30% per year. However, the overall contribution to the EU electricity market still remains small, around 3% when excluding large hydro (European Commission, 1999).

If the EU countries are classified according to the share of renewable energy sources, it becomes clear from Table 3.4 that Austria, Portugal, Sweden, Finland and Spain have the largest share of RES-E. At least 20 per cent of their electricity consumption comes from RES (incl. Large hydropower). Italy, France and Greece comprise the second group with 10 to 20 per cent of electricity consumption from RES. The remaining countries only have small shares of RES-E in electricity consumption.

However, if we disregard of large hydropower the ranking changes. Austria and Finland are still amongst the highest producers of RES-E, but then Denmark is also an important RES-E producer. In Denmark, RES-E is mainly produced with wind turbines and some combustion of biomass and waste. CHP systems, using wood waste and other biomass are widespread in Finland. Shares of renewables (excl. large hydro) in Greece, the UK, Belgium, Ireland and Luxembourg are very low. It is striking that in 1996 without large hydro, none of the EU countries produces more than 10 per cent of the domestic consumption of electricity. (Note: this has recently changed in Denmark. In early 1999 the share of renewable electricity production in this country exceeded 10%).

Another controversial renewable energy source is waste. Figures on the share of waste in RES-E are poor. In 1995, exploitation of the energy in municipal solid waste was especially large in Germany, France, Denmark and the Netherlands.

The largest increase in production of RES-E, excluding large hydro, has taken place in Denmark (from 2.4% in 1990 to 10% in 1999), the Netherlands (from 1.4% in 1990 to 3.5% in 1997), Spain (from 2.6% in 1994 to 4.0% in 1996) and Sweden (from 4.1% in 1994 to 5.3% in 1996). In other Member States, such as Germany and Belgium, the share of RES-E remained rather stable. The highest levels and largest increases in installed wind power capacity occurred in Denmark, Germany, Spain, the Netherlands and the UK (see Table 3.5).

Table 3.5 *Wind energy in EU Member States [MW]*

	End of March 1999	End of 1998	End of 1997
Austria	32	30	20
Belgium	12	8	7
Denmark	1560	1448	1148
Finland	18	17	12
France	19	19	10
Germany	3068	2875	2081
Greece	63	39	29
Ireland	73	73	53
Italy	223	180	103
Luxembourg	9	9	2
Netherlands	369	361	319
Portugal	60	60	38
Spain	834	707	512
Sweden	187	174	122
UK	341	333	319
Total	6868	6333	4775

Source: New Energy, no.2, May 1999.

It is expected that the importance of RES-E increase significantly over the coming years. This is confirmed by targets for the share of renewables generated electricity (excluding large hydro) in the different countries, see Table 3.6 (European Commission, 1999).

Table 3.6 *Targets for renewables and RES-E in the Member States*

	Share of RES-E	Renewable sources
Austria	3% in 2005	excl. hydro and waste
Belgium	3% in 2010 (2004)	
Denmark	20% in 2005 79% in 2030	
Finland	• 100 MW wind in 2005 • 25% increase in bio energy in 2005	Wind
France		
Germany		
Greece	255-355 MW in 2003	
Ireland	19.7% in 2010	incl. Large hydro
Italy		
Luxembourg		
Netherlands	3% in 2000, 17% in 2020	
Portugal	837 MW in 2006	
Spain	1200 MW in 2000	excl. Large hydro, incl. Waste
Sweden		
UK	10% in 2010	incl. Large hydro

3.4.2 Renewable energy instruments

All Member States support RES in one or more ways, via research and development, tax reductions/exemptions, guaranteed prices, investment subsidies and the like. The magnitude of the support varies largely between the Member States. Given the national situations, both policy priorities and the presence of natural resources differ between countries. Thus, there is a variety of incentive schemes for renewables within the EU Member States.

Investment subsidies

The most widespread instrument to stimulate renewable energy sources has been subsidies. In general, they can be divided into subsidies on renewable energy capacity and subsidies on renewable energy output. Subsidies on installed capacity only stimulate supply but not demand of renewable electricity. Moreover, subsidies on installed capacity might be unfairly distributed if the total amount of subsidy is limited, and they have to be abolished if the technology that is stimulated becomes too widespread (Schaeffer et al., 1999). In general, relatively higher levels of subsidy are given to promote the technological development of the as yet less economical technologies, such as rooftop PV systems. Technologies closer to the market, such as wind, do also in many cases profit from subsidies, albeit at relatively lower levels (European Commission, 1999).

Austria
Subsidy programmes for wind, hydropower, landfill gas, biomass and bio-gas systems. Subsidies were about 30% of investments.

Belgium
Subsidies of 15% (Walloon Region) and 25% (Flanders) of investment costs in RES apply.

Finland
Investment subsidy to heat and power plants when there is an opportunity for increased use of biomass (peat or wood). Maximum percentages apply on a case-by-case basis for new technologies: wind power 40%, other investment in renewable energy 30%.

France
A maximum subsidy of 30% of investments in biomass projects applies. For photovoltaic, small wind power and small hydropower projects in remote areas subsidies of 95% apply.

Germany
Investment subsidies used to be in place, e.g. during the 250 MW wind power programme.

Greece
Special framework for RES: capital investment subsidies up to 40%, interest subsidy up to 40%, subsidy for leasing up to 40%. Tax deduction up to 100% and interest subsidy up to 40% for investments in RES.

Luxembourg
First five wind power schemes subsidised with 3000 LUF/kW (75 Euro/kW). Private homes and other projects receive 25% of investment costs when installing photovoltaic systems.

Netherlands
Investors in renewable energy projects are eligible for a capital subsidy funded by a Green Fund at reduced interest rates (about 1.5%). In addition, accelerated depreciation and a tax credit, equalling to 15-20% of subsidy is applicable.

Sweden
Since mid 1997, new wind power plants receive a 15% subsidy of total investment costs for plants larger than 200 kW. New biomass facilities receive an investment subsidy of up to 25% of the investment costs (3000 SEK/kW or 344 Euro/kW). New small-scale hydropower (100 – 1500 kW) is also eligible for subsidies.

Feed-in tariffs (mainly based on Cerveny and Resch, 1998)

Subsidies on output, in the form of guaranteed prices in combination with a purchase obligation by the utilities, have proved to be very successful in promoting the deployment of renewable energy sources. The levels of guaranteed prices vary considerably from country to country. On average, regulation in Germany, Denmark, Spain and Italy offer the highest prices (European Commission, 1999). The appropriate regulatory authority to reflect falling prices due to technological progress may modify the fixed tariff. However, this may be resisted by existing RES-E generators. The tariff may also be supplemented with subsidies from the State, as e.g. in Denmark where a subsidy per kWh delivered to the grid is paid to independent producers (European Commission, 1999).

Austria

In Austria, the feed-in tariffs have seasonal (winter/summer) and time-of-day differentiations (day/night and weekends). For wind and photovoltaic systems, the average feed-in tariff over a year varies from 0.56 and 0.68 ATS/kWh (0.040 to 0.049 Euro/kWh).

Table 3.7 *Austrian feed-in tariffs in 1998*

		night/weekend [ATS/kWh]	day [ATS/kWh]	night/weekend [Euro/kWh]	day [Euro/kWh]
Wind and	Summer	0.40	0.55	0.029	0.040
Photovoltaic	Winter	0.61	1.08	0.044	0.078
Biomass	Summer	0.38	0.55	0.028	0.040
	Winter	0.59	0.90	0.043	0.065

Until early 1998, additional to the regular feed-in tariffs, utilities paid a bonus to independent producers for a period of three years after the construction of a new plant ('three-year agreement'). The bonus for wind and photovoltaic systems has been 100% and for biomass systems 20%.

Belgium

RES-E fed into the grid for a constant period of 24 hours a day receives an average of 2.26 BFR/kWh (0.056 Euro/kWh). RES-E supplied for only 10 hours a day during peak load and daytime hours, producers receive an average of 2.92 BFR/kWh (0.073 Euro/kWh). Discontinuous generation (i.e. photovoltaic and wind power) receives 1.98 BFR/kWh (0.050 Euro/kWh).

Denmark

A state subsidy of 0.07 DKK/kWh (0.009 Euro/kWh) applies for electricity production based on natural gas and renewable sources. Additionally, 0.17 DKK/kWh (0.023 Euro/kWh) is granted for RES-E.

Electricity from biomass systems is paid on the basis of avoided cost of the utilities and averages 0.27 DKK/kWh (0.036 Euro/kWh). In addition the energy/carbon tax is reimbursed and a government subsidy applies, which bring the total average feed-in tariff for biomass based electricity to 0.54 DKK/kWh (0.073 Euro/kWh). For wind power systems, the price is fixed at 85% of the net price for a consumer of 20000 kWh /year, and averages 0.31 DKK/kWh (0.042 Euro/kWh). In addition, a government subsidy for feed-in tariffs and reimbursement of the energy/carbon tax applies to wind power, totalling 0.27 DKK/kWh (0.036 Euro/kWh). This brings the total annual average price for wind power to 0.58 DKK/kWh (0.078 Euro/kWh). For photovoltaic systems feed-in tariffs are the same as for biomass.

The political agreement on electricity reform (March 1999) provides for a settlement price of 0.33 DKK/kWh (0.045 Euro/kWh, corresponding to the 85% rule) and a 0.10 DKK/kWh (0.014 Euro/kWh, 'CO_2 10 ore') tax refund for wind power until a well functioning market for renewables has been established. In addition, a 0.17 DKK/kWh price subsidy for wind capacity up to

200 kW for the first 25000 full-load hours will be paid. For wind capacity between 201-599 kW the first 15000 full-load hours and for capacity of 600 kW and above the first 12000 full-load hours the 0.17 DKK/kWh also will apply. The CO_2 10-ore tax refund and 0.17 DKK/kWh price subsidy also will apply for other private RE-plants. For biogas plants the settlement price will be 0.33 DKK/kWh (0.045 Euro/kWh). Existing RE-systems financed by these rules will not get RE-certificates.

New wind turbines constructed up till the end of 2002 will receive the settlement price of 0.33 DKK/kWh (0.045 Euro/kWh) for a period of 10 years. Other new RE-plants will get 0.50 DKK/kWh (0.068 Euro/kWh) for a 10 year period. Special provisions for the replacements of old wind turbines will also be implemented.

France
EdF is obliged to purchase independent power production at a rate based on the avoided cost for EdF, which is about 0.3 FRF/kWh (0.046 Euro/kWh). This tariff is mainly used for small hydropower. For CHP from biomass and waste an average value of 0.4 FRF/kWh (0.060 Euro/kWh) applies.

Germany
The Stromeinspeisungsgesetz (Electricity feed-in law) in Germany provides for a fixed price that all renewable generators receive and operators of the grid are forced to accept renewable electricity produced in their area. To protect the operators of the grid for high financial loads, a toughness condition is included in the new act. A regional limit of 5% renewable electricity is set. If the renewable electricity production increases this threshold in a supply area, the operator is exempted from the obligation to purchase and refund.

The price is fixed on the basis of average revenues during the last but one year, i.e. the value for 1995, as published in the official federal statistics, is the starting point for the 1997 calculation of the fixed price. In 1997 the fixed tariff amounts to 0.1906 DM/kWh (0.098 Euro/kWh). The rate for hydro and biomass systems totals at least 80% of the average revenue (1997: 0.1524 DM/kWh or 0.078 Euro/kWh). For hydro with an output of more than 500 kWh, the rate is 80% for the deliveries up to 500 kWh and 65% for the additional supply (1997: 0.1238 DM/kWh or 0.063 Euro/kWh). For solar electricity and wind power the rate is at least 90% of the average revenue (1997: 0.1715 DM/kWh or 0.088 Euro/kWh).

Greece
Feed-in tariffs in Greece are based on the selling price of electricity and depend on the grid type (high/low voltage). For autoproducers that sell their surplus power produced with renewable sources to the Public Power Corporation (PPC) the tariff is 70% of the selling price (depending on the voltage and peak zone 4.91 to 18.08 GDR/kWh or 0.015 to 0.054 Euro/kWh). For Independent Power Producers (IPPs) it is 90% of the selling price, i.e. 6.31 to 18.79 GDR/kWh (0.019 to 0.057 Euro/kWh). In addition, the IPPs receive a capacity credit that varies with the type of renewable system (wind and solar, small hydro, biomass) and the voltage of the interconnected system.

Italy
Feed-in tariffs in Italy are based on avoided cost and higher investments cost for RES-E projects, and apply for eight years. A distinction is made between IPPs and autoproducers. IPPs production from biomass and photovoltaic systems receive 270.5 L/kWh (0.141 Euro/kWh). After eight years the rate is reduced to 89.9 L/kWh (0.047 Euro/kWh). Electricity from wind turbines receive 183.7 L/kWh (0.096 Euro/kWh). For autoproducers the feed-in rates differ for peak load (days) and off-peak (nights, weekends and August) deliveries. In addition the rate depends on the regularity of their deliveries. The average annual rate for biomass and photovoltaic systems is estimated at 225 L/kWh (0.117 Euro/kWh). After eight years the rates are reduced.

For wind power the rate for peak deliveries is 232.9 L/kWh (0.122 Euro/kWh), the low rate is 47.9 L/kWh (0.025 Euro/kWh) and a bonus is granted for regular deliveries.

Luxembourg
For non-utility electricity, feed-in rates differ between small and large producers. Producers of up to 500 kW of electricity from wind and photovoltaic systems (and some biomass) received 4.03 LUF/kWh (0.100 Euro/kWh) in 1997. The rate for producers in the category 501 to 1500 kW amounts to 2.30 LUF/kWh (0.058 Euro/kWh) during the day and 1.20 LUF/kWh (0.030 Euro/kWh) during night hours. A bonus of 4500 LUF/kW (112 Euro/kW) is granted for average peak load deliveries.

Portugal
RES-E producers are guaranteed to receive 90% of the income received by applying the prices in the start-up year.

Spain
Feed-in tariffs for six different categories (according to size and technology) of electricity generation from renewables and CHP are based on avoided costs. The average feed-in tariff for biomass-based electricity is about 10.56 PTA/kWh (0.065 Euro/kWh). For wind, photovoltaic and small hydro projects the rate is about 12 PTA/kWh (0.074 Euro/kWh). Since 1997 a special regime for producers of up to 50 MW, using co-generation and renewable sources, applies. The feed-in tariff in this special regime is set at 80-90% of the average price (excl. any tax) of electricity.

Sweden
Small generators (<1.5 MW) have to receive a price that is in line with the average household tariff minus the costs for administration and the profit mark-up. The average rate for wind power was 0.27 SEK/kWh (0.031 Euro/kWh) in 1996. In addition, a governmental environmental bonus of 0.125 SEK/kWh (0.017 Euro/kWh) applies. Biomass plants do not receive the environmental bonus.

Bidding systems
One way to give all players an equal opportunity that includes a mechanism to drive down costs is to provide a limited subsidy on output that is awarded to only a limited number of investors. These investors will have to compete for the subsidy through a bidding system. For each bidding round only the most cost-effective offers will be selected to get the subsidy. The RES electricity is sold at market prices, while the difference between sale and purchase price is financed through a non-discriminatory levy on all domestic electricity consumption. The Member State decides on the desired level of RES, the mix between different renewable energy sources, their growth rate over time and the level of long-term security offered to producers over time.

Bidding or tendering systems currently prevails in the United Kingdom and Ireland. France and Austria also use this instrument on a small scale.

Austria
In May 1998, investors in wind turbines were invited to submit their offers. Contracts were awarded to the most cost-effective projects. Information on the capacity and winning bids is lacking.

France
A bidding process was introduced in 1996 under the national wind power programme EOLE 2005. In the final stage, to be reached in 2005, a total output of 250 to 500 MW is to be achieved. For the first stage of 15 MW, a feed-in tariff of 0.38 FRF/kWh (0.058 Euro/kWh) during 15 years has been achieved. For the next stage of 35 MW, the tariff is expected to reduce to 0.34 FRF/kWh (0.052 Euro/kWh).

Ireland
The principal support instrument for RES-E in Ireland is the Alternative Energy Requirement (AER). It is a competitive bidding system and guarantees the successful developers a 15 year power purchasing contract with ESB at the amount of their bids which is indexed. Additionally, developers can get capital subsidies. Since 1994, there have been 4 AER rounds. In the first AER round feed-in tariffs were fixed in advance amounting to 6.1 to 6.6 p/kWh for day hours and 2.4 to 2.5 p/kWh for night and weekend hours. The 111 MW had to be completed at the end of 1997, however, only 75 MW was actually completed at that time. The second round focused on biomass and waste-to-energy projects. The project must be completed by the end of 1999 and will receive a subsidy of 9.3 million Euro. The third round treated the technologies separately in the competition with an additional small wind (<5 MW) and pilot wave energy plant included. The bidding cap for the wave plant was 5 p/kWh. Additional capital subsidies of 80000 Euro per MW installed (1.24 million Euro for the wave plant) were offered.

Table 3.8 *Results of the Irish AER rounds [MW]*

	AER 1 (1994)	AER 2	AER 3 (1997)	AER 4
Wind	73	-	101 large 36.5 small (<5MW)	
Biomass and biogas (and waste)	12	30	17	
Hydro	4	-	4.4	
CHP	22	-	-	
Total	111 (end of 1997)	30 (end of 1999)	160	
Completed	75			
Bidding cap	-	3.6 p/kWh	3.9 p/kWh	
Successful bids	4 p/kWh (0.051 Euro/kWh)	3.2 p/kWh (0.014 Euro/kWh)	2.21-3.9 p/kWh (0.028-0.05 Euro/kWh)	

United Kingdom
Renewable energy is supported in the UK by a market mechanism known as the Non-Fossil Fuel Obligation (NFFO). The previous Government’s renewable energy policy was to award five NFFO Orders, the last of which was recently announced. The NFFO obliges the current Regional Electricity Companies (RECs) to buy a certain amount of renewable electricity at a premium price. NFFO contracts are awarded as a result of competitive bidding within a technology band on a pre-arranged date. This means that wind projects compete against other wind projects but not against, for example, waste to energy projects. The cheapest bids per kWh within each technology band are awarded contracts, and these are announced as an Order by the Secretary of State (for example, NFFO1).

The NFFO generators are paid their (premium) bid price per kWh. The Non-Fossil Purchasing Agency (NFPA), a wholly owned accounting body of the RECs, reimburses the difference between the premium price and the pool selling price to the RECs. This difference is paid for by a Fossil Fuel Levy on electricity, paid for by electricity consumers. Renewable energy projects received around £137 million in 1997/98 from the fossil fuel levy (FFL), with £116 going to the NFFO in England and Wales. NFFO1 and NFFO2 contracts were until the end of 1998, while NFFO3 to NFFO5 contracts are for 15 years, following a maximum 5 year development period.

Table 3.9 *NFFO prices [p/kWh]*

Technology Band	NFFO1 Cost-justification	NFFO2 Strike Price	NFFO3 Average Price	NFFO4 Average Price	NFFO5 Average Price
Wind	10.0	11.0	4.43	3.56	2.88
Wind sub-band	-	-	5.29	4.57	4.18
Hydro	7.5	6.0	4.46	4.25	4.08
Landfill Gas	6.4	5.7	3.76	3.01	2.73
M&IW (mass burn)	6.0	6.55	3.89	-	-
M&IW (fluidised bed)	-	-	-	2.75	2.43
Sewage Gas	6.0	5.9	-	-	-
EC&A&FW (gasification)	-	-	8.65	5.51	-
EC&A&FW (residual)	-	5.9	5.07	-	-
EC&A&FW (AD)	6.0	-	-	-	-
M&IW with CHP	-	-	-	3.23	2.63
Average price	7.0	7.2	4.35	3.46	2.71
Total contracted [MW]	152.12	472.23	626.91	842.72	1177
Total completed/commissioned [MW]	144.53	173.73	652.39	847.42	n.a.

M&IW = Municipal and Industrial Waste
EC&A&FW = Energy Crops and Agricultural and Forestry Waste
AD = Anaerobic Digestion

Voluntary green pricing

Green energy in the form of green electricity has been offered as a product to customers since 1995, first in the Netherlands and later on also in other European countries (e.g. Finland, Sweden, UK, and Germany). Customers that buy green electricity pay a premium on their electricity price. Their utility guarantees that the same amount of electricity for which they pay a premium price has been produced at a renewable basis. This is monitored by an independent organisation, often NGO's such as the World Wildlife Fund. Green electricity pricing is a voluntary market initiative of the electricity sector.

Table 3.10 *Overview of voluntary green pricing systems*

	Organisation/accreditation	Name of label	Price difference
Finland	• Nature Conservation Society New hydro, peat and waste are excluded	• Eco label	• 0.05 FIM/kWh
	• Various utilities	• Various 'flavours' of electricity	• 0.05 FIM/kWh
Germany	• Approx. 15 nation-wide schemes • Large number of local schemes		
Netherlands	Various utilities:		
	• NUON	• Natuurstroom	
	• ENW/Remu (World Wildlife Fund)	• Ecostroom	
	• Pnem/Mega		
		• Groene stroom	
Sweden	• Nature Conservation Society	• Bra miljöval	
	• Vattenfall	• Elvira fund	
UK	Various utilities • Green Electron • The Renewable Energy Company • WRE		

Fiscal instruments

Some EU countries support renewable electricity via the tax system. These schemes may take different forms. These forms range from rebates on general energy taxes, rebates from special emission taxes, proposals for lower VAT rates, tax exemption for green funds, to fiscal attractive depreciation schemes.

Finland

In 1990, Finland was the first country to impose a carbon-based tax. Renewable energy sources were exempted from this tax, peat has been taxed at a lower rate because it is considered as a 'slowly renewable'. Later on, the focus of taxation shifted from input fuels to the end-product, i.e. electricity. For private consumers, the service sector, farmers and the public sector the tax on electricity was 31 FIM/MWh (5.4 Euro/MWh) in 1997 and 33 FIM/MWh in 1998. For industries and greenhouses the tax was 16.75 FIM/MWh (2.8 Euro/MWh) in 1997 and 20.2 FIM/MWh in 1998. Electricity produced with wood-based fuel, wind and small hydropower is refunded as a subsidy to the producer.

Greece

Tax deduction for costs involving the purchasing and installation of renewable energy applications since 1995 (75-100% deduction).

Italy

Consumers pay a thermo levy and a renewable new plants levy to the national compensation electric fund. This fund pays the avoided fuel costs and a subsidy to the RES-E producers.

Netherlands

Since 1997 domestic consumers pay a Regulatory Energy Tax (REB) on their electricity consumption (above a level of 800 kWh/year)of 3.5 cents/kWh, including 17.5 % VAT (appr. 1.6 Eurocents/kWh). The aim of this tax is to stimulate energy conservation. The tax is paid by the consumers to the utilities, which have to transfer it to the treasury. An exception is made for electricity generated by renewables. This rule of exception increases the profitability of renewables. Currently the exception rule applies to all renewables, except waste incineration.

Another fiscal incentive is to so called VAMIL scheme (Accelerated Depreciation of Environmental Investments) This allows investors in environmental technologies (defined explicitly by a VAMIL-list) to freely offset their investments against taxable profits, resulting for the investor in an interest benefit. All renewable technologies are included in the VAMIL-list.

Since January 1997 there exists an Energy Investment Relief Scheme. Investments technologies that are explicitly defined on a qualifying list (including renewable energy technologies) may be offset against taxable profit at a rate varying from 40% to 52% of the total investment (with a maximum of Dfl 50 million (= appr. Euro 22.5 million) per investment).

Last but not least there are green funds. Private persons investing in a green fund are exempted from tax on the interest income from that fund. Under the current tax system in the Netherlands this comes down to return on investments criteria that can be about 50% lower than for other investments.

Table 3.11 *Instruments for stimulating electricity generation from RES*

	Investment subsidy	Feed-in tariff	Tender	Fiscal or tax	Voluntary schemes	Green certificates
Austria	o	+	o			
Belgium		o		o		+
Denmark		o		o		+
Finland	+			o	+	
France	+	o	o			
Germany	+	+			o	
Greece	+	+		o		
Ireland	+		+	o		
Italy		o		o		
Luxembourg		o				
Netherlands	+			o	o	+
Portugal		o				
Spain		o		o		
Sweden	+	o			o	
UK			+		o	

+ = main instrument
o = additional instrument

4. GREEN CERTIFICATE SYSTEMS IN EUROPE

4.1 Netherlands

A system of green certificates for RES-E is actually implemented in the Netherlands. The initiative was taken by the electricity sector. However, the new Electricity Act (and for that matter also the proposal for a new Gas Act) also provides for the possibility to introduce RES-E obligations with certificates after 2000.

In January 1998, the Dutch energy distribution companies, united in EnergieNed, have voluntarily introduced the Green Label system, which establishes a market for renewable electricity. The certificate system should achieve a target of 1.7 billion kWh electricity produced by renewable energy sources in 2000. The first binding target is set for (the end of) 2000, up till then the distributors have the chance to get acquainted with the Green Labels. It is expected that trading will really develop in the year 2000 when distribution companies have to meet their individual targets. Thereafter, no target applies, so trade in certificates is expected to drop.

Each distribution company is allotted a minimum target (quota) for electricity from renewable sources, based on past sales volumes (in 1995). In order to meet its quota, a distributor has to hand over so-called Green Labels. Producers of renewable electricity, who receive one Green Label for every 10,000 kWh electricity produced from renewable sources, create the Green Labels. Distributors and customers generating their own electricity from renewable sources can also receive Green Labels in return. If their renewable autogeneration exceeds their obligatory targets, they can capitalise the difference by selling their Labels. This will encourage further introduction of autogeneration of renewable electricity by private individuals, offices and firms.

Since the end of 1998, EnergieNed has taken several initiatives to internationalise the Green Label system. Contacts exist with German (PreussenElektra, REW), Danish (Elkraft) and British (Eastern, National Wind Power) utilities on this issue. The Dutch ENW-NUON group has bought the first Green Labels from the British producer of renewable energy, National Wind Power.

4.2 Denmark

In a political agreement of 3 March 1999 on a new Danish Electricity Act, a market for green certificates with obligations for the consumer was announced. The obligation will be 20% by 31 December 2003, compared to the 10% share of electricity production today. 500 MW onshore wind and 300 MW offshore can reach this, for instance. Certificates will be issued fore electricity produced by wind turbines, biomass, solar cells, geothermal plants, small hydro-energy plants (<10MW) and ‘new renewable energy technologies’ (whatever that may be). Production from existing renewable plants that is already financed by other (transitional) instruments will not get certificates. For subsequent years, intermediate obligations will be announced, which shall not surpass 20%. If the development of renewable sources in a single year will, against expectations, not be enough to cover the demand induced by the obligation, then the commitment to purchase will be reduced in accordance. After 2003 obligations on consumers will continue to play an important role, possibly besides other measures. Post-2003 targets have not yet been set. The penalty to the consumer for not fulfilling the purchase obligation is set at 0.27 DKK/kWh (0.037 Euro/kWh). There is a minimum price to be paid by the supply-obligation companies for a certificate when issued. This minimum is set at 0.10 DKK/kWh (0.014 Euro/kWh).

4.3 Belgium

Article 7 of the federal law of April 1999 on the organisation of the electricity market incorporates the possibility to establish market-based instruments in order to ensure a minimum supply of RES-E against a minimum price.

The regional government of Flanders issued a draft decree for the introduction of TGCs. The decree is to be approved by parliament end of 1999 and the certificate system should start already in 2000. A target of 3% RES-E in 2010 has been proposed with a penalty of 5 BF per kWh (0.12 Euro/kWh) if the supply companies fail to meet the target. The new government, which included the Green Party, will probably change the date of this target to 2004. The target is to be reached entirely with domestic production. Eventually, international trade in certificates have to emerge. However, Belgium is awaiting the viewpoint of the European Commission in this matter. Moreover, a link with CO_2 policy is not yet foreseen in the Belgium green certificate system. The regional government of Wallonia approves the instrument of a quota market.

The target is very ambitious, since it means a 31% per year growth rate of renewables between 2001 and 2004, only to be reached with domestic production. It forms a new challenge the electricity industry in addition to the nuclear phase down.

4.4 Finland

In Finland it was decided that a green electricity market should be a market initiative in which the government will play no role. The green electricity market is taking its first steps in Finland. The market is a totally voluntary initiative on the part of utilities, consumers and the Nature Conservation Society. The Nature Conservation Society announced a national accreditation standard for Green Energy in July 1998. The standard covers electricity and heat production from renewable sources. The Society took two years to prepare the standard and is now working on harmonising its accreditation criteria with the Norwegian Nature Conservation Society's energy 'ecolabel' and the Swedish Nature Conservation Society's 'Bra miljöval' 'ecolabel for electricity' which has been in operation since November 1995

Utilities can request accreditation, which they are awarded after the Society has checked that they fulfil the criteria. In general, wind, old hydro, biomass and PV are accredited, (within set boundary conditions). New hydro is specifically excluded from the scheme as well as the use of peat and any form of energy from waste. The Society plans to label energy efficiency measures in the future, and has designed stringent conditions for this.

Some consumers are willing to pay a higher tariff for green electricity (typically FIM 0.05/kWh) and ten to fifteen utilities, to date, have applied for and been awarded the green label. The Nature Conservation Society charges for the accreditation service and will audit each utility every third year after accreditation, charging again for this service. In addition to the Nature Conservation Society label, various utilities have announced their own labels for wind electricity and bio-electricity. These 'flavours' of electricity also attract a premium (also around FIM 0.05/kWh). Around ten utilities now offer wind electricity. Individual customers for wind electricity are counted in hundreds, but it is likely that their number will increase.

4.5 Germany

The discussion on quotation models for the promotion of electricity from renewable energy sources, which could be supplemented by tradable green certificates has intensified recently. For the promotion of local CHP schemes, detailed proposals to introduce a quotation model in combination with tradable certificates have been worked out. Because of the sharp decrease of wholesale market prices for electricity, most of the CHP plants operated for district heating at the municipal level are not economically viable any more. As CHP is one of the most important measures for the reduction of greenhouse gases and conservation of fossil fuel, it is intended not to look at these CHP plants as 'sunk costs' but to enhance their economic viability. An instrument for this, which is regarded to be compatible with a market-based framework, would be an obligation for each consumer to buy a minimum quota of electricity from CHP or to buy the corresponding amount of CHP certificates. A draft for federal regulation for such an instrument has been developed by some Länder governments (including the social-democratic government of Schleswig-Holstein) and is supported by the local utilities. This will be a main topic of the upcoming discussion on necessary amendments to the new Act on the Electricity and Gas Supply.

In the field of electricity from renewable energy sources, a discussion on quotation models and green certificates has begun in the scientific community. Some scientific and legal experts are closely monitoring the developments in the Netherlands and in Denmark. For Germany, first conceptual drafts have been published. These first drafts have produced quite strong opposition mainly from the associations of renewable electricity producers and environmental NGOs. Both groups argue, that the current strong momentum in the development of wind energy, which has been produced by the feed-in regulation, could be stopped, if the promotional instrument is changed. One of the substantial arguments for keeping the feed-in regulation is that mainly private investors have produced the strong development of wind energy in the past eight years. Those investors can deal much better with a guaranteed feed-in tariff than with a defined quota for electricity from renewable energy sources, because the development of the price for the certificates can not be predicted. This will make it more difficult to raise money from private investors or to get credits from banks for renewable electricity projects. There is also a beginning discussion on quotation models and green certificates for electricity from renewable energy sources in the electricity industry. The utility association VDEW has formed a working group on this subject and has announced to publish a conceptual draft.

In the electricity industry, there is not yet a common position regarding quotation models and 'green' certificates for electricity from renewable energy sources. PreussenElektra (PE), the transmission system operator in the largest part of northern Germany, has suggested to introduce minimum quota. But PE is opposing the principle of the TGC system to separate the physical flow of electricity from the trade of certificates. PE argues, that the electricity fed in under the regulation reduces the operation of their power plants. The 'trade floor model' of PE treats RES-E electricity and its 'green' quality together and obliges other system operators not only to buy TGC, but also to buy the electricity at the same time. Bayernwerk is more in favour of a funding system, which in fact would lead to a tendering system. RWE on the other hand is taking part in the RECS group and has decided to establish a TGC test market together with utilities from the Netherlands, Denmark and the UK. Others like HEW are monitoring the development very closely.

4.6 RECS

A number of utilities from the Netherlands, Denmark, Germany and the UK, organised under the acronym RECS (Renewable Electricity Certificate System) have started to prepare the possibility of international green certificate trading. A first pilot trade in green certificates took place in early 1999 between National Wind Power (UK) and Energie Noord West (NL). Many practical issues are tackled in a working group of these utilities. International trade is expected to start in the year 2000. At that moment at least two countries (NL and DK) will have green certificate systems, which makes international trade possible. Utilities from other countries are also considering setting up green certificate systems, in order to be able to take part in international trade.

Table 4.1 *Overview of green certificate activities in Member States*

	Activity at the level of		
	Government/legislation	Electricity sector/RECS	Consumers (green pricing)
Austria			
Belgium	×	×	
Denmark	×	×	
Finland		×	×
France			
Germany	(×)	×	×
Greece			
Ireland			
Italy		×	
Luxembourg			
Netherlands	×	×	×
Portugal			
Spain			
Sweden			×
UK		×	×

5. INTERACTION OF GREEN CERTIFICATES WITH OTHER INSTRUMENTS FOR THE PROMOTION OF RES

5.1 Introduction

In the EU a variety of instruments exists for the promotion of RES-E (electricity generated from renewable energy sources). Chapter 2 has pointed out that a demand for TGC can be produced by different instruments. The system of TGC (Tradable Green Certificates) in combination with an instrument creating the demand for TGC could possibly replace the existing instruments and lead to a harmonisation of national schemes.

In three cases, combinations of different instruments for the promotion of RES-E could be relevant:

- If a country decides to switch to the TGC system, there will be a need for a transition phase from the current instrument to the new system.
- Some countries might decide to keep their existing promotion schemes but might want to allow their RES-E producers to take part in GC trading with other countries, which have introduced the TGC system.
- A permanent combination of instruments could be regarded as useful to compensate for possible disadvantages of the TGC system.

In the following, a systematic discussion of the interaction of different instruments is given.

5.2 Definition of the instruments under investigation

Regarding the instruments for the promotion of RES-E, different variants and combinations are existing or are under discussion in EU countries. So it is necessary to define more closely what shaping of the instruments is meant in the following discussion.

The instruments can be split into price-driven and capacity-driven instruments. The former systems are supporting the costs of electricity production while the latter fix a capacity target, which has to be met. The following figure shows this distinction.

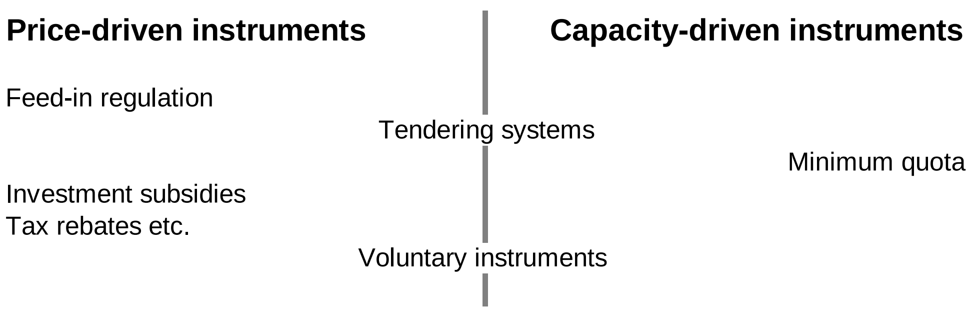

Figure 5.1 *Categories of instruments*

Tradable Green Certificates could play a role in each of the instruments. However, in most discussions and analyses they are related to obligations.

5.2.1 Feed-in regulation

The feed-in regulation consists of an obligation for energy utilities to purchase electricity generated from RES by independent producers and to pay minimum feed-in tariffs for this electricity. The tariffs exceed long term marginal costs of electricity production and are set by a regulatory authority. They differ between various technologies for the generation of RES-E with regard to their different production costs.

The extra costs for the utilities induced by this regulation are distributed among all consumers. This can be done by a fund, which balances the different cost burdens between all utilities. The utilities can recover these costs by a uniform surcharge on their system tariffs. In this way, a feed-in regulation is compatible with a liberalised market and every consumer of electricity (with the exception of autoproducers, but including electricity imports) has to contribute to the expansion of RES-E production.

The objective of setting fixed prices is to reduce the financial risk of the independent electricity producers and to improve the profitability of the plants. If the tariffs are set high enough, this regulation gives strong incentives to invest in RES-E plants. A disadvantage of this system is a lack of competition for the lowest production.

The feed-in regulation is a price-driven instrument and therefore does not guarantee a minimum growth of RES-E generation, nor does it limit the development with an upper ceiling. Old and new installations are eligible equally for the feed-in tariff.

5.2.2 Tendering systems

In this scheme tenders are invited by a public body to compete either for a certain financial budget or a certain capacity of RES-E generation. There are separate tenders for different generation technologies. Within each technology band the cheapest bids per kWh are awarded contracts and receive the subsidy.

Generators, which have been selected, sell their production to the local utility. The operator pays the bid price per kWh. The difference between this price and the market price of electricity (premium) is reimbursed by a fund, which is financed by a non discriminatory levy paid by all electricity consumers.

An evident advantage of this instrument is strong competition between investors in new plants: Only the most cost-effective offers will be selected, so the generators have a strong incentive to reduce their costs. On the other hand small investors may not be able to deal with this pressure. As a consequence big industrial projects are likely to dominate the awarded contracts. Furthermore, an unsteady tendering process can lead to unsteady investment in RES-E plants.

Tendering systems can either be a price-driven instrument or a capacity-driven instrument. By definition, the tender can only be met by installing new capacity. The premium payment then is guaranteed for a fixed number of years.

5.2.3 Tradable Green Certificates

Tradable Green Certificates (TGC) allows to separate the specific value of renewable electricity from the physical flow of electricity by creating a market for renewable certificates. It refers to the fact that RES-E cannot be physically separated from other (‘system’) power once it has been fed into the system.

Under the TGC system, each producer of RES-E is in fact producing two goods: Firstly the electricity, which is fed into the system and is sold at market prices. Secondly, for each pre-defined unit of electricity produced from renewable energy sources and fed into the system, the producer receives a certificate (in the Netherlands, each certificate stands for 10.000 kWh of RES-E).

TGC are used here to create a promotional system for the generation of electricity from RES: Each distributor of electricity is obliged to show Green Certificates corresponding to a defined portion of the electricity supplied to his customers. To fulfil this obligation, he can either produce RES-E himself or he can buy TGC from other generators.

The price of certificates will depend on the quota to be met (inelastic demand) and the supply. A high price of green certificates will thus encourage production of new renewable electricity. As the costs of TGC or those of the corresponding autoproduction of RES-E by the distributor can be passed on to the consumers of electricity, a rising quota will usually induce price increases.

The system of a minimum quota in combination with TGC can lead to a transparent market process. It imposes a high pressure on cost reduction on the generators and therefore is only effective for the development of those RES-E technologies for which costs are close to the market costs of electricity[3]. To reduce the volatility of TGC prices, balancing mechanisms like financial instruments will be necessary. Nevertheless, this system might put small generators of RES-E at a disadvantage because of high transaction costs for those hedging instruments.

A precondition for any TGC system is that every RES-E generator has the possibility to sell his electricity. This means that a non-discriminating access to the system has to be guaranteed. To facilitate easy power sales from fluctuating generation sources, a spot market could be established.

This system is clearly a capacity-driven instrument, which is able to set a binding target for the expansion of RES-E. Old and new plants can create certificates equally.

5.2.4 Investment subsidies

Investment subsidies are a very widespread instrument for the promotion of renewable energy sources. The subsidies can either be calculated from the renewable energy output or on the installed capacity, the latter version is more common.

Investment subsidies can be adjusted precisely to the kind of technology, to the size and location of the installation depending on the requirement for financial support. Thus, a targeted promotion of renewable energy sources can be attained. Gradually decreasing investment subsidies are effective in giving potential investors an incentive not to delay their investments because of expected price decreases of technology.

Investment subsidies based only on the installed capacity do not give incentives to operate the plant efficiently. Public investment subsidy programs usually require the applicant to wait for the approval of the subsidy before beginning to install the plant. In connection with unsteady subsidisation budgets this often leads to delays in investments.

Investment subsidies are a price-driven instrument and usually apply only for new installations.

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[3] By definition, the TGC system represents a market mechanism to implement the most cost-effective RES-E technologies. It is possible, that for reasons of technology development, RES-E sources like PV systems are to be promoted, which have higher costs than other RES-E technologies. This can be achieved either by differentiating TGCs for different technology bands or by additional instruments like subsidies.

5.2.5 Tax rebates etc.

There are different options to promote the generation of electricity from RES with fiscal instruments:

- Electricity from RES can be exempted from taxes, eg. energy taxes.
- If there is no exemption for RES, taxes can be (partially or wholly) refunded.
- Lower VAT rate may be applied for RES-E systems.
- Investment in RES-E plants may be exempted from income taxes etc.

The first two options lead to an improved competitiveness of the RES-E on the electricity market and apply for old and new plants. The latter options have similar impact as investment subsidies based on the installed capacity (see Section 5.2.4 above) and apply for new installations.

Tax rebates are a price-driven instrument.

5.2.6 Voluntary instruments (Green Pricing, Green Electricity Supply)

Under the voluntary instruments of Green Pricing or Green Electricity Supply electricity consumers pay a surplus on their electricity bill for the promotion of electricity from RES on a voluntary basis. The surplus can be a fixed sum per month (or per year) or it can be a surcharge on the price per kWh of electricity sold to the customer. It is also possible, that a surcharge is paid for only a part of the electricity demand, which is then declared as 'green electricity'. In turn for this surplus, the supplier generates electricity from RES in plants built and operated by himself or he buys electricity from RES from other generators.

Basically, two types of these voluntary schemes can be separated:

Green Pricing Fund System
Under this scheme, the surplus paid by the customers (as a regular lump sum or as a surcharge per kWh) is collected in a fund. From this fund, 'additional costs' of electricity production from RES compared to other sources are paid for. Under the Fund System, there is no direct link between the number of kWh consumed by the customer and the kWh produced from RES. Usually, only new plants are eligible for financial support from Green Pricing Funds. These funds are a price-driven instrument.

Green Electricity Supply
Under this system, the supplier guarantees that in turn for a given amount of money, a certain number of kWh from RES will be produced. Thus, there exists a specified price for each kWh from RES bought by the customer. In case that the customer pays a fixed sum per month (or per year), he receives a certain number of kWh from RES. If the customer pays a surcharge on the price per kWh delivered to him, he can decide whether he wants only partial or complete supply from 'Green Electricity'.

Most suppliers of Green electricity are including both old and new plants in their production portfolio. Accreditation schemes for Green Electricity usually demand a minimum share of new plants.

5.3 Identification of relevant combinations of instruments

All EU-15 countries are currently using combinations of instruments for the promotion of electricity generation from RES. 12 countries offer feed-in tariffs for independent power producers from RES, although there exist large differences in the level of guaranteed tariffs. Most of these countries also offer investment subsidies and/or fiscal support for RES-E. In the Netherlands for instance, investment subsidies and fiscal support are offered in addition to the TGC system.

For further discussion, it is appropriate to define characteristic situations with combinations of instruments which are already existing or which could be arising when a system of TGC is developed in EU countries.

These situations will be characterised firstly by a *major instrument* and secondly by additional instruments. This means, that one instrument is regarded as the basis for the promotion of RES-E, while additional instruments are applied as well for specific reasons, e.g. in order to promote specific RES-E technologies or to compensate for disadvantages of the major instrument[4]. The following Table shows the relevant combinations of instruments.

Table 5.1 *Relevant combinations of instruments*

Major instrument Additional instrument	Feed-in regulation	Tendering system	Tradable Green Certificates
Investment subsidy	×	×	×
Fiscal or tax rebates	×	×	×
Green Pricing, Green Electricity	×	×	×
Feed-in regulation		×	×
Tendering system	×		×
Tradable Green Certificates	×	×	

Systems with a feed-in regulation
Combinations of a feed-in regulation with investment subsidies, fiscal or tax rebates and voluntary instruments (Green Pricing, Green Electricity) are already existing in countries like Austria, Germany, Greece, Spain and Sweden. In Austria and France, a combination with a tendering system has been implemented with regard to wind capacity.

Systems with a tendering system
Combinations of a tendering system with investment subsidies and fiscal or tax rebates are already existing in the UK and in Ireland. In the UK, voluntary instruments are currently evolving (as they do in other countries) and the first international transaction with Green Certificates has already taken place.

Systems with Tradable Green Certificates
The Netherlands is the only EU country with a (voluntary) quota target for distribution companies and with tradable Green Labels. At the same time, investment subsidies and fiscal or tax rebates are in place and voluntary green electricity sales are increasing as well. In addition to these existing combinations, a co-existence of TGC and a feed-in regulation could be effective for the promotion of RES-E and therefore will be included in the discussion.

5.4 Interaction of different instruments

In the following, three scenarios with combinations of instruments are discussed. Each scenario is defined by one ‘major instrument’ for the promotion of RES-E, which can be
1. Feed-in regulation,
2. Tendering system, or
3. Tradable Green Certificates.

[4] The definition of a major instrument is an abstraction of the complex situation in practice, where single instruments often are effective only for some RES-E technologies.

Following Table 5.1, the relevant combinations of one ‘major instrument’ with other instruments are examined. Although this systematic approach is used here, not all combinations are discussed in the same detail. The main attention is directed towards the combinations of the TGC system with other instruments.

5.4.1 Feed-in regulations and other instruments

A guaranteed feed-in tariff makes investments in those RES-E plants profitable, whose generation costs are lower than the feed-in tariff. So, the guaranteed tariff sets a signal for investors to look for such projects and to invest in those plants.

Investment subsidies

If in addition to the feed-in tariff the generation costs of the plants are reduced by investment subsidies, then investments are becoming economically viable, which would otherwise not be profitable. So, investment subsides in combination with a feed-in regulation in general can make sense to extend the viable potential of RES-E.

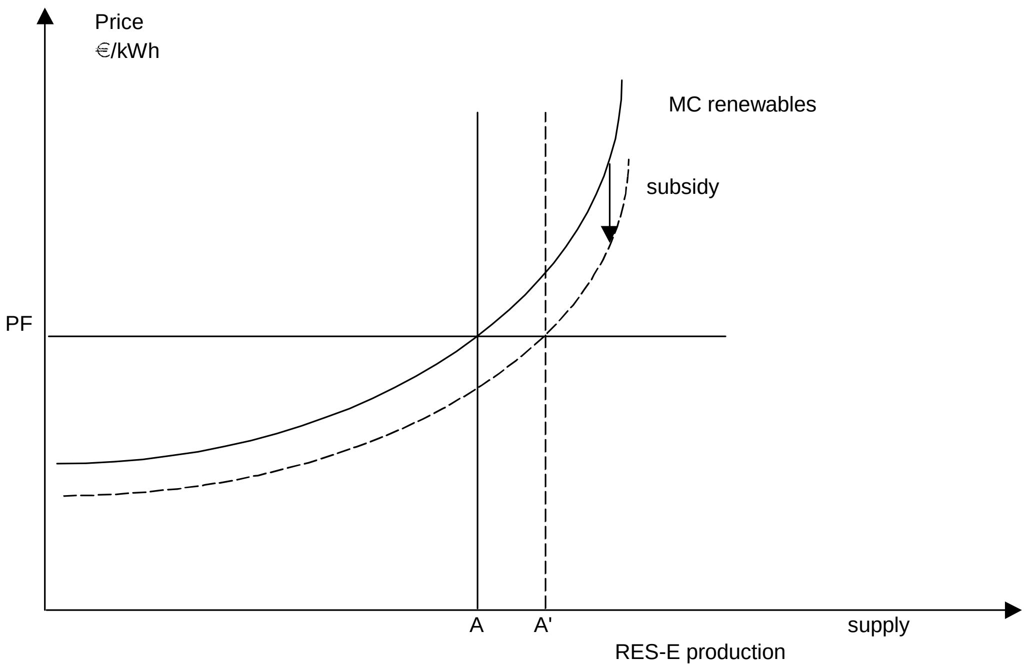

Figure 5.2 *Combination of a feed-in regulation and an investment subsidy*

MC renewables: Marginal cost curve of RES-E production

PF: Feed-in tariff

Problems may arise, if the subsidy is given to all investors *without specification*. Although this leads to an extension of the economic potential of RES-E (from the investor‘s point of view), it would give an extra windfall profit to those plants, which would already be profitable without the subsidy. The subsidy would have the same effect as a general increase of the feed-in tariff.

On the other hand, *specific* investment subsidies can help to develop certain technologies, eg. photovoltaic systems, which are not becoming viable through the feed-in tariff alone. The same may apply for the development of wind power in regions, which are not optimal for windmills because of the wind conditions. Thus, targeted subsidies can close the gap between the general feed-in tariff and the generation costs of specific RES-E technologies.

In these cases, the subsidy can create technology bands or geographic regions, where RES-E plants are financed even if they have higher costs than the limit generally accepted through the definition of the feed-in tariff. This implies that specific investment subsidies should be clearly justified. In the case of PV systems, the justification can be seen in the development and market introduction of an important RES-E technology with a very large potential. In the case of wind power in interior regions, a better balance of the regional development of wind power could be one of the reasons.

In theory it would be possible to define a sophisticated system of specific feed-in tariffs for different technologies and geographic regions to realise this kind of 'fine-tuning' within the feed-in regulation. But this would make the regulation complex and difficult to handle. So it seems appropriate to create the feed-in regulation as a general instrument for the promotion of RES-E in order to keep it rather simple. For specific situations, additional investment subsidies can be granted and in these cases higher administrative requirements may be justified.

If the investment subsidy is paid from a public budget (which is usually the case), another dimension of the interaction with the feed-in regulation becomes important: through the feed-in regulation extra costs of RES-E production are distributed among all electricity consumers, therefore it follows the 'polluter-pays'-principle.[5] If a considerable part of this burden is passed on to public budgets, this principle would be disregarded. Again, investment subsidies only make sense, if they help to achieve a certain target like e.g. the development of a promising RES-E technology, which is of general interest.

Tax rebates etc.
In general, the interaction of fiscal instruments like tax rebates or refunds with a feed-in regulation is quite similar to those of investment subsidies from public budgets. In this respect, the discussion in the last section also applies to fiscal instruments.

A more specific discussion is necessary for the refund of energy taxes to producers of RES-E. As the implementation of an energy tax on electricity can be justified by the internalisation of external costs of fossil and nuclear power, it is sensible to exempt RES-E from this tax.

Green Pricing/Green Electricity Supply
The feed-in regulation distributes the extra costs of electricity from RES fed into the system under the regulation among all consumers of electricity. Every consumer has to pay his contribution for the renewable part of electricity in the public generation mix. Therefore each consumer has the right to be credited with the share of renewable electricity he has paid for.

In this context, the voluntary instruments of Green Pricing or Green Electricity Supply mean that consumers can decide whether they want to meet a higher share of their electricity demand by generation from RES than it is included in the public generation mix anyway. For this reason, he decides to buy his electricity demand from a 'green supplier' and pays a higher price per kWh, if necessary.

It might be regarded as a principle, that this deliberate decision should lead to a higher generation of electricity from RES than in the reference case, where the consumer buys 'regular' or system electricity. Therefore it is necessary to distinguish clearly between RES-E financed by the feed-in regulation and 'Green Electricity', which has been generated because of a voluntary decision of a consumer. For example, RES-E fed in after the regulation and which has been paid for by all consumers of electricity should not be sold a second time as 'Green Electricity'. As

[5] In practice of most countries the major part of the burden of financing the expansion of RES-E generation under the feed-in regulation is passed on to captive or small customers, so this principle is not followed completely.

‘Green Electricity’ is not (necessarily) a system on a governmental level, this question can be regarded as the task of consumer protection organisations.[6]
If this is ensured, voluntary schemes like Green Pricing or Green Electricity Supply can be a good supplement to the feed-in regulation.

Tendering systems
A feed-in regulation could be combined with a tendering system, eg. to define capacity targets for RES-E technologies which are not economically viable under the feed-in regulation (eg. PV systems). This could help to solve the problem, that a feed-in regulation usually can only support technologies which are rather competitive with other RES-E technologies (because in practice the feed-in tariffs are not very differentiated for different technologies).

In general, the interaction of a feed-in regulation and specific invitations for tenders for clearly defined RES-E technologies bears no problems. The regulation would act as the general instrument for RES-E promotion and tenders would be invited for technologies with generation costs well above the feed-in tariff, which are to be developed, too. It would have to be decided whether contractors under the tendering processes shall be entitled for a feed-in tariff or not. Both options are possible.

The costs for the premium payments for the contracts awarded under the tendering process could be included easily into the balancing fund, which is operated by the distributors to even out different costs under the feed-in regulation.

However it would not make sense to invite tenders for technologies, which are already viable under the feed-in regulation. In this case, there would be no incentive to offer tenders lower than the feed-in tariff, so most tenders would be slightly above this tariff. This would not lead to a considerable extension of RES-E production.

Green certificates
Now it is assumed that country A has decided to choose a feed-in regulation as the major national instrument for the promotion of RES-E. At the same time, private agents from that country want to take part in an international system of TGC.

As country A has not introduced a minimum obligation of RES-E, the distributors of country A do not need to buy TGC unless for speculation (in order to sell them later at a higher price). So the relevant case is that RES-E producers from country A want to sell certificates to distributors in country B, which has chosen the TGC system and has introduced a minimum obligation. Quite similar would be the case, if an investor from another country wants to operate RES-E plants in country A and to make use of the certificates.

First of all, it is necessary that there exists an international standard of how TGC are defined (amount of electricity, time of validity etc.), how they are issued and how they can be traded. This of course is a general prerequisite of any international transaction of TGC.

In a second step, it has to be decided whether the feed-in regulation and the trade of GC should be allowed to be combined. If this would be possible, then the price of certificates sold by generators in country A would be subsidised by the feed-in tariff. This would either subsidise the international equilibrium price of certificates by payments from the electricity consumers of country A (in the case that generators with higher costs are driven out by the subsidised plants) or it would mean an additional profit of the plant operator (if the plant would be viable under the international TGC system without the subsidy).

[6] The distinction between the mandatory feed-in regulation and the voluntary system of ‘Green Electricity’ should be addressed in accreditation schemes for ‘Green Electricity’.

As both effects are not desirable, it is important to clearly distinguish between the national instrument of a feed-in regulation and the international TGC trade. This means that the national accreditation scheme for TGC (which has to be introduced in country A if agents of that country want to take part in GC trading) must ensure that RES-E plants which are receiving payments under the feed-in tariff are not allowed to issue TGC. However, if somebody (a national or an international investor) wants to invest in a RES-E plant without making use of the feed-in regulation, his plant would create TGC. As there is no demand for TGC in country A, the only use of these certificates would be to be transferred to agents in countries with a TGC system.

Under these framework conditions, an investor in RES-E plants in country A would have the possibility to choose whether he wants to claim payments under the feed-in regulation or whether he wants to take part in the (international) TGC market. This decision will depend on the relation between the feed-in tariff and the expected price of the TGC. If the price of TGC is expected to be lower than the feed-in tariff then of course the investor will claim payments under the feed-in regulation and vice versa.

This makes clear that feed-in tariffs which are significantly lower than the expected price of the TGC on the international market would not make much sense. However this general statement must be qualified because of two reasons:
- Although the feed-in tariff is usually not fixed in absolute terms (e.g. it is calculated from average electricity prices, which are currently falling), the volatility of the TGC price will be higher and therefore induces risks for the investors.
- The transaction costs for the participation in an international TGC market (including the use of hedging instruments) may be high for small investors, therefore they might prefer a feed-in tariff.

Another serious problem arises when a feed-in regulation is combined with an international TGC system. If some countries have introduced minimum obligations for RES-E and country A has not done so (and trading of GC is allowed), then the most cost-effective potentials for RES-E generation in country A might be systematically exploited by investors who want to sell Certificates to agents in other countries. All RES-E plants from utilities in country A, which are not entitled for the feed-in regulation, would be able to create and sell Certificates while the distributors of country A have no minimum obligation.

This would lead to a significant distortion of the international TGC market: The low-cost generation from country A would reduce the price of the TGC for all participants in the GC system. But a part of the obligation would be met by generation in country A, which has no RES-E target. It would not be possible to determine, whether this plants would have been installed without the TGC, too. So it would not be possible to know, to what extent the obligation actually has led to additional RES-E production in those countries with a RES-E target.

If RES-E producers in a country which has not introduced minimum obligations (but has chosen the feed-in regulation to promote RES-E generation) are entitled to issue and sell TGC, the supply of TGC will be increased while the demand (in countries with minimum obligations) remains the same. This could have a strong impact on the international TGC prices.

5.4.2 Tendering systems and other instruments

Under a tendering system, contracts are awarded to those generators who have offered the lowest bids. Once the contracts are awarded, the generators are paid their bid price, which means they receive premium payments in addition to the market price of electricity for the duration of the contract. The tenders are invited for different RES-E technology bands.

Investment subsidies

If a generator has the possibility to receive investment subsidies for his plant, then he is able to offer a lower production price under the tendering system. This may lead to an advantage, if other generators are not receiving subsidies.

If the tenders are issued for a given capacity of RES-E production (and the RES-E generation does not become competitive with market prices through the subsidy alone), then the subsidy does not lead to an extension of RES-E production.

In contrast to the combination with a feed-in regulation, investment subsidies do not necessarily lead to extra windfall profits under a tendering system. If a generator has received a subsidy, then he still has an incentive to calculate his production costs as low as possible to make sure that he will be successful in the tendering process. If he is awarded a contract, then he receives only his bid price, which will be calculated lower than in the case without the subsidy.

If subsidies from public budgets are given to all investors *without specification*, this results in a shift of the financial burden for the extension of RES-E generation from the consumers to the taxpayers, which would be in contradiction to the 'polluter pays' principle.

Certainly, *specific* investment subsidies could help to develop technologies which are not competitive under the tendering system alone. The same applies for geographical regions, where RES-E production is not competitive. But, as the invitations for tenders can be specified very easily to technology bands, the additional promotion of specific RES-E technologies through subsidies does not seem to be necessary under the tendering system. However, subsidies can make sense to stimulate RES-E production at sites (in geographical regions) which are not most favourable for electricity generation from renewables.

Tax rebates etc.

Here, the argumentation of the section above applies correspondingly: Fiscal instruments interact with the tendering system in a similar way to investment subsidies. With the exemption of energy taxes, a general tax rebate for all RES-E technologies is not sensible.

Green Pricing/Green Electricity Supply

Similar to the feed-in regulation, the tendering system lays down, under which conditions RES-E plants should be built and included in the general electricity generation mix.[7] Every consumer has to pay a contribution for this renewable part of the generation mix.

If consumers want a higher share of their demand to be produced from RES-E, they can use the voluntary schemes of Green Pricing or Green Electricity Supply.

Corresponding to the combination of those voluntary instruments with other mandatory schemes for the promotion of RES-E, a clear distinction should be made between RES-E generation for the voluntary 'Green' market and those under the tendering system. This is mainly a problem of accurate accreditation schemes for 'Green Electricity'.

If this distinction is ensured, voluntary schemes like Green Pricing or Green Electricity Supply can be a good supplement to a tendering system.

Feed-in regulation

The conditions of the contracts, which are awarded under the tendering system, can be regarded as individual feed-in tariffs for the generators which have been successful in the tendering process. The mechanisms of paying (individual) premium prices to those generators and the financ-

[7] While the feed-in regulation defines the maximum costs of RES-E generation to be included in the generation mix (price-driven regulation), the tendering system lays down the demand for capacity (capacity-driven instrument).

ing of these premium payments through a general fund are quite similar to those of the feed-in regulation.

Generally it would be possible to introduce a system of guaranteed (general) feed-in tariffs for independent operators of specific RES-E technologies in combination with a tendering system. One reason to do so could be the problem, that small investors usually are not successful in the tendering process. Those investors may find better opportunities under a feed-in regulation.

On the other hand, the fixed feed-in tariff would contradict to the competitional character of the tendering system. Therefore it should be tried first to improve the conditions for investments in small-scale plants under the tendering system, eg. by specific invitations for tenders from investors in those plants.

Green Certificates

In this chapter, it is assumed that a country A has decided to choose a tendering system as the major national instrument for the promotion of RES-E. At the same time, private agents want to take part in an international system of TGC[8].

This situation is quite similar to the case described earlier on the interaction of green certificates in a situation in which a feed-in system is the main promotion mechanism. As country A has not introduced a minimum obligation of RES-E, the distributors of country A do not need to buy TGC unless for speculation (in order to sell them later at a higher price). It should also be clear that it makes no sense to offer Certificates bought from abroad during a national tendering process. So the relevant case is that RES-E producers from country A want to sell certificates to distributors in Country B, which has chosen the TGC system and has introduced a minimum obligation. Quite similar would be the case, if an investor from another country wants to operate RES-E plants in country A and to make use of the certificates.

Again, the general prerequisite of international transactions of TGC has to be fulfilled: There has to be an international standard of how TGC are defined (amount of electricity, time of validity etc.), how they are issued and how they can be traded.

Secondly, it has to be decided whether the tendering system and the trade of GC should be allowed to be combined. If this would be possible, then the price of certificates sold by generators in country A would be subsidised by the payments under the contracts awarded in the tendering system. Similar to the earlier case, this would either subsidise the international equilibrium price of certificates by payments from the electricity consumers of country A (in the case that generators with higher costs are driven out by the subsidised plants) or it would mean an additional profit of the plant operator (if the plant would be viable under the international TGC system without the subsidy). In addition to this, some RES-E generation would be counted two times: Once to meet the national targets for expanding RES-E generation by the tendering system and once more under the TGC system.

As all these effects are not desirable, it is important to clearly distinguish between the national instrument of a tendering system and the international TGC trade. This means that the national accreditation scheme for TGC (which has to be introduced in country A if agents of that country want to take part in GC trading) must ensure that RES-E plants which have been awarded contracts under the tendering system are not allowed to issue TGC. However, if somebody (a national or an international investor) wants to invest in a RES-E plant without taking part in the tendering process (and therefore will not receive premium payments), his plant would create TGC. As there is no demand for TGC in country A, the only use of these certificates would be to be transferred to agents in countries with a TGC system.

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8 In fact, this constellation has already become reality, as there has been a transaction of Certificates from the UK to the Netherlands.

Under these framework conditions, an investor in RES-E would have the possibility to choose whether he wants to take part in a (national) tendering process or whether he wants to take part in the (international) TGC market. This decision will depend on his assessment of the market situations. If the generator thinks that in international comparison his production costs are rather competitive, then it might be more profitable to go into the TGC market where high profits are possible for generators with low costs. If he regards his production to be more expensive, it might be safer to take part in the national tendering process to check his competitiveness prior to the investment.

Therefore it is possible that low-cost generators will be lost for the national tendering processes. This results in higher premium payments for the contracts awarded and therefore in higher costs to be covered by all national consumers.

Another serious problem arises in case that a tendering system is combined with an international TGC system. If some countries have introduced minimum obligations for RES-E and country A has not done so (and trading of GC is allowed), then the most cost-effective potentials for RES-E generation in country A might be systematically exploited by investors who want to sell Certificates to agents in other countries. In addition to this 'old' RES-E plants from country A, which have not been built as a result of the tendering system or whose contracts have expired, would be entitled to produce TGC while the distributors of country A have no minimum obligation. Similar to the situation in Chapter 4.1.5 this would lead to a significant distortion of the international TGC market.

If RES-E producers in a country which has not introduced minimum obligations (but has chosen a tendering system to promote RES-E generation) are entitled to issue and sell TGC, the supply of TGC will be increased while the demand (in countries with minimum obligations) remains the same. This could have a strong impact on the international TGC prices.

5.4.3 Green certificates and other instruments

Investment subsidies

If a generator of RES-E receives a subsidy under the TGC system, he can cover generation costs equal to the sum of three terms:

- market price for electricity,
- value of the TGC,
- subsidy[9].

The analysis of the interaction of these two instruments is in some way similar to the combination of subsidies with a feed-in regulation or a tendering system:

- If the subsidy is given to all generators of RES-E *without specification*, then the price of the certificates will be reduced by the value of the subsidy per kWh. In contrast to the combination with the feed-in regulation, the subsidy does not expand the economic potential of RES-E production (from the investor's point of view), due to the pre-defined quota.

[9] In the case of an investment subsidy calculated from the installed capacity, it would have to be converted in a specific figure per kWh generated.

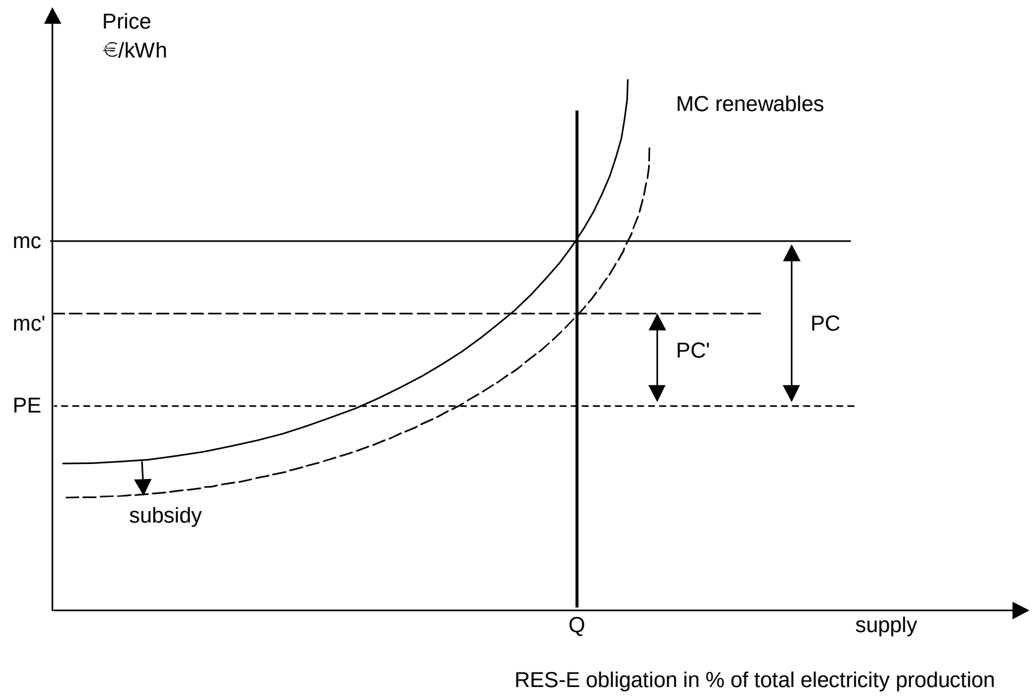

Figure 5.3 *Combination of a TGC system and investment subsidies*

- If the subsidy is given to *specific* investors (e.g. in those technologies, which are not expected to be economically viable under the TGC system alone), this also leads to a reduction of the price of the certificates and not to an expansion of RES-E generation. But, of course, if the subsidy reduces the marginal costs of the subsidised plant to that extent, that other plants are driven out of the TGC market, then the subsidised plant is pushed into the market successfully.

The long-term effect of an investment subsidy is not easy to predict in a TGC system, as it is not known in advance, how the price of the certificates will develop. So it is possible, that a plant (e.g. biomass) receives an investment subsidy and later still is not competitive against other RES-E plants and therefore will not be operated. This uncertainty would be lower in systems with feed-in regulations or tendering systems.

The subsidisation of RES-E plants from public budgets under the TGC system shifts a part of the financial burden of the development of RES from the consumers of electricity to the taxpayers. Similar to the combination with other instruments, this contradicts to the ‘polluter-pays’-principle.

In the case of combinations of a TGC system with other instruments, special attention is paid to international aspects, i.e. the interaction of instruments if a cross-border trade of TGC is possible. The following Figure shows the interaction of an international TGC system (represented by two countries A and B, both having an obligation) with an additional subsidy in country A.

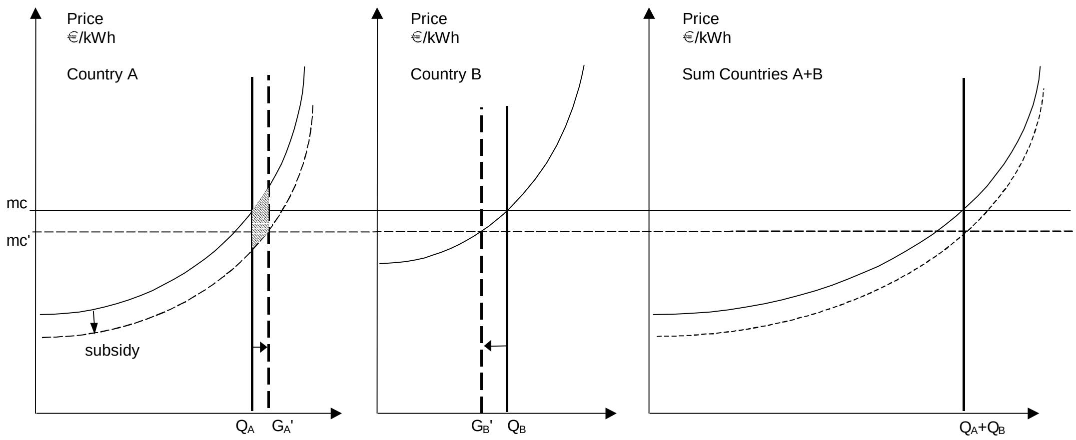

Figure 5.4 *International effects of a combination of a TGC system and investment subsidies*

To simplify the analysis, in this Figure as well as in other similar Figures in this Chapter, it is assumed that in the situation before an additional incentive scheme is introduced, the countries A and B happen to have the same equilibrium price. This means that both countries produce the amount of renewables as they are obliged to, and that there is no trade.

As shown in the Figure above, a subsidy in country A leads to a shift downwards not only for the marginal cost curve of country A, but also for the MC curve for the sum of RES-E potentials of countries A and B. From the intersection of this curve (in the right part of the figure) with the sum of the obligations Q_A+Q_B, the new equilibrium price for RES-E in both countries results. As the figure shows, this leads to a smaller RES-E generation G_B' in country B and a higher generation G_A' in country A. The subsidy therefore leads to a shift in the regional allocation of investments and will lead to trade of certificates from country A to country B.

On the other hand, the taxpayers of country A are subsidising not only the price of the certificates in their countries but in all countries participating in the TGC system. In the Figure above, the subsidy in favour of consumers in country B is proportional to the hatched area.

This makes clear that investment subsidies under a TGC system should be targeted very precisely to technologies of special interest and should have a total budget significantly lower than the volume of the TGC market to avoid severe market distortions.

Tax rebates etc.

As in the other two scenarios, the interaction of fiscal instruments like tax rebates or refunds with a TGC system is in general quite similar to those of investment subsidies from public budgets. In this respect, the discussion in the foregoing section also applies to fiscal instruments.

Once again, the exemption of RES-E from a general energy tax (or a tax refund) is sensible with regard to the different external costs of fossil and nuclear power on one hand and RES-E on the other.

Green Pricing/Green Electricity Supply

Under a TGC system with a defined quota for RES-E the state has decided how much electricity from RES shall be produced and paid for by the totality of electricity consumers. Still it is possible (and to be expected) that a part of the consumers wants to buy a higher share of their electricity demand from RES than it is defined by the quota. Therefore voluntary instruments like Green Pricing and the supply of Green Electricity make sense under a TGC system. The existence of Green Certificates can even make it easier for the supplier of 'Green Electricity' to prove that he has actually generated or bought electricity from RES for his customers, although some restrictions apply.

An important feature of this combination of instruments is, whether voluntary purchases of certificates are counting for the obligation. If the obligation is not put on the consumer of electricity or if he has the possibility to delegate his obligation to his supplier, then certificates bought as a surplus on the quota on a voluntary basis could be used to directly reduce the obligation for other consumers.

If this would be the case, then the voluntary purchase of certificates would not lead to any increase of RES-E generation. The only effect would be that other consumers would have to pay less for their obligation. This would not be encouraging for consumers to buy certificates on a voluntary basis. Therefore, like in the other scenarios, it should be ensured that voluntary contributions lead to an increase of electricity generation from RES, i.e. that voluntary purchases of certificates induce a higher generation of RES-E as it is required by the quota[10].

Therefore it is necessary to distinguish clearly between Green Certificates, which are used to fulfil the obligation and those which are related to voluntary purchases of 'Green Electricity'.

This can be done in two ways:
1. From the beginning, two types of certificates exist: The general type is used to meet the minimum obligation and can be traded freely ('free certificates'). A second type is reserved only for the voluntary 'Green Electricity' market and can not be used to meet the obligation nor can they be traded ('bound certificates')[11].
2. There exists only one type of certificates which can be traded freely. They can either be used to meet the general obligation or to prove to the 'Green Electricity' customers that the appropriate amount of RES-E has been produced for them. In both cases, the certificates are becoming invalid for further transactions once they have been used.

The first alternative is creating a separate market for 'Green Electricity Certificates' and therefore allows to introduce more complex criteria for the accreditation of electricity for this market (e.g. a distinction between old and new plants or exclusion of specific technologies like waste incineration). These 'sophisticated' certificates should be compatible downwards, i.e. if they are not used for the 'Green Electricity' market, they can be used to meet the quota obligation. The vice-versa recognition of 'simple' certificates for the 'Green Electricity' market would not be possible, if additional accreditation criteria are necessary for this market. But there seems to be no reason why these certificates should actually be bound to the generator and not allowed to be traded.

However, if in the latter case the uniform type of certificates bears enough information on its production (e.g. the technology of the plant, the date of putting into operation ...), then additional criteria for the accreditation of electricity for a voluntary 'green' market can be verified.

Finally it should be noted that the combination of voluntary instruments with a TGC system leads to an expansion of total RES-E generation, if the voluntary purchases are not counting for the general obligation. The Figure below shows, that a higher demand for certificates in county A means that the international equilibrium price for the TGC will rise, because the new RES-E target is the sum of the obligations in the countries A and B and of the generation demanded by the voluntary customers in country A. This leads to a higher RES-E generation also in country B, while the resulting generation in country A (G_A'') is dependent on the shape of the MC curves.

[10] Nevertheless it is likely in the longer term that the size of the voluntary market will be taken into account when the quota is fixed.

[11] This distinction of two types of certificates is used for example by the Dutch utility NUON/ENW, whereas other utilities in the Netherlands like PNEM/Mega have been claiming that they are willing to use the voluntary contributions from their Green Pricing customers to meet the quota obligation of all customers.

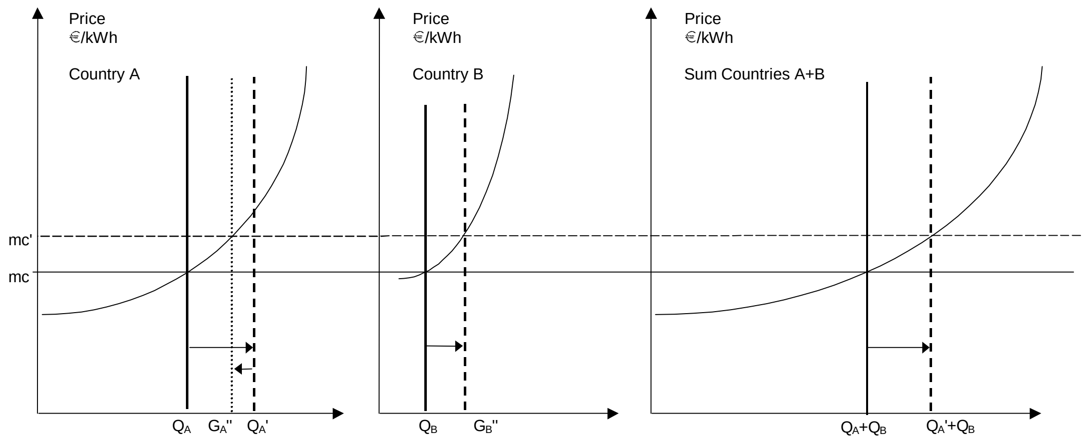

Figure 5.5 *International effects of a combination of a TGC system and voluntary 'Green Pricing'*

Feed-in regulation

In this section it is assumed that in addition to the general system of TGC with a minimum obligation for RES-E a feed-in regulation is in effect, which applies for non-utility renewable plants. (The alternative to include a minimum price guarantee within the TGC system will be treated in this project as a question of the design a TGC system.) Although this would be a mixture of a capacity-driven and a price-driven instrument, this situation is likely to occur in a transition phase (e.g. from a feed-in regulation to a TGC system). It can also occur if a country decides to encourage private investments in RES-E plants by providing reliable feed-in conditions under a TGC system.

To simplify the analysis, it is further assumed that there is only one market price for 'conventional' electricity, which is known by all parties. Moreover, a simplified feed-in regulation with only one tariff for all RES-E generation is analysed in the first stage. The Figure below shows the general correlation between the market price, the feed-in tariff and the marginal cost curve for RES-E.

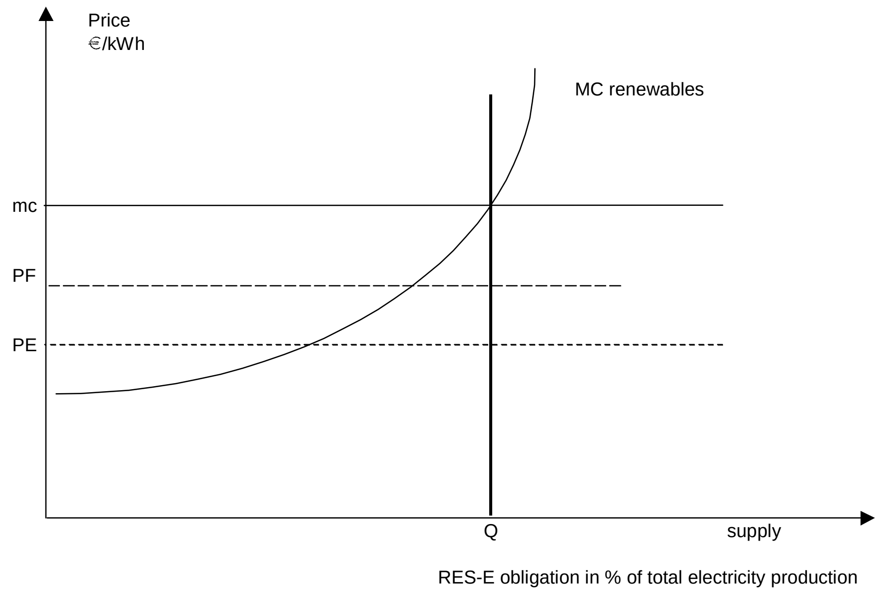

Figure 5.6 *Combination of a TGC system and a feed-in regulation (general)*

MC renewables: Marginal cost curve of RES-E production
PF: Feed-in tariff
PE: Market price for electricity

Three models for the combination of the TGC system and the feed-in regulation could be implemented alternatively:

1. Complete separation

The electricity fed in after the regulation may not be used by anybody to meet the obligation. This means that the obligation has to be met only by plants, which have been built by utilities or which are not eligible for the feed-in regulation for other reasons. Electricity from RES fed in from independent generators under the regulation does not produce certificates and increases total RES-E production to a level above the quota which has been fixed by the state.

This separation of the systems would be very simple to handle. But the feed-in regulation would increase the price of the certificates, if some generation is operated under the regulation which would otherwise have been contributing to meet the obligation. In this case, additional RES-E generation from a higher part of the marginal cost curve will be necessary to meet the obligation and therefore the equilibrium price increases. The higher a general feed-in tariff is, the larger the part of RES-E potential will be, which is covered by the regulation and therefore can not contribute to the obligation and the higher TGC prices will be. The feed-in regulation would have no effect on the price of TGC, if it would apply only for technologies, which are not viable under the TGC system (e.g. PV systems).

This model would contradict to the approach of the capacity-based instrument of the quota system. The state would in fact not be able to set a general target for RES-E development, as the activities of the independent generators can not be predicted in a reliable way.

2. Independent RES-E generators may sell certificates

In this model, electricity fed in after the regulation is producing certificates, which can be sold by the independent generators. So, the generators receive three payments:

- the market price of electricity,
- the difference between the feed-in tariff and the market price of electricity,
- the price of the certificates.

Alternative 1

If the feed-in tariff is fixed regardless of the price of the certificates, this would mean a considerable advantage for the independent generators under the feed-in regulation in comparison to other generators (esp. the utilities): The feed-in tariff would have the effect of a specific subsidy for independent generators. Under the idealised assumption, that independent generators have the same investment opportunities as utilities, they would clearly dominate the market for RES-E. The price of the certificates PC2 would result as the difference between the marginal cost mc* and the feed-in tariff PF (see Figure 5.7).

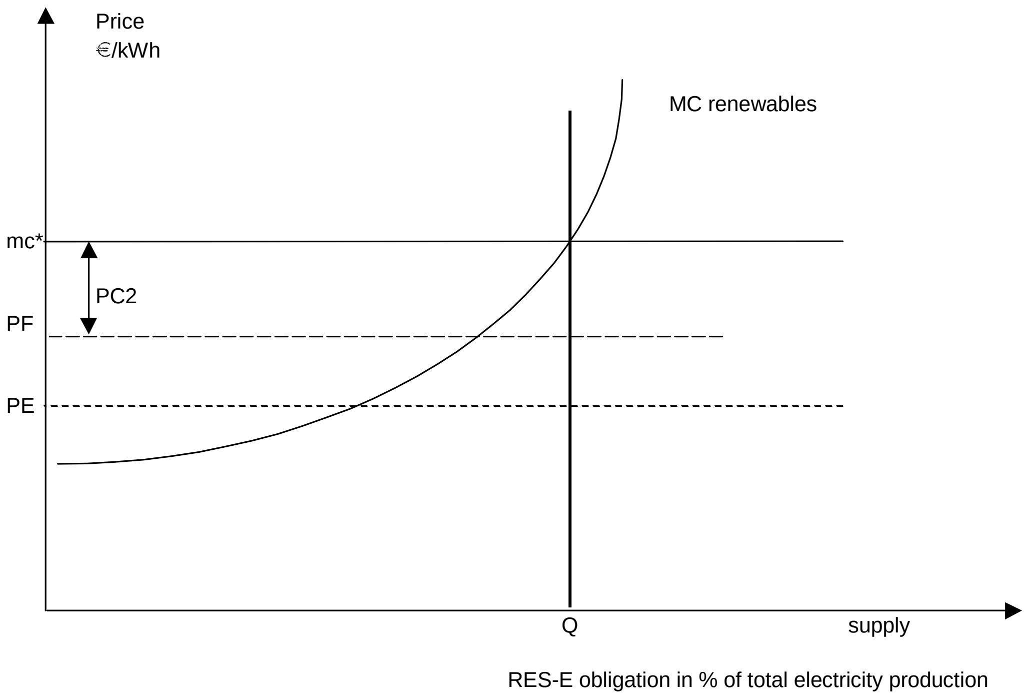

Figure 5.7 *Combination of a TGC system and a feed-in regulation, model 2*

MC renewables:	Marginal cost curve of RES-E production
PF:	Feed-in tariff
PE:	Market price for electricity
PC2:	Price of the certificates

The discrimination of generators which are not eligible for the feed-in regulation would lead to a considerable market distortion. This could only be prevented, if all renewable plants would be entitled for the feed-in tariff (esp. the plants operated by utilities[12]).

With this expansion of the feed-in regulation, the combination with the TGC system would lead to reasonable results from a national point of view:

- The quota defines the RES-E production target (i.e. the independent generation does not expand RES-E production).
- Independent generators receive a guaranteed feed-in tariff (as do the utilities, this may require more differentiated feed-in tariffs).
- The marginal costs of the last plant mc* remain unchanged.
- Again, the price of the certificates PC2 would be the difference between the marginal costs mc* and the feed-in tariff PF.

The higher the feed-in tariff is, the lower the price of the certificates would be. In the borderline case, a very high feed-in tariff would lead to a RES-E production above the minimum quota Q, then the price for the certificates would be zero.

This strong effect of the feed-in tariff on the price of the certificates would lead to severe problems in the case of an international market for TGC: As the feed-in tariff would have the same effect as a general subsidy for the price of the certificates, the RES-E potentials of the respective country would be exploited to meet the obligations in other countries (see Figure 5.3). To avoid

[12] This could mean that in a system of unbundled utilities, the system operation unit of a utility would pay the same feed-in tariff to the generation unit of the same utility as it would do in the case of an independent generator from RES.

market distortions, a common standard of feed-in regulations would be necessary in all participating countries. This seems not to be a realistic option.

In addition to this, the expansion of the feed-in regulation to all generators including utilities, which would be necessary in this model, would contradict completely to the approach, that the general instrument for the promotion of RES-E should be the TGC market in combination with a general obligation.

Alternative 2
The feed-in regulation could be used as a backup scheme to the TGC market, which guarantees minimum payments to a specific group of (independent) generators. For those generators, a certain minimum payment would be fixed. If those generators do not receive this payment through the sale of their certificates, because the market price of certificates is too low, then the difference between the earnings from the sale of certificates and the fixed minimum payment would be balanced by additional payments from the energy utility.

This system would enable those generators to offer their certificates at a very low price or even for free. They would have no incentive to maximise their earnings from the sale of TGC, because they have a guarantee of receiving additional payments from the utilities. Therefore this alternative would also lead to a distortion of the TGC market.

3. Utility receives certificates
In this model the independent generator can decide whether he wants to sell his electricity at market prices and to sell his certificates himself or whether he wants to use the feed-in regulation. In the latter case, he is not only selling his electricity to the utility but at the same time sells the certificates, too. In other words: Electricity fed in under the regulation is regarded as a bundle of physical electricity and the corresponding certificates. The utility, which pays the feed-in tariff, receives electricity and the corresponding certificates in turn.

The utility can use these certificates to meet its obligation. If the number of certificates it has bought from the independent generator is not enough to fulfil the quota, then it has to build own RES-E plants or to buy additional certificates. If the number of certificates it is receiving from the independent generator is higher than its obligation, then it can sell the surplus of certificates.

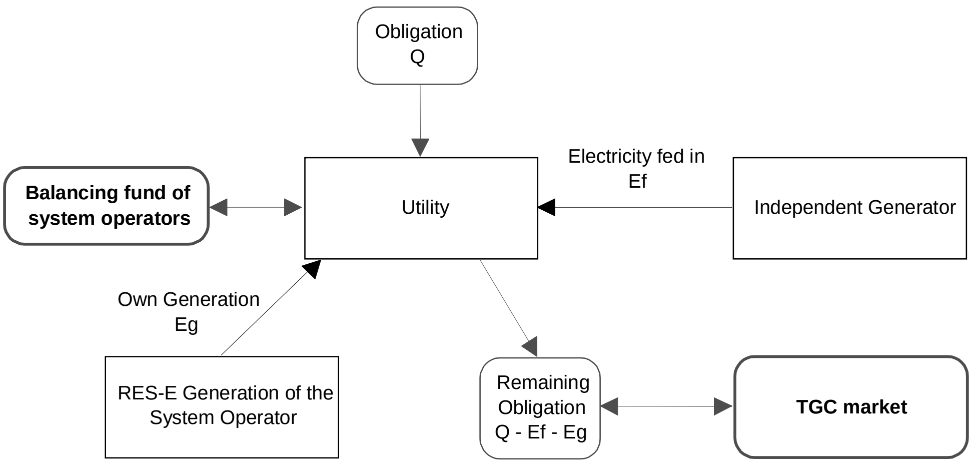

Figure 5.8 *Combination of TGC and feed-in regulation, model 3: Utility receives certificates*

With this model, the price of the certificates is independent from the feed-in tariff and the problems connected with models 1 and 2 can be avoided. This model also means that there would be no distortion on the international market for TGC.

Figure 5.8 shows that in a combination of TGC and feed-in regulation two balancing mechanisms are necessary:

- The TGC market, which balances RES-E production and the obligation, where certificates can be traded and their market price is determined.
- The balancing fund of utilities, which balances the costs of the feed-in regulation among all utilities.

The purpose of the balancing fund is to avoid uneven financial burdens for those utilities who have a high generation of independent producers in their service area and to distribute the costs for the electricity fed in under the regulation among all consumers. It is clear that in the ideal case, where the feed-in tariff is equal to the price of the certificates, this balancing fund would have nothing to do. Those utilities who have no electricity fed into their system would have to buy certificates at the same price as the feed-in tariff and there would be no imbalance to even out.

This makes clear that the balancing fund of the utilities not only has to balance the costs of electricity fed into the system (as it would do in a system with only a feed-in regulation) but also has to take into account the market price of the certificates. For an equal distribution of the total costs for the production of RES-E the fund has to balance the difference between the feed-in tariff and the price of the certificates.

The combination of a TGC system and a feed-in regulation could be used for a more specific promotion of RES-E technologies: For technologies not being competitive under a TGC system without additional support (e.g. PV systems), a specific feed-in tariff could be fixed. To set an absolute limit for the funding of these technologies, a maximum budget for this specific feed-in tariff could be set.

Tendering system

Here it is assumed that a TGC system is combined with a tendering process. One reason to do so could be the promotion of specific technologies, which might not be competitive under the TGC system, e.g. PV systems. (Here it is assumed that in contrary to the TGC system the tendering system is separating several technology bands. The alternative to call for tenders for specific types of certificates instead of RES-E electricity will be treated in this project as a question of the design a TGC system.)

In theory, it is very easy to divide the quota for RES-E into two parts: one part covered by the tendering system and the other part (or ‘remaining quota’) forming an obligation for the distributors. Of course it is necessary to define the size of the tenders in co-ordination with the total RES-E quota. The total size of the different technology bands of the tenders should be significantly smaller than the amount of RES-E to be produced under the quota, otherwise the remaining quota would be zero and no TGC market would be established.

In such a combination, a generator of RES-E can either take part in a tendering process or he can sell certificates. If a generator is awarded a contract, then he is not allowed to sell certificates on the TGC market. Similar to the case of the feed-in regulation under the TGC system, both promotional mechanisms have to be separated.

In practice a problem arises from the fact that there is a considerable time lag between the time when the contract is awarded under the tendering system and the start-up of RES-E production. Usually, planning and construction of the RES-E plants take several years. This means, that in a given year, the results of the tenders of former years have to be taken into account when the obligation for the distributors is fixed.

The obligation then is defined as

$$O_{dist} = Q_{total} - \frac{\sum_i \sum_t c_{i,t}}{E_{dist}}$$

where

O_{dist} is the obligation for the distributors in a given year [%]

Q_{total} is the total quota for RES-E in that year [%]

$c_{i,t}$ is the RES-E production contracted in that year under the contracts awarded in year i for the technology t

E_{dist} is the total electricity delivered by the distributors in that year

When TGC and tendering systems are used at the same time, an important difference between these instruments has to be taken into account. Under the TGC system, each producer can sell his certificates at the market price, which is the same price for all transactions (at a given time, as the price is dependent on supply and demand). Under the tendering system, each generator has a strong incentive to reduce his costs and to offer his production at the lowest price possible. But even if higher bids are awarded contracts too, each contractor receives only his bid price.

So if for a given technology a generator has the possibility to choose whether he wants to take part in a tendering process or whether he wants to take part in the TGC market, his decision will strongly depend on his assessment of the market situation. If the generator thinks that his production costs are rather competitive, then it might be more profitable to go into the TGC market where profits are possible for generators with low costs. If he regards his production to be more expensive, it might be safer to take part in the tendering process to check his competitiveness prior to the investment. So if tenders are not limited to specific technologies, the combination with a TGC system might lead to economic inefficiencies.

On the other hand, it is sensible to combine tenders for specific technologies, which are not competitive with other RES-E technologies, with a general TGC market. With this combination, (small) separate markets for those specific technologies are created, whereas the general TGC market is served by established RES-E technologies.

It should be noted, however, that this combination of TGC and a tendering system would have some impact on the price of certificates. If the national target is divided into a part that is reserved for specific RES-E technologies *with higher costs*, and an obligation, which has to be met by all distributors, then the equilibrium price for the certificates would be lower compared to the case without the ‘high-cost’-tenders. From the international perspective, the target of the respective country would be reduced (from Q_A to G_A’ in the Figure below) and therefore less RES-E plants would have to be built through the TGC market. This would reduce the costs for RES-E expansion in all other countries (from mc to mc’ in the figure below), while in the respective country some extra costs have to be covered for the ‘high-cost’-tenders.

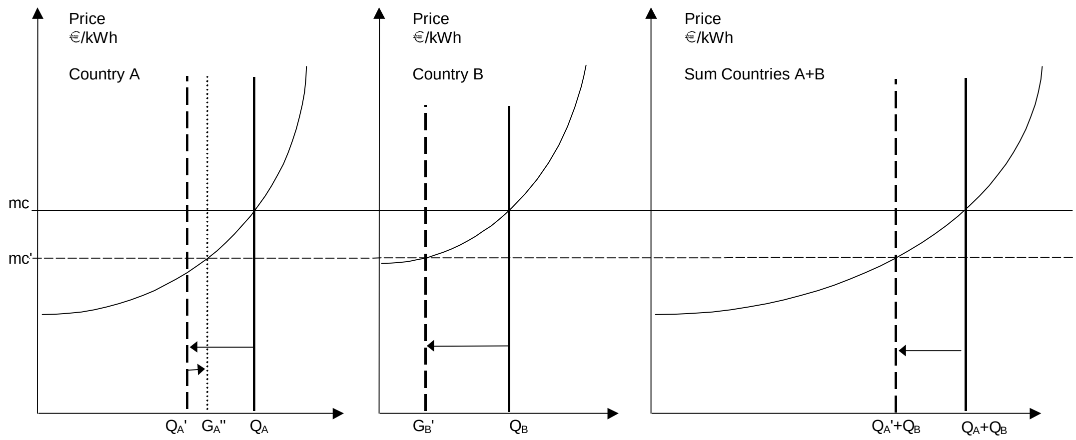

Figure 5.9 *International effects of a combination of a TGC system and a tendering system*

The Figure shows, that the new international equilibrium price mc' will lead not only to a reduction of RES-E production in county A, but also in country B. The resulting RES-E generation in country A under the TGC system can differ from the national target Q_A' (resulting in G_A''), depending on the shape of the different MC curves in both countries.

If a TGC system and a tendering system are combined, two separate balancing mechanisms are necessary:
- The TGC market.
- The fund which finances the premium paid to the generators which have been awarded contracts.

5.5 Conclusions

The different combinations of instruments for the promotion of RES-E form a complex situation. Most combinations can make sense if certain conditions apply. Only few combinations can lead to significant market distortions.

Generally, *investment subsidies* can be used for a 'fine-tuning' of the promotional effect of a feed-in regulation, a tendering system or a system of TGC for specific RES-E technologies. Unspecified subsidies would not make sense under all three instruments. Only under the feed-in regulation subsidies lead to an extension of RES-E generation. The same applies for *fiscal instruments* although exemptions or refunds of energy taxes for RES-E generators are sensible.

The use of subsidies and tax reductions leads to a shift of the financial burden for the development of RES-E from the consumer of electricity to the taxpayer. Therefore these instruments should be used only with limits.

Voluntary instruments like Green Pricing or Green Electricity Supply can form a good supplement to general instruments for RES-E promotion. To encourage electricity consumers to pay more for Green electricity on a voluntary basis , a clear distinction between the effects of the mandatory and the voluntary instruments should be guaranteed. This is mainly a question of appropriate accreditation schemes for electricity under the voluntary instruments.

If RES-E producers in a country which has not introduced minimum obligations (but has chosen other instruments to promote RES-E generation) are entitled to issue and sell TGC, the total supply of TGC will be increased while the demand (in countries with minimum obligations) remains the same. This could have a strong impact on the international TGC prices and could lead to a significant market distortion.

Under a *feed-in regulation*, specific invitations for tenders in technology bands which are not viable under the regulation can be a very good supplement. In comparison with targeted investment subsidies, preference should be given to specific tendering processes because these do not shift the financial burden to the taxpayers.

This recommendation does not apply vice versa: Under a general system of *tendering processes* a guaranteed feed-in tariff does not make much sense. If the promotion of RES-E is to be targeted more precisely, a better specification of technology bands for the tendering processes would be appropriate.

If an international *system of TGC* has been established, then it still is possible to make use of feed-in tariffs or tendering processes on the national level, although those additional instruments then should have a limited volume well below those of the TGC system. Both additional instruments could help to develop technologies which are not profitable under the TGC system alone, eg. PV systems. In these cases, a part of the general RES-E quota would be fulfilled through the feed-in regulation or the tendering process, the remaining obligation would have to be met through the TGC market. (Correspondingly it would be possible to guarantee minimum prices for TGC from specific technologies or to issue tenders for those certificates. This will be analysed in the design phase of this project.)

A combination of a TGC system and a feed-in regulation could help to encourage small-scale investors to invest in RES-E plants, which would not be able to deal with uncertainties of the TGC market and with corresponding financial instruments for risk reduction.

In all cases with combinations of an international TGC market and other instruments for the promotion of RES, the design of the instruments should ensure that the effects on the international certificate market are minimised.

6. INTERACTION BETWEEN TRADABLE GREEN CERTIFICATES AND CARBON EMISSIONS TRADING

6.1 Introduction

This Chapter outlines the principles which underlie Tradable Green Certificates (TGCs) and Carbon Emissions Trading (CET), and examines some possible ways in which they might interact. The TGC and CET systems have different aims, one promotes the use of electricity produced from Renewable Energy (RE) sources, the other is designed to reduce total CO_2 emissions worldwide. When combining the two systems, therefore, it is essential that these two sets of aims be kept in mind. It is clear that the way in which these systems might be implemented has enormous impacts on their potential efficacy; as does their interaction with other policy instruments relating to pollution, international trade, the structure of electricity markets and the liberalisation of energy markets within the EU.

This Chapter outlines the basic principles underlying both systems and then suggests some ways in which they might interact. The Kyoto Protocol to the UN Framework Convention on Climate Change and the theory behind emissions trading is described. Furthermore, brief descriptions of experience with implementing emissions trading systems to date are given. Section 6.5 examines ways in which interactions between TGC and CET might occur, and Section 6.6 concludes the discussion so far.

6.2 Climate change

6.2.1 Climate change and the Kyoto Protocol

In 1992, UN Framework Convention on Climate Change (FCCC) was agreed. Its main aim was the

> *'stabilisation of GHG concentrations in the atmosphere at a level that would prevent dangerous anthropogenic interference with the climate system'*

After much negotiation, the Kyoto Protocol to the FCCC was agreed at the third meeting of the 'Conference of Parties' (CoP3) in 1997.

The Protocol set legally binding targets for the overall reduction of greenhouse gas (GHG) emissions of industrialised countries by 5.2% of 1990 levels by the period 2008-2012. It has so far been signed by 84 countries. The signatories (known as 'Annex 1 countries') are all industrialised or newly industrialised countries. Developing countries (sometimes referred to as 'non-Annex 1 countries') have no GHG reduction targets.

The Protocol is to be developed further at annual meetings of the 'Conference of Parties'. CoP5 is due to take place in Bonn at the end of 1999, and the final details on how the Protocol might be implemented are due to be agreed at CoP6 at the end of the year 2000.

Under the Kyoto Protocol, two types of 'flexibility mechanisms' are included to allow countries to meet their commitments jointly in order to minimise costs. They are:
- Emissions trading (under Article 17 of the Protocol), and
- Joint Implementation (under Articles 6 and 12).

Emissions trading
Emissions trading allows countries to buy and sell emissions allowances or credits from each other. In this way, countries with high cost of GHG abatement actions can buy allowances or credits from countries with lower abatement costs, who undertake GHG abatement actions in addition to those required to meet their own targets in order to generate extra credits for sale.

Joint Implementation
Joint Implementation allows signatories to the protocol to agree joint abatement actions which will result in an overall reduction of GHG emissions for the signatories as a unit. In particular, a 'donor' country can finance an emissions reduction action in a 'host' country, receiving in return for this a GHG emissions allowance it can use as part of meeting its own target.

Under the Kyoto Protocol there are two types of Joint Implementation activities under consideration. One, (under Article 6) is straightforward joint actions between two countries that have agreed targets under the protocol (i.e. two Annex 1 countries) – a type of 'closed' Joint Implementation. The other (under Article 12) involves one country with a GHG abatement target and a developing country that has no abatement targets – a type of 'open' Joint Implementation. This type of Joint Implementation is known as the 'Clean Development Mechanism' because the countries that provide the low-cost abatement opportunities under this Article are all developing countries. The Clean Development Mechanism is highly controversial.

6.2.2 Climate change commitments in the EU

Under Article 4 of the Protocol, countries are allowed jointly to fulfil their commitments if they agree and declare it when they ratify the Protocol. The EU has declared itself as such a unit and has made a joint commitment under the Kyoto Protocol to an 8% reduction in GHG emissions by the 2008-2012-commitment period.

The declaration allows the EU to distribute its commitment between Member States in order to achieve equity in burden sharing over the EU as a whole and cost efficiency in fulfilling the commitment over the EU as a whole.

Table 6.1 shows the range of emissions reduction commitments made by various countries. Some countries are allowed to stabilise their emissions levels at 1990 levels within the commitment period, while others are allowed to increase emissions.

Table 6.1 *Emissions reduction commitments for various countries [%]*

Country	Emissions reduction commitment
EU Collectively	-8
EU Member States (Individually)	-8
Bulgaria, Czech Republic, Estonia, Latvia, Lithuania, Romania, Slovakia, Slovenia	-8
USA	-7
Canada, Japan	-6
Hungary, Poland	-6
Croatia	-5
New Zealand	0
Russian Federation, Ukraine	0
Norway	+1
Australia	+8
Iceland	+10

Source: Adapted from Kyoto Protocol to the UN FCCC.

Over the 5 year commitment period therefore, the EU is allowed to emit a total of 5 times 92% of their total 1990 GHG emissions. The total allows for the fact that variations will occur in total GHG emissions from year to year, due to environmental, climatic and other factors.

The EU's aggregate 8% commitment to GHG reductions was divided between Member States in 1998, with a final agreement being announced in June 1998 (see over for the division of the EU's commitment).

There is a wide range of commitment levels in the EU, which reflects many factors, including the current emissions total and the level of industrial activity in each State. The agreed levels were fiercely negotiated, and many States won relaxation of the level of emissions reduction proposed for them by the European Presidency.

Austria, for example, saw its commitment relaxed from a 19% reduction to a 13% reduction, while Portugal is allowed an increase of 27% rather than a proposed increase of 24%. Others (such as Sweden, which agreed to an increase of 4% rather than 5%) accepted more stringent commitments. Luxembourg, the UK, Finland, France, Spain and Greece all accepted the levels proposed by the Presidency.

Member States also have their own internal commitments to climate change actions.

Table 6.2 *Division of emissions reduction commitments for EU Member States [%]*

Country	Emissions reduction commitment
Austria	-13
Belgium	-7.5
Denmark	-21
Germany	-21
Finland	0
France	0
Greece	+25
Ireland	+13
Italy	-6.5
Luxembourg	-28
Netherlands	-6
Portugal	+27
Spain	+15
Sweden	+4
UK	-12.5

Source: ENDS Daily 17th June 1998.

6.2.3 Greenhouse gas abatement actions

Six gases (known as the greenhouse gases (GHGs)) have been linked to the risk of climate change. The GHGs have been ranked by the Inter-governmental Panel on Climate Change (IPCC) in terms of their hundred year 'Global Warming Potential' (GWP). This effectively converts them to tonnes of carbon equivalent. For each GHG, there are a number of sources covered by the Protocol, most of which are either industrial or agricultural activities. Annex A of the UNFCC lists the main sectors covered by the Convention. These are:

- Energy (both fuel combustion and fugitive emissions from fuels)
- Industrial processes
- Solvent and other product use
- Agriculture
- Waste.

The energy sector has by far the largest number of sub-sectors. It is thought to make the largest contribution to the total global GHG emission each year (for example, CO_2 released due to the combustion of fossil fuels accounted for over 80% of the GHG emissions from industrialised countries in 1990). It is obvious, therefore, that the energy sector will be the focus of much GHG abatement activity.

Table 6.3 shows the GWPs of the six gases, together with their qualifying sources.

Table 6.3 *The Global Warming Potential and qualifying sources of the six greenhouse gases*

Greenhouse gas	Qualifying sources	Global warming potential
Carbon Dioxide (CO_2)	Fossil fuel combustion, cement	1
Methane (CH_4)	Rice, cattle, biomass combustion and decay, fossil fuel production	21
Nitrous Oxide (N_2O)	Fertilisers, fossil fuel combustion, land conversion to agriculture	310
Hydrofluorocarbons (HFCs)	Industry, refrigerants	140 – 11 700 (most usual value is 1300)
Perfluorocarbons (PFCs)	Industry, aluminium, electronic and electrical industry, fire fighting, solvents	CF_4 is 6 500, C_2F_6 is 9 200 (average is around 6 770)
Sulphur Hexafluoride (SF_6)	Electronic and electric industry, insulation	23 900

Source: EEP climate change briefing paper No.11, UN Framework Convention on Climate Change.

While energy efficiency and 'clean burn' technologies and fuels will provide some steps towards the reduction of CO_2 emissions, there will be some countries for which these steps will be more costly than others. Such countries may therefore prefer to 'buy' their emissions reductions from states with lower emissions reductions costs. This exchange is known as 'Emissions trading' (or, if it is restricted to trades of CO_2 allowances, 'Carbon Emissions Trading') and is described in the next section.

6.3 Emissions trading

6.3.1 Introduction

Underlying principles

Emissions trading is based on the idea that participants in an emissions reduction scheme can lower the overall cost of meeting an agreed target by buying and selling emissions allowances and/or credits. This is based to some extent on the principle that participants have a right (sometimes regarded as a 'property right') to cause an agreed level of environmental damage, although in practice it is more complex than this.

Once the 'acceptable' level of polluting activity has been determined by political processes, governmental (or other) bodies can assign polluting 'allowances' to polluters (in the case of Carbon Emissions Trading (CET), emitters could be, for example, large power producers or users).

In the case of energy, there is much debate about where the 'polluting activity' occurs in the supply chain. For example, are the fossil fuel suppliers responsible for releasing the fuel into the supply chain? Are the power stations responsible for the CO_2 they release to the atmosphere in flue gases? Or is the consumer responsible for the pollution caused by the energy they use? At the moment, energy efficiency taxation schemes have, in general, been imposed on energy users, but trading schemes for emissions quotas have operated between other actors in the energy supply chain.

Some of the polluters will find that the cost of reducing emissions is high, while others will find the cost relatively low. Some will find it easy to achieve more reductions than they are required to, while others will struggle to meet their target. Trading allows those with high emissions reduction costs to pay others (with low emissions reduction costs) to carry out extra actions on their behalf, so that the total amount of pollution from all participants stays within the agreed limit. It should also, in an ideal world, allow the total agreed emissions reduction to be achieved at the lowest possible cost.

In fact, trading itself is not free of cost, and polluters rarely have perfect information about the opportunities for trade, but it is estimated that trading systems are a highly cost efficient way of introducing pollution control.

The USA Environmental Protection Agency (EPA) estimates that the 'Lead Phasedown Program' it initiated in the 1970s, which included a tradable allowance system, saved the industry as a whole around 20% of its projected cost (World Bank). The issue of cost saving is discussed further in Section 6.3.2.

How the system works: allowances vs. credits

An emissions-trading scheme can work in one of two ways:

1. The polluter can emit up to a certain amount of the pollutant, and can trade any of that allowance with other polluters, reducing or increasing their own allowance in the process.
2. Pollution allowances up to the allowed amount cannot be sold. Trading is only allowed if the emissions reduction target is exceeded by the polluter, who thus generates emissions trading 'credits' which can then be sold.

Table 6.4 below contrasts the two frameworks.

Table 6.4 *Emission allowances vs credits*

Emission Reduction Credit	Emission Allowance
Scheme: 'Baseline and credit'	Scheme: 'Cap and Trade'
Applies to emission reductions below defined baseline	Applies to all emissions
Only emission reductions can be traded	All emissions can be traded
Credits are generated when a source reduces its emissions below an agreed baseline	Allowances are allocated by the regulatory authority
May develop incrementally as a means of introducing flexibility into existing regulatory structure	Trading must be built into the regulatory structure from the beginning
Participation in the credit market is voluntary – sources can just meet existing standards	Participation in the program is mandatory – the overall emission cap still applies even if sources do not trade

Source: Sorrel and Skea 1999.

Pollution typology

Emissions trading schemes are based on the assumption that emissions have similar impacts regardless of the emission location. In fact this does not apply to all types of pollution. One way of categorising pollution types is using two variables:

1. The extent to which the pollutant mixes into the medium (i.e. air, water or land) into which it is emitted, and
2. The extent to which the pollutant builds up in the environment, or is broken down and assimilated by it.

Combining these two variables gives four broad types of pollutant.

1. not mixed into emission medium, accumulated over time,
2. not mixed into emission medium, broken down and assimilated over time,
3. well mixed into emission medium, accumulated over time,
4. well mixed into emission medium, broken down and assimilated over time.

In practice, all pollutants behave in slightly different ways, but the typology is a useful guide to examining the appropriateness of emissions trading schemes. It is obvious that pollutants of type 1 and 2 are not appropriate for trading schemes, unless these are based on the measurement of the concentration of pollutants in each location. In practice this is highly complex and unlikely to be workable.

Pollution types 3 and 4 are the most suitable for trading schemes. Pollution type 3 can be traded via a 'stock' scheme that allows emission of a pollutant up to a total quantity, after which emissions are prohibited, unless the permit is replenished. Pollution type 4 can be traded via a 'flow' scheme, where a certain rate of emissions is allowed. The greenhouse gases, like CFC emissions, can be traded via either stock or flow permits, depending on whether they are regarded as being of pollutant type 3 or 4. GHGs have the same global impacts regardless of emission location and are therefore well suited to emissions trading schemes.

The next section describes experience of implementation of emissions trading schemes so far. The schemes relate mostly to the trading of the 'Acid Rain' gases SO_x and NO_x.

6.3.2 Implementation options and experience

Emissions trading has been carried out largely in the USA, where it was introduced to combat air pollution due to SO_x and NO_x in the 1970s and evolved over the following decades. Experience with emissions trading in the EU is limited. International trades in emissions are limited to a few exchanges of CFC allowances in relation to the Montreal Protocol. With the agreement of the Kyoto Protocol, however, this looks set to change. This section outlines some experiences with emissions trading so far.

USA Acid Rain Programme

The USA Acid Rain Programme, launched in 1995, allows any power station in the USA to trade SO_2 allowances with any other power station. The programme aims to cut SO_2 emissions from US power stations by over 50%.

The first phase, which runs to the year 2000, requires 110 of the largest stations to cut emissions by a total of 3.6 million tons/year. The second phase extends this to a further 800 stations, requiring a further cut of 5 million tons/year. After 2000, emissions cannot exceed 8.95 million tons/year in total.

Programme participants are allocated a certain number of 'Sulphur Dioxide Allowances' (SDAs) each year, which they can trade with other participants. Unused allowances can be 'banked' for use in future. The programme has a computerised tracking system and imposes hard penalties on participants that infringe its rules.

So far the programme has performed well, and the emissions reduction targets for phase 1 have been exceeded by 3.4 million tons. These have been 'banked' as credits for use during phase 2. The allowance market is buoyant, and SDAs are being traded for around $90/ton, which is around a factor of ten less than some early predictions suggested. The trading system is estimated to have cut overall emissions reduction costs by between 30 and 50% (Sorrel and Skea).

RECLAIM
The Regional Clean Air Incentives Market (RECLAIM) programme in Southern California covers both SO_2 and NO_X emissions, and allows 400 of the largest power production plants in the area to trade emissions of both. The system was introduced in 1994, replacing an 'Air Quality Management Plan' which the state had previously begun in 1991. Under RECLAIM, plants receive a certain number of emission allowances each year, depending on their peak fuel consumption over an agreed baseline period. Emission allowances are valid for one year only and cannot be banked. Allowances are made in two cycles, spaced by 6 months, in order to prevent uneven use of allowances over the year. Allowances are also made in two separate zones of the region. Plants in the upwind zone cannot buy allowances from plants in the downwind zone[13].

It is estimated that the programme will cut the overall cost of reducing emissions in the region by around 40% in the period 1994 –2000 (Sorrel and Skea).

The Montreal Protocol
The Montreal Protocol was agreed in 1987. It set out limits for the production and use of ozone depleting substances, principally chlorofluorocarbons (CFCs). The Protocol allowed industrialised countries to trade production and consumption allowances, subject to certain rules. There was some international trade of allowances (in 1992-1993, for example, EU companies were involved in 20 transactions), but because of commercial sensitivities, little data is available on the size of the trades or the prices paid for allowances.

Within the USA, trading was carried out between companies producing and importing substances controlled by the Protocol. The Environmental Protection Agency estimates that within the USA, the trading system allowed them to meet targets cost effectively and quickly. The industrialised nations of the world succeeded in phasing out the use of ozone depleting substances by 1995 (Anderson).

BP internal CET system
There is growing interest in carbon trading, especially in the USA, and several large companies are investigating the business possibilities relating to it. BP Amoco, for example, has recently set up an internal trading system, where divisions (or 'Business Units') of BP Amoco can trade emissions internationally between themselves. The scheme is restricted to the Business Units that are responsible for emissions, i.e. it does not include the marketing activities. The trading system involves 14 of the company's Business Units (see Figure 6.1 below) which represent around 10% of the total number of Units.

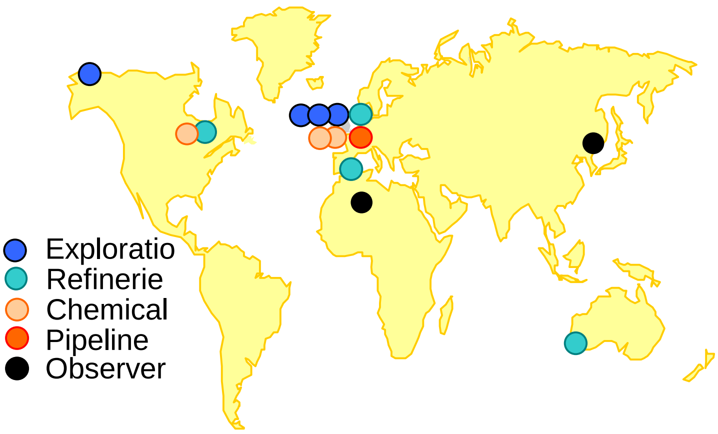

Figure 6.1 *Location of Business Units in BP Amoco trading system (Source: BP Amoco)*

[13] This is due to the fact that SO_2 and NO_X do not mix uniformly on a regional level, but have localised impacts.

Twelve of these are located in 'Annex 1' countries and will take part in trading activities. The other two are located in Non-Annex 1 countries, and will have 'Observer' role for at least the first few years of the scheme.

The scheme designers have opted for an 'allowance' approach to trading, with a fraction of the allowance reserved for the stimulation of trade or to allow new entrants. The company has endeavoured to replicate, as far as possible, the trading conditions they believe will follow the implementation of the Kyoto Protocol and has asked all Business Units involved to calculate the cost of compliance without trading, in order to estimate the cost-effectiveness of the trade approach. There are still no published results from the system.

Netherlands Acid Rain Covenant
In 1990 the Netherlands Association of Electricity Producers (SEP) agreed a 'covenant' with the national and provincial governments to reduce SO_x and NO_x by the year 2000. Under the agreement, SEP can design its own implementation strategy as long as all existing plants meet minimum emission standards and new plants are constructed according to (new) higher standards than those of existing plants.

The system does not include tradable permits, but does allow plants to negotiate rights to emit within the sector. This is expected to result in a cost saving of up to 50% overall when compared to the approach where the same standard is applied to each plant rather than to the sector as a whole. This therefore represents an intermediate stage between the 'tradable permit' approach and the imposition of the same standard on all actors.

Activities implemented jointly under the Kyoto Protocol
At the first Conference of the Parties an agreement was reached which allowed for a pilot phase for Joint Implementation. The phase was due to begin in 1995 and continue to the end of 1999. Projects under this phase are known as 'Activities Implemented Jointly' (AIJ) and do not result in credits under the Kyoto Protocol. They do, however, give participants (and the CoP) information on and experience of how JI might operate.

AIJ projects have been implemented in a variety of countries, and results of most of these are yet to emerge. However, studies of some of the projects (Jackson) show that there are issues emerging that must be addressed before JI or the CDM can be implemented on a wide scale.

The EU
DG XVI of the EC has recently proposed that the EU should work towards an internal GHG emissions trading system by 2005, which would provide valuable experience when the first Kyoto Protocol commitment period of 2008 – 2012 begins. First indications are that the system would initially be restricted to carbon trading, probably within a single sector (which may be energy supply). A Green paper will probably be issued on this within the year by DG XVI.

6.3.3 Key issues

Trading of emissions allowances is highly complex, and during the early years of experience with such trading, several important issues have emerged. This section outlines some of the issues, as they relate to emissions trading only (rather than TGC as well)

Interaction with other environment policies
The trading of allowances for GHG emissions interacts strongly with other environmental instruments. In particular, the implementation of pollution control measures can have a strong im-

pact on the cost efficiency of trading systems. In the EU, pollution is to be controlled by the 'Directive on Integrated Pollution Prevention and Control[14].

The European Directive on Integrated Pollution Prevention and Control (IPPC[15]) (Directive 96/61/EC) will be introduced in all EU Member States in 1999. The Directive is based on the central principle that polluting industries should use 'Best Available Techniques' (BAT) to control polluting emissions to air, land and water in an integrated manner (it includes a requirement that industrial processes are energy-efficient). This prevents polluters from circumventing emissions limits applied to one medium (i.e. air, land or water) by releasing pollutants into another. The Directive covers all energy intensive industrial sectors.

While a system of trading emissions of (say) CO_2 accepts that some polluters will perform better than others, BAT requires all polluters to reach the same standard. More rigorous implementation of IPPC principles could therefore undermine the potential for carbon emissions trading schemes.

In order to implement the IPPC Directive, the regulator must be able to understand the equipment and techniques used by operators, and to be able to judge whether or not these are the 'Best Available' to them. Regulation is therefore very hands-on. There is little incentive for innovation by operators, as they 'follow' a prescribed process, rather than try to achieve a target for emissions reductions.

The IPPC directive is not target driven – it has no overall targets. It is technology-based, and allows polluters to operate only if they have obtained a permit that sets out emissions limits for the duration of the permit together with emissions reduction actions to be undertaken by the operator.

In contrast to this, the Kyoto Protocol is completely target-driven and is not technology-based. The regulator is not involved with decisions as to which technology or technique an operator uses to reduce emissions. Under the Protocol, there is a much greater incentive for polluters to innovate to reduce the cost of achieving a given level of emissions reduction, and to generate extra emissions 'credits' that can then be sold.

The IPPC Directive could be implemented in such a way as to allow CET, but this depends on the culture of regulation in Member States. In some states, regulation is carried out in a manner that allows flexibility and negotiation, and generic standards are interpreted in such a way as to allow local standards to depart significantly from each other as local conditions dictate. It is likely that emissions trading systems could operate in parallel with the IPPC in such States.

In other Member States, local standards are directly extrapolated from generic frameworks, so that the same rules and quantitative standards apply to all operators, regardless of local conditions. It is possible that emissions trading could not operate within such an interpretation.

An example of a case in which a strict interpretation of pollution law hampered a potential trading scheme is the UK's attempt to introduce a sulphur emissions trading scheme in the context of pollution legislation that required the use of 'Best Available Technology Not Entailing Excessive Cost' (BATNEEC). A strict interpretation of the BATNEEC principle by the regulator meant that trading could not happen within the UK.

[14] This section draws heavily on a paper by Adrian Smith and Steve Sorrel entitled 'Interaction between environmental policy instruments: carbon emissions trading and Integrated Pollution Prevention and Control'.

[15] The IPPC is not to be confused with the IPCC (International Panel on Climate Change, the international forum of scientists and policy makers studying the effect of antropogenetic emission of greenhouse gases).

This gives some indication that trading systems for carbon (or other) emissions (or, in fact, RE quotas) is not workable within a regulatory framework that is essentially driven by adherence to the same standard by every actor.

Allocation of initial quotas/allowances
The initial allocation of emissions quotas and permits has been a major issue in trading schemes implemented so far. In general, permits are distributed partly on the basis of historic emissions patterns (this is known as 'grandfathering'). There are two major problems with this approach, however. It does not take into account the fact that plants may have reduced emissions in the recent past – one way around this is to agree a 'baseline year' with the participants, but this can itself be complex. 'Benchmarking' can also be used for some emissions allowance allocation – this is most appropriate where applied to all the major actors in one relatively homogeneous industrial sector (such as cement and steel). Another problem with grandfathering is the issue of new entrants on the market. Will they be allocated permits freely or will they have to buy them. Will this not induce new entry barriers?

Experience of emissions trading so far has shown that it is also necessary to retain some of the pollution allowance for distribution at a later date, e.g. at auction (World Bank). This allows new actors to enter the sector, and can also provide market information on the cost of emission reductions.

Monitoring and verification
The credibility of any emissions trading system is closely linked to its system of monitoring and verification. The level of intervention required for this (and therefore its cost) depends on the system of trading adopted. The costs of monitoring and verification are not negligible. For example, in the USA, the EPA found that the Acid Rain programme required full time staff of 150. Over the first five years of the programme, administrative costs were around $60 million (Mullins, quoted in World Bank paper). This equates roughly to $1.50/ton of carbon reduction. In addition to this, programme participants were required to install monitoring equipment at an estimated cost of around $6/kW of installed capacity (Kruger and Dean, also quoted in World Bank paper).

It is likely that carbon emissions trading will require verification via accounting and accreditation rather than emissions level monitoring. However, the other GHGs, especially the three halogenated gases covered by the Kyoto protocol (hydrofluorocarbons, perfluourocarbons and sulphur hexafluoride) are likely to require extensive monitoring before they can be phased into trading schemes.

Time boundaries and 'banking'
Some permits are assigned a time boundary – i.e. they expire after a certain date. This can raise certain problems:

- Shortages or build-ups towards the expiry date
- Banking and borrowing refer to the practice of keeping permits for use in later emissions periods, or borrowing permits from future periods, when there are not enough in the current period.

The Kyoto Protocol commitment uses a five year 'commitment period' in order to avoid problems raised by tight time boundaries. However, this could have impacts on the nature of trading towards the end of the commitment period.

'Hot Air'
It is worth noting at this point that the Russian Federation commitment is complicated by the fact that their emissions of GHG have plummeted since 1990 due to the country's economic restructuring. Even if Russia takes no further GHG abatement action, the country will probably

emit far less than it is allowed by its emissions commitment. This means that the Federation will have an artificial excess of emissions allowances, which it could in theory then sell to other Annex 1 countries. This is known as the ‘Hot Air’ problem.

Trading and market risks

There have been some assessments of the possible risks associated with international trading of GHG emissions allowances. The World Bank, for instance, has carried out surveys and analysis of this, with particular reference to the CDM. The World Bank is currently proposing to set up a ‘Carbon Fund’ which it says could bear many of the risks of CDM transactions (World Bank). In particular, it proposes that accreditation and validation risks could be removed by World Bank involvement.

6.4 Tradable green certificates (TGC)

The principles of a TGC system have been described in Chapter 2. There are several issues that deserve special attention with regard to a TGC-system and its relation to climate change policy.

6.4.1 Definition of renewable energy

An important issue in such a system, and especially in an international system is the definition of renewable energy. While most Member States agree that solar power, wind power, small-scale hydro and most biomass resources are all renewable, there is disagreement on other sources. Large hydro and the combustion of waste are problematic in most Member States, and have been specifically excluded from the definition of ‘renewable’ energy in some instances. The EC, for example, does not include large scale hydro power in its RE programmes as it is thought to be financially viable and not in need of further support. Table 6.5 below lists the criteria used by various RE accreditation systems worldwide.

Table 6.5 *RE accreditation*

Country/Region	Accreditation introduced	Licensing body	Criteria
Sweden	Late 1980s	SNF (Society for Nature Protection)	Only ‘old’ hydro allowed, no new hydro. Biomass allowed only if not produced by a monoculture.
USA/California	1997	CRES	Small (<30MW) hydro permitted. Biomass from waste allowed.
Canada	1997	Terra Choice	Hydro allowed if <20MW. (Production from fuel cells accredited).
Australia/New South Wales	1996	SEDA	New hydro allowed. Combustion of biomass from waste allowed but not other waste combustion.
Switzerland	1999	VFE	Hydro allowed when it meets agreed environmental criteria.
UK	1999	Energy Savings Trust	Pre –1990 (i.e. large-scale) hydro allowed as long as it makes up < 50% of the ‘renewable offering’. All energy derived from waste will be accredited.

Source: Mårtensson, 1999.

As the Table shows, hydropower has criteria applied to it that are not applied to other RE sources (mainly relating to environmental criteria and financial performance). Energy from waste is sometimes regarded as renewable, but usually subject to certain constraints. In Sweden, biomass is regarded as renewable only if it is not produced in a monoculture.

6.4.2 Allocation of targets

The EU as a whole has a target of meeting 12% of its gross energy consumption from renewable sources by 2010. Member States also have their own targets for RE use, some of which relate to electricity alone (the UK, for example, aims to meet 10% of its electricity demand from RE by the year 2010). The EU target for RE can be shared out in various ways across the EU.

In some ways the burden sharing process for RE targets is analogous to that required for GHG emissions reductions targets. The EU ‘bubble’ agreed a total GHG emissions reduction commitment of 8% under the Kyoto Protocol. However this was translated by the burden-sharing negotiations into widely different commitment levels for Member States, ranging from a 28% reduction for Luxembourg to a 27% increase for Portugal.

6.4.3 Credibility

In order for the trading of Green Certificates to be effective in terms of helping to achieve RE targets, it must be credible in the eyes of all stakeholders. This means that there must be an internationally recognised system of independent accreditation for the labels, backed by monitoring and verification actions in all Member States. This issue is the subject of another EU research project.

6.4.4 Time boundaries of quotas and targets

The time boundary assigned to a quota for RE electricity, and the lifetime of ‘Certificates’ issued in any one target period are crucial to the stability of any potential trading system. The intermittency of RE generation (due to natural fluctuations in resource availability) means that the quantity of electricity produced is not predictable within any short time frame. This is quite similar to the prediction of GHG emissions, which are dependent on a number of stochastic processes. In order to overcome this, the Kyoto Protocol has set out a five year ‘commitment period’ within which allowances for GHG emissions can be moved between years in order to cover variations due to climate etc. There is also discussion of the possibility of ‘banking’ unused allowances for use in future commitment periods, and of ‘borrowing’ allowances from future commitment periods if it is not possible to meet the emissions reductions targets within the timescale agreed. It seems likely that ‘banking’ will be allowed under the implementation of the Protocol, whereas ‘borrowing’ will not.

Another issue relates to RE electricity alone, and has no analogy in the climate change debate. The structure of electricity trading arrangements in some EU Member States means that some electricity supply systems penalise any producer automatically for being intermittent (this may well happen in the UK, when the current Review of Electricity Arrangements is completed). This means that RE electricity could be disadvantaged by the structure and operation of the supply industry itself. This may well mean that in Member States where there is no requirement for the grid operator to take electricity produced from renewable generators, the electricity from RE schemes is not taken by the grid at all.

6.4.5 Technical limitations of the grid

Although the ‘Green Certificates’ system is based on the supposition that the ‘green-ness’ can be detached from ‘Green’ electricity and sold separately in order to meet RE quotas, in fact this is not completely true. In some senses, the debate about Green Electricity has assumed that electricity is like an emission of CO_2, which has the same impact on Global Warming, regardless of the place it is emitted. A delivery of electricity to the grid, however, has local and regional impacts within the supply network, and cannot be accepted by the grid unless there is some relatively local demand for it.

Scotland, for example, has one of the best wind power resources in Europe. However, it is not possible to exploit all the wind power in Scotland with a view to trading 'Green Certificates' elsewhere in the EU without taking into account the fact that the electricity produced in Scotland has to match a portion of the demand on the UK grid.

This issue requires further investigation, with particular attention being paid to the technical impacts of TGC systems.

6.5 Interaction between TGC and CET

6.5.1 Introduction

In this section we examine some of the effects of different levels of interaction between systems of Tradable Green Certificates (TGC) and Carbon Emissions Trading (CET). As both TGC and CET are in their infancy and we have no data against which to test our theories, this section is purely hypothetical. The interactions are examined in a general way in order to explore the impacts of various interactions for RE electricity.

6.5.2 Key issues

Position of obligations

The trading of Carbon Emissions related to energy may be upstream, i.e. between producers (such as large generating plants) or downstream (i.e. between suppliers or consumers). The trading of Green Certificates is likely to be between downstream actors. This raises questions about how the trading systems could interact – how would the obligations be passed between levels of actors, for instance, and how much intervention on the part of a regulatory, accreditation and/or exchange body would be needed to facilitate this.

International trades

It is likely that international trading of GHG emissions quotas will emerge under the Kyoto Protocol. It is also possible that international trading of TGCs could emerge. This would mean that RE from the EU would be in direct competition with RE from other countries. Some of these could well be countries with very low exploitation costs for RE (such as some developing countries), which would be a challenge to the competitiveness of EU-produced green electricity.

Qualifying Levels

There has been some discussion of the imposition of 'qualifying levels' of domestic internal actions before trading is allowed. This would ensure that Member States (or actors within them, if this obligation were to passed down to others) were required to undertake at least some actions within national borders before being allowed to participated in trading exchanges. This has been discussed in relation to the CDM of the Kyoto Protocol, where it may be possible under certain arrangements for a country to undertake no GHG emissions reductions actions within its own borders, but pass all the obligation on to another country by an open form of JI.

The 'value' of RE

Renewable electricity has a 'value' to society that depends on several of its characteristics. There is, for instance the value of the electricity itself, the value due to the fact that RE schemes are often embedded in supply networks and the social and environmental value of replacing conventional generation with generation from RE sources.

In this Chapter we are considering the interaction between TGC and CET, so the component of the value that interests us is related to the environmental benefits of using electricity produced from RE sources. We will refer to this value as V_E, and split it into two components: V_{CC} and

V_{EOTHER}, where V_{CC} is the component of the value that refers to climate change benefits, and V_{EOTHER} represents all other environmental benefits of using RE-sourced electricity

(i.e. $V_E = V_{CC} + V_{EOTHER}$).

One issue that has emerged in the course of this study is that these three components are given quite different values in various Member States of the EU. This is reflected in the variety of fiscal mechanisms used to support RE. Some states operate 'Environmental' taxes or 'eco-taxes', rebates from which are offered to some forms of RE; others operate CO_2 taxes, for which RE can gain a rebate; some operate no 'eco-tax'-type mechanism at all; in some cases the rebate is only allowed if the RE scheme is not in receipt of other types of state support.

The situation seems at the moment to be far from the 'level playing field' needed to allow free trade of RE electricity between states.

6.5.3 Interaction options

Option A: Minimal interaction between TGC and CET

Description
In this scenario government determines that a TGC system does not interact with any other instrument related to climate change policy (including taxation). Certificates are traded internationally, but do not qualify for any rebate on ecotaxes such as carbon taxes or climate change levies and cannot be used to release any carbon emissions quotas for trade. Used this way, TGC can isolate RE policy from climate change policy.

Impacts
Under this arrangement, the TGC system reflects the value to society of RE-source electricity minus its contribution to climate change targets. TGC prices are strongly linked to the penalty level set for failing to achieve target levels for RE and are not linked to levels of environmental taxes or carbon quota prices.

One way of expressing this is to say that trade will only occur if the condition below is met:

$$P_{TGC} = F(D,S) \leq P_{PENALTY} - C_T$$

Where:	P_{TGC}	= Price of TGC
	$F(D,S)$	= Function of demand and supply
	$P_{PENALTY}$	= Price of penalty for failing to reach RE quota
	C_T	= Cost of trade

It is clear that the size and units of the TGC and CE quota (prices) will probably be different, but it is assumed that some representational equivalence for the sake of clarity in the discussion.

Comments
- This scenario does not exist at present. In the Netherlands, the price of the penalty is linked to the market price for TGCs, but a rebate of the ecotax is given on electricity from RE, even though this happens at a different point in the supply chain from the position of the certificate obligation.
- Separating RE support instruments from climate change taxes/trading gives a strong signal that RE has no contribution to make towards climate change targets (something which anti-wind power lobby groups state repeatedly in some countries).

- RE policy does have aims which are additional to climate change policy (such as security of supply, increased rural employment, the development of domestic industries) which could be lost if RE is linked solely to climate change impacts.
- If V_{CC} is not incorporated in the Green Certificate price, then the remaining values could well be more 'local' and hence the tradability is less justified.

Option B: Interaction limited to rebates on ecotax/carbon tax/climate change levy at the national level only

Description
Under this configuration, electricity industry actors (who could be anywhere on the supply chain) can claim rebates of ecotaxes (which, for the purposes of this discussion includes carbon taxes, climate change levies etc) for electricity produced, supplied or consumed by RE schemes when the electricity is produced within national borders. However, in this scenario there is no full interaction between TGC and CET systems.

Impacts
This scenario would have the effect of making RE produced at a national level more attractive (on a cost basis) than that produced elsewhere. It would also mean that the price of TGCs would be affected by penalty levels, national target levels, the level of rebate allowed on taxation and the way in which the rebate is implemented.

It is especially important to consider the point in the electricity supply chain at which the rebate is given. Where the rebate is given to producers, this would probably mean that V_{CC}, the 'value' given to the climate change impacts of RE electricity, would not be incorporated into the price for the Green Certificate. If this were to be the case, the equation given in the section above, i.e.

$P_{TGC} = F(D,S) \leq P_{PENALTY} - C_T$
would still hold true. This case represents the current situation in the Netherlands (although it is not possible to identify if the tax rebate does in fact represent exactly the climate change value of RE-source electricity).

If the rebate were to be given at the point of electricity use (the situation currently considered in Denmark and the UK, for example) then the impact on the trade of TGCs would be slightly different. In this case, P_{REBATE} functions as a floor price for the green certificate, and the condition for trade might be expressed in the equation:

$$P_{REBATE(national)} \leq P_{TGC(national)} = F(D, S) \leq P_{PENALTY(national)} - C_T$$

Where:		
	$P_{TGC(national)}$	= Price of TGC within country
	$P_{PENALTY(national)}$	= Price of (national) penalty for failing to reach RE quota
	$P_{REBATE(national)}$	= Rebate allowed on 'ecotax' for electricity from RE sources within national borders.
	C_T	= Cost of trade
	$F(D,S)$	= Function of demand and supply

It is clear that $P_{TGC(national)}$ would vary from country to country, and that actors within a country operating this system would probably be prepared to pay a price for TGCs from other countries which was governed by the equation above with the rebate term removed.

Comments
- This scenario exists at the moment by default – i.e. rebates are allowed on ecotaxes on RE electricity produced within national borders simply because RE electricity trades have not yet been carried out extensively between Member States.

- It would be interesting to note if the single international TGC trade (between the Netherlands and the UK) has attracted a rebate on the Netherlands ecotax within the Netherlands and if there has been any debate surrounding this.
- As we stated above, the current situation in the Netherlands is modelled by the first option described above, whilst in Denmark the second option is under consideration. This could make trade between these two countries difficult as the Danish certificates will also incorporate more ‘greenness/societal value’ than the Dutch certificates.
- It seems unlikely (and perhaps illegal?) that taxation can ultimately be structured to allow rebates on RE produced within national borders. This would represent a significant price advantage for domestically produced ‘green’ electricity.
- On the other hand, this structure does allow the support of national attempts to reach GHG emissions reduction and RE targets.
- If P_{REBATE} becomes very high, the price of Green Certificates is no longer determined by demand and supply, but will be fixed by the rebate. In that case the system has become a fixed-price system (or better, a fixed-premium system).

Option C: Interaction includes rebates on ecotaxes at the national level and interacts with a nationally valid CET system

Description
a. ‘Value’ represented by ecotax rebate
In this scenario V_{CC} is translated into both a tax rebate and into a price for a national tradable carbon quota (a function of demand and supply in this market) and can be expressed by the equation:

$$V_{CC} = V_{Ccrebate} + V_{CCcq} \Rightarrow P_{REBATE} + P_{CQ(national)}$$

Where, $P_{CQ(national)}$ = Price of nationally traded carbon quota. The other terms are as above.
Now there are four different possibilities, listed below.

1. *Both parts of V_{CC} are incorporated, together with the remaining societal benefits, in the green certificate.*

   In this case $P_{REBATE} + P_{CQ(national)}$ functions as a floor price for P_{TGC}:

   $$P_{REBATE} + P_{CQ(national)} \leq P_{TGC} = F(D,S) \leq P_{PENALTY} - C_T$$

2. *Only the part of V_{CC} that is represented by the tax rebate is incorporated in the green certificate, together with the remaining societal value.*

   For the tradable quota part an additional climate change certificate is issued. In this case P_{REBATE} functions as a floor price for P_{TGC} and can be expressed as:

   $$P_{REBATE} \leq P_{TGC} = F(D, S) \leq P_{PENALTY} - C_T$$

3. *Only the part of V_{CC} that is represented by the climate change quota is incorporated in the green certificate, together with the remaining societal value.*

   In this case $P_{CQ(national)}$ functions as a floor price for the green certificate:

   $$P_{CQ(national)} \leq P_{TGC} = F(D,S) \leq P_{PENALTY} - C_T$$

4. *V_{CC} is left out of the green certificate.*

   In this case, V_{CC} is awarded to the producer of green electricity in the form of a higher price for their electricity (tax rebate) and an additional carbon quota certificate. As a consequence of this, the green certificate only incorporates the societal benefits that are not related to climate change and we can express this as:

   $P_{TGC} \leq P_{PENALTY} - C_T$

   This is identical to the first option outlined in this section, i.e. there is no interaction between the green certificate system and climate change policy.

b. Position of ecotax rebate on the electricity supply chain
In this interaction option, electricity system actors (i.e. at the nationally determined point on the supply chain) can claim rebates on any relevant 'ecotaxes' applied within their national borders for RE electricity sourced from any EU Member State.

In Member States where the electricity *producer* is awarded the rebate, this means that national producers remain the only actors eligible to claim a rebate. However, in states where the *supplier* or *user* is awarded the rebate, TGCs sourced from outside national borders can be used to claim from the rebate body.

Imbalances could occur with a variety of rebate structures. They are most likely where the rebate is given to the producer of the RE electricity (and hence the TGC) in the state where the TGC is produced. This is illustrated by the matrix below, which shows how the point of the supply chain at which the rebate is given can determine whether a rebate is received at all by RE-sourced electricity. (It is assumed that the RE-sourced electricity is certified by the TGC, which of course, may not be the case. Nevertheless it does illustrate that harmonisation is also needed with regard to the point at which a rebate is granted if a trading system is to operate robustly).

Table 6.6 *TGC production and use in different countries – Impact on ecotax rebates*

In country where TGC is produced	In country where TGC is used to meet quota		
	1. Rebate awarded to producer of RE electricity	2. Rebate awarded to supplier of RE electricity	3. Rebate awarded to user of RE electricity
1. Rebate awarded to producer of RE electricity	Rebate awarded in country of origin ✓	Rebate awarded in both countries ✗	Rebate awarded in both countries ✗
2. Rebate awarded to supplier of RE electricity	No rebate ✗	Rebate awarded in supplier's country ✓	Rebate awarded in country of use (and possibly in country of the supply company, if this is different) ?
3. Rebate awarded to user of RE electricity	No rebate ✗	Rebate awarded in supplier's country ✓	Rebate awarded in country of use ✓

As we stated above, it can be seen that awarding the rebate to the *producer* of RE electricity gives rise to the most apparent imbalance in rebate payments if trade of TGCs. Rebates to other system actors do not give rise to the imbalances so readily. However, it is worth noting that the only situation where imbalances do not arise is one where the rebate is granted *at the same point in the supply chain in all countries participating in the trade.*

An example of a possible imbalance could occur if trades were to take place between Denmark (where a rebate is granted to the *producer* of RE electricity) and the Netherlands (where the user is awarded a rebate). Possible ways to avoid such imbalances include:

- Awarding rebates at the same point in the supply chain in all participating countries.
- Refunding rebates 'at the border' when TGCs are exported (c.f. VAT refunds).
- Structuring the trade agreement for TGCs to take rebate imbalances into account.

c. Carbon emissions trading

Option C is also based on the assumption that a CET system is operating *within the country* and that by using RE electricity, rather than 'brown' electricity, actors release a certain amount of their carbon emissions quota, which they can then use as they wish within their national CET system.

Impacts

Under this scenario, it is clear that the trade of TGCs is linked not only to the components outlined in the previous sections, but also to the exchange of carbon emissions quotas that are tradable within the country.

If a national *producer* is awarded the rebate, the condition for trade may be expressed using the equation below:

$P_{REBATE} + P_{CQ(national)} \leq P_{TGC} = F(D,S) \leq P_{PENALTY} - C_T$

i.e., in this case, the floor price for P_{TGC} is given by the sum $P_{REBATE} + P_{CQ(national)}$.

Where:		
	$P_{TGC(national)}$	= Price of TGC within country
	$P_{PENALTY}$	= Price of penalty for failing to reach RE quota
	P_{REBATE}	= Rebate allowed on 'ecotax' for electricity from RE sources within national borders
	$P_{CQ(national)}$	= Price of tradable carbon quota within country
	C_T	= Cost of trade
	$F(D,S)$	= Function of demand and supply

Other variations of this cover the situation in which the rebate is awarded to the supplier or user, depending on how this is operated.

Comments

- This situation does not exist at present. If it does emerge, it could possibly be an intermediate stage between the current situation and the scenario described in the section below.
- As we pointed out above, the electricity industry actors trading in TGCs may not be the same as the actors trading carbon emissions quotas. For example, the obligation to achieve an RE quota may be placed on electricity consumers, where the carbon emissions quotas may be placed on the electricity producers (or the producers of pollution).
- At this stage, it becomes obvious that national agencies for the trading of both Green Certificates and Carbon quotas must interact very closely.
- It is also clear that the cost of trading is likely to increase as the trading system becomes more complex and begins to interact with others.

Option D: Interaction includes rebates on ecotaxes at the international level and interacts with an international CET system.

Description

This situation could emerge if liberalisation within the EU is achieved in the markets for both TGCs and CETs. Under this situation, rebates on ecotaxes are available for RE electricity sourced from any EU Member State (via TGCs). RE electricity can also be used freely to release CET quotas which can then be used within an EU-wide CET system as desired.

Impacts

At this point, the price of TGCs is still linked to nationally-defined penalty levels for failing to meet RE targets and also to national ecotax rebate levels for RE electricity. It is also strongly linked to the price of internationally tradable CET quotas.

The ceiling price of TGCs is therefore similar to that in the section above, with the terms modified to include the 'international' rather than the 'national' aspects.

Comments

- In this trading situation TGCs become doubly valuable, reflecting their impacts on both RE policy and climate change policy.
- $P_{CQ(international)}$ is likely to be determined by another complex set of factors, but it is possible that greatest among these will be the penalty imposed for failing to meet carbon emissions targets. This means that $P_{TGC(national)}$ could depend quite closely on this penalty, especially if it so large that it dominates the equation.
- There are variations on this scenario, which could include a different level of rebate for nationally- and internationally-sourced TGCs (if this were to be legal).
- Trading systems for TGC and CET would have to interact closely on a national and an international level.
- The cost of trading is therefore unlikely to be negligible.
- Wide variations in
  - the level of rebate allowed on 'ecotaxes' or
  - penalties for failing to reach RE targets or
  - penalties for failing to achieve Carbon emissions targets

  may introduce unfair competitive advantages in some EU Member States. At this point it becomes apparent that the complete liberalisation of the TGC and the CET market will require some harmonisation of these boundaries.
- The point on the supply chain at which rebates/subsidies etc are given has an impact on the fairness of the trading systems in which national actors operate.

Option E: Straight equivalence adopted between TGCs and CETs

Description

In this interaction option an 'exchange rate' is fixed between TGCs and CETs, and they are then regarded as exchangeable without risk or price fluctuation. This assumes that the value of RE to climate change policy has been fixed, and that this then dominates over RE targets.

Impacts

As energy efficiency is likely to be a more cost effective way of achieving climate change targets than the adoption of RE (in the medium to short term at least), this scenario could result in a situation where the development of the RE is held back by an emphasis on more cost effective ways of reducing GHG emissions. This would, of course, depend on the exchange rate adopted, which would have to be negotiated at the inception of the scheme.

The price ceiling equation below gives some indication of the way this might operate.

$P_{TGC(national)} + C_T = K \cdot P_{CQ(international)}$

Where:	$P_{TGC(national)}$	= Price of TGC within country
	K	= Exchange rate (fixed)
	$P_{CQ(international)}$	= Price of CET quota on international exchange.
	C_T	= Cost of trade

Comments

- Adopting such an exchange rate would value benefits of RE in relation to climate change only, and could possibly de-value any other positive impacts of adopting RE.
- It seems that this scenario is unlikely to appear within the EU.
- The scenario can be regarded as effectively introducing a variation on the GHG emissions limits agreed by negotiation (for example, by allowing countries with higher RE resources more room to manoeuvre within their emissions reduction targets). This itself would have to be the subject of much negotiation.
- The exchange rate adopted between the two trading systems would by definition include an evaluation of the benefits of RE to climate change targets.
- The level adopted for the exchange rate could have a considerable effect on whether RE develops further within the EU.

6.6 Discussion and conclusions

6.6.1 Design of trading systems

It is clear that the design of both carbon emissions and Green Certificates trading systems will determine the interaction between them. In effect, both represent new currency systems, and it is essential that these currencies be designed so that they accurately reflect the environmental and economic targets they are designed to achieve. In particular, (in both cases) any penalty imposed by government for failing to achieve targets will give a strong signal about the value of the certificate traded.

The exchange rate between the systems would be closely determined by the economic performance of both sectors.

Both systems will require monitoring and accreditation, which will have an impact on the cost of trade.

As mentioned above, the energy sector actors trading in TGCs may not be the same as the actors trading carbon emissions quotas. For example, the obligation to achieve an RE quota may be placed on electricity consumers, while at the same time the carbon emissions quotas may be placed on the electricity producers (or the producers of pollution). This may introduce extra complexity in the trading system, with increased trading costs.

6.6.2 Implications for renewable energy deployment

The interaction options laid out in Section 6.5.3 can be summarised by the price ceiling equation below:

$P_{TGC} = F(P_{PENALTY}, P_{REBATE}, P_{CQ}, C_T)$

Where:	P_{TGC}	= Price of TGC
	$P_{PENALTY}$	= Price of penalty for failing to reach RE quota
	P_{REBATE}	= Rebate allowed on ‘ecotax’ for electricity from RE
	P_{CQ}	= Price of CET quota
	C_T	= Cost of trade
	F	= Interaction function

All of the terms in the equation can be examined in cases where they are applicable within national or international trading systems or a combination of both. In some of the cases examined in Section 6.5.3, some of the terms are set to zero, but the general equation still holds.

As stated above, RE policy has aims that are additional to climate change policy. Aims laid out in the White Paper, (such as security of supply, increased employment, the development of the industry) could be lost if RE is regarded solely as an instrument for the achievement of climate change targets.

The interaction options examined above demonstrate that an interaction between trading systems for Green Certificates and carbon emissions quotas could be extremely beneficial to the deployment of RE (assuming, of course, that a favourable price for Green Certificates translates into increased deployment of RE). In particular, option D, or a variation on it (where all the terms in the equation have positive value), seems likely to value TGCs quite highly, reflecting the fact that they have benefits that are linked to climate change *and* to other issues that are important to the EU as a whole.

7. SUMMARY AND CONCLUSIONS

7.1 Introduction

The purpose of the project 'The Implication of Tradable Green Certificates on the Deployment of Renewable Electricity' is to systematically investigate whether and under what conditions a Tradable Green Certificate (TGC) system can provide a viable scheme to promote renewables. For that purpose the project is divided in four phases: Inventory (what is going on?), Analysis (how does or could a TGC system work?), Design (how should, under different circumstances a TGC system be designed to become successful) and Dissemination (to share, discuss and refine our insights). This report covers the insights gained during the first two phases (Inventory and Analysis) of the project.

The Inventory phase is covered in Chapters 2, 3, and 4. In these chapters an introduction to the concept of green certificates is followed by an overview on the state of renewable energy penetration and policy in the EU Member States. This overview also includes an assessment of the state of liberalisation of the electricity markets as an important background of renewable policy. Chapter 4 gives an overview of current activities with regard to Green Certificates in the EU Member States.

The two core parts of this report are Chapters 5 and 6. These Chapters systematically investigate the interaction of a TGC system with other possible incentive mechanisms as well as the interaction with Climate Policy options, such as Climate Change taxes and Climate Emission Trading (CET).

7.2 Summary

7.2.1 Introduction to green certificates

In a green certificate system, each kWh of renewable electricity is certified. This certificate has two purposes. It functions as an accounting system to verify whether demand has been met or, when there is no demand, to measure the amount of electricity produced from renewable energy sources (RES-E). Secondly, it facilitates trade: through the establishment of green certificates a separate market for the renewable characteristic of electricity can be created, apart from the market for physical electricity.

Supply of certificates is provided for by the producers of green electricity. Demand can originate from several sources: There might be a voluntary demand of consumers (e.g. by green pricing). Demand can also be imposed by the government on consumers or other actors in the electricity supply chain (generators, distributors, suppliers) via an obligation to generate, transmit, deliver or buy a certain amount of green certificates. This obligation can concern either a certain amount to be bought, or it could have the form of a certain minimum price at which the certificates have to be bought. The government itself can also act as a buyer of green certificates e.g. by buying them at a minimum price or by a tendering procedure. In practice demand might come from a combination of these sources. Trade of certificates can be bilateral, or via a spot market. A spot market will enhance the transparency of the certificate market. On such a market derivatives like put options, call options or futures could be created. Brokers might act as a middleman between demand and supply.

There are six functions to be taken care of in a green certificate system: Issuing of certificates, registration of location of certificates and trade transactions, an exchange market, banking/accounting of the certificates on a certificate account and the redemption of the certificates, and last but not least the verification of all these functions to avoid fraud.

If demand is organised by putting an obligation on an actor in the electricity supply chain, the question is what the most appropriate location of this obligation might be. Against the background of liberalisation this obligation should be put as downstream as possible, to avoid market distortions. This means that the preferably final consumers should be obligated. Another possibility is to oblige suppliers, but only if there is a strict licensing system for suppliers and if the obligation is included in this license.

The stability of a green certificate market depends on several factors. Prices may be volatile and investment horizons might be too long or to insecure in a liberalised environment. Supply may be unable to follow demand because of institutional barriers. One possible source of price volatility is the combination of restricted validity of certificates (e.g. only for the year in which it is produced) and climate factors, such as differences in the amount of wind or solar irradiation in a given year. To improve the stability the validity period of certificates should be as long as possible, and the possibility of banking certificates, to be used in later years, could be introduced. More flexibility can be introduced by allowing future certificates to be used for accounting for a current demand. Rules should be set up to regulate this. Financial derivatives like e.g. put options can help to stabilise the market as well. In the case of an obligation as the main driver of demand, this obligation should be set for a long term to enhance investor security. Intermediate targets will be necessary for a viable spot market, which will improve the transparency of the certificate market.

7.2.2 Liberalisation and RES-penetration and RES-policy in the EU

The Electricity Directive

In December 1996 the Electricity Directive was adopted by the Council of Ministers. Before this date in most of the Member States the electricity was organised as a public sector, in some cases in a centralist and monopolist way, in other cases consisting of many small local utilities. The Directive is intended to give guidelines how to restructure this sector into a more commercial one. These guidelines include indications how to regulate generators (authorisation or tendering), transmission (high voltage, responsible for dispatching and interconnection with other systems), and distribution (low voltage, responsible for security and reliability of the system). These activities should be *unbundled*, i.e. electricity undertakings should account these activities separately. Furthermore access to the grid for third parties should be regulated, either by defining a price for suppliers to use the grid, either by negotiating this access.

Minimal requirements for market opening (i.e. the consumers that are free to choose their supplier) have been set: 26% of the market should be opened in 1999 (above 40 GW of consumption), the next year later this is augmented to 28% (above 20 GWh) and in 2003 33% of the market should be free (33%). Most Member States have developed schedules that largely surpass these targets. The UK and Germany for instance have liberalised their markets for 100% already. Others, like the Netherlands, intend to do so, but in several steps. Countries like Greece, Ireland and France seem to stick to the minimum requirements.

In order to secure economic or environmental interests the Government may impose Public Service Obligations on actors in the electricity market. To avoid imbalance in the opening of the electricity markets, access from other, less liberalised markets, may be denied.

7.2.3 Renewable electricity

In 1996 about 13.5% of the electricity came from renewable sources in the Member States. Most of this was coming from large hydro. The EU White Paper target of 12% renewable energy in 2010 translates to 23.5% of renewable electricity. Austria, Portugal, Sweden, Finland and Spain have the largest share of renewable electricity. Italy, France and Greece form a second group. In the other countries the contribution was less than 10% in 1996. In the last years Denmark has reached the 10% level as well. Instead of large hydro, wind forms the main contribution to renewable electricity in this country.

Of the 15 Member States, 10 have set targets to increase renewables, either as a percentage of total electricity consumption, either in the form of projected installed capacity. In most countries large hydro is not subject to these targets, as it is regarded as competitive already. Waste is another form of energy of which the renewable status differs between countries.

There is a variety of incentive policies deployed in the Member States. The three main schemes are feed-in regulations (often as a fixed percentage of the consumer price), tendering procedures (financed by a levy on electricity) and green certificate schemes. Apart from that in many countries a voluntary market for renewable electricity (green tariffs) develops. Furthermore there is a tendency in a number of countries to 'green' the fiscal system, for which renewables often are exempted, so that there competitive position is improved.

7.2.4 Green Certificates in Europe

By 1999 the *Netherlands* is the only country where a green certificate system (the Green Label System) is in place (since January 1998). This is a voluntary system, in the sense that it is not led by the government, but set up by the electricity sector within the framework of their Environmental Action Plan. A voluntary target of producing 1700 GWh has been set for the year 2000. Green Labels are also used to account for the voluntary demand market, which is growing steadily in the Netherlands. After the year 2000 this system will probably be replaced by a governmental green certificate system. In *Denmark* agreement has been reached to introduce a green certificate system as soon as possible, probably starting in the year 2000. The target is to enlarge the contribution of renewables from the 10% in 1999 to 20% by the end of 2003. A number of regulations have been set up to facilitate the transition from the current feed-in and tax-credit system to the new system. In *Belgium* a green certificate system will be introduced starting in 2001. The target is set at 3% for the year 2010, where it is almost zero at this moment. In *Finland* the production of renewable electricity is certified by the Nature Conservation Society and a voluntary market for green electricity is developing. In *Germany* the green certificate system is heavily discussed as an alternative to the current feed-in system. A voluntary market for green electricity is evolving rapidly, but access to the grid has not been regulated yet. The instrument of certificates is being considered as well for CHP. A draft for federal regulation has been set up by some Länder governments, supported by some local utilities. It will be part of the upcoming discussion on amendments to the Act on Electricity and Gas Supply.

An initiative from the sector itself has resulted in the RECS-group (Renewable Energy Certificate System). This group of utilities and government agencies is preparing for an international pilot trade in green certificates. For that purpose a detailed set of Basic Commitments have been set up, to ensure international trade will be possible. In the year 2000 at least two countries will have green certificate systems (Netherlands and Denmark) and international trade might be expected.

7.2.5 Interaction with other incentive schemes

The interaction of the three main incentive schemes (tender, feed-in and green certificates) with all possible incentive measures (the three just mentioned and investment subsidies, tax credits, and green pricing) have been systematically investigated, with the main focus on those combinations including TGCs. Each time it has been investigated how such a combination could work in practice, what kind of problems can be expected, how these could be handled and what the consequences are. This has been done at a national level, as well as taking into account international trade of TGCs.

The main conclusions are the following. Distortions are expected in situations in which feed-in regulations or a tendering system are combined with an international TGC-system. An international system of TGCs could be supplemented by feed-in tariffs or tendering on a national level. This will lead to a shift in trade flows as well as a shift in burden from consumers to taxpayers. Taxpayers from one country will in that case contribute to finance targets of other countries, while possibly stimulating their domestic investors. An international green certificate system should be carefully designed to avoid unintended consequences.

7.2.6 Interaction with Climate Change Policy

Commitments to mitigate greenhouse gases have been made in Kyoto. The EU as a whole should reduce 8% in the period 2008-212 with regard to the year 1990. Within the EU this target has been translated further into Member State targets. In several Member States tax systems have been adapted to include incentives to reduce carbon emissions. Also several flexibility mechanisms to reach these targets have been agreed upon, at least in principle, not in detail. One of these mechanisms is Carbon Emission Trading (CET). Several other examples of emission trading exist, ranging from the US Acid Rain Programme to British Petrol's internal CET system. Analysing this systems serves as an example for TGC, at least on some points, and provide insights in the key issues when it comes to interaction between TGC and CET. These key issues include the different positions of obligations (upstream for CET and downstream for TGC), how to organise international trade and link both systems, the question whether there should be minimum domestic levels and the question what part of the value of renewable electricity corresponds to the climate change problem and what part are related to other issues. A complicating factor is that these other issues (acidification, creation of jobs, etc.) might be more local and if the climate change value part of green certificates appears to be minimal, or is taken out of the certificate, the justifiability of internationally trading of green certificates can be questioned.

The interaction between TGC and climate change policy options has been studied systematically. Four main options of interaction have been identified:

- Minimal interaction between TGC and CET.
- Interaction limited to rebates on ecotax/carbon tax/ climate change levy at national level only.
- Interaction includes rebates on ecotaxes at the national level and interactis with a nationally valid CET system.
- Interaction includes rebates on ecotaxes at the international level and interacts with an international system.

A specific conclusion could be drawn with regard to interaction of TGCs with ecotax rebates in international trade. The most distortion occurs if the rebate is given to the producer of renewable electricity. Rebates to downstream actors gives less imbalances.

In general it can be said that interaction between trading systems for green certificate systems and carbon emission quota could be beneficial to the deployment of renewable energy.

7.3 Main conclusions

Most EU countries have some kind of policy supporting renewable sourced electricity (RES-E). Tradable Green Certificates (TGCs) are only implemented in the Netherlands. Denmark and Belgium have the political intention to establish a TGC-system, starting in 2000. Discussion on TGCs is going on in Germany, Finland and the UK. Practical issues that are relevant for national systems are widely discussed and tackled in these countries. An important discussion point is the way in which demand for green certificates is generated. One important source will be voluntary demand of customers for ‘green electricity’. This product is offered in a number of countries and receiving growing response although to date only a small percentage of the customers is participating. Another way of generating demand for green certificates is an obligation from the Government. In a liberalised market, the obligation ideally should be put at the level of the customers, because it is the least distortive.

International trading of green certificates is prepared by a group of utility companies from the Member States mentioned above. This initiative is known as RECS (Renewable Energy Certificate System). The discussion on the role of government agencies at the national as well as at the European level in such privately started systems can be expected to intensify in the coming year.

Distortions are expected in situations in which feed-in regulations or a tendering system are combined with an international TGC-system. An international system of TGCs could be supplemented by feed-in tariffs or tendering on a national level. This will lead to a shift in trade flows as well as a shift in burden from consumers to taxpayers. Taxpayers from one country will in that case contribute to finance targets of other countries, while possibly stimulating their domestic investors. An international green certificate system should be carefully designed to avoid unintended consequences.

Interaction of TGCs with climate change policy is an important issue. If the external value of the generation of renewable electricity is reduced to its value to avoid climate change, the tradability of green certificates is justified, and it can be expected that green certificate systems will be transformed and incorporated into a system of tradable climate change emission quota. However, this will not do justice to the remaining external values of renewable electricity. Part of these remaining values (e.g. emission of acids, job creation, diversification etc.) are related relatively more to the location of production than the value of avoiding climate change emissions. The question is whether making these values tradable all over Europe is justified. In general it can be said that interaction between trading systems for green certificate systems and carbon emission quota could be beneficial to the deployment of renewable energy.

Last but not least it is important that the production of renewable electricity will get its real value in the electricity market. Moreover, the way prices for renewable electricity come about in different Member States should not differ too much from each other, as this will distort the market for green certificates.

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