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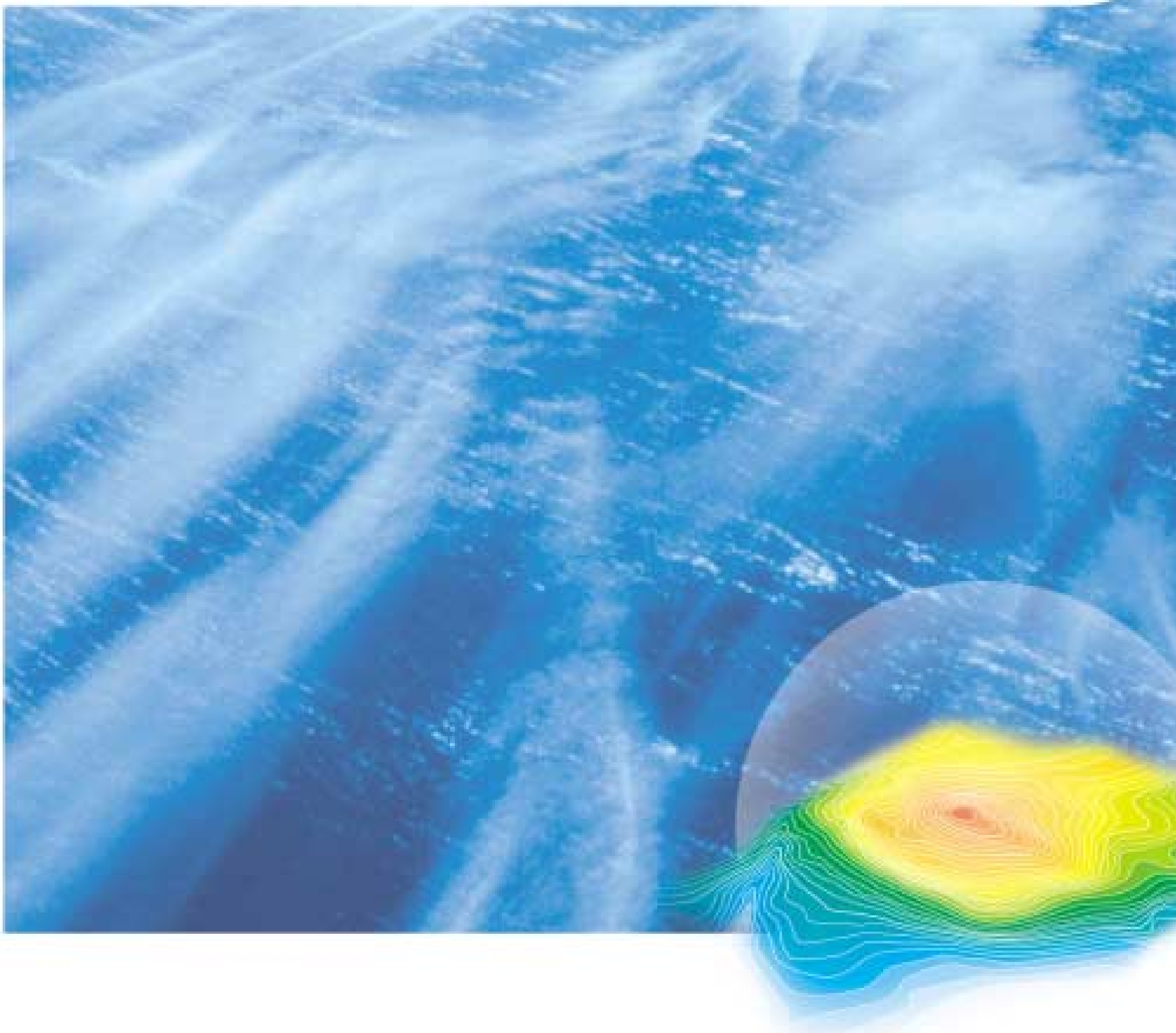

Economic Analysis of RES-E Support Mechanisms

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ECONOMIC ANALYSIS OF RES-E SUPPORT MECHANISMS

Content

LIST OF FIGURES

LIST OF TABLES

EXECUTIVE SUMMARY

The Irish Government is currently developing future targets, policies and programmes for renewable energy for the period beyond 2005. This study serves to inform and assist this process by providing a detailed analysis of the impacts of employing the principle market support instruments to meet a range of targets for renewable electricity penetration in Ireland up to 2020.

The Irish renewable energy market is currently characterised by uncertainty with respect to long-term targets, policies and measures. This policy vacuum has resulted in lenders being reluctant to loan and equity owners seeking higher returns. It has thus withheld potential investors from the Irish renewable energy market and is therefore an important barrier to the realisation of targets. The analysis provided, highlights the importance of a long-term policy perspective and certainty on the tariff structure for renewables and price setting for electricity. Special attention is paid to the opportunities existing in new small-scale renewable energy investments and the market for biomass electricity. Opportunities arise from Ireland's good climate conditions for wind and biomass (specifically solid biomass and biogas), and the availability of high skilled workers facilitating the development of a strong national renewable energy industry. The establishment of a European carbon market and the reform of CAP provide further opportunities for the stimulation of a renewable energy sector. The first improves the competitive position of renewables against conventional power supplies; the second facilitates the introduction of direct support schemes for producers of energy crops, reflecting the net carbon value of energy crops.

The European Directive on the promotion of renewable electricity has set targets for the amount of electricity to be generated from renewable energy sources. In this, Ireland is required to achieve a 13.2% share of renewable generated electricity by the year 2010. The choice of instruments is not prescribed and as a result each Member State has adopted its own set of promotion instruments. Typically, two or more instruments are combined to meet multiple goals. The following types of instruments are discussed in detail:

- The fixed feed-in tariff; the primary support instrument used in Europe
- The renewable obligations, that have become increasingly popular in recent years and are often combined with a tradable green certificate (TGC) system
- The competitive tender scheme; such as the Alternative Energy Requirement currently used in Ireland
- A fixed premium that supplements the market price gained for the electricity supplied to the market

Other types of instruments discussed include fiscal incentives – such as a CO_2 or energy tax exemptions for renewables – and financial incentives, allowing corporate or private investors to deduct part of their renewable energy investments from corporate or income taxes.

The study quantifies the impacts of these different types of support systems on society and on renewable energy deployment within Ireland. The calculations are based on simulations with the ***Green-X*** model, which allows a comparative and quantitative analysis of the interactions between RES-E instruments in a dynamic context. This means that electricity demand, production costs as well as the economic potential of renewable electricity production can vary every year and react to the actual demand and supply of the previous years. The actual penetration of the different renewable electricity technologies furthermore depends on the level of social acceptance, technical barriers, such as grid connection restrictions, market saturation and administrative constraints. The modelling results and corresponding analysis identify and explain the strengths and weaknesses of each supporting instrument and thereby provide valuable input to the selection of the optimal package of support schemes for Ireland. Figure 4-5 illustrates the total available RES-E potential in Ireland up to 2020 at generation costs in 2006, i.e. neglecting cost reduction due to technological learning.

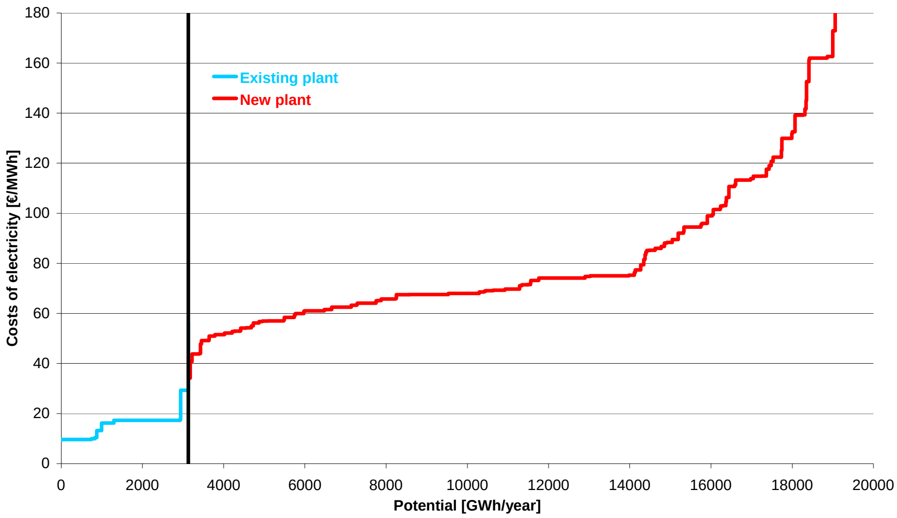

Figure 0-1 Static cost-resource curve for all RES-E options in Ireland – representing the achieved potential (i.e. existing plant) up to 2005 and the additional mid-term potential (i.e. new plant) up to 2020

Support instruments have to be effective for increasing the penetration of RES-E and efficient with respect to minimising the resulting public costs (transfer cost for society). The criteria used for the evaluation of various instruments are based on the following two conditions:

- *Minimise generation costs:*

  This aim is fulfilled if total RES-E generation costs are minimised. In other words, the system should provide incentives for investors to choose technologies, sizes and sites so that generation costs are minimised.

- *Lower producer profits – reduce transfer costs for consumer*

If such cost-efficient systems are found – as a second step – various options should be evaluated with the aim to minimise transfer costs for consumer / society.[1] This means that feed-in tariffs, subsidies or trading systems should be designed in a way that public transfer payments are also minimised. This implies lowering producer surplus[2].

The technology specific development of RES-E generation in the period 2005-2020 is illustrated in Figure 0-2 assuming a quota obligation with tradable green certificates and a RES-E target of 13.2% in 2010. The deployment of the different technologies varies by the chosen strategy. Independent of the strategy it is projected that wind onshore, followed by wind offshore, solid biomass and biogas contributes most to the RES-E generation in 2020.

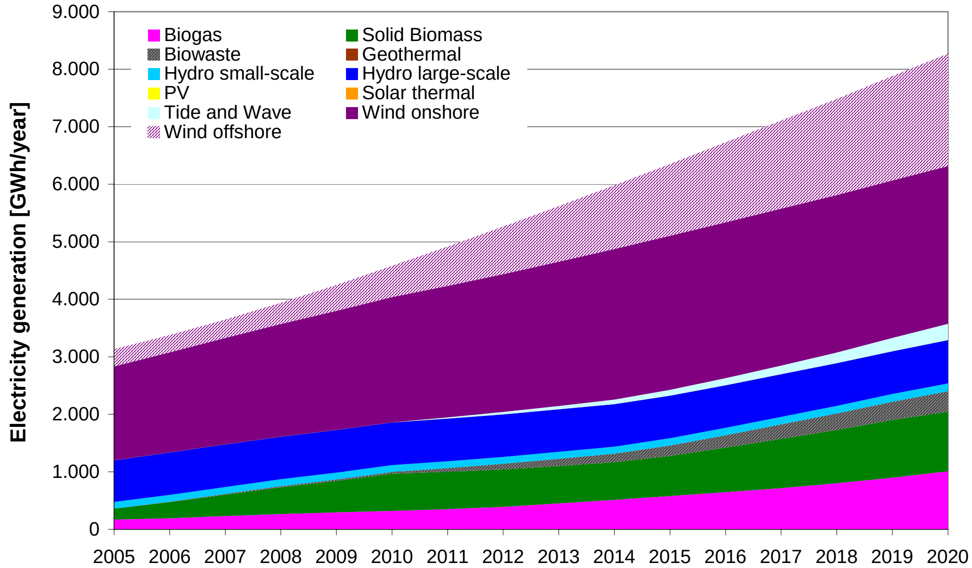

Figure 0-2 Development of RES-E generation 2005-2020 assuming a quota obligation with tradable green certificates and a RES-E target of 13.2% in 2010.

Figure 0-3 shows the financial support additional to the expected electricity market price (i.e. the price for conventional power) per MWh of promoted electricity generation from RES for three types of support mechanisms. Results are shown for the year 2010

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[1] Transfer costs for consumer / society (sometimes also called additional / premium costs for society in this report) are defined as direct premium financial transfer costs from the consumer to the producer due to the RES-E policy compared to the case that consumers would purchase conventional electricity from the power market. This means that these costs do not consider any indirect costs or externalities (environmental benefits, change of employment, etc.). The transfer costs for society are either expressed in Mio €/yr or related to the total electricity consumption. In the later case the premium costs refer to each MWh of electricity consumed.

[2] The producer surplus is defined as the profit of the green electricity generators. If for example, a green producer receives a feed-in tariff of 60 € for each MWh of electricity he sells and his generation costs are 40 €/MWh, the resulting profit would be 20 € for each MWh. The sum of the profits of all green generators defines the producer surplus.

with a target of 13.2% of renewable generated electricity and for the year 2020, where a target of 20% is assumed. The costs depicted relate to the costs for society of new RES-E deployment in the year 2006. The costs incurred under a quota system are largely affected by the assumed costs of capital. The shaded areas indicate the cost difference between assumed levels of 6.5 and 8.6%. The costs incurred under a tender scheme are highly influenced by the absence (coloured bars) or existence (coloured and shaded bars) of strategic bidding.

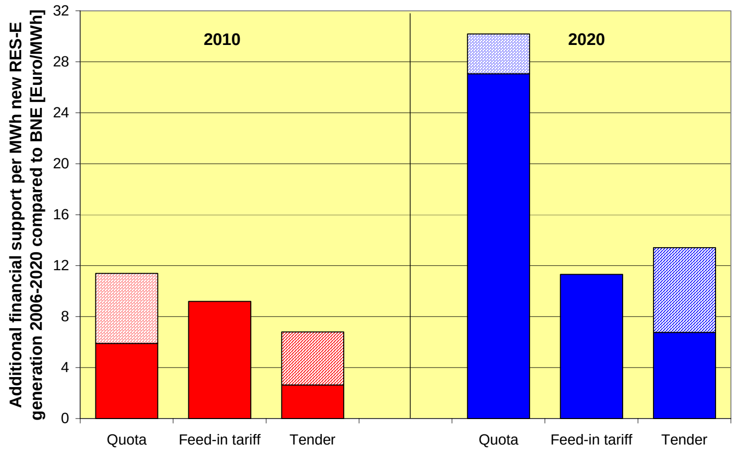

Figure 0-3 Financial support per MWh required under different support mechanisms for new RES-E deployment in 2006-2020 for the year 2010 (13.2% target) and the year 2020 (20% target)

Note: Quota obligation: lower level WACC = 6.5%, higher level WACC = 8.6%); Tender: lower level no strategic bidding, higher level full strategic bidding)

Clearly the total costs for society of reaching the 2010 target are lowest under a tender scheme, but only in the case where there is limited or no strategic bidding. The quota system becomes inefficient from a social perspective when higher targets are assumed, as is illustrated by the costs depicted for the year 2020. This is due to higher risk premiums resulting from larger uncertainties on return on investments and due to higher windfall profits for cheaper RES-E technologies as just one average price signal is given. In the case of lower targets this disadvantage reduces, improving the efficiency gap to the other instruments. Introducing specific targets for individual technologies or implementing an additional support scheme for less efficient technologies can reduce the windfall profits. However, administrative costs rise in these more complex systems.

The costs for the energy sector to meet renewable electricity targets are lower under a quota system than under a feed-in tariff system. However, as the profits for the sector under a quota system can be much higher than under a feed-in tariff scheme, the total costs for society under a feed-in tariff scheme are lower than under a trading system. Moreover, costs can be significantly higher in a quota system when high-risk premiums need to be considered and/or when high transaction costs are incurred in a trading scheme. Technology-specific tariff setting within a feed-in tariff scheme can significantly reduce the producer surplus and thus the costs for society. Simulation variants show that enhanced co-firing opportunities also significantly reduce the transfer costs for society in the long term.[3]

Figure 0-4 shows the costs for society for the three different policy instruments as a function of the RES-E target level. The steep cost curves show that a target setting beyond 20-25% will incur high additional costs for society. The differences in total costs between the different types of support instruments largely increase when targets become more stringent.

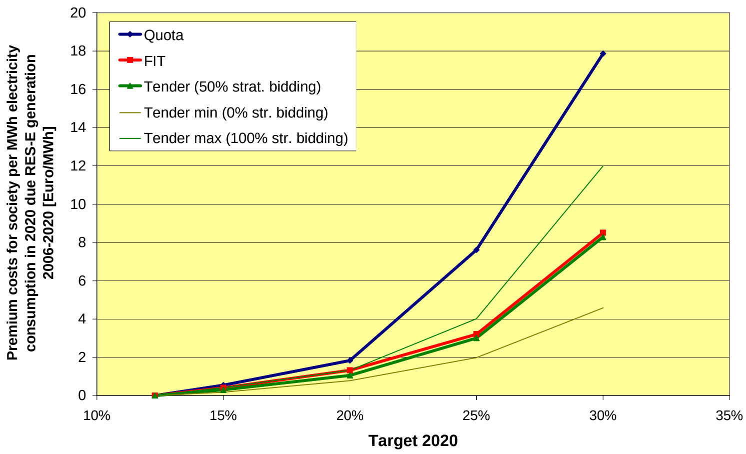

Figure 0-4 Average premium costs on electricity price due to RES-E policy 2006-2020 dependent on RES-E target 2020 default scenarios

[3] Note, the inclusion of co-firing does not lead to (dramatically) reduced transfer costs for society irrespective of the support mechanism up to 2010. The reason for this is that other “cheap” options are available to reach the 2010 target.

INTRODUCTION

The Irish Government is currently developing future targets, policies and programmes for renewable energy for the period beyond 2005, taking into account, inter alia, existing and future climate change commitments and the European RES-E Directive[4]. According to this Directive, 13.2% of Ireland's gross electricity demand should come from renewable energy sources by 2010.

Support mechanisms will be required to stimulate the deployment of most renewable energy technologies until they have matured and become competitive with existing energy technology options. A number of different measures can be employed to stimulate the development of renewable energy generation capacity. The type and structure of this market support exists within the context of national and international policies on renewable energy development, climate change and security of energy supply, including the structure of the liberalised electricity market, the EU RES-E Directive and the EU Emissions Trading Directive.

OBJECTIVES AND DELIVERABLES OF THIS STUDY

The main objective of this study is:

to quantify the impacts of RES-E support mechanisms on society and on renewable energy deployment within Ireland.

In order to meet this objective the study:

- **provides a detailed economic, financial, and regulatory analysis** of the various market based policy instruments that may be utilised to meet specified targets for penetration of RE in Ireland.
- **seeks to increase the understanding of the various impacts of energy policy choices in Ireland.** This is achieved using complex simulation tools that facilitate a robust understanding of the consequences of using various policy mechanisms.
- **assists in the formulation and implementation of renewable energy policy.** Although this study does not provide an action plan for Government, it contributes to decisions regarding the selection, and implementation, of an optimal RES-E support mechanism for Ireland. The outputs of the different RES-E target based scenarios for the individual mechanisms clarify the strengths and weaknesses of each and thereby provide valuable input to inform the selection of the optimal mechanism for Ireland.

It is important to note that the focus of this study is on RES-E, i.e. *electricity* from renewable energy sources. Renewable energy also has a key role to play in the

[4] Directive 2001/77/EC of the European Parliament and of the Council on the promotion of electricity production from renewable energy sources in the internal electricity market", dated 27th September 2001.

thermal energy market and *transport* energy market but this falls outside of the scope of this study.

1.1 METHODOLOGY

In this study, a complex simulation tool is used to quantify the effects of RE support instruments. The computer model ***Green-X***[5] is an independent computer programme and has been developed within the EU founded project Green-X. It allows for a comparative and quantitative analysis of the interactions between RES-E instruments in a dynamic context both for the EU as a whole and individual EU-15 Member States.

The general modelling approach to describe the electricity generation technologies is to derive *dynamic cost-resource curves* for each generation in the investigated region. Dynamic cost curves are characterised by the fact that the costs as well as the potential for electricity generation can change year by year. The magnitude of these changes is given endogenously in the model, i.e. the difference in the values compared to the previous year depends on the outcome of this year and the (policy) framework conditions set for the simulation year. The equilibrium level of the dynamic cost-resource curves for both supply and demand in each market segment on an annual basis provides the model outputs.

Deriving dynamic cost resource curves is carried out in three steps:

- The development of *static cost-resource curves* for each generation and demand reduction option on a technology and country-level;
- The *dynamic assessment*, including a dynamic assessment of costs as well as of potential restrictions, in order to derive annual dynamic cost-resource curves.
- The derivation of the *dynamic cost-resource curve*

The structure of this report follows a staged approach. Chapter 2 provides an overview of the current situation regarding RES-E in Ireland and the current national and EU policy context. Chapter 3 introduces and critiques the RES-E market support mechanisms that are examined in the study, with additional detail provided in Annex 1.

Chapter 4 presents the static cost-resource curves in summary form, with additional detail provided in Annex 2. Chapter 5 establishes the different scenarios, underpinning assumptions and input data that are fed into a dynamic assessment for individual model runs.

Chapter 6 presents the key results of the model runs for different target RES-E penetrations and timeframes, comparing the three support mechanisms in terms of effectiveness and efficiency. Extensive additional model run results are presented in Annex III, arising from changes to assumptions regarding the key input parameters.

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[5] The toolbox ***Green-X*** refers to the version 1.6.4 developed in April 2004. The final version, which will be available at the end of the research project in October 2004 includes additional tool. For more details see Annex II or www.green-x.at. Note these additional tools are of no or only minor relevance for carrying out this analysis.

Chapter 7 discusses the results and presents the key conclusions of the study. Suggested further research to more deeply inform policy decisions are also provided in this chapter.

2 RES-E IN IRELAND AND ITS POLICY CONTEXT

Renewable energy is clearly integrated within both energy and climate change policy, but is also affected by other environmental, social and economic policies. Newly adopted or proposed policies in these areas may influence the availability of renewable energy resources or the competitive position of renewables vis-à-vis non-renewable power production and thereby affect the price support required to ensure deployment. This chapter discusses current installed RES-E capacity and electricity production, the Irish policy framework and the European policy context.

2.1 CURRENT STATUS OF RES-E IN IRELAND

Large-scale hydro power[6] has to date been the dominant renewable energy source used for electricity generation in Ireland, although the recent acceleration in wind energy deployment makes it likely to take the leading position in the short term. Table 2-1 and Table 2-2-2 depict the historical development in terms of renewable electricity production from 1990 to 2003[7]. In 2003, RES-E contributed 4.1% to Ireland's gross electricity consumption (a drop from 5.4% in 2002 due to low rainfall reducing hydro production). The target for Ireland under the RES-E Directive is to reach 13.2% by 2010.

Table 2-1 Electricity generation from RES-E in Ireland, 1990-2003

		1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003
Total electricity generation	[GWh/a]	697	746	822	780	939	729	763	817	1,174	1,124	1,185	1,022	1,391	1,219
of which bioenergy (landfill gas)	[GWh/a]	0	0	0	0	0	0	27	89	89	91	95	92	91	70
of which hydro power	[GWh/a]	697	746	817	765	920	713	722	678	916	846	846	596	912	592
Small scale	*[GWh/a]*	*70*	*93*	*102*	*98*	*118*	*92*	*95*	*90*	*123*	*114*	*114*	*78*	*130*	*84*
Large scale	*[GWh/a]*	*627*	*653*	*715*	*667*	*802*	*621*	*627*	*588*	*793*	*732*	*732*	*518*	*782*	*508*
of which PV	[GWh/a]	0.02	0.02	0.02	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0	0
of which wind (onshore)	[GWh/a]	0	0	5	15	19	16	14	50	169	187	244	334	388	557

Source: Eurostat, SEI, SERG (UCC)

Table 2-2 Installed RES-E generating capacity in Ireland, 1990-2003

		1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003
Total electricity capacity	[MW]	228	235	241	242	242	242	251	279	310	320	370	376	392	444
of which bioenergy (landfill gas)	[MW]	0	0	0	0	0	0	8	12	12	15	15	15	15	15
of which hydro power	[MW]	228	235	235	236	236	236	237	237	237	237	237	237	240	240
Small scale	*[MW]*	*23*	*29*	*29*	*30*	*30*	*30*	*31*	31	*32*	*32*	*32*	*31*	*34*	*34*
Large scale	*[MW]*	*206*	*206*	*206*	*206*	*206*	*206*	*206*	206	*206*	*206*	*206*	*206*	*206*	*206*
of which PV	[MW]	0.00	0.00	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0	0	0
of which wind (onshore)	[MW]	0	0	7	7	7	7	7	31	60	68	118	124	138	189

stored) energy and is excluded from this analysis

7 Note: EUROSTAT data for large and small-scale hydro generation is amended here to take account of known data errors.

Source: Eurostat, SEI, SERG (UCC)

2.2 IRISH POLICY FRAMEWORK FOR RES-E

The market environment, within which renewable energy deployment in Ireland takes place, is currently undergoing significant change and contains many uncertainties. The regulatory environment has been considerably altered with the adoption of the Electricity Regulation Act, 1999 and related measures implemented subsequently, in particular Statutory Instrument 304 of 2003 establishing the new market arrangements for electricity. The main elements in the current Irish policy framework include:

- *The Green Paper on Sustainable Energy (1999),* setting targets for additional renewable energy electricity generating capacity up to 2005 and identifying options for meeting future energy demand.
- *The Alternative Energy Requirement (AER),* the main instrument supporting the deployment of additional renewable electricity production capacity on the Irish market.
- *The Public Service Obligation (PSO),* which obliges the ESB to purchase all electricity generated from peat (for security of supply reasons) and from renewables with AER contracts (for environmental reasons). The PSO is financed from a capacity based fixed charge applied to all electricity customers.
- *The Electricity Regulation Act 1999*, defining the regulatory framework for implementation of Directive 96/92/EC relating to the development of a liberalised internal electricity market. The Act resulted in the establishment of the CER and an interim bilateral trading market for electricity, through Statutory Instrument (SI) 49 of 2000 (Trading arrangements in electricity).
- *SI 304 of 2003* (Market arrangements for electricity), defining a new system of trading electricity based on a mandatory centralised pool and locational marginal pricing.
- *The National Allocation Plan* for CO_2 emission allowances, implementing the EU Emissions Trading Directive 2003/87/EC and placing a value on the environmental cost of fossil fuel power production and thus affecting the relative market position of renewables.

2.3 EUROPEAN POLICY FRAMEWORK

In addition to the national policy context, the development of RES-E is directly affected by current European Community legislation, including the following:

- *The White Paper on Renewable Energy*, which has set a target of doubling the contribution by renewable energy to total primary energy consumption from 6% in 1997 to 12% in 2010;
- *The Green paper on Security of Energy Supply in Europe*, identifying renewable energy as an important contribution to lowering European energy import dependency;
- *Directive 2001/77/EC on the promotion of renewable electricity* (RES-E Directive) in the internal market, aiming at reaching a 22% share of renewable generated electricity by the year 2010 and specifying indicative targets for its Member States;
- *Directive 2002/91/EC on the energy performance of buildings*, supporting inter alia the application of renewable heating applications;
- *Directive 2003/30/EC on the promotion of biofuels*, aiming to increase the share of biofuels in total transport fuels to 5.75% by the year 2010 and creating opportunities to provide direct financial support to promote the use of biofuels;
- *Directive 2003/96/EC on taxation of energy products and electricity*, specifying minimum tax rates and allowing for tax exemption of energy products and electricity from renewable sources.

Other European legislation and policy requirements that affect the position of renewable electricity developments include:

- *Directive 2003/54/EC on the completion of the internal energy market in the European Community*, aimed at achieving full competition in the European electricity generation and supply market by 2005. It furthermore requires electricity companies to disclose the fuel mix as well as the environmental quality of their electricity supplies;
- *EU State Aid guidelines for environmental protection*, allowing direct support for investments in renewable energy and other environmentally beneficial projects;
- *EU Competition guidelines*, requiring member states to prevent and restrict distortion of competition within the common market;
- *EU enlargement*, possibly resulting in new opportunities for exploitation of renewable energy resources, in particular for bio-energy;
- *Directive 2003/87/EC establishing a greenhouse gas emissions trading system* that will result in a clear and transparent carbon market price, thus lowering the price gap between conventional fuels for power production and renewables;
- *Directive 2004/8/EC on the promotion of high-quality CHP in the internal market*, providing possibilities to support the use of CHP from renewable sources;
- *Common Agricultural Policy (CAP) reform*, including the proposal to introduce direct support schemes for producers of energy crops;
- *Framework Waste Directive* 91/692/EEC, requiring intensified actions for recycling and re-use of products, and establishing a preference for waste incineration with energy recovery over land filling waste streams. This will result in fewer opportunities for landfill gas and prompt an increase of energy production from waste;

- Other environmental Directives that are likely to result in small cost increases for fossil-fuelled electricity generation, therewith positively affecting the competitive position of renewables, including:
    - *Directive 2001/80/EC, the 'Large Combustion Plant Directive'* limiting pollutant emissions from combustion plants larger than 50 MW rated thermal input, resulting in a small cost increase in the costs of conventional fuelled electricity;
    - *Directive 2001/81/EC, the 'National Emissions Ceiling Directive'* limiting acidifying and eutrophying pollutant emissions;
    - *Directive 96/61/EC concerning integrated pollution prevention and control*, also likely to result in small cost increases for conventional power, therewith positively affecting the competitive position of renewables;
- Ongoing EU discussions on monitoring the progress on achieving indicative renewable electricity targets at Member State level, possible harmonisation of promotion policies and specification of future (2020) targets.

2.4 MARKET BARRIERS AND OPPORTUNITIES

Changing market characteristics and policy objectives continuously affect the design, operation and impacts of RES-E promotion policies. Important aspects here include the institutional framework, the choice of support mechanism and the electricity market structure. The sections below identify and discuss the key barriers to the increased uptake of RES-E in Ireland. This includes cost and market pricing, legal and regulatory issues, knowledge and public support and technological barriers. Some of these barriers are discussed in DCMNR's consultation document "Options for future renewable energy policy, targets and programmes" (DCMNR 2003a) and are therefore not repeated here in detail. Additional important matters are the design of climate change policies and CAP reform, a detailed analysis of which also falls outside of the scope of this study.

2.4.1 Policy vacuum

The Irish renewable energy market is currently characterised by uncertainty with respect to long-term targets, policies and measures. A further characteristic is the sole focus to date on the electricity market, with negligible support for renewable energy in the thermal or transport markets despite the fact that 65% of energy consumption is in these markets[8]. Apart from the indicative target for renewable electricity derived from the EU RES-E directive no other targets have been specified and no detail is currently available regarding future policies and measures to promote the uptake of renewable energy technologies.

This policy vacuum has resulted in lenders being reluctant to loan and equity owners seeking higher returns. It has thus withheld potential investors from the Irish renewable

[8] This is particularly important in the context of the future of the sugar industry post GATT and of farming in general post CAP reform.

energy market and is therefore an important barrier to the realisation of targets. A number of actions are underway (including this work and other commissioned studies) to inform the development of new policies and measures and address the gap. A tax-based mechanism that was used to a limited extent in renewable energy investments was withdrawn in recent years and new sources of equity have been slow to emerge [DCMNR, 2003a].

Ireland has seen a strong economic growth in the past two decades, and continued growth is expected.[9] The opportunities for the development of a strong national renewable energy industry shows promise; high resource availability, a highly skilled workforce, especially in engineering and raw material processing industry and evident widespread regional benefits, especially in less economically developed areas. However, despite these positive characteristics, little development has taken place. Wind power capacity has been the only significant area of expansion in recent periods. There has been some development of electricity generation from biomass, in the form of landfill gas generation. Expansion of small scale hydropower capacity is continuing at a slow pace, but hydro has almost reached its limit with the main potential large scale sites already developed. The renewable energy industry here is small and weak and has not developed in Ireland as it has in Denmark or Germany.

2.4.2 Legal, institutional and social aspects

The Irish electricity market is a small and relatively closed market with a small number of market actors. Market liberalisation has created the possibilities for market competition and opportunities to distinguish green electricity from conventional power supplies. This will be further enhanced with the completion of market opening and the new market arrangements being set up by CER. The delayed opening-up of the electricity market and the continuing dominant position of the incumbent electricity supply company has however resulted in significantly less new market entrants compared with other European electricity markets. Further incentives for distinguishing green products might arise from the requirements on the disclosure of fuel mix and the environmental impact of power supplies.

The capacity shortage in electricity supply in the Irish market creates a parallel urgent thrust for action. Small-scale renewable energy projects with a relatively short lead time could be one important part of the solution, but clear support measures need to be put in place to reduce investment risks. The market situation is currently too uncertain however, in particular for such small-scale projects, with smaller investors and new market entrants finding it difficult to establish a position against incumbents within the context of the stop/start AER process.

Another part of the solution exists on the demand-side. Opportunities in energy saving and increases in energy efficiency can play a vital role - for example in the new building regulations. Apart from lowering energy demand – and thus reducing the risk of shortages – energy savings and efficiency improvements also alleviate the costs of

[9] The growth expectations underlying this study are elaborated in section 5.2.1. and are based on ESRI's Medium Term Review 2003 – 2010 [ESRI (2003)]

meeting the renewable electricity target – as this is defined as a share of gross electricity consumption - and greenhouse gas reductions.

2.4.3 Overview of market barriers and opportunities

In summary the following main market barriers and opportunities are identified:

Market barriers:

- Lack of long-term policy perspective.
- Absence of targets and measures for renewable energy sources other than wind
- Uncertainty on the tariff structure and price setting for electricity
- The low level of prices for successful AER projects act as a barrier to new small green IPPs entering the market
- Market concentration, resulting in market entrance barriers especially for smaller renewable energy investments
- The current structure of the PSO for peat, resulting in a barrier to market entrance of renewables having to compete with peat.
- Establishment of an Irish renewable energy industry not being a focus of planning and industrial development
- Lack of policy integration between agriculture and energy

Market opportunities

- The establishment of an emissions trading system, improving the economic value of renewable investment opportunities
- Opportunities arising from the CAP reform such as the introduction of direct support schemes for producers of energy crops, reflecting the net carbon value of energy crops.
- Relatively good climate conditions for wind and biomass, providing opportunities to both the domestic market as well as sales of green credits or carbon credits
- Technical and economic viability of co-firing biomass in coal and peat plants
- The availability of high skilled workers facilitating development of strong national renewable energy industry, specifically in less economically developed areas

3 RENEWABLE ELECTRICITY SUPPORT MECHANISMS

3.1 TYPES OF SUPPORT MECHANISMS

Most current EU Member States have set the indicative EU RES-E Directive targets as the guide to their national RES-E policy, although only a minority of Member States have actually adopted legally binding targets. The support mechanisms for renewable energy currently employed across the EU are mostly directed towards the electricity market. In accordance to the EU Treaty and the principle of subsidiarity, the choice of instruments is not prescribed at EU level, and as a result each Member State has adopted its own set of promotion instruments and typically two or more instruments are combined to meet multiple goals. The RES-E Directive does however provide for (Article 4(2)) a 'Community framework with regard to support schemes' should the indicative targets in the Directive not be achieved.

Annex I provides a short overview of the main promotion strategies used in the current EU Member States, covering the following:

- The fixed feed-in tariff as the primary support instrument used in Europe
- The renewable obligations, also called quota obligations or renewable portfolio standards that have become increasingly popular in recent years often combined with a tradable green certificate (TGC) system
- The competitive tender scheme; the instrument that is the best known in Ireland for the promotion of renewable energy
- A fixed premium that supplements the market price gained for the electricity supplied to the market
- Financial incentives allowing renewable energy investments or earnings from such investments to be (partially) deducted from corporate income tax or carried forward against future tax payments.
- Fiscal incentives such as CO_2 or energy tax exemptions for renewables.

Analysis of the choices made regarding renewable energy support instruments shows an increasing shift to integrated policies. This is important for Ireland, where opportunities exist to co-ordinate aspects of agricultural and industrial policies together with energy and environmental policies.

3.2 IRISH RES-E SUPPORT MECHANISMS EMPLOYED TO DATE

This section provides a brief critique of the policies employed to date to promote renewable energy in Ireland. These are described elsewhere in more detail, for example DCMNR (2003a). The overview here serves only as a background to the following sections.

The Alternative Energy Requirement

The AER bidding scheme provides investment certainty to successful bidders through the awarding of a long-term supply contract (up to 15 years for most RES-E, only 10 years for biomass CHP). The AER is mostly criticised for being a stop-start programme where future targets are unknown, both in terms of installed capacity and technology preferences.

Other criticisms are that the focus on least cost tends to lead to relatively poor quality of equipment, that stimulation is not provided to rise above the set targets and that eligible projects may not exceed certain capacity levels, which may lead to a certain inefficiency of project design. The AER has thus so far not stimulated higher-cost options such as solar, wave and tidal energy.

The AER is funded through the PSO levy for renewables. Some AER projects also took advantage of a tax relief system relating to capital allowances. This incentive had not been designed specifically to support renewables and was removed in the 2003 budget along with the removal of other tax relief schemes.

Emissions Trading

The EU Emissions Trading Directive was partially implemented with the publication by EPA (2004) of the National Allocation Plan (NAP). The NAP provides a total of 67.5 million allowances (each representing 1 tonne of CO_2) in the period 2005 – 2007 to all installations with a thermal input capacity exceeding 20 MW. This represents 98% of forecast emissions and compares with a recommended allocation of 110.1 million allowances in the Kyoto period, representing 84% of projected emissions. The shortage of allowances in the fossil-fuelled power sector will slightly improve the competitive position of renewable power production. The National Allocation Plan also includes a small new entrant reserve, partially earmarked for new CHP capacity, but the small reserve might not be sufficient to facilitate required new fossil-fired capacities. This might result in a competitive disadvantage for new entrants in the fossil-fired/CHP power market vis-à-vis incumbents that receive nearly all their required allowances for free.

A CO_2 taxation scheme was considered for all energy consumers not participating in the EU emissions trading scheme (ETS). This scheme was projected to be introduced at the end of 2004 but was recently abandoned by Government as the emission reductions projected from such a tax were relatively low. A phased, incremental basis for taxation was anticipated to provide a long-term progressive stimulation for energy saving and possibly to renewable investments.

Separately, the Minister for Finance announced in his December 2003 budget statement a 5 cents increase in excise on petrol and diesel, which is a similar level as the proposed carbon tax.

Waste management policy

Ireland's waste management policy is articulated in "Changing our ways", which contains a policy plan for new waste management practices. The Waste Management Bill contains a levy on landfill of waste. These policies are expected to double landfill gas generating capacity from 12 to 25 MW, and generate an additional 200,000 MWh renewable electricity per year. Thermal facilities expected to generate 500,000 MWh electricity and 360,000 heat per year. A total of 5.8 MW is expected to be build in 2005. Another 10 MW is assumed to be build by 2008.

The waste management policies interact with the AER scheme that awarded 6 MW additional landfill gas generating capacity in AER V and includes 9.8 MW planned capacity under AER VI.

R, D & D programme

The €16.25M renewable energy Research, Development & Demonstration programme is a relatively new instrument for which no monitoring data is available. The programme will not in itself be adequate to bring RE technologies to market penetration on a full economic cost basis, but combined with other instruments it may be successful in stimulating new technologies or achieving cost reductions for existing technologies.

Other measures

Other measures that directly or indirectly support the uptake of renewables include:

- Tax relief for corporate investments in renewable energy projects made available through section 62 of the 1998 Finance Act. Investments can be deducted from corporation tax (which is actually relatively low compared to other EU Member States). The regulation will stay in place at least until 2006, but the steady reduction in corporation tax rates since 1998 remove the attractiveness of this incentive.
- Tax relief on income tax for individual's investment in renewable energy projects. Tax deduction offered under the Business Expansion Scheme. Limited to a maximum of €31,750 per year per individual.
- Ireland adopted new housing regulations from January 1st, 2004 thereby complying with a number of requirements under the EU Directive on the energy performance of buildings. This may provide additional incentives for energy saving and the use of renewable sources for heating.
- The new market arrangements for electricity as planned will not contain any 'special rules' for renewables (such as a market floor price, for example). The issue of priority dispatch for renewables is currently under discussion in the context of consrtraints on wind energy output for system security reasons. If support is required and deemed appropriate, the CER favours supporting renewables outside of the trading arrangements through additional support mechanisms. In its submission to the DCMNR consultation CER mentions for example that "Under the MAE, a competitive tender or fixed feed-in system can be accommodated via a

Contract for Difference (CfD). A green certificate and production credit mechanisms can operate alongside the market arrangements." (CER, 2004).

Observation

One of the most striking features of the current RES-E support mechanism in Ireland is that it includes very little support to the application for biomass generated electricity, despite the large potential for biomass.

There is limited biomass inclusion in the AER competitions, no support for co-firing and no plans are made so far on using set-aside payments from the CAP reform to enhance sustainable bio-energy developments. Moreover, with the current allocation of the PSO payments, the subsidy for peat is over three times as high as for electricity from biomass[10]. A more equitable balance of payments would significantly increase the economic potential of renewables, especially technologies such as co-firing of biomass and landfill gas that could penetrate the market in a relatively short timeframe. Bord na Mona concluded that co-fuelling is technically feasible and given current energy prices and subsidies co-fuelling with green chipped wood seems economically viable. The economic viability will be further improved with emissions trading impacting on electricity prices. In addition, the diversification of renewable energy sources seems an urgent matter due to the uncertainties associated with the impacts of high wind penetration on the electricity grid.

3.3 IMPACT ASSESSMENT

The success of renewable energy support policies can be judged against a number of criteria including:

- effectiveness - the increase in installed capacity or renewable electricity supplied,
- efficiency – measured by the additional RES-E delivered relative to the budget spent,
- market efficiency - the ability to reduce the costs for society and driving down the longer-term costs of renewable technologies

This section contains a short assessment of the four main types of policy instruments distinguished in this report according to the main judging criteria. The short analysis does not seek to provide a full impact assessment but serves to complement conclusions drawn in DCMNR's consultation document (DCMNR, 2003a, chapter 4). More information on the four main support instruments is included in Annex I,

[10] 2004 PSO payments of € 74.5 million of which € 58.5 million allocated to peat and € 16 million allocated to renewables. The amount of power to be generated by each is in a ratio of 1.3 :1, which results in a subsidy for peat to be 3.3 times more than for renewable energy (calculated from: CER, 2003c).

complemented by some further information on fiscal and financial support instruments.

It should be noted that the reasons why some policies are more successful than others are strongly dependent on the national and social context and it is certainly not always the case that a policy which works at one time in one place will be universally applicable.

3.3.1 Feed-in tariffs

Guaranteed feed-in tariff schemes often act as a great stimulus for developing a local renewable industry and in providing investment certainty, simplicity and scalability. Consequently this positively affects cost reductions in the medium and long term. The effectiveness of guaranteed feed-in tariffs highly depends on its design conditions, especially the level of the tariff. The high guaranteed feed-in tariff systems used in Germany and Spain (among others) have resulted in large amounts of RES-E deployment. The combination of high levels of support, long-term contracts and guaranteed or priority access to grid have successfully lowered investment risks and resulted in significant deployment. The effectiveness significantly reduces when conditions are less optimal, including lower tariffs, shorter duration contracts, greater administrative complexity, and limited or no guaranteed grid access.

In terms of efficiency, however, most guaranteed feed-in schemes are not optimal as the tariffs are fixed and as a result do not reduce with market prices and thus do not ensure least-cost deployment. The costs to society may therefore be higher than for other support mechanisms. These disadvantages can be tackled by applying technology specific tariffs, which are frequently adapted (benchmarked) to market prices and/or renewable technology cost reductions. In such an advanced feed-in tariff scheme, the tariffs decrease at a pre-set moment in time; often related to the then achieved reduction of production costs or increase of installed capacity.

A drawback is that these built-in flexibilities result in higher administrative costs. When the feed-in tariff is designed as a premium system (e.g. in Spain; see section 3.3.4 below) the investment risks are higher.

3.3.2 Quota systems in combination with tradable green certificates

Quota systems as well as tender procedures in principal have a higher degree of competition built in and consequently include more effective drivers for achieving least cost supplies. Important conditions to achieving such cost reductions are the existence of multiple and independent suppliers that together are able to create a significant volume of renewable investments. Experience with quota systems shows that the costs of meeting the quota are uncertain and may vary greatly. By nature, this thus increases the investment risks and is less suitable for smaller renewable energy markets or for supporting technologies at an early stage of market deployment.

Transaction costs are also higher as suppliers have to negotiate each purchase contract themselves and have to pay for monitoring and verification costs. When technology bands are not specified the quota system will tend to favour the lowest cost technologies. Labelling or branding of different technologies might favour some penetration of more expensive technologies, but this voluntary demand seems small. Quota systems provide no incentive to investments beyond the target set.

Quota systems combined with tradable green certificates increase the efficiency of the system and provides a clear pricing signal. If designed properly – that is with appropriate non-compliance penalties, monitoring and enforcement – such systems can be very effective at achieving targets. Long-term target specification is required to increase investment certainty. The UK obligation system clearly benefits from the long-term target setting and the design of non-compliance payments (non-compliance revenues are recycled to compliant participants, in other words paid to a competing supplier). Experiences in the Polish system shows that lack of good monitoring and enforcing possibilities combined with lack of non-compliance penalties (3 years after the start of the quota system penalties have not yet been set) results in low effectiveness.

3.3.3 Tender schemes

Experiences with competitive tender schemes have shown that cost reductions are a key success factor of well-designed tender procedures. In practice, long lead times between successful tendering and the start of production have resulted in higher transaction and administrative costs than required in a more optimal situation. Effectiveness is greatly influenced by its design, especially with respect to pre-arranged planning permission, resulting prices and the number of bidders. The uncertainty in resulting deployments of tendering policies have been extensively discussed in Ireland and have been successfully addressed in the wind arena by the Renewable Energy Strategy Group. Large uncertainties still exist for all other technologies, as they have hardly been included in recent AER rounds and no information is available on future rounds.

Investor certainty can be low, especially for new market entrants and transaction costs are often perceived as too high to prepare actual bids.

3.3.4 Fixed Premium system

A fixed premium system is in fact a variant of the fixed feed-in tariff system. Instead of fixing the price paid per kWh, a premium payment is made for the renewable value of RES-E. This premium is paid in addition to the market price for electricity. This system is often also called an environmental or green bonus system as in theory it reflects the green or environmental value of the renewable electricity product. In this way, the combination of a fixed premium system for renewable electricity and a taxing scheme for conventional electricity is close to the theoretically optimal concept of internalising external costs. In practice the premium value is fixed on the basis of market observations, calculating the fraction of renewable energy production costs that cannot be recovered in the current electricity market and translating this into a premium rate. The best-known example of such a premium system is the Spanish system, where renewable electricity producers are given the choice to either sell their electricity for fixed feed-in tariffs or receive the market electricity prices plus the premium payment.

The advantages and disadvantages of the system are largely similar to those of the fixed feed-in tariff system. It provides a long-term investment certainty – although the premium system provides less certainty than the fixed price system - and the system is relatively easy in terms of understanding, access and administration. The premium system largely addresses the main criticism regarding the fixed feed-in system, namely that its payments do not follow price developments in the electricity commodity market. It also encourages RES-E generators to actively participate in the liberalised market. This addresses another criticism of fixed feed-in systems, that they do not prepare the industry for participation in the market. However, the main criticism still holds that when premium values are fixed on a long term basis, the system does not hold sufficient incentives for technology price reductions or dynamic market efficiency improvements.

4 COSTS AND POTENTIAL OF RES-E IN IRELAND

For electricity generation, a broad set of different RE technology options currently exist. To carry out a comprehensive investigation of the future development of RES-E in Ireland, a national and regional quantification of the RES potential is needed. Indeed, such a quantification exercise was carried out in 1997[11]and this has been supplemented since with more recent resource specific analyses (offshore wind energy, wave energy, recovered vegetable oil and dry agricultural residues).

The following overview on potential and costs for RES-E in Ireland and the EU-15 is mainly based on in-depth investigations carried out within the EU project ***Green*-X**[12]: The overall ***Green*-X** database with respect to RES-E has been further refined and critically reviewed for Ireland, integrating the results contained in the consultation document on future policy options, DCMNR (2003a) and the updated resource study undertaken by ESBI (2004).

There are significant variations in total generation costs that depend largely on the energy source and also on the capital costs of the technology employed. For certain individual energy sources another important correlation appears; namely the correlation between the cost of electricity generation and the availability of capacity. Because every energy source, fossil, (nuclear) or renewable, used for electricity generation has limitations, the costs depend on previous resource exploitation and installed capacity. Electricity generation costs from wind increase, for example, if the best sites have already been used.

Strategies for a forced market penetration of RES-E in a future electricity market must be based on a detailed analysis of costs and potentials for electricity generation from different RE technologies and conventional power production. Such an analysis has been undertaken within this project with the help of a preliminary version of the computer toolbox ***Green*-X**.[13] Before such an analysis can be carried out, however, cost and potential of RES-E technologies should be briefly described.[14]

4.1.1 RES-E potential in Ireland

RES-E such as hydropower or wind energy represents energy sources characterised by a natural volatility. To ensure compatibility between varying historic data future projections, historic data for RES-E generation was converted into electricity generation potentials – the *achieved* potential. *Future* potentials were then assessed taking into account the country-specific situation as well as deployment constraints.

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[11] ESBI and ETSU (1997) *Total renewable energy resource in Ireland.* Altener funded project XVII/4.1030/T4/95/IRL

[12] The toolbox ***Green*-X** represents the major output of the currently ongoing research project *Green*-X – a joint European research project funded within the 5th framework program of the European Commission, DG RESEARCH. For details see Annex II or visit the project web-site www.green-x.at

[13] Details with respect to the carried out analysis is given in chapter 5.

[14] The methodology used as well as the determination of the electricity potential for each RES-E technologies is described in more detail in Annex I of this report.

Ireland has one of the best wind energy climates in Europe. Until recently, the rate of wind energy deployment in Ireland was relatively modest at approximately 20 MW of installed capacity per year between 1997 and 2002. The total current installed wind generating capacity connected (August 2004) is 229 MW, with a further 259 MW under construction. Signed connection agreements are in place for a total of 823 MW capacity (including those built and under construction). This represents 13% of Ireland's installed generation capacity in 2005, using projections of installed capacity from ESB NG (2004). In addition live offers totaling 39 MW are in place, 1369 MW of applications are being processed and a further 271 MW of applications are being checked by the Transmission System Operator.

Ireland also has some of the best climatic conditions and land resources available in Europe for the growing of biomass (Green-X toolbox; Coford (2004); van den Broek (2000) and Tipperary (2003)). Up to 330,000 ha is potentially available for energy crops for heat, power or transport fuels by 2008 or 2010.[15] One of the challenges facing the bio-energy sector is the diversity of the resources, technologies and markets, making it difficult to build a single biomass strategy. Significant co-firing opportunities are also believed to exist and ElectroWatt and Econo are currently jointly undertaking a study on biomass co-firing commissioned by SEI.

Figure 4-1 provides an overview of the different RES-E options available in Ireland. The (projected) *achieved potential by the end of 2005*[17] and the projected *additional realisable mid-term potential (up to 2020)*[18] are provided for each RES-E separately. Hydropower currently dominates but does not show significant additional potential. The largest future potential is found in the wind energy sector followed by solid biomass and biogas – but promising future options also include tidal and wave.

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15 Based on Department of Agriculture factsheet on Irish Agriculture 2003. I.E. About 5.0 million ha of agricultural land in Ireland of which 650,000 ha is forest. 30,000 ha is set-aside. Less than 400,000 ha is in tillage, leaving about 4 million in grassland.

17 Note, in accordance with the analysis (as described in chapter 5 for the development of RES-E in the near future – i.e. up to the end of 2005 – it has been decided to stick to one default projection. This projection is based on information on planned and currently implemented RES-E projects (which have successfully participated in prior AER competitions)

18 The additional realisable mid-term potential represents the maximal additional achievable potential assuming that all existing barriers can be overcome and all driving forces are active.

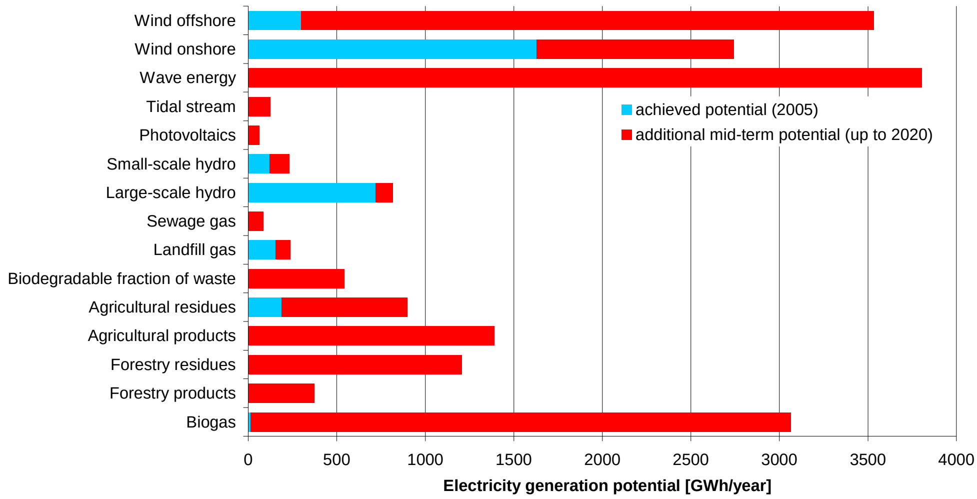

Figure 4-1 Overview of RES-E electricity generation potential for Ireland

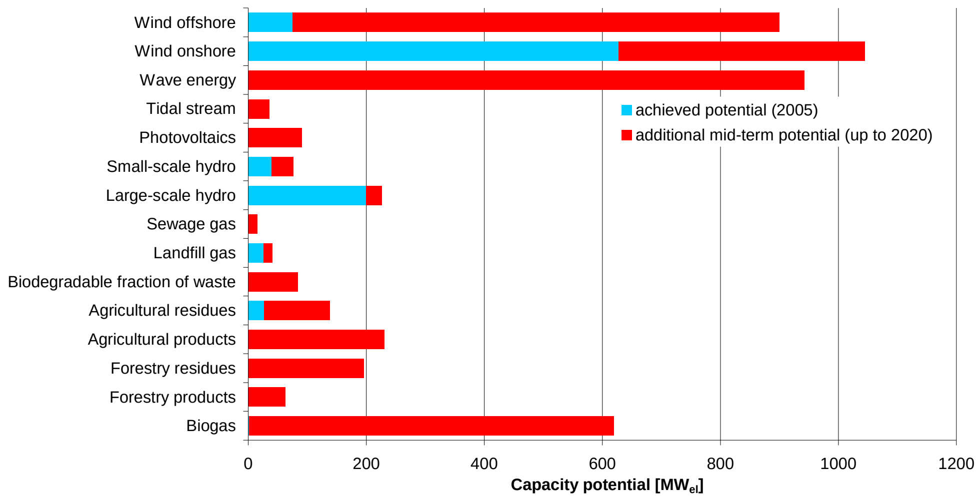

Figure 4-2 Overview of RES-E generating capacity potential Ireland

Figure 4-2 also depicts the achieved and additional mid-term potential realisable for Ireland, however, in this case in terms of installed electricity generation capacity.

By the end of 2005 an installed capacity of all RES-E plant of around 996 MW (or 3130 GWh in terms of electricity generation potential) is anticipated. By contrast, taking into account all future RES-E options, the results show a huge additional realisable mid-term potential of the order of 3710 MW (or 16 TWh in terms of electricity generation potential).

4.1.2 Costs of RES-E in Ireland

In addition to resource availability, the electricity generation costs are a critical determinant of actual RES-E penetration. The high capital investment costs of various RES-E options have been a major impediment to broader market penetration. For all

RES-E technologies that have entered the market, investment costs have decreased substantially since market introduction.

All renewables, apart from biomass (biogas, solid biomass, sewage and landfill gas) have zero fuel costs, so electricity generation costs are determined – aside from investment costs – by operation & maintenance costs only. Therefore, running costs for RES-E are normally low compared to fossil fuels.

For the calculation of the possible offer prices a general distinction is drawn between currently installed plant and additional new potential capacity. For existing plants only the short-term marginal costs (running costs) are relevant for the economic decision whether the plant should be used for electricity generation or not. For new capacity however the long-term marginal costs are important.

In order to give a better illustration of the current economic conditions of the various RES-E options, marginal electricity generation costs are depicted in Figure 4-3 and Figure 4-4, respectively. Again, to be consistent with the scenario runs, generation costs[19] refer to the start year for model simulations, i.e. 2006, but are expressed in 2002€. To illustrate the range, these costs are compared to the projected best new entrant price (BNE) for the year 2006.[20]

The broad range of costs for several RES-E is due to (i) resource-specific conditions, e.g. for photovoltaics or wind energy differences appear between regions (site conditions, location) and (ii) the technological options available – compare e.g. co-firing and small-scale CHP plants in case of biomass.

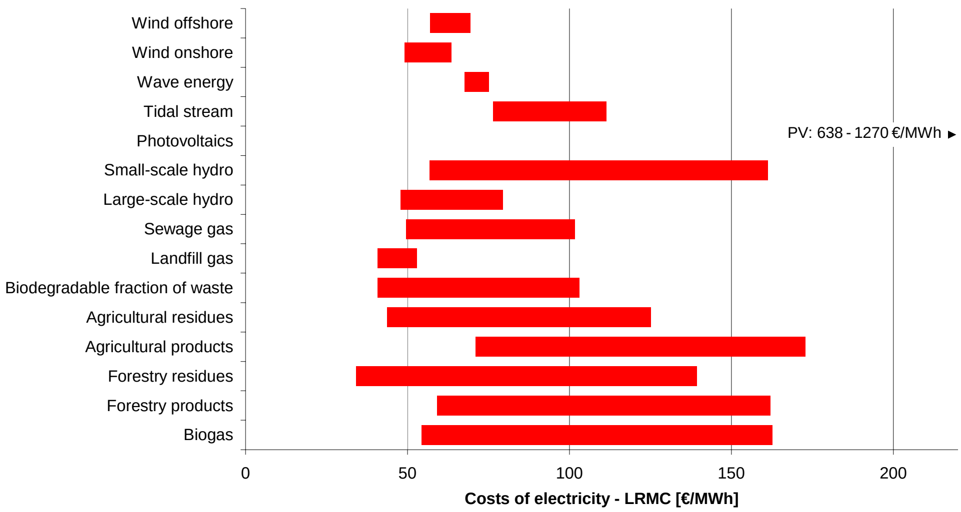

Figure 4-3 Long-run marginal generation costs of various RES-E technologies in Ireland 2006 Note: The projected Best new entrance (BNE) price for 2006 is 44,7 €/MWh (DCMNR, 2003a)

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19 This implies that for long-term marginal generation costs (as applied to new plants), a weighted average cost of capital WACC of 6.5% and a pay-back time of 15 years a default capital recovery factor is used.

20 For details with respect to the BNE price refer to general model assumptions in chapter 5.

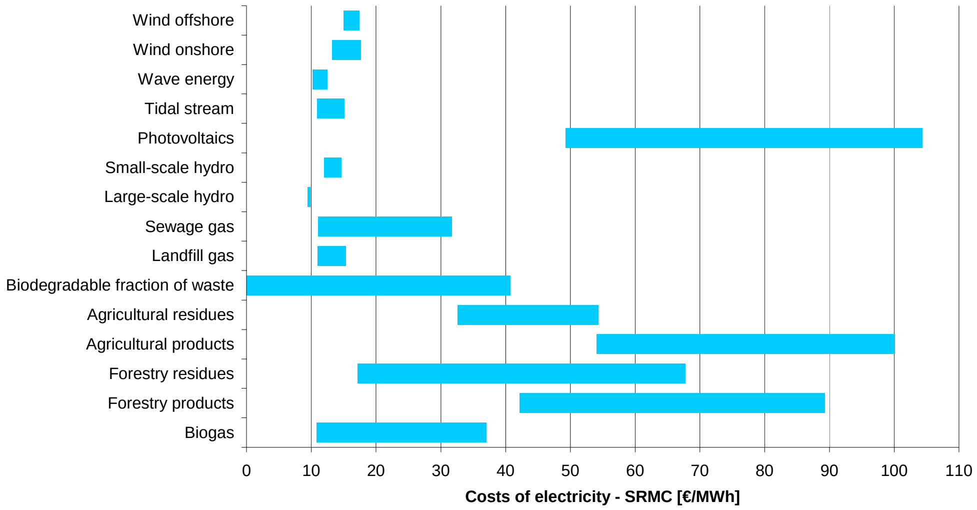

Figure 4-4 Short-run marginal generation costs of various RES-E technologies in Ireland 2006. Note: The projected Best new entrance (BNE) price for 2006 is 44,7 €/MWh (DCMNR, 2003a)

The model ***Green-X*** is used to determine the generation costs in the simulation runs (see next chapter). In this model, the calculation of electricity generation costs for the various generation options is carried out using a rather complex mechanism. Plant-specific data (e.g. investment costs, efficiencies, full load-hours, etc.) are linked to general model parameters such as interest rate and depreciation time. The latter parameters depend on a set of scenario specific conditions like policy instrument settings, long-term planning stability or considered RES-E technology. In the analysis these conditions are considered at different weighted average costs of capital. For details refer to Annex II of this report.

4.1.3 Resulting cost-resource curve for RES-E in Ireland

The formal analysis of generation costs and related potentials (of electricity generation) by means of cost-resource curves[21] enables simulation of the effects of the market support instruments employed to increase RES-E penetration and to derive important conclusions for energy policy makers.

Figure 4-5[22] depicts a static cost-resource curve including all RES-E options for Ireland. Please note that this figure shows a static view. While the costs refer to projected investment and O&M costs for the year 2006[23], the maximum potential available up to 2020 is presented. In the computer model ***Green-X*** costs are adapted (yearly) according to technological learning (and for some technologies according to expert cost projections), i.e. they decrease over time. The available mid-term potential

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21 Please note that a more detailed description of the methodology as well as the database on cost-resource curves for RES-E utilised in the modelling is provided in Annex II of this report.

22 As explained above, cost-resource curves (for existing and possibly new plant) are included in the database of the model ***Green-X*** by RES-E category. A comprehensive examination of the results is provided in Annex I of this report.

23 Note, the expressed costs refer to the start year for the simulation runs (i.e. 2006) but are specified in $€_{2002}$.

(up to 2020) is converted to the available potential for the year of simulation by applying a comprehensive barrier assessment.

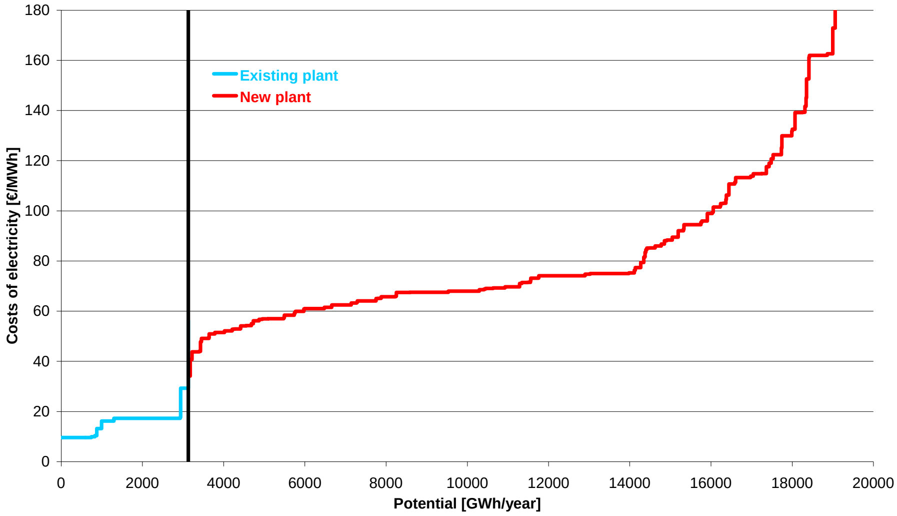

Figure 4-5 Static cost-resource curve for all RES-E options in Ireland – representing the achieved potential (i.e. existing plant) up to 2005 and the additional mid-term potential (i.e. new plant) up to 2020

4.2 COSTS AND POTENTIAL FOR RES-E IN OTHER EU MEMBER STATES - AN INTERNATIONAL COMPARISON

In order to assess the amount and the value of RES-E technologies in Ireland it is important to compare costs as well as available potential with other countries.

4.2.1 Historical development of RES-E in EU-15 countries

Figure 4-6 shows a comparison for each EU country in 2001 of:

(i) total electricity consumption, and

(ii) amount of electricity generated from RES.

The data are based on comprehensive data-collection (Eurostat (2003), IEA (2002) and statistical information gained on a national level). Three countries, Austria, Sweden and Portugal, generate more than a third of electricity from these sources; others a much lower proportion.

The largest share of RES is still provided by ‘large-scale’ (installed capacity >10 MW) hydropower, as evident from Figure 4-7. Such plants have mostly been established before the post-1970’s ‘new renewables’. The shares of the other ‘new renewable’ technologies are depicted in more detail in Figure 4-8. It shows that small hydro, biomass, municipal solid waste (MSW) and wind are currently the most important. There are a number of noteworthy observations including:

(i) the large proportion of operating wind power in Denmark, Spain, and Germany,

(ii) the significant contribution of geothermal power in Italy, and

(iii) the relatively high proportion of RES-E generated from biomass in the UK (including landfill gas, municipal waste and sewage gas), Finland, Sweden and Germany.

Figure 4-9 shows the corresponding development of 'new renewables' over time (1990-2001), with (left-hand side) and without (right-hand side) hydropower.

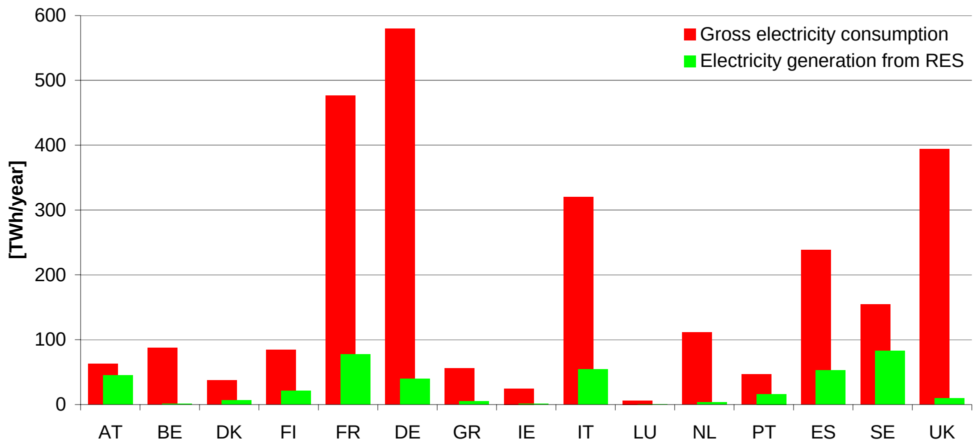

Figure 4-6 Electricity generation from RES and gross electricity consumption in EU countries in 2001. Source: Own investigations; Eurostat, 2003.

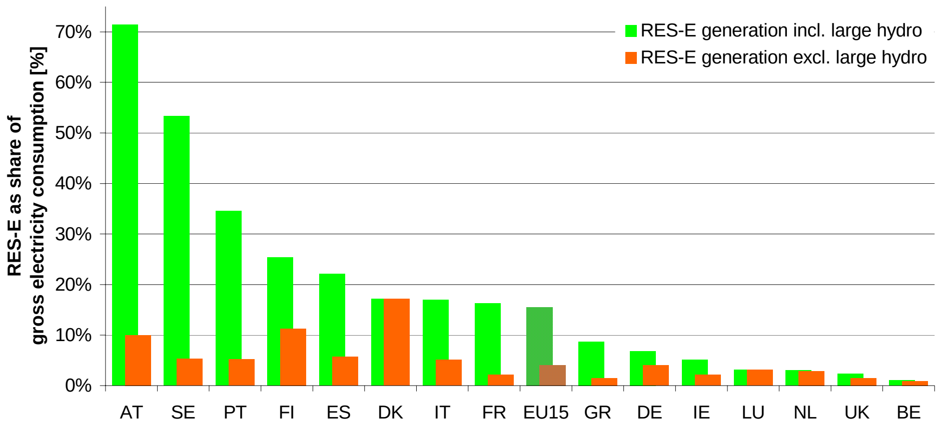

Figure 4-7 EU-15 countries ranked by the contribution of RES-E (with and without large hydro) to gross electricity consumption in 2001. Source: Own investigations; Eurostat, 2003.

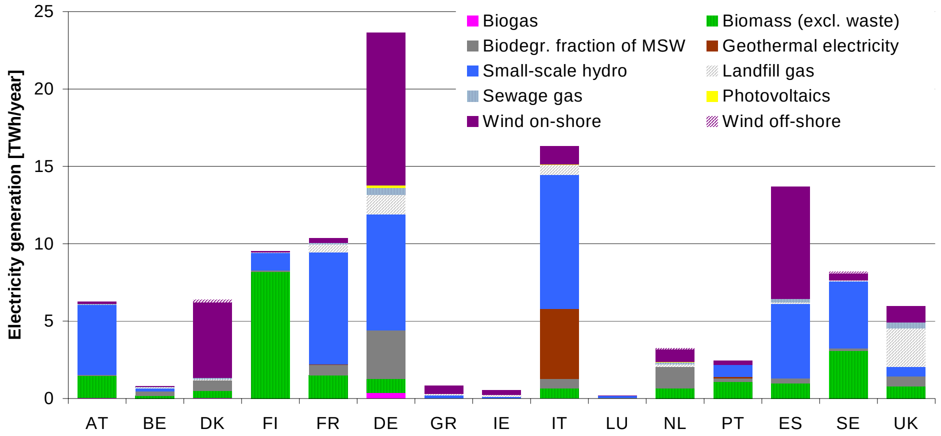

Figure 4-8 Electricity generation from various RES in EU countries in 2001. Source: Own investigations; Eurostat, 2003.

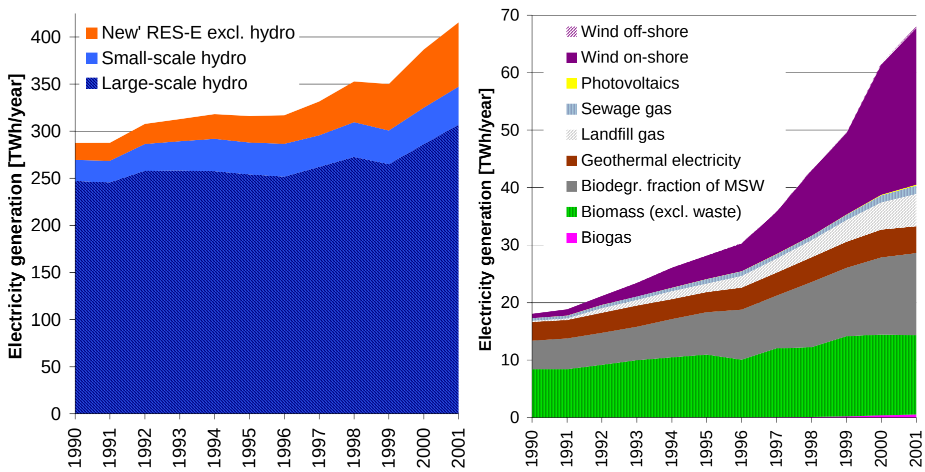

Figure 4-9 Electricity generation from RES in EU-15 countries from 1990 to 2001 – including (left-hand side) & excluding (right-hand side) hydro. Source: Own investigations; Eurostat, 2003.

4.2.2 Comparison of RES-E potentials in EU-15 countries

An overview on the different RES-E options available in total EU-15 up to 2020 is given in Figure 4-10. The achieved potential, i.e. the existing plant, for RES-E in EU-15 countries has been derived within the project ***Green-X***. It is evident from comparison with Figure 4-1 that there are a number of features common to Ireland and the EU as a whole, including the dominance of hydro power and its limited future potential, the large future potential of wind energy (incl. on- and offshore), solid biomass and biogas. In addition, new technologies like wave power and tidal stream or solar thermal electricity are yet to be developed for both the EU and Ireland.

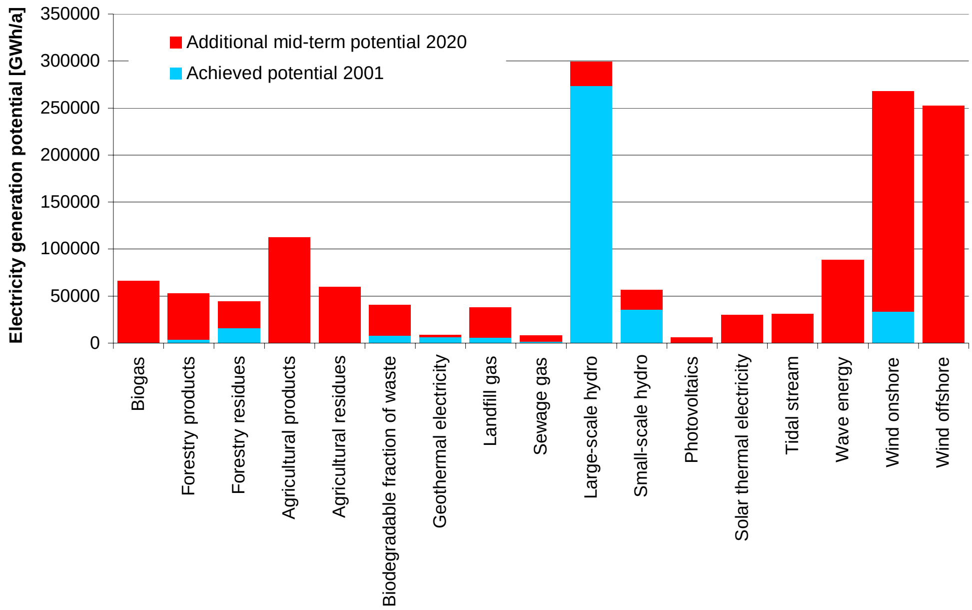

Figure 4-10 Achieved (2001) & additional mid-term RES-E potential (up to 2020) in EU-15 countries (RES-E-specific illustration)

Next, Figure 4-11 depicts the achieved and additional mid-term potential for RES-E by country. For EU-15 the already achieved potential for RES-E equals 386 TWh[24], whereas the additional realisable potential up to 2020 amounts to 1078 TWh.

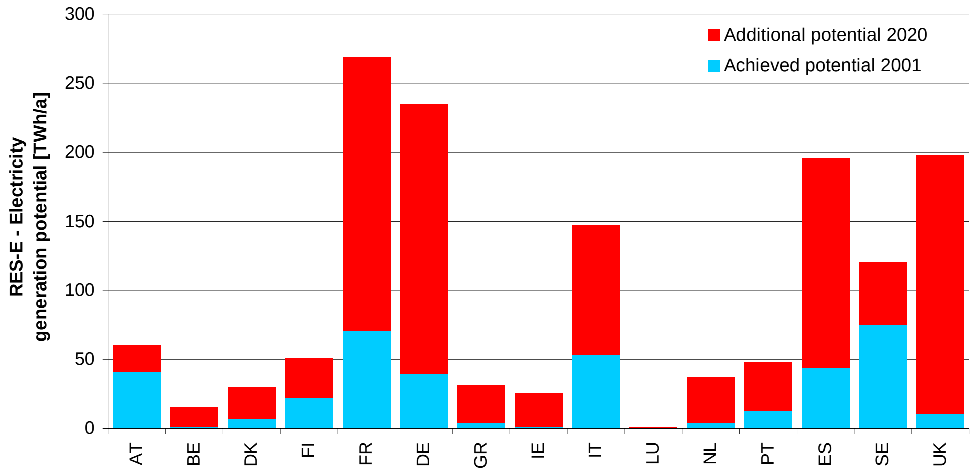

Figure 4-11 Achieved (2001) & additional mid-term RES-E potential (up to 2020) in EU-15 countries (country-specific illustration)

[24] The electricity generation potential represents the output potential of all plants installed up to the end of each year. Of course, figures for actual generation and generation potentials differ in most cases – due to the fact that in contrast to the actual data, potential figures represent, e.g. in case of hydropower, the normal hydrological conditions, and furthermore, not all plants are installed at the beginning of each year.

4.2.3 Economics

Long-run as well as short-run marginal generation costs for new RES-E are expressed in Figure 4-12 and Figure 4-13. These costs refer to the default start year of the simulation, i.e. 2006 and are expressed in 2002€. The broad range of costs for several RES-E represents the country-specific differences occurring at present.

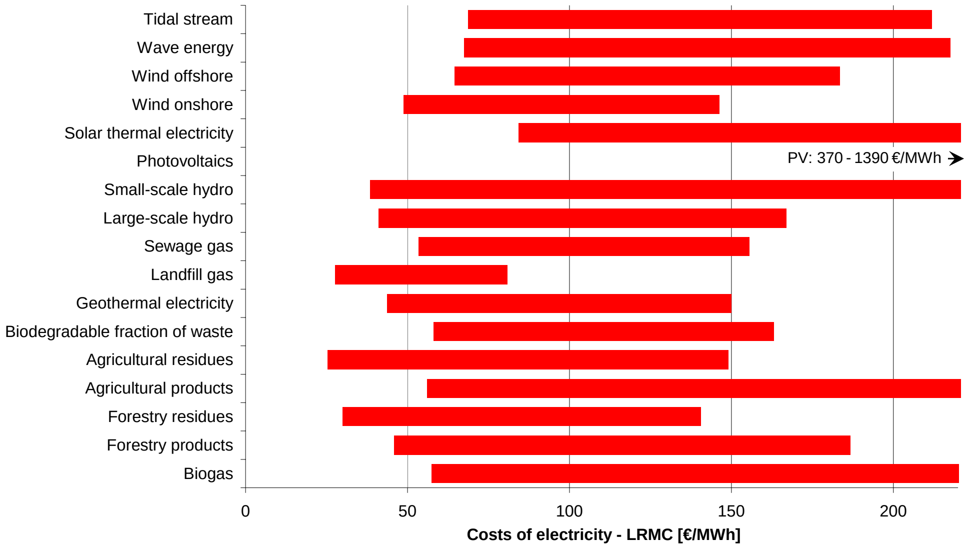

Figure 4-12 Overview of long-run marginal generation costs for RES-E in EU-15 countries 2006

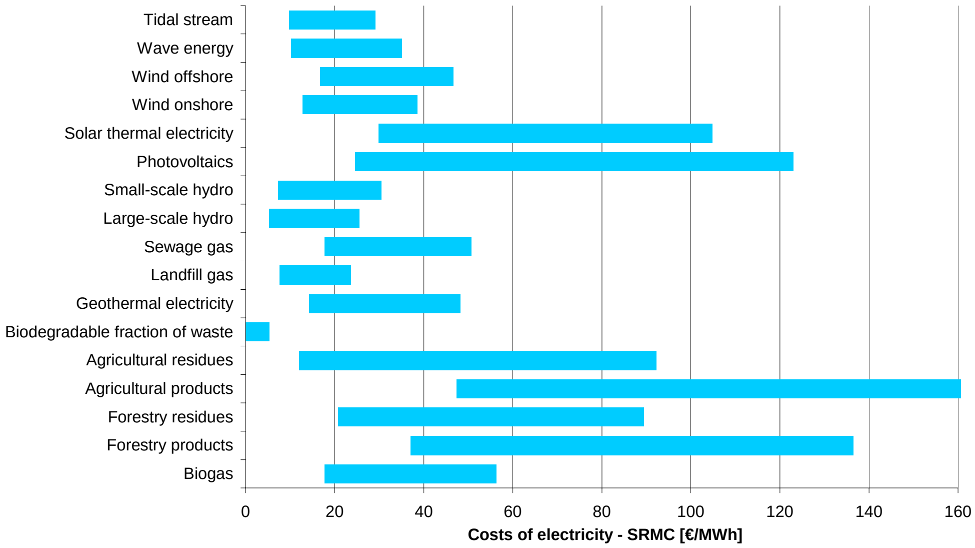

Figure 4-13 Overview of short-run marginal generation costs for RES-E in EU-15 countries 2006

5 DEVELOPING THE SCENARIOS

In this chapter, the impacts of different RES-E support mechanisms on society and on renewable energy deployment are analysed, taking into account a number of objectives and opportunities. First, the method of approach is presented in brief, including a description of the simulation model ***Green*-X**. Next, general framework conditions as set for the simulation runs are presented, followed by a definition of the design of the invested support mechanisms. As a next step the analysed scenarios are then defined. Finally, the results of the simulation runs are presented and discussed.

5.1 METHOD OF APPROACH

5.1.1 Evaluation criteria

Support instruments have to be effective in increasing the penetration of RES-E and efficient with respect to minimising the resulting public costs (transfer cost for society). The criteria used for the evaluation of various instruments are based on the following two conditions:

- *Minimise generation costs:*

  This aim is fulfilled if total RES-E generation costs (GC) are minimised. In other words, the system should provide incentives for investors to choose technologies, sizes and sites so that generation costs are minimised.

- *Lower producer profits – reduce transfer costs for consumer*

  If such cost-efficient systems are found – as a second step – various options should be evaluated with the aim to minimise transfer costs for consumer / society.[25] This means that feed-in tariffs, subsidies or trading systems should be designed in a way that public transfer payments are also minimised. This implies lowering producer surplus (PS)[26].

In some cases both goals – minimise generation costs and producer surplus – may not be reached together so compromise solutions must be found. For a better illustration of the used cost definitions the various cost elements are expressed in Figure 5-1.

[25] Transfer costs for consumer / society (sometimes also called additional / premium costs for society in this report) are defined as direct premium financial transfer costs from the consumer to the producer due to the RES-E policy compared to the case that consumers would purchase conventional electricity from the power market. This means that these costs do not consider any indirect costs or externalities (environmental benefits, change of employment, etc.). The transfer costs for society are either expressed in Mio €/yr or related to the total electricity consumption. In the later case the premium costs refer to each MWh of electricity consumed.

[26] The producer surplus is defined as the profit of the green electricity generators. If for example, a green producer receives a feed-in tariff of 60 € for each MWh of electricity he sells and his generation costs are 40 €/MWh, the resulting profit would be 20 € for each MWh. The sum of the profits of all green generators defines the producer surplus.

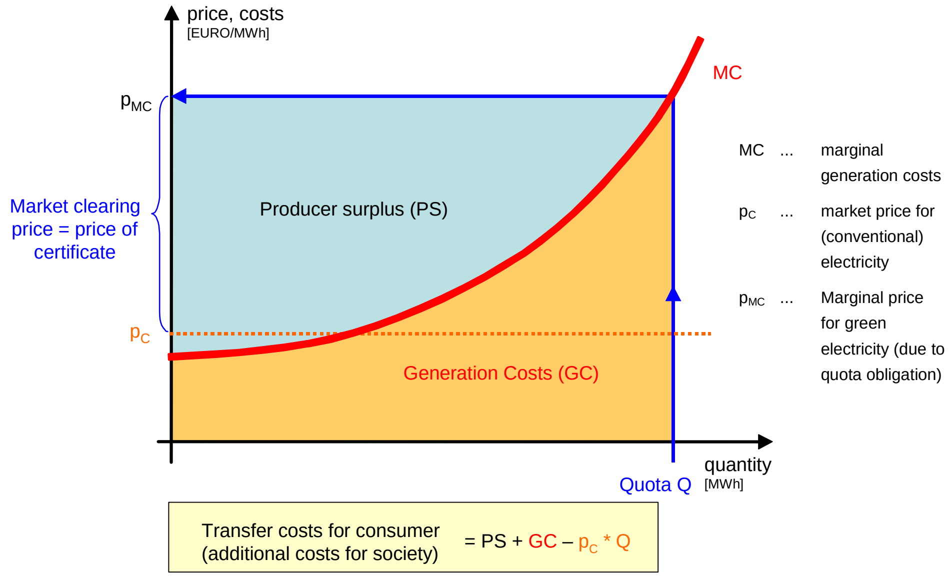

Figure 5-1 Basic definitions of the cost elements (illustrated for a TGC-system)

The support mechanisms are tested against these criteria using the output from ***Green-X*** simulation runs. The results are delivered on an annual basis per technology for each year in the period 2005-2020 and can be categorized as follows:

- General results – including:

  Installed capacity [MW]

  Total fuel input electricity generation [TJ, MW]

  Total electricity generation [GWh]

  Market price Tradable Green Certificates [€/MWh]

- Impact on producer – including:

  Total electricity generation costs [M€, €/MWh]

  Total producer surplus electricity gen.[M€, €/MWh]

  Marginal gen. costs per techn. electricity gen.[€/MWh]

- Impact on consumer – including:

  Additional transfer costs for society due to promotion of RES-E [M€, €/MWh]

As ***Green-X*** represents a dynamic simulation tool, the user has the option of changing policy and parameter settings within a simulation run (i.e. by year). In addition, intermediate results are also accessible.

5.2 GENERAL ASSUMPTIONS USED FOR THE *GREEN-X* MODEL RUNS

5.2.1 Gross electricity consumption

Penetration targets set in the model are based on projected gross electricity consumption[30]. This is consistent with the indicative target for RES-E generation in the Renewable Electricity Directive (2001/77/EC) and with the DCMNR policy consultation document. The projected gross electricity consumption for the period 2003-2010 is based on consumption data from 2002 and the growth rates contained in the ESBNG's Generation Adequacy Report 2004-2010.[31] For the period 2010–2020, growth rates from ESRI's Medium Term Review[32] for total final consumption of electricity are applied to 2010 projections. Figure 5-6 depicts both, the historical development of gross electricity consumption and the forecast as assumed for the model runs until 2020.

Projected growth rates for gross electricity consumption beyond 2010 are lower than in the current decade illustrated by the broken line in Figure 5-2. This is mainly due to lower anticipated economic growth rates and an increase in electricity system efficiency. This assumption is in line with the PRIMES projections made by the EC (Mantzos et. at., 2003).

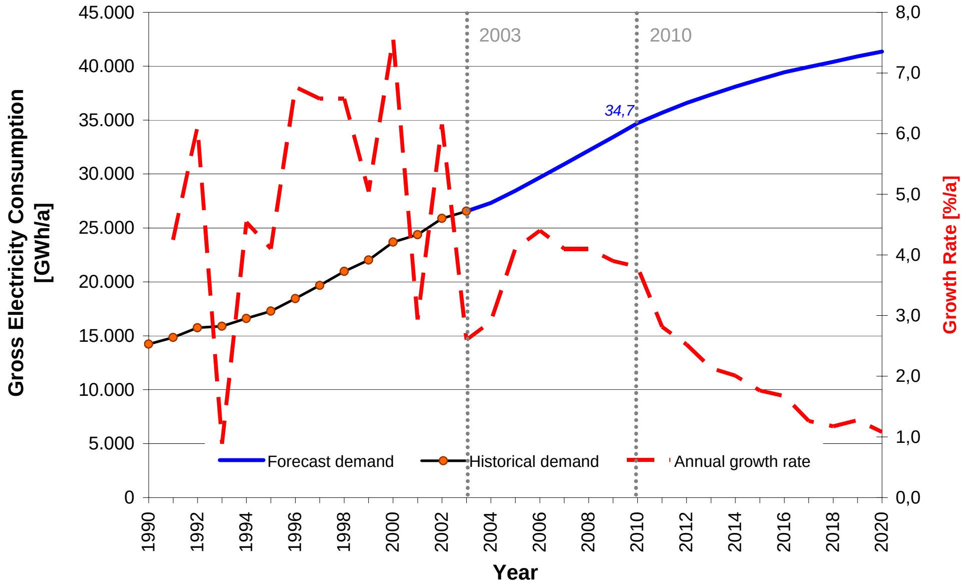

Figure 5-2 Average Historical development and forecast of total electricity consumption for Ireland 1990-2020

30 The sum of electricity generated plus net electricity imports

31 The EC forecasts for the business as usual case 33 121 GWh and for the energy efficiency scenario 31 473 GWh for the year 2010 (EC 2003a, 2003b). Forecast from SEI is 33 209 GWh (DCMNR consultation document; draft version September 2004).

32 ESRI (2003) Medium Term Review 2003 – 2010

5.2.2 Primary energy prices for biomass products

Table 5-1 depicts the assumed price developments for biomass in Ireland. Price data for 2003 were agreed with SEI. The price forecasts are based on an assessment conducted within the project Green-X. It is assumed that the costs for bioenergy products remain constant until 2010. In the period 2010-2015 a slight price increase of 0.5% per annum and after 2015 a rise of 1% is projected.

Table 5-1 Price assumptions for biomass products

Bioenergy product	**Price 2003 [€/MWh]**	**Price change [%]**		
		2001-2010	2010-2015	2016-2020
Biogas:	0.0	0.0%	0.5%	1.0%
Landfill gas:	0.0	0.0%	0.5%	1.0%
Sewage gas:	0.0	0.0%	0.5%	1.0%
Forestry products	17.0	0.0%	0.5%	1.0%
Forestry residues	12.0	0.0%	0.5%	1.0%
Agricultural products (energy crops)	19.38	0.0%	0.5%	1.0%
Agricultural residues	8.5	0.0%	0.5%	1.0%
Biogenic fraction of waste	-4.0	0.0%	0.5%	1.0%

5.2.3 Electricity prices

A reasonable forecast of (conventional) electricity prices is of significant importance in the evaluation of the cost efficiency of RES-E technologies and in the determination of additional societal costs associated with the promotion of RES-E. In this analysis, the best new entrant (BNE[33]) price serves as the reference price for electricity. The BNE price is calculated on an annual basis and refers to the hypothetical price of electricity that would be secured from the most efficient new plant entering the market in that year. The rationale underpinning the choice of BNE as the reference price is that, firstly, electricity demand is projected to increase significantly and, secondly, existing reserve capacity is low in Ireland. The provision of new electricity capacity is therefore necessary in Ireland, to ensure security of electricity supply.

Figure 5-3 depicts the historical BNE prices published by CER for the period 2001-2004 as well as existing forecasts. Ilex (2003)[34] projects a BNE price in the new (post 2005) electricity market of 45.0 Euro/MWh and 41.6 Euro/MWh for 2006 and 2008 respectively, excluding costs of carbon. Assuming additional CO_2-costs of 10 Euro/t-CO_2[35], the BNE price increases by between 2.4 to 3.6 Euro/MWh.

Consequently the forecasted BNE price including carbon is 48.4 Euro/MWh[36] (2006) and 45.7 Euro/MWh[37] (2008). Price projections beyond 2008 are not available from

[33] The configuration and size of the BNE is assumed to be a CCGT employing a single shaft, "1+1" configuration with an output of about 390-400 MW. Investment and operating costs have been estimated for a BNE of this configuration.

[34] Ilex (2003) *Impacts of the EU ETS on the Irish electricity market* Published by CER as CER/03/084

[35] Under the EU Emissions Trading scheme.

[36] Permit price 10 Euro/t-CO2, 90% free allocation., see CER 03/284 page 10 table 2

CER. Brattle and Henwood estimate an electricity price of 49.3 Euro/MWh for 2009 (Bazilian, 2004).

Generally, the configuration and size of the BNE price reflects the operation of a combined cycle gas turbine (CCGT) with an output of about 390-400 MW. Considering the price projection for gas on the international markets (see Figure 5-4) and assuming that a premium price due to climate policy continues into the future, it can be argued that the BNE price will not fall[38]. Therefore it is assumed for the model runs that the price level corresponds to the BNE price level for 2004, € 47.9 / MWh. In addition, assuming a constant reference price (BNE) allows the model to:

(i) show the impact of technological learning and

(ii) present the development of the transfer costs for society over time.

In a sensitivity analysis, however, the case that the BNE follows the projection as made in the DCMNR consultation document (DCMNR, 2003a) is investigated. This means, the BNE is 44.7 Euro/MWh for the period 2005-2010 and 42.3 Euro/MWh for 2011-2020, see also Figure 5-3.

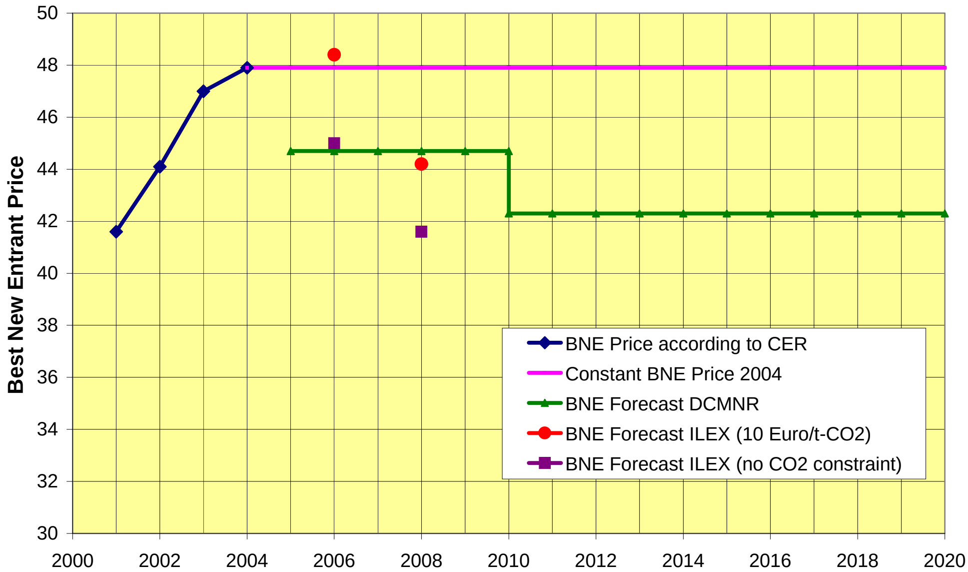

Figure 5-3 Historical BNE Price and different projections 2001-2020.

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[37] Permit price 10 Euro/t-CO2, 80% free allocation, see CER 03/284 page 10 table 2

[38] This is borne out by the publication (after this analysis was completed) by CER of BNE price for 2005 of €53.6 / MWh that includes €1.1 / MWh allowance for the purchase of carbon credits under the emissions trading scheme. (CER/03/297)

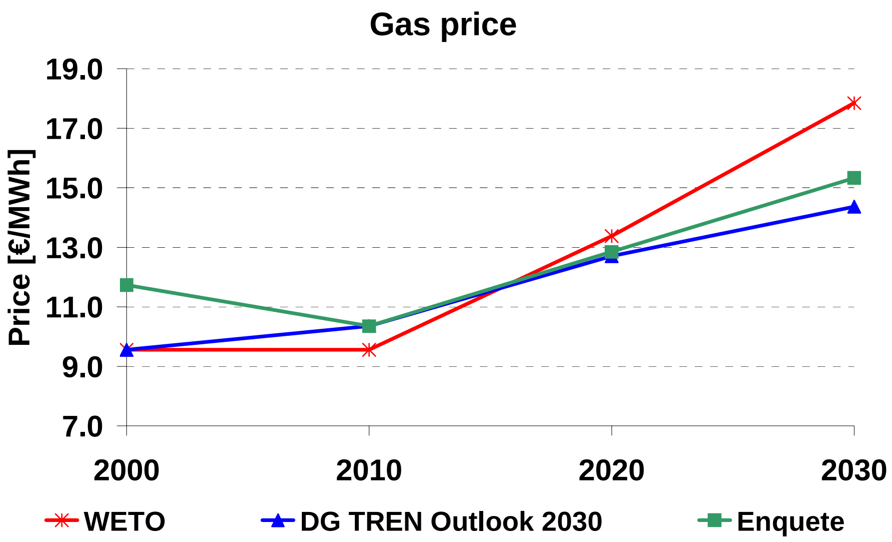

Figure 5-4 International gas price projections for Europe 2000-2030

5.2.4 Weighted average cost of capital

The determination of necessary rate of return is based on the weighted average cost of capital (WACC) methodology. The WACC formula[39] determines the required rate of return on a company's total asset base and in the case of the BNE is determined by the Capital Asset Pricing Model (CAPM) and the return on debt. Formally, the pre-tax cost of capital is given by:

$$WACC = g_d \cdot r_d + g_e \cdot r_e = g_d \cdot [r_{fd} + r_{pd}] + g_e \cdot [r_{fe} + \beta \cdot r_{pe}] \cdot (1 + r_t)$$

Table 5-2 Value setting WACC calculation:

	Abbreviation / calculation	Default risk assessment		Higher risk assessment	
		Debt (d)	Equity (e)	Dept (d)	Equity (e)
Share equity / debt	g	75.0%	25.0%	70.0%	30.0%
Nominal risk free rate	r_n	4.1%	4.1%	4.1%	4.1%
Inflation rate	i	1.9%	1.9%	1.9%	1.9%
Real risk free rate	$r_f = r_n - i$	2.2%	2.2%	2.2%	2.2%
Expected market rate of return	r_m	4.7%	7.5%	4.7%	10.7%
Risk premium	$r_p = r_m - r_f$	2.5%	5.3%	2.5%	8.5%
Equity beta	β		1.59		1.59
Tax rate (corporation tax)	r_t		12.5%		12.5%
Post-tax cost	r_{pt}	4.7%	10.6%	4.7%	15.7%
Real cost	$r = r_{pt} * (1+r_t)$	4.7%	12.0%	4.7%	17.7%
Weighted average cost of capital	*WACC*	6.5%		8.6%	

[39] The WACC represents the necessary rate a prospective investor will look for a prospective investing in a new plant.

To be consistent with the BNE approach, most of the values used here were those used in the calculation of the BNE price, compare with CER (2003). Generally, two different WACC options are considered in the analysis; one risk level equal to that assumed for calculating the BNE and a higher risk level characterised by a higher expected market rate of return. The first value is used as a default value; the second is used for the sensitivity analysis and is applied in scenarios with lower long-term planning stability. All relevant values are summarised in Table 5-2.[40]

5.2.5 Future cost projection – technological learning

Forecasting technology development is a crucial activity, especially for a long time horizon. As already mentioned, within the **Green-X** model dynamic investment as well as O&M costs are considered.

As technological learning, however, appears on an international level, cost forecasts for Ireland are exogenously given for the simulation run. More precisely, annual cost reductions associated with investment costs are linked to projections derived for the project *FORRES 2020* (see Ragwitz et. al., 2003). The resulting development of investment costs for different RES-E technologies is depicted in Figure 5-5.

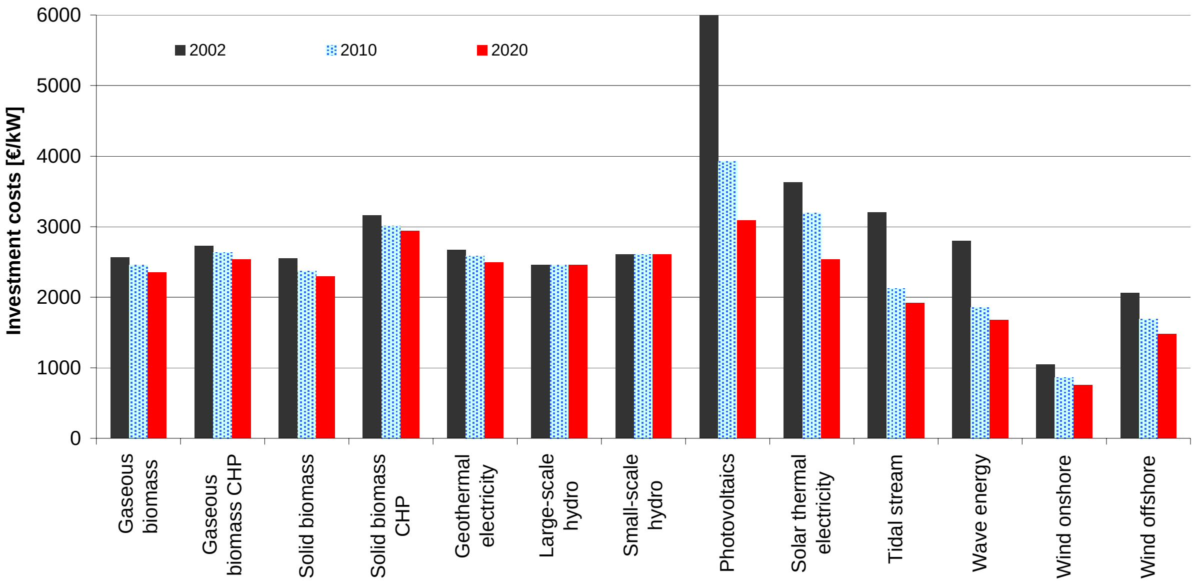

Figure 5-5 Cost reduction according to 'FORRES 2020' PS-scenario with strengthened policy support: Development of (average) specific investment costs by RES-E category

[40] Note, to avoid confusion, the project team do not consider technology-specific risk premiums (different WACC according to their maturity and risk characteristics) as the core objective of this project is to quantify the effects of different RES-E support mechanisms and not the determine the exact setting of the support level. In the later case a technology specific WACC approach is useful. In a further step, however, such a sensitivity analysis can be carried out with the model **Green-X**.

5.3 UNDERPINNING ASSUMPTIONS FOR DIFFERENT SCENARIOS

Within this project – as agreed with SEI – the three most important support schemes within the EU are analysed, namely: a quota obligation in combination with tradable green certificates, a feed-in tariff system and a competitive tendering scheme. A number of key input parameters are defined for each of the model runs and these are detailed here.

5.3.1 General scenario conditions

In the model run, it is assumed that all investigated strategies – BAU (with no additional policies) as well as the other policy scenarios - are characterised by:

- Stable planning horizon [41]
  The effectiveness of various RES-E support schemes largely depends on the stable long term planning security provided by the system. A stable planning horizon is important to create a sound investment climate and to reduce transfer costs for society as a result of a lower risk premium. Investor confidence depends on the expected continuity of the scheme, as well as the political risk. Long-term stability, especially for independent power producers, is important for achieving an acceptable risk-return profile;
- Continuous RES-E policy / long term RES-E targets
  A continuous and medium to long-term focussed energy policy scheme is important (i) to attract the interest of potential investors in RES-E technologies and (ii) to increase the confidence of bank institutions, leading to lower loans for investments. Such a policy is characterised by long-term RES-E targets or RES-E policy schemes.
- Clear and well defined tariff structure and price setting for electricity
  If the support structure - including expected revenues - is well known for investors this reduces delays that can be expected in implementing the plants.
- Restriction of the duration in which investors can receive the (additional) financial support
  By restricting the duration of the possible public support, transfer costs for society can be reduced. In the model runs, independent from the support scheme, it is assumed that the time frame is restricted to 15 years. This value fits to the current AER power purchase agreements.
- Financial support is restricted to new capacity only
  This means that only plants constructed after 2005 – the start year of the different scenarios – are allowed to receive support. Public support is not provided to plants that are (i) either fully depreciated, (ii) were supported in the past or (iii) still receive

[41] The lack of a stable planning horizon has been and is still one of the main barriers to a stronger deployment of renewable electricity as the risk for potential investor increases. The consequences are that either, the transfer costs for society would rise significantly due to the higher necessary internal rate of return for the investors or the actual RES-E deployment remains moderate despite a “high” financial support.

public support through an AER contract before the year 2005. Otherwise much higher transfer costs for society occur.

- Reduced investment costs over time.
  This relates to technological learning and the effects are illustrated in Figure 5-5.

- Reduction in barriers and high public acceptance in the long term.
  In the scenario runs it is assumed that the existing social, market and technical barriers (.e.g. grid integration) can be overcome in time.

Transfer costs for society hugely depends on the design of the policy instruments. Based on the experiences we made so far – compare e.g. Huber et. al. (2004) - the design options of the instruments are chosen in a way that transfer costs for society are low. For the sensitivity analysis these conditions are compared with less efficient design options, e.g. considering new and existing facilities versus only new capacity in the quota system.[42]

The individual model input assumptions used for each of the support mechanisms investigated are described in the following sections. These are described in more detail in Annex III.

5.3.2 Model input assumptions – quota obligation

- Tradable green certificates are standardised, i.e. there is just one kind of certificate. Within the TGC system it is assumed that both a high level of market transparency and appropriate level of trading volume exist leading to an idealised, fully competitive TGC market.[43] In addition, it is assumed that investors are seeking the most efficient RES-E resources.
- Additional support for less mature RES-E technologies does not exist. An additional support system may help – especially in the case of an ambitious RES-E target - to reduce the transfer costs for society as the windfall profits for “cheap” technologies can be reduced (significantly). The disadvantage of an additional support mechanism is that administration and transaction costs increase due to the introduction of a second RES-E instrument. In the sensitivity analysis, the effects of good and bad additional support settings are shown.
- The yearly interim targets are set in a way that the percentage increase between the single years is constant in the period 2006-2010 (reaching the corresponding interim target) and 2011-2020, respectively;
- Penalty for not fulfilling the quota obligation amounts to 197.9 Euro/MWh. For the fulfilment of the obligation it is important that the penalty for not purchasing a TGC is higher than the investment needed to meet the quota, i.e. the lowest penalty level must exceed the expected marginal generation costs within the system. Investors have an incentive to build plants with long-term marginal cost up to 197.9

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[42] Note: Instruments are design that the costs will be low, however, are not optimised in a way that minimal social costs occur.

[43] Otherwise costs rise due to strategic price setting.

Euro/MWh to reaching the quota obligation. As the penalty serves as a ceiling price for TGC, the maximum TGC price is restricted by the penalty minus expected power price.[44, 45]

5.3.3 Model input assumptions – feed-in tariff scheme

- Guaranteed tariffs are technology specific, i.e. they (can) vary between the different (sub)-technologies.
- Tariffs are set as low as is reasonable. The goal has been to set the tariff as low as possible without causing a lower deployment rate over the RES-E portfolio. If the deployment of a certain RES-E technology was insensitive to a feed-in tariff level of 60 Euro/MWh, 70 Euro/MWh or 100 Euro/MWh, the 60 Euro/MWh level was selected. Otherwise, higher transfer costs for consumers occur without any additional RES-E deployment. In practice, RES-E deployment rates are sensitive to the tariff level. Hence a compromise between possible reduction of the tariff and the lower RES-E specific deployment must be made.[46]
- Guaranteed tariffs decrease over time or at least remain constant for certain RES-E technologies. This means that the tariffs for new facilities and, hence, new contracts, is changed every year. The decrease depends on the reduction in investment costs due to technological learning. By employing such a procedure, investors have a reduced incentive to postpone their investments;
- Tariffs for wind energy are designed as a stepped feed-in tariff. [47,48] This means that the feed-in tariff will be reduced if generation is high. The reduction in the guaranteed price, however, must be less than the total revenue that can be gained if an efficient plant and location are chosen; otherwise investors have no incentive to implement the most efficient technologies and locations. Profits will thus be higher at more cost effective sites;[49]

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[44] Analytically: Max(TGC price) = penalty – BNE = 197.9 Euro/MWh – 47.9 Euro/MWh = 150 Euro/MWh.

[45] The limitation of the maximum TGC price is only necessary in the case of a very high obligation. In the model runs this assumption is only needed for the years 2006-2012 assuming a 30% RES-E target in 2020, see Annex III case 2.5.1 and 2.5.2.

[46] Note: Attempts have been made to find a low tariff level over the whole RES-E portfolio. The magnitude of the tariff, however, is not optimised in a way that transfer costs for society are minimised. This means that an additional reduction of the transfer costs is feasible is, but requires a more detailed analysis. Such a procedure can be carried out in a next step.

[47] A stepped tariff e.g. is implemented in Germany.

[48] One important condition for such a scheme is the measurable and standardised unit or baseline used for differentiation. If the costs for electricity generation are mainly based on the full-load hours, the latter can be such a suitable baseline. However, not every renewable energy technology fulfils this constraint. For wind energy or biogas this criteria is fulfilled, i.e. a stepped feed-in tariff is easy to implement. In the case of biomass, where costs mainly depends on the specific fuel input a distinction between different biomass fractions is useful and partly considered in the model runs.

[49] If one major political and societal objective is to promote a homogeneous distribution of a RES technology (e.g. wind plants should not only be located near the shore) the ‘stepped’ feed-in tariff must be adjusted so the producer’s profits from generating electricity is independent of the generation costs, Furthermore, by granting a ‘marginal’ higher profit if investor choose an efficient plant, a compromise between cost efficiency (and the disadvantage of location hot spots) and homogeneous distribution (and the disadvantage of economic inefficiency) can be adjusted.

5.3.4 Model input assumptions – competitive tendering scheme

- Call for tenders are separated into two technology-groups
  - Wind on- and off-shore
  - All other RES-E technologies
- A higher split leads, on the one hand, to more specific calls and hence a more diversified RES-E deployment, but, on the other hand, reduces the cost effectiveness among the different RES-E technologies. The selection of the single tender portfolios must be made with caution as, on the one hand, too much diversification can lead to oligopolies and, on the other hand, the absence of a technology split favours strategic bidding within one technology-group.
- Competition between the potential investors exists. It is assumed that no oligopoly or monopoly structures arise, leading to a higher *general* bid level and, hence, higher transfer costs for society.
- Strategic bidding does not exist / strategic bidding fully occurs. If too much capacity volume is launched within one tender, potential investors are invited to react strategically. More precisely, if an investor knows that his generation costs are (much) lower than the marginal bid that will still be accepted (win) (due to better location, lower fuel costs, etc.), he can increase his offer strategically, i.e. the offer price will be a bit lower than the expected marginal offer. [50] In the model the two extreme cases – no strategic and full strategic bidding – are simulated. In this way, the range of strategic bidding effects can be determined.
- The yearly capacity targeted within one tender-group is constant for the periods 2006-2010 (reaching the corresponding interim target) and 2011-2020. This means that a continuous policy is assumed, thereby removing the stop / go nature of the current AER scheme. This condition leads to a more stable environment for investors and RES-E developers, increasing the confidence that targets will be met.

5.4 DEFINITION OF INVESTIGATED SCENARIOS

[50] Note, such a behaviour differs from oligopoly or monopoly behaviour as in the later case the general bid level rise, i.e. also the marginal bid. Here only the bids lower then the unaffected marginal bid are influenced by strategic behaviour.

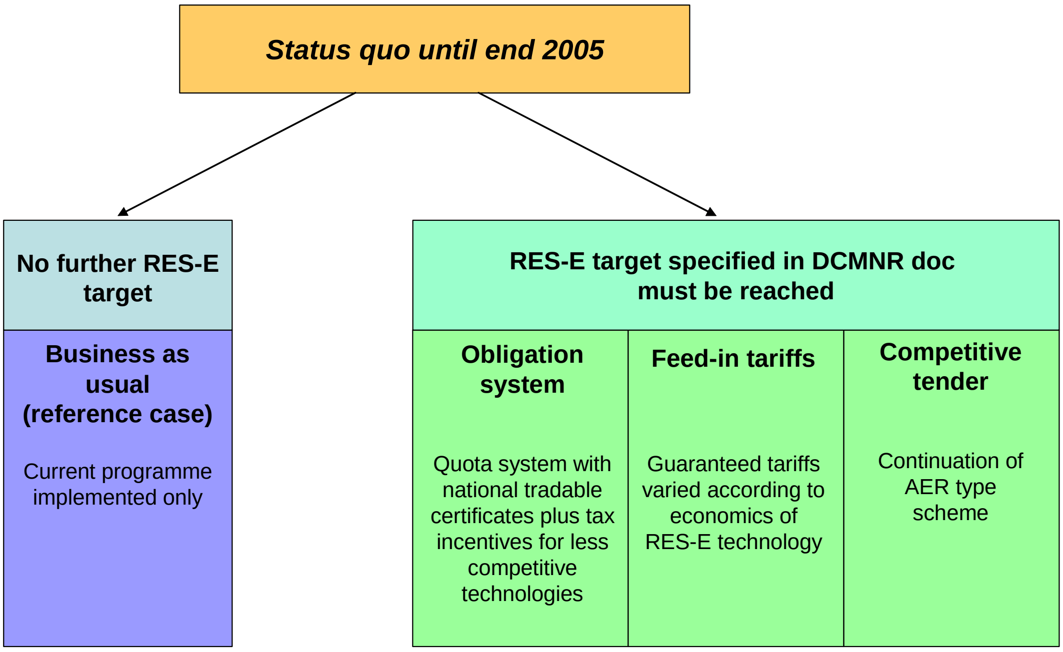


Figure 5-6 Scenario analysis

The basis for economic analysis of different support options is defined within a set of scenarios that describe likely and possible policy developments. Two distinct scenario-paths have been agreed with SEI and analysed, namely:

(i) a business-as-usual scenario and

(ii) selected policy scenarios reaching indicative targets specified in the DCMNR Consultation document (DCMNR, 2003a).

In addition, it is assumed that different strategy paths start in the year 2006. This means that until 2006 the BAU path applies. Figure 5-6 gives an overview of the scenario structure.

5.4.1 Current situation up to end of 2005:

The Green Paper on Sustainable Energy, published in 1999, set a RES-E target of an additional 500 MW by 2005. To meet this target and to promote RES-E technologies, tender rounds AER V and AER VI were introduced. The results of the offers arising from these rounds are summarised in Table 5-3. In this study, it is necessary to assess when these projects are anticipated to come on-stream and feed that information into the model. The focus on wind energy within AER VI is clear as it represents 93% of the contracts offered. A number of recent developments in wind energy in Ireland make it difficult to determine when these projects are likely to be commissioned and this was taken into account by the project team.

Table 5-3 RES-E Generating Capacities offered under AER VI

	AER VI announcement (incl.	**AER VI price cap**

	AER V) [MW]	[Euro/MWh]
Biomass	8	64,12
Biomass CHP	28	70,00
Biogas	2	70,00
Hydro	5	70,18
Wind onshore	485	52,16 – 57,42
Wind offshore	50	85,00
TOTAL	**578**	**58,75**

*average level

In addition to the AER process however, a number of projects have been constructed that have taken advantage of the opportunities to sell green electricity to customers under bilateral agreements within the liberalised electricity market.[51] The most significant of these are for wind energy, representing a cumulative installed capacity of 83 MW since 2000 (including the only offshore wind farm with an installed capacity of 25 MW). A number of wind energy projects have also been commissioned that secured funding under the EU 5th and 6th Framework Programmes representing a further 6 MW.

Progress has been significantly slower than anticipated regarding the delivery of AER projects. By the end of August 2004, only 39 MW of wind power was commissioned and the AER VI contracts had not yet been issued. State Aids approval is being sought for the offshore wind energy projects, the biomass CHP plants and an additional 140 MW, the latter in order to facilitate the issuing of additional AER VI contracts.

A number of significant uncertainties are associated with these projects related to connection to the electricity network and securing of finance. The biggest uncertainty currently relates to the timing of connection to the electricity network. A moratorium on the offering of new grid connection agreements for wind farms was put in place in December 2003[52] until the year's end. It was extended until the end of March 2004[53] and subsequently until the end of April 2004[54]. The moratorium was lifted subject to adoption of the transmission and distribution grid codes for wind energy, which effectively means it continues until the end of September. The requirement for dynamic modelling prior to gird connection raises a further uncertainty in the timeframe.

ESB NG (2003a) produced a report on wind farm connections that fed into the moratorium process[55]. This report provided a list of wind farms that have secured wind

[51] DCMNR (2004) Details of Wind Energy Electricity Generating Plant in operation at end March 2004. Available from www.dcmnr.ie

[52] CER (2003) Letter from Commission for Energy Regulation re ESBNG Proposal to Limit New Wind Connections (cer03283)

[53] CER (2003e) CER Letter to ESBNG regarding ESBNG request to extend the limitation of New Wind Connections (cer03310)

[54] CER (2004) Connection Offers To Wind Generators notice on website 31st March 2004.

[55] ESB NG (2003a) Interim policy on wind connections (cer 03282)

farm connection agreements, together with the scheduled year for connection. Based on the timing uncertainties that exist, this document was used as a basis for estimating when new wind farm capacity is likely to be commissioned. While a number of these projects may not have secure market access, or planning permission, it is felt to be the best source available and thus used in the modelling[56].

Table 5-4 Assumed timing of RES-E capacity in the period 2001-2005 under AER VI

Technology	2001-2005	Excepted year of implementation				
		2001	2002	2003	2004	2005
Biogas	2 MW					2 MW
Landfill gas,	11 MW				3 MW	8 MW
Sewage gas						
Solid Biomass (all sub-categories)*						
Biomass CHP	27 MW				3 MW	24 MW
Hydro small-scale	2 MW				2 MW	
Wind-onshore	509 MW	9 MW	13 MW	63 MW	288 MW	136 MW
Wind-offshore	75 MW			25 MW		50 MW
TOTAL	**626 MW**	**9 MW**	**13 MW**	**88 MW**	**296 MW**	**220 MW**

The new capacity for on-shore wind refers to the accepted connection offers for wind power (288 MW in 2004 and 136 MW in 2005). With respect to off-shore wind, it is assumed (recognising it is ambitious) that 50 MW will be installed in 2005 (adding to the 25 MW installed in 2003 and commissioned in 2004).

It is assumed that the biogas, biomass (joint tender for solid biomass, landfill gas and sewage gas) and biomass CHP projects will be commissioned by the end of 2005. Table 5-4 summarises these assumptions. It is worth mentioning that the overall anticipated growth in renewable energy capacity in the period 2001 – 2005 is 626 MW. This is lower than the sum of AER V and AER VI projects together with the plant built under the liberalised market and that built with EU support (representing a total of 645 MW). It is higher than the Green Paper target (500 MW), although it was intended that this target be met by 2005 (meaning all plant in place by the end of 2004).

This data was deemed the most useful available upon which to base the modelling assumptions. The uncertainties that have arisen since December 2003 are likely to impact on the connection timetables projected by ESB NG. The result of this is that the total capacity in table 5.6 is not likely to be achieved until the middle or end of 2006.

5.4.2 Different scenarios in the period 2006-2020:

In the period 2006-2020 a number of different scenarios are developed and simulated using the computer model ***Green*-X**. This means that until the end of 2005 the current policy is valid and only after the year 2005 the effects of different RES-E promotion

[56] It is noted that following the analysis additional information has become available that changes the expected implementation times. Those in table 5.6 are the timeframes used in the model.

strategies on RES-E capacity, electricity generation, and corresponding costs will be analysed.

To analyse the sensitivity of the data and the assumptions, various sensitivity analyses are also carried out. More precisely, model runs have been made assuming the following sensitivity tests

- Decreasing BNE price
- Higher WACC
- Ambitious utilisation of biomass co-firing

Note the development of the BNE price and – to a certain degree - the WACC are beyond to control of Government. The scenarios therefore contain sensitivities with respect to both policy choices and non-policy choices.

Business as usual scenario 2006-2010

In this strategy path, it is assumed that no new policies or measures are introduced for the period after 2005. The request for EU State Aids clearance for an additional 140 MW AER VI contracts is thus assumed to be the only new capacity built with Government support after 2005. Table 5-5 summarises the assumptions made for the BAU policy scenario.

It is clearly possible that new capacity will be constructed without direct Government support, either via the liberalised electricity market or with support under an EU 6th Framework Programme. However, the focus here is on projects delivered with national support.

Table 5-5 Governmental supported capacity in the period 2005 – 2010 under the AER VI contract.

Technology	**2006-2010**	**Excepted year of implementation**				
		2006	**2007**	**2008**	**2009**	**2010**
Biogas						
Landfill gas,						
Sewage gas						
Solid Biomass (all sub-categories)*						
Biomass CHP						
Hydro small-scale						
Wind-onshore	140 MW	70 MW	70 MW			
Wind-offshore						
TOTAL	**140 MW**	**70 MW**	**70 MW**	**0 MW**	**0 MW**	**0 MW**

It is useful to check this scenario against existing Strategy Papers for Ireland that cover the period post 2005.

- The National Climate Change Strategy for Ireland sets a greenhouse gas emission target for renewable energy of an additional 1 Mt-CO_2 reduction by 2010 compared to the business as usual case. This is to be achieved by the Green Paper target alone however, and will not require additional capacity beyond 2005.
- The business as usual case referred to in the NCCS is derived from *Renewable Energy – Strategy for the Future,* a statement of Government policy on renewable energy issued in 1996. The targets in that document predate the Green Paper and amount to just 31 MW of new RE capacity per year for the period 2000 – 2010. This amounts to 155 MW in the period 2006 – 2010 and is close to the 140 MW additional AERVI projects for which State Aids clearance is being sought. This scenario therefore assumes that just the 140 MW will be built with Government support from 2006.

Fulfilment of the targets indicated in DCMNR policy consultation

For the portfolio of scenarios it is assumed that the indicative RES-E targets in DCMNR (2003a) for the year 2020 must be reached, specifically these are 15%, 20%, 25% and 30% of gross electricity consumption. In addition, the indicative targets for 2010 (13.2%, 15%, 20%) should also be reached as interim targets. Figure 5-7 depicts the target setting according to the DCMNR requirement.

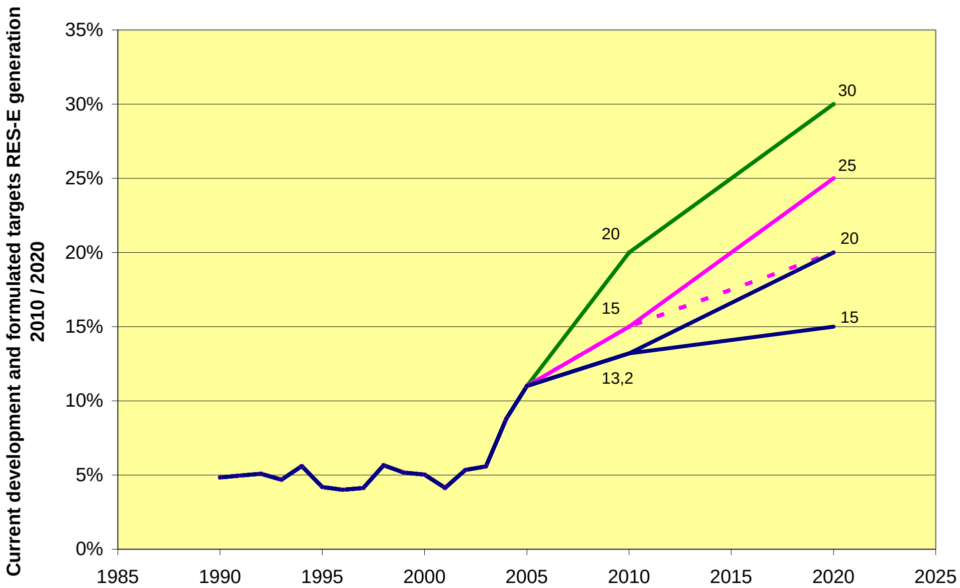


Figure 5-7 Targets specified in DCMNR policy consultation

To restrict the analysis and the complexity of the results, a comprehensive sensitivity analysis is carried out for one key scenario. For this scenario, effects of different policies, electricity prices (BNE) and other key assumptions like weighted average cost of capital factors or ambitious co-firing are determined. All variants from default changes are summarised in Table 5-6.

Table 5-6 Variants considered in the scenarios runs

Variant	Default assumption	Sensitivity analysis
WACC	6,5%	8,6%
Guaranteed duration of promotion scheme	15 yr	8 yr
BNE	const. 47,9	decreasing BNE
Co-firing of biomass allowed	yes	no
Ambitious use of co-firing	no	yes
Existing plants included in promotion scheme[1]	no	yes
Tax incentives, investment subsidies[2]	no	yes

The key scenario selected assumes reaching the 20% target in 2020, with an interim target of either 13.2% or 15% for 2010. For the other scenarios, the portfolio of RES-E capacity as well as the cost range is determined. However, this is done without carrying out a comprehensive sensitivity analysis.

In addition to identifying the optimal RES-E portfolio under different target setting assumptions, the economic efficiency of reaching these targets is also analysed. In other words, the impacts for society, producer and industry of reaching the targets under different policy schemes are assessed. The framework conditions as well as the most important results for all investigated cases are described in Annex III.

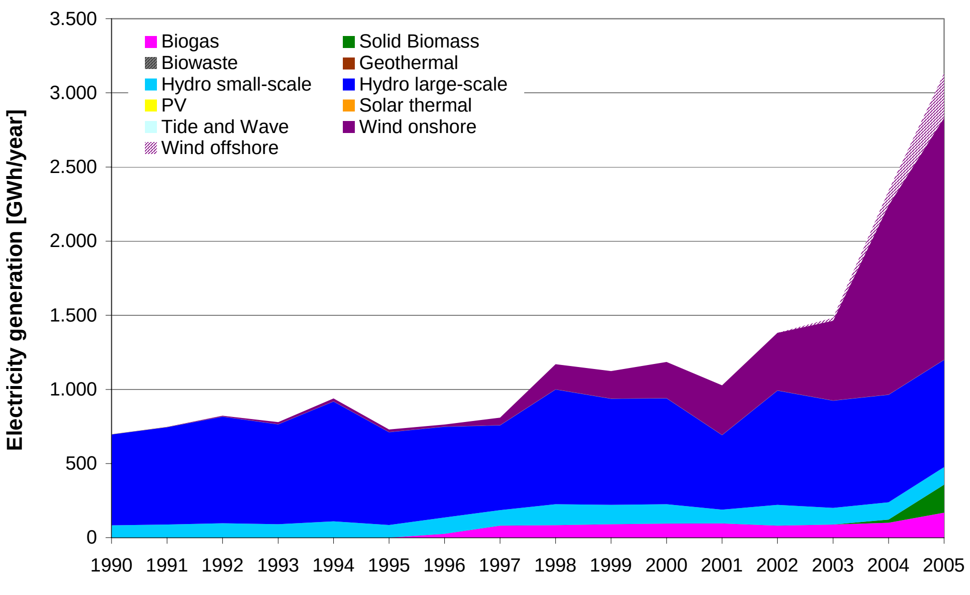
6 ANALYSIS OF POTENTIAL RES-E SUPPORT MECHANISMS IN IRELAND

The scenario analysis was carried out using the model and simulation tool ***Green-X***[57]. Market developments and barriers previously identified are used as input parameters to the ***Green-X*** model. The model outputs the following results for each year:

- total electricity generation of RES-E (and conventional electricity) within the country
- share of RES-E generation on total electricity production
- average generation costs of RES-E per kWh
- electricity generation for each RES-E technology
- average generation costs for each RES-E technology per kWh
- impact of selected strategies on total costs and benefits for society (consumer) – premium price due to RES-E strategy

Sections 6.1 - 6.6 summarise the key results for the scenarios and sensitivity analyses. More detailed results are available in Annex III of this report.

6.1 CURRENT SITUATION UP TO THE END OF 2005



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[57] Version 1.6.4. The key elements are described in 0.

[59] As mentioned previously, based on the impact of delays that became apparent after the modelling was complete, this level of penetration is more likely to be achieved in 2006 at the earliest.

Figure 6-1 Development of RES-E generation 1990-2005 according to the BAU scenario

The development of RES-E electricity generation by source up to the end of 2005 is shown in Figure 6-1. As a result of the AER V and VI tender, effective in particular for the years 2004 and 2005, total electricity generation for RES-E increases significantly. In 2005 a share of around 11.25% of gross electricity consumption is projected[59].

The development of the new RES-E capacity is shown in Figure 6-2. Since besides the AER no additional plant is built, the projected new capacity is equal to the assumed deployment under AER (see Table 5-4). It can be seen that the AER is most effective in the years 2004 and 2005, when it can be expected that in this period a lot of wind projects will be realised.

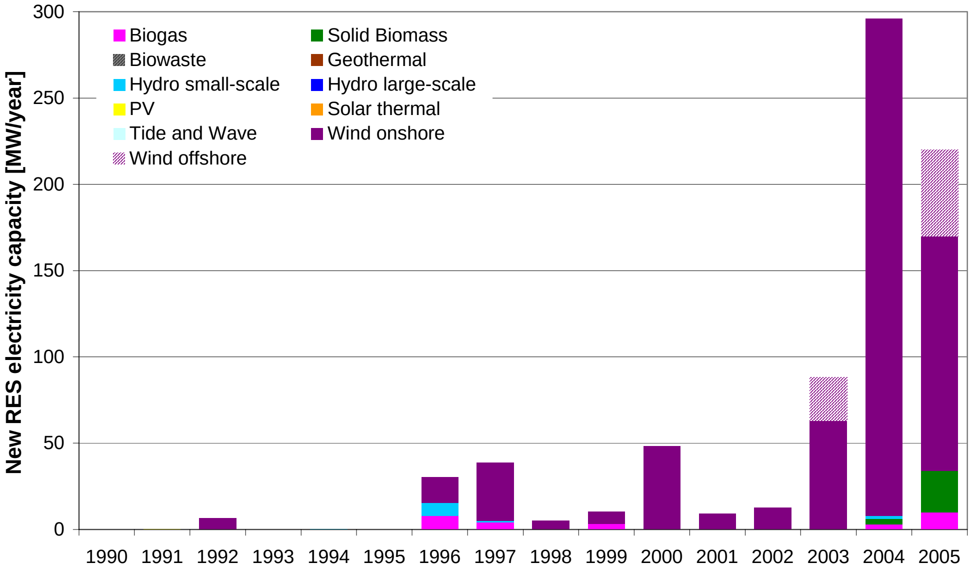

Figure 6-2 Development of new RES-E capacity 1990-2005 according to the historical development and the BAU scenario up to 2005

6.2 SCENARIO 1 - BUSINESS AS USUAL (PERIOD 2006-2020)

The BAU scenario assumes a continuation of existing policies only (and no further AER rounds) beyond 2005. Existing barriers and restrictions remain in place, but may be reduced over time.

Projected RES-E electricity generation developments in the period 2005-2020 are depicted in Figure 6-3 and the data is summarised in Table 6-1. RES-E production rises in the years 2006 and 2007 by around 18%. Despite this “huge” increase the RES-E share of gross electricity consumption rises by only around 0.9%, as electricity demand growth in the same period equals 4.1%.

After 2007 additional increases are driven only by cost effective RES-E technology options, as no further RES-E promotion strategy is assumed. More precisely, cost efficient options are limited to co-firing of biomass in existing peat plants (Edenderry), landfill gas, onshore wind, and in the period after 2010 / 2015 offshore wind and wave energy.

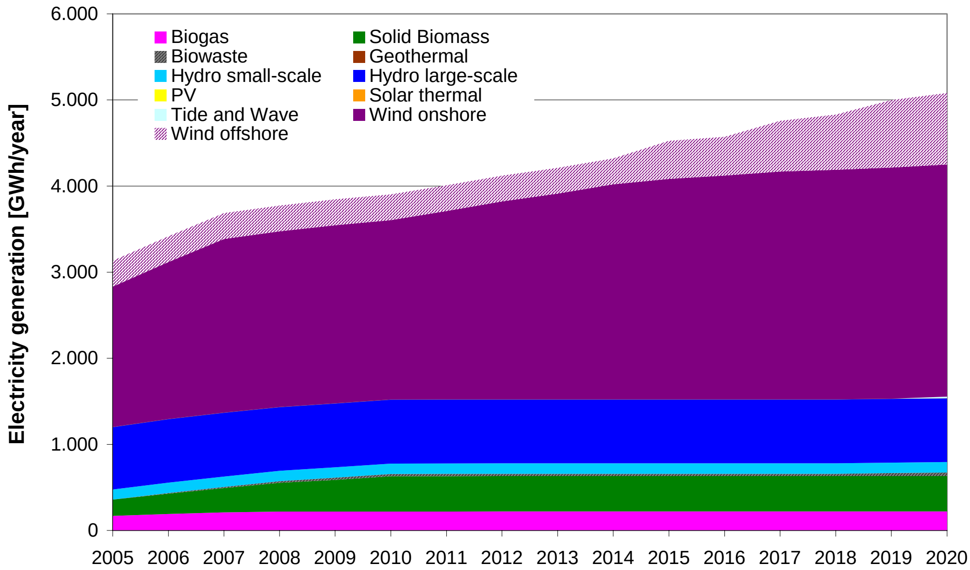

Figure 6-3 Development of RES-E generation 1990-2020 according to the BAU scenario

Table 6-1 RES-E generation and capacity according to the BAU scenario (including both projected government supported and non-supported RES-E deployment)

BAU-Scenario	2005		2010		2015		2020	
	[GWh]	[MW]	[GWh]	[MW]	[GWh]	[MW]	[GWh]	[MW]
Biogas	169	28	218	37	221	37	221	37
Solid biomass	189	27	411	70	411	70	411	70
Biowaste	0	0	27	4	27	4	41	6
Hydro large-scale	725	200	742	206	742	206	742	206
Hydro small-scale	118	39	121	39	121	39	121	39
Photovoltaics	0	0	0	0	0	0	0	0
Tide & wave	0	0	0	0	0	0	19	5
Wind onshore	16310	625	2084	790	2561	969	2697	1023
Wind offshore	300	75	300	75	441	110	830	211
RES-E TOTAL	**3132**	**994**	**3904**	**1222**	**4525**	**1438**	**5081**	**1599**
Share of GEC	11.0%		11.2%		11.7%		12.3%	

The development of RES-E generation without any market support - this is the case after 2007 - is sensitive and depends on:

- the conventional electricity price / BNE price development
- the development of the electricity market and the RES-E technologies (e.g. influencing the necessary rate of return and risk factors)
- the option of co-firing in existing and new conventional power plants

In order to investigate more deeply, a sensitivity analysis has been carried out. The key findings relating to the aforementioned issues are summarised in Figure 6-4 and Table 6-2.[60]

The option of co-firing in conventional power plants is considered feasible in a comprehensive way as analysed by e.g. COFORD (2003). Ambitious co-firing[61] does not increase the share of RES-E relative to the BAU assumptions. The reason is that the costs are still slightly higher than the BNE price.[62] Also, with respect to the costs for society no changes compared to the BAU default assumption arise.

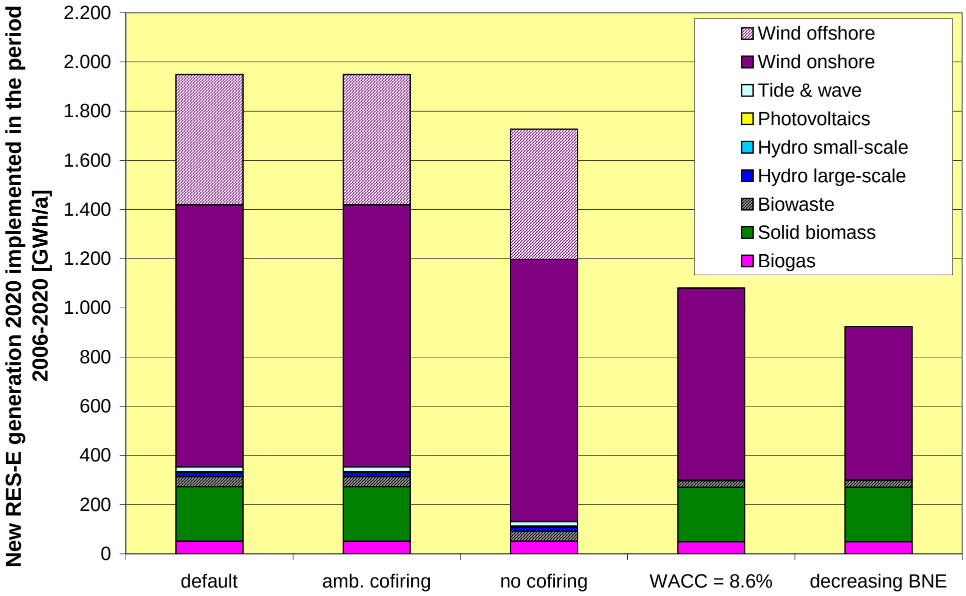

Figure 6-4 Comparison of RES-E generation in 2020 from capacities implemented in 2006-2020

In a scenario where co-firing is excluded, the total share of RES-E reaches 11%.

The development of RES-E is significantly reduced when assuming a higher internal rate of return[63] (e.g. due to higher risk assessment) or lower future BNE prices[64] (as

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[60] Comprehensive information can be found in Annex III.

[61] Ambitious co-firing means that the following conditions are fulfilled: (i) technical possibility (including the logistics of biomass transport), (ii) decisions taken by plant owners, (iii) political support (included in chosen promotion strategy), and (iv) social acceptance of co-firing

[62] Using a more detailed primary biomass price structure for the model runs, it could be possible that some parts are cost effective even without any public support. Also a change in the PSO system from peat to biomass could turn around the results. To clarify this point, a more detailed analysis is required.

[63] Around 45% compared with default case.

forecasted by Ilex (2003), see also section 5.2.3). More precisely, under these conditions there is a lower penetration of small and large hydro power and on-shore wind capacity. Moreover, off-shore wind developments are halted. Obviously, both a higher interest rate and a lower conventional power price (BNE), will most likely result in higher transfer costs for society, assuming similar targets have to be met.

The modelling results clearly show that the development of RES-E in Ireland without any additional policy support is very uncertain. The indicative EU target for 2010 will not be achieved and the share of RES-E will be 11.2% of gross electricity consumption in 2010.

Table 6-2 Comparison of different variants BAU scenarios 2020

	Total RES-E generation 2020 [GWh/yr]	Electricity generation in 2020 from new plants 2006-2010 [GWh/yr]	Total transfer costs for society due to new installed RES-E capacity 2006-2020 in the period 2006-2010 [M€]	Additional financial support per MWh new RES-E 2006-2020 in 2020 compare to BNE [€/MWh]	Premium costs on electricity price due to RES-E policy 2006-2020 [Euro/MWh RES-E] [€/MWh]
default	5081	1949	14	0,46	0,022
amb. cofiring	5081	1949	14	0,46	0,022
no cofiring	4859	1727	14	0,52	0,022
WACC = 8.6%	4209	1077	43	2,66	0,069
decreasing BNE	4052	920	41	2,96	0,066

6.3 SCENARIO 2 - 20% RES-E TARGET 2020 (KEY SCENARIO)

In this scenario, a number of policy schemes and policy design variants will be described in which the share of RES-E should be 20% in 2020. Due to the huge amount of scenarios and variants, the detailed results from each single scenario are presented in Annex III of this report. In the main report the analysis is focused on the comparison of different effects occurring under different assumptions.

[64] Around 53% compared with default case.

[67] Note the additional electricity generation from (small) hydro power differs among the investigated scenarios between plus 9 and 38 GWh/yr. The level of additional RES-E generation depends on the financial support.

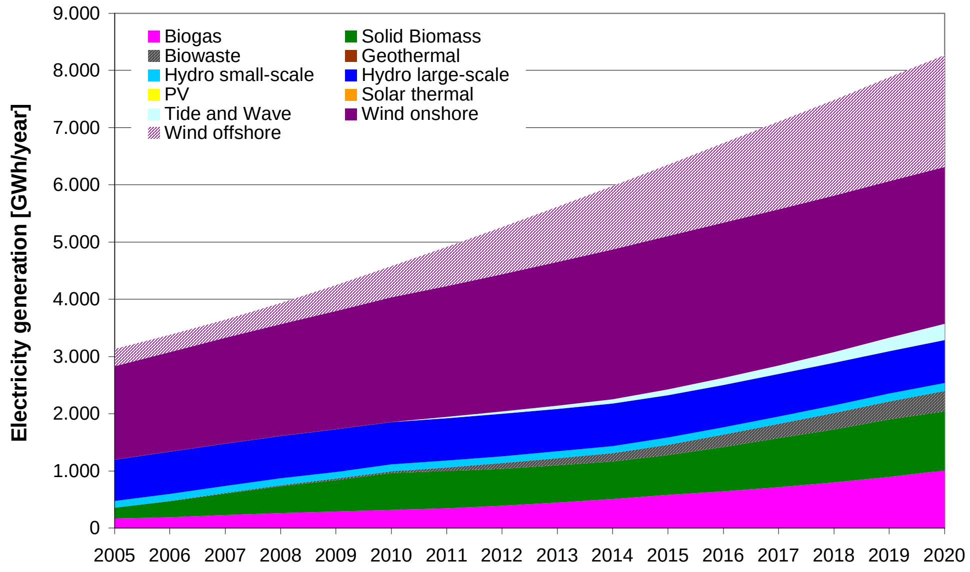

Figure 6-5 Development of RES-E generation 2005-2020 assuming a quota obligation with tradable green certificates and a RES-E target of 13.2% in 2010.

Figure 6-6 illustrates a typical RES-E deployment for the case that the indicative RES-E target of 13.2% for 2010 will be reached by the introduction of a quota system in combination with tradable green certificates. Note that although both the portfolio and the dynamic development of RES-E varies according to scenario, the results display a number of key similar features, i.e. in all cases a range of different technologies contribute to the RES-E deployment.

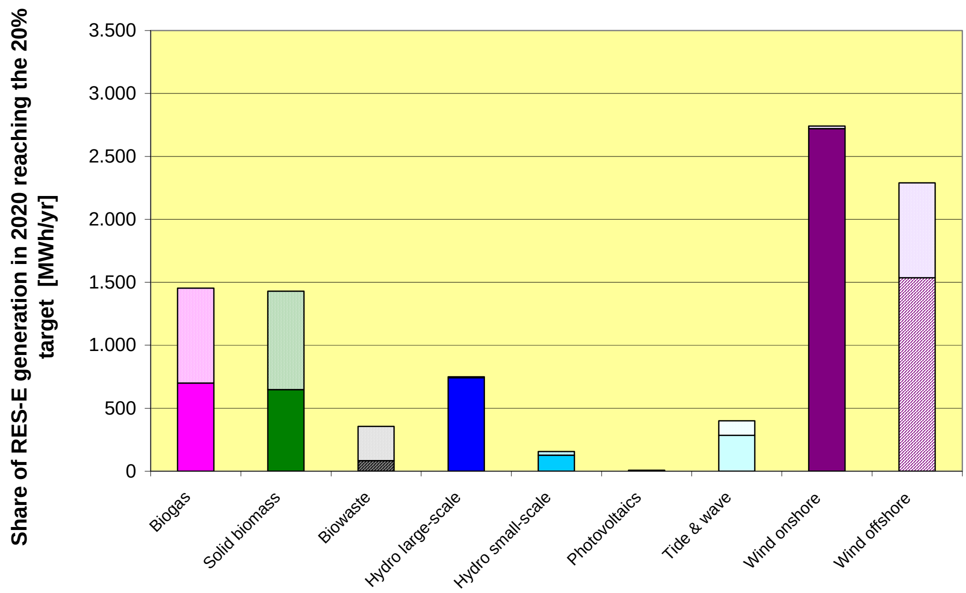

Figure 6-6 Portfolio of RES-E technologies reaching 20% target in 2020 (dotted area = spread due to different support mechanisms)

Figure 6-6 depicts the mix of RES-E generation on the basis of different policy schemes for the target year 2020. The dotted area indicates the spread occurring due to different instruments and design variants. In all investigated scenarios RES-E generation from hydro power and on-shore wind is relatively constant, i.e. independent of the support mechanism, the electricity production from these technologies is relatively well forecasted. The reason this is the case for hydro power is that the potential for additional hydro power is limited in Ireland.[67] With respect to on-shore wind, the relative low generation costs make it rational to exploit most of the available potential in all support mechanisms, up to the maximum assumed potential of around 1,000 MW. The greatest uncertainty with respect to RES-E deployment occurs for biogas (inclusive of both landfill and sewage gas), solid biomass and off-shore wind production. This uncertainty mainly depends on:

- the feasibility of building up a huge co-firing capacity for biomass,
- the policy focusing on a diversity of RES-E technologies (not only exploiting wind resources),

Table 6-3 Comparison of different scenarios 20% RES-E target 2020

	Strategy	Share of RES-E 2010	Electricity generation in 2020 from new plants 2006-2020	Total transfer costs for society due to new installed RES-E capacity 2006-2020 in the period 2006-2020	Additional financial support per MWh (compared with BNE) in 2020 for new RES-E built in 2006-2020	Premium costs on electricity price due to RES-E policy 2006-2020 [Euro/MWh RES-E]
		[%]	[GWh/yr]	[M€]	[€/MWh]	[€/MWh]
Quota obligation	amb. cofiring	13.2	5138	1267	16,4	2,04
	amb. cofiring	15.0	5138	525	6,8	0,85
	amb cofiring, duration 8 yr	15.0	5124	445	5,8	0,72
	amb. cofiring; WACC = 8.6%	15.0	5138	759	9,8	1,22
	default	13.2	5138	2085	27,1	3,36
	default all plants	13.2	5139	2930	38,0	4,72
	default WACC = 8.6%	13.2	5138	2326	30,2	3,75
	default	15.0	5138	1137	14,8	1,83
	default; duration 8 yr	15.0	5123	851	11,1	1,37
	default & investment subsidy	15.0	5135	839	10,9	1,35
	default & tax relief	15.0	5134	1261	16,4	2,03
	default, WACC = 8.6%	15.0	5138	1582	20,5	2,55
	default, WACC = 8.6%; duration 8 yr	15.0	5137	1118	14,5	1,80
	default, WACC = 8.6%; all plants	15.0	5137	2452	31,8	3,95
FIT	amb. cofiring	13.2	5053	712	9,4	1,15
	amb. cofiring	14.7	5284	582	7,3	0,94
	default	13.2	4907	833	11,3	1,34
	default	14.9	5070	818	10,8	1,32
	default, more biomass	15.9	5003	1215	16,2	1,96
Tender scheme	amb. cofiring, no str.bidding	13.2	5295	361	4,6	0,58
	amb. cofiring, str.bidding	13.2	5295	865	10,9	1,39
	amb. cofiring, no str. bidding	14.3	5205	328	4,2	0,53
	amb. cofiring, str. bidding	14.3	5205	755	9,7	1,22
	amb. cofiring, WACC = 8.6%, no str. bid.	14.3	5215	673	8,6	1,08
	amb. cofiring, WACC = 8.6%, str. bidding	14.3	5215	1167	14,9	1,88
	default, no str. bidding	13.2	5186	526	6,8	0,85
	default, str. bidding	13.2	5186	1043	13,4	1,68
	default, WACC = 8,6%, no str. bidding	13.2	5155	893	11,6	1,44
	default, WACC = 8.6%, str. bidding	13.2	5155	1373	17,8	2,21
	default, no str. bidding	14.2	5155	473	6,1	0,76
	default, str. bidding	14.2	5155	941	12,2	1,52
	default, WACC = 8,6%, no str. bidding	14.3	5130	859	11,2	1,38
	default, WACC = 8.6%, str. bidding	14.3	5130	1296	16,8	2,09

The most important indicators of various investigated cases are summarised in Table 6-3.

This comprises:

- the additional installed electricity generation in the investigated period 2006-2020[68]

[68] The level should be theoretically equal as the same share of RES-E should be achieved. In practice, however, a target is not exact reachable by other instruments than a quota obligation, which per definition refers to the aimed target.

- transfer costs for society of new installed RES-E capacity in the period 2006-2020 (divided into costs arise before the year 2020 and costs beyond the target year due to valid contract or available tradable green certificates)
- average (additional) financial support per MWh in 2020 to new RES-E capacity 2006-2020. This value indicates the additional costs of RES-E compared to the BNE price.
- average premium costs on electricity price in 2020 due to RES-E policy 2006-2020. This indicator refers the total transfer costs for society (in million Euro) to each MWh of electricity consumed. It shows the necessary premium on the electricity price under the assumption that the costs of the whole RES-E policy should be financed via a premium on the electricity price or an additional distribution fee.

The results associated with the different support mechanisms and variants are now discussed. Figure 6-7, Figure 6-9 and Figure 6-10 summarise the additional transfer costs for society in terms of average (additional) financial support per MWh of new RES-E generation in the period 2006-2020 compared to the BNE price.[69]

6.3.1 Quota obligation with tradable green certificates (TGCs)

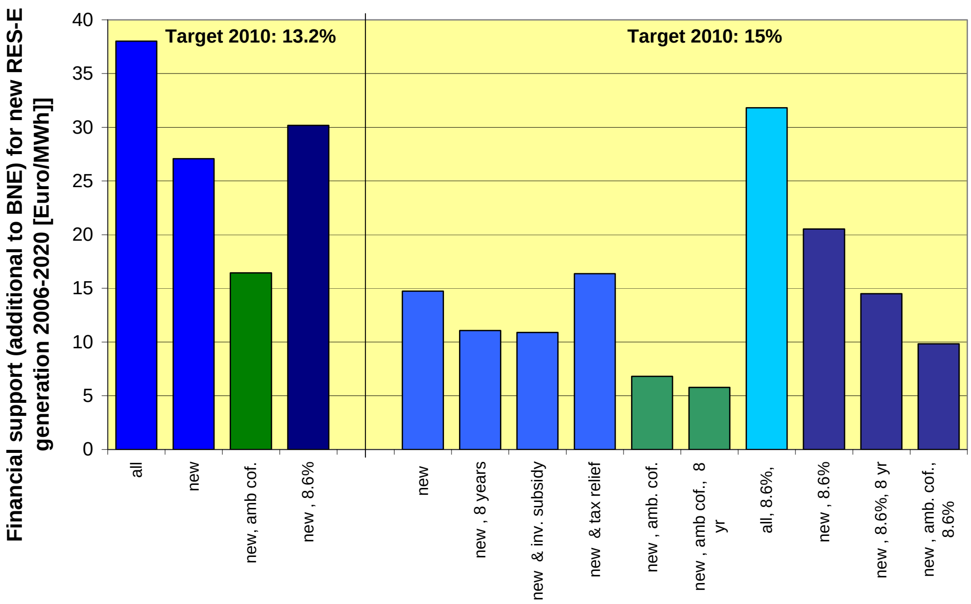

Figure 6-7 Average additional financial support per MWh (relative to BNE) in the year 2020 for new RES-E built in the period 2006-2020 reaching 20% target in 2020 under a quota obligation scheme

[69] Much lower additional costs will be indicated, if the premium costs refer to the total electricity consumption than to the additional support per MWh new RES.E generation.

The additional necessary financial support per MWh in the year 2020 due to the RES-E policy in the period 2006-2020 is depicted in Figure 6-7.

The development of TGCs prices up to 2020 is depicted for different scenarios and variants in Figure 6-8.

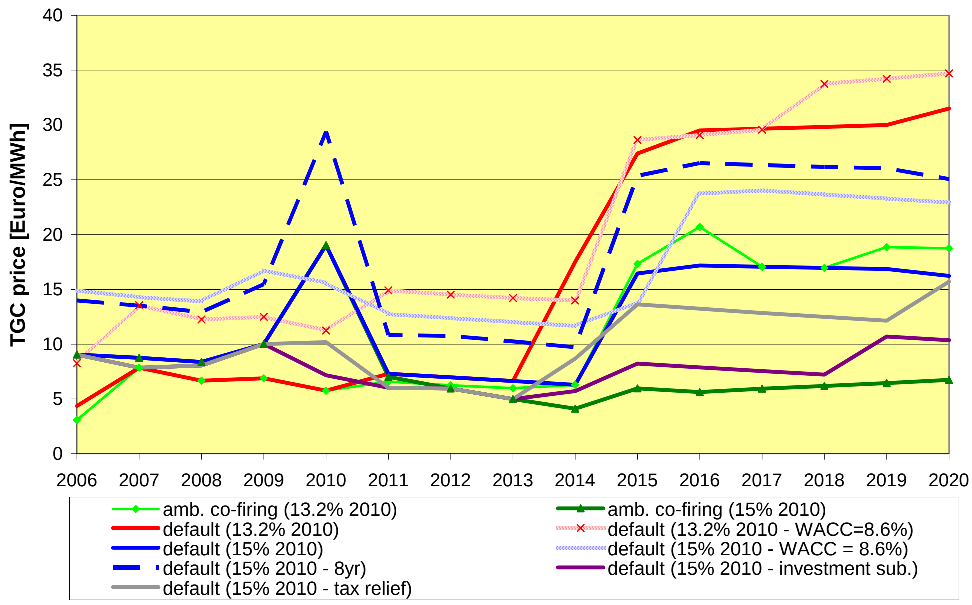

Figure 6-8 Development of TGCs prices reaching the 20% target in 2020

The key features of this analysis are that

A 15% interim target for 2010 leads to lower costs than a 13.2% target for society

The analysis shows that, (surprisingly), social costs are much lower per MWh if a 15% target is set for 2010 instead of a 13.2% target.[70] This means that the choice of interim targets (yearly obligation up to 2020) is very critical to the costs to consumers. The reasons for these lower costs are:

- Only slightly higher TGC prices are evident in the period 2006-2010 despite the higher quota level, because additional capacity with only "marginal" higher generation costs is available in this period. Hence, imposing a higher quota leads only to slightly higher TGCs prices.
- Lower costs beyond 2013 are due to the smaller amount of additional capacity. For the 13.2% case, similar to the period before 2010 "cheap" capacity is available beyond 2010. As the total amount of new RES-E capacity exceeds the relative cheap available potential[71], other technologies with higher costs must be installed reaching the 2020 target.

[70] Note: There is an uncertainty with respect the total costs for society as the TGC price beyond 2020 is unknown – depending e.g. on the targets set beyond 2020 and the development of investment costs. In the model it is assumed that the TGC price in the period 2021-2034 is constant and equal to the TGC price for the year 2020.

[71] The yearly necessary increase starting from a level of 13.2% in 2010 is higher than beginning from 15% in 2010.

- Lower TGC price in 2020 influencing the social costs for the period beyond 2020.[72, 73]

Include only new capacity into the quota system:

Under the standard assumption that all RES-E technologies are included into the quota system, i.e. both existing and new RES-E capacity are permitted to generate TGCs, costs for society are higher than if only new capacity is included in the quota obligation. In the Irish case, costs are around 50% higher if all plants have the possibility to participate in the trading scheme. The reason is that substantial windfall profits for already depreciated plants or plants already receiving support under other schemes (e.g. existing contracts signed under AER in the past) occur.

Extending this to a dynamic context, it is useful to issue TGCs only over a per-defined period of time. This means, a distinction between new and old plants should not be viewed only from the static point-of-view. A rolling redemption provides a dynamic solution. In practice, such a system can be implemented for plant not older than x years.[74] Hence, the issuing body awards TGCs only to these facilities. Moreover this can be used to set incentives for maintenance, upgrade, expansion and revitalisation of existing plant, TGCs should be issued also for the incremental generation of electricity of such facilities.´

A more restricted duration in which TGC can be generated (may) reduce costs for society:

As already mentioned above, a restricted pre-defined issuing time for TGCs is useful. A brief duration leads to higher TGC prices. The duration where society is imposed with higher costs, however, is shorter. The analysis shows that costs for society are lower for 8 year TGCs compared with 15 year TGCs. This result, however, cannot be generalised. The costs depend on the TGC price development. As the price is rising over time, a shorter duration helps to reduce social costs. In the case of falling TGC prices the reverse is true.[75]

Additional support for less cost efficient technologies reduces transfer costs for society:

In addition, it seems to be useful to give additional support for RES-E technologies having higher generation costs (e.g. investment subsidies / tax relief). The reason is that the TGC price remains lower, reducing the windfall profit for cheaper technologies. However, these results are very sensitive. Depending on the additional support, total costs may exceed the price level without any additional

[72] Even, if you compare the transfer costs for society that occur in the period 2006-2020 (see Table 6-3), costs are higher in the case of the 13.2% RES-E target – 868 Mio Euro compared to 589 Mio Euro in the case of 15% interim target for 2010. Under relatively equal total transfer costs, this should not the case, as under a 15% interim target more capacity should be financed in the period 2006-2020 than beyond 2020 compare to the interim target of 13.2%.

[73] Maybe it is useful to assume the same TGC price level for the period beyond 2020. In this case a low level beyond 2020 leads to a higher level in the period before, as the investors have to bring in their investment costs.

[74] In the simulations, the default period is 15 years, with a sensitivity analysis assuming an issuing period of 8 years.

[75] This would be the case assuming a 15% target in 2020.

instrument; as is evident in the comparison of "new & investment subsidy" with "new & tax relief" in Figure 6-7.[76] This means, a careful setting is necessary, requiring a more detailed analysis beyond the scope of this study.

Use full basket of RES-E technologies:

If it is possible to include significant amounts of co-firing, costs for society can be reduced. The reason is that, under these conditions, cheaper RES-E technologies are available.

The advantage of a shorter duration (8 years instead of 15 years) is lower however, under this assumption, as TGC prices are more stable over the investigated period. Note, this conclusion is not generally valid. It depends (significantly) on the target and the available technology mix.

Higher risk premium for TGCs:

From Figure 6-8 it can be seen that a forecast of TGCs price is uncertain, depending on various conditions. They can be influenced by many different factors - both under governmental and non-governmental control, - e.g. oligopoly market structure, investor behaviour, regulatory framework conditions, grid extension, biomass policy, social acceptance, etc. Most of these factors are uncertain in the future.

Therefore, despite the assumption of a politically stable environment[77], a TGC system causes a higher risk for potential investors. This higher risk is reflected in a higher WACC value. An international comparison with respect to used interest rates shows that a WACC of 8.6% is more realistic for TGC systems than 6.5% due to higher uncertainty (Cleijne et. al., 2004). A higher WACC results in higher transfer costs for society, independently from the chosen quota design option or other variants (of scenarios).

6.3.2 Feed-in tariff scheme

[76] Note: The difference not primarily depends on the chosen instrument, but on the level of additional support.

[77] As for all other cases it is assumed that the quota system remains over the investigated period and beyond (up to 2035 if the duration is 15 years).

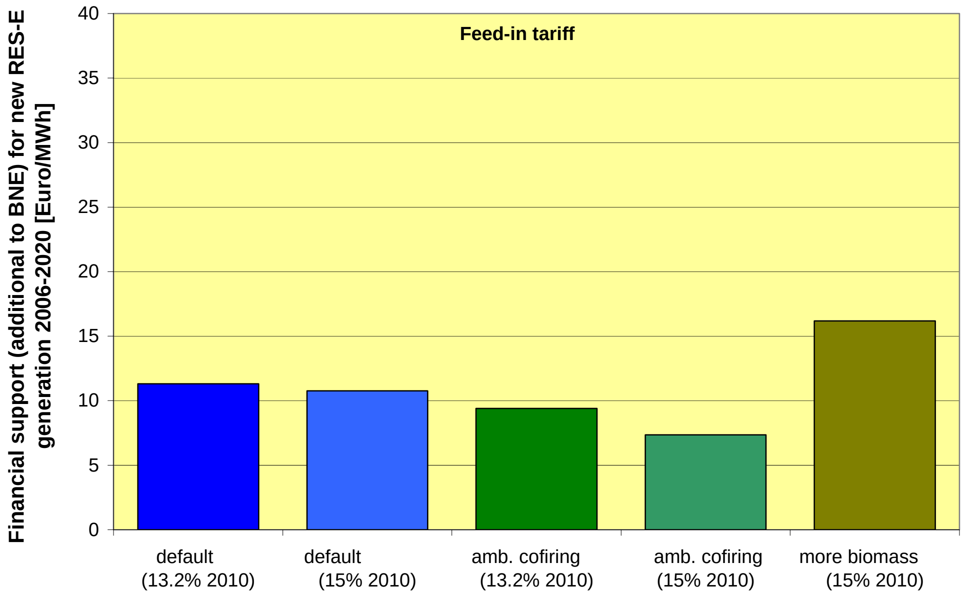

Figure 6-9 Average additional financial support per MWh (relative to BNE) in the year 2020 for new RES-E built in the period 2006-2020 reaching 20% target in 2020 under a feed-in tariff scheme

Five model runs have been made simulating the effect of a feed-in tariff scheme, namely:

- using default assumptions an interim target of 13.2% and 15% for 2010
- including the option of significant co-firing of biomass in conventional power plants again for the interim target of 13.2% and 15% for 2010
- a strategy favouring biomass products (without extensive co-firing).

The transfer costs for society of the different options / assumptions are depicted in Figure 6-9. The main findings are:

- using an interim target 13.2% rather than 15% results in higher costs, but the difference in transaction costs is much lower than investigated in the case of a TGC system
- the total costs for society can be reduced by around 30% following a comprehensive co-firing strategy compared to the default strategy.
- allowing a (inadequate) higher grant for currently less cost effective technologies causes total social costs to rise.[78]

6.3.3 Competitive tender scheme

Simulation runs have been carried out for competitive tendering schemes analysing the sensitivity of:

[78] As already mentioned, the level of the tariffs and the yearly reduction are not designed in a way to minimise social costs.

- using different interim target setting (13.2% versus 14.2% in 2010)[79]
- pursuing or not pursuing ambitious co-firing
- risk assessment of potential investors

Figure 6-10 shows the impact of varying these input parameters on the additional financial support levels necessary to achieve 20% penetration by 2020. For each set of input data the spread in support relates to whether it is assumed that strategic bidding takes place or not. The lower level assumes no strategic bidding and that full competition occurs among the potential investors[80].

As was the case for quota and feed-in tariffs, setting a higher interim target reduces the additional support required. The effects of strategic bidding clearly have a much greater impact on the support levels.

This is an interesting result as a tender procedure represents the least cost option for society from a theoretical point-of-view, due to the competition among potential investors. In practice, however, conditions exist leading to higher costs than theoretically anticipated. Strategic bidding in this case – feasible in an oligopolistic environment, where full competition is resisted – causes costs to increase.[81]

The key results regarding transfer costs for society are that the additional financial costs are mainly determined by the risk assessment of the market / investor. It is therefore more important to reduce the WACC than the decision regarding the interim targets (e.g. 13.2% or 14.2% in 2010) or the inclusion of co-firing within the mechanism or not.

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[79] For the sensitivity analysis a constant RES-E promotion over time (constant capacity) is assumed. Therefore, the 15% target will not be reached. Pursuing a 15% target for 2010 would emphasise the effect of lower transfer costs for society compared to an interim target of 13.2%.

[80] The higher level indicates the necessary financial support assuming that investors offer strategic bids. Hence, in this case, transfer costs for society exceed the marginal long-term generation costs. The more efficient the plant, the greater the possibility of strategic bidding. In the model it is assumed that the marginal investors receiving a positive contract has no possibility to increase his bid, i.e. there ever exist enough competition that the marginal bid level remains constant and do not increase due to the oligopoly structure.

[81] All already mentioned, this fact is considered in the simulation runs.

[83] One remedy is that less cost efficient technologies receive additional financial support. Such a strategy, however, contradicts, the principle underpinning a TGC system, namely the promotion of least cost generation options.

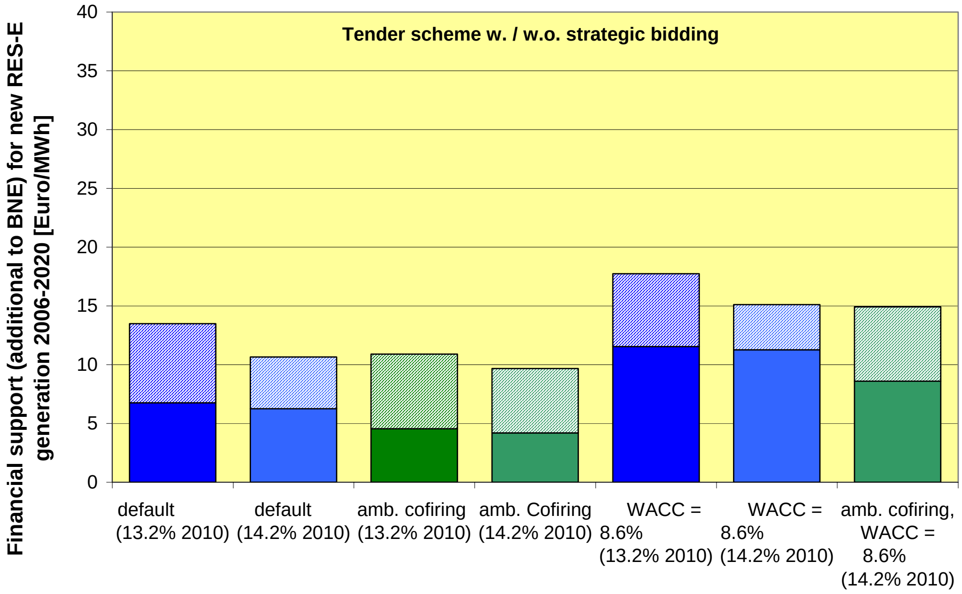

Figure 6-10 Average additional financial support per MWh (relative to BNE) in the year 2020 for new RES-E built in the period 2006-2020 reaching 20% target in 2020 under a tender scheme

Note: Tender lower level: No strategic bidding; Higher level: full strategic bidding

6.3.4 Comparison of the different support mechanisms

A comparison of the different instruments shows that costs for society are high in the case of a quota system based on TGCs, despite the fact that this instrument allows total costs of the RES-E system to be minimised. The reason is that most of the efficiency gains occurring as a result of the market can be claimed by the investors – all producers receive the same marginal price, independent of their actual generation costs.[83]

Due to the technology specific tariff setting within a feed-in tariff scheme, producer surplus can be significantly reduced. In total, society gains from this instrument, despite higher total RES-E system costs, compared to the trading scheme.[84] Comparing a tender system with a feed-in tariff scheme shows that the costs for the consumer are lower in the first case when neglecting strategic behaviour of potential investors. However, when including strategic behaviour, costs for society is in the same range as for a guaranteed tariff.

The modelling results do not include administrative costs, i.e. administrative costs associated with organising tender competitions, the costs of setting-up and maintaining a TGC trading system nor the administrative costs of a feed-in tariff scheme are included. Administrative costs are closely correlated to the complexity of the system. Simple guaranteed feed-in tariff systems often have relatively low administrative costs. Combined obligation and certificate systems are by nature more

84 Assuming a higher WACC in the case of a quota obligation. Assuming – unrealistically – the same WACC value, the instruments are similar efficient from the societies-point-of-view at the target of 20%.

complex and induce somewhat higher administrative costs of compliance. The creation of a trading platform helps to reduce these costs. In tendering procedures the total administrative costs can be more easily controlled. However, with its higher uncertainty in resulting penetration, the costs per unit of delivered output are more uncertain.

Scenario path 13.2% in 2010 and 20% in 2020

For each of the three support mechanisms, the results show that an interim 2010 target of 13.2% results in a requirement for greater additional financial support than the 15% interim target. It is interesting however, to examine the impacts associated with the 13.2% interim target in more detail, as it ensures minimal compliance with the EU Directive. Table 6-4 summarises the key impact assessment parameters for the different support mechanisms for the year 2010, namely electricity generated, transfer costs to society, additional financial support required (relative to BNE) and the premium costs added to electricity prices[85].

Table 6-4 Comparison of different support mechanisms 13.2% RES-E target 2010

Strategy		Electricity generation in 2010 from new plants 2006-2010	Total transfer costs (2006-2010) for society due to new installed RES-E capacity in the period 2006-2010	Additional financial support per MWh (relative to BNE) in 2010 for new RES-E projects built in 2006-2010	Premium costs added to electricity price in 2010 due to RES-E policy 2006-2020 [Euro/MWh RES-E]
		[GWh/yr]	[M€]	[€/MWh]	[€/MWh]
Quota obligation	amb. cofiring	1448	128	5,9	0,21
	Amb. cofiring, WACC = 8.6%	1448	247	11,4	0,40
	default	1448	128	5,9	0,21
	default all plants	1449	414	19,0	0,67
	default WACC = 8.6%	1448	247	11,4	0,40
FIT	Amb. cofiring	1456	200	9,2	0,32
	default	1505	208	9,2	0,33
Tender scheme	Amb. cofiring, no str.bidding	1432	52	2,4	0,08
	Amb. cofiring, str.bidding	1432	156	7,3	0,25
	default, no str. bidding	1406	56	2,6	0,09
	default, str. bidding	1406	143	6,8	0,23
	default, WACC = 8,6%, no str. bidding	1408	131	6,2	0,21
	default, WACC = 8.6%, str. bidding	1408	266	12,6	0,43

Figure 6-11 focuses on one of these parameters, additional financial support for the three support mechanisms. The figures reflect the amount of support required per MWh (relative to BNE € 47.9 / MWh) in the year 2010 for new RES-E generation built in the period 2006-2010. The right-hand-side of Figure 6-11 shows the impact on financial support of including ambitious co-firing. Three interesting results occur:

[85] The results for 2020 were shown in Table 6-3.

- the inclusion of co-firing does not lead to (dramatically) reduced transfer costs for society irrespective of the support mechanism. The reason for this is that other "cheap" options are available to reach the 2010 target;
- transfer costs for society are lowest under a tender scheme (assuming strategic bidding can be avoided to a high degree and WACC is low too). Under the assumption of a higher WACC (e.g. 8.6% compared to 6.5%), the costs are similar to the other instruments.
- the costs imposed on the consumer applying a TGC system or a feed-in tariff scheme are in the same magnitude.[86]

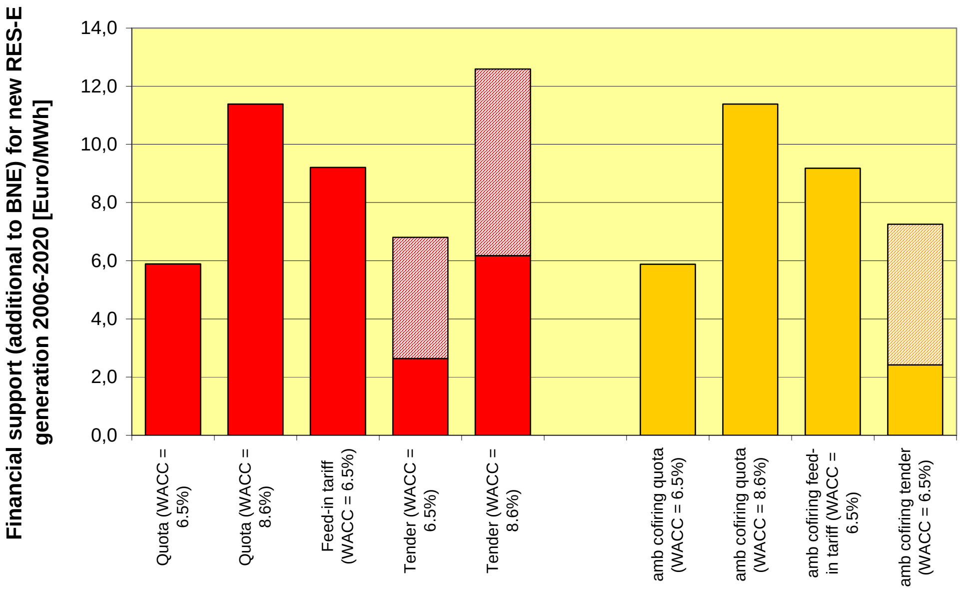

Figure 6-11 Average additional financial support per MWh (relative to BNE) in the year 2010 for new RES-E built in the period 2006-2010 reaching a 13.2% target in 2010

Comparing the instruments in 2020, quite different conclusions can be drawn, as shown in Figure 6-12.

- the inclusion of co-firing reduces the additional financial support relative to BNE (€ 47.9 / MWh) significantly, by close to 40% for a TGC system and by approximately 15-20% for both a feed-in tariff scheme or a competitive tendering scheme. This is because a 20% RES-E target in 2020 is more ambitious and all alternative cheap options are exhausted to reach it. If these cheap options cannot be used, the support required rises accordingly.
- The financial support required for a feed-in system is close to that for a competitive tender system – this again assumes a medium level strategic bidding and a low WACC.

[86] Note, both instruments are not optimised. Neither additional support within a TGC system, nor optimal price setting under a feed-in scheme is investigated. Such an analysis can be carried out in the next step.

- Support required for a quota system exceed that for the other two schemes. This can be reduced, by allowing for co-firing and if additional support is granted for less mature technologies.[87]

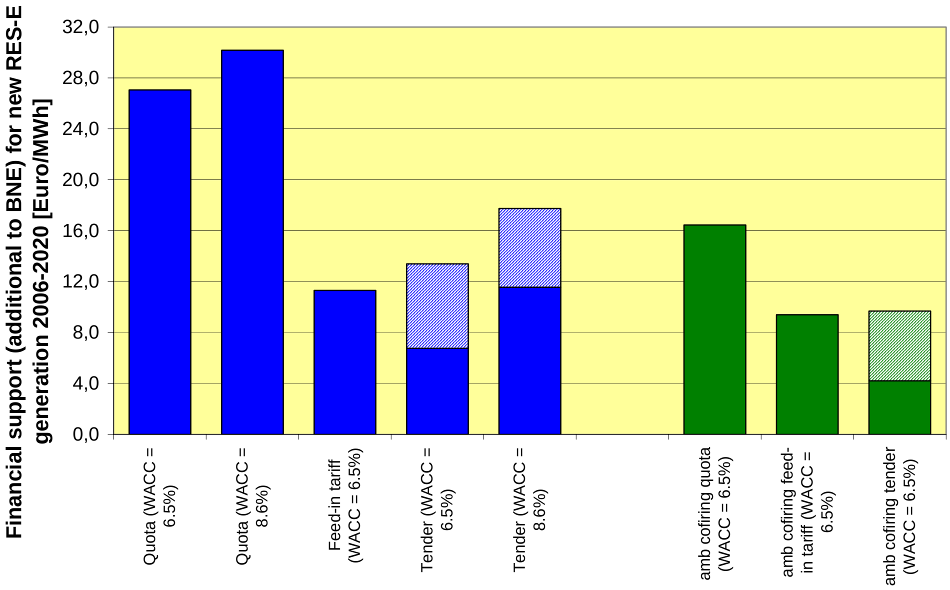

Figure 6-12 Average additional financial support per MWh in the year 2020 (relative to BNE) for new RES-E built in the period 2006-2020 reaching a 20% target in 2020

6.4 SCENARIO 3 – 15% RES-E TARGET 2020

The 15% target case is characterised by a low increase of RES-E capacity in the period beyond 2010. This is illustrated in Figure 6-13, which shows the case of a quota obligation with the interim target of 13.2% in 2010.

The contribution of individual technologies to the RES-E production mix in 2020 is depicted in Figure 6-14.[89] The portfolio is dominated by on-shore wind farms (due to their lower production costs) followed by off-shore wind, biomass (considering an ambitious use of co-firing), biogas and existing hydro power. It is also notable, that wave energy contributes to the RES-E portfolio, even assuming this low (relative to the other targets examined) RES-E target for 2020.

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87 This conclusion can not directly drawn from the example the 13.2% in 2010, but is shown for a 15% interim target, see
Table 6-3.

89 Of course, quite different mixes are feasible, leading, however, to much higher prices both for the installed RES-E system and the society.

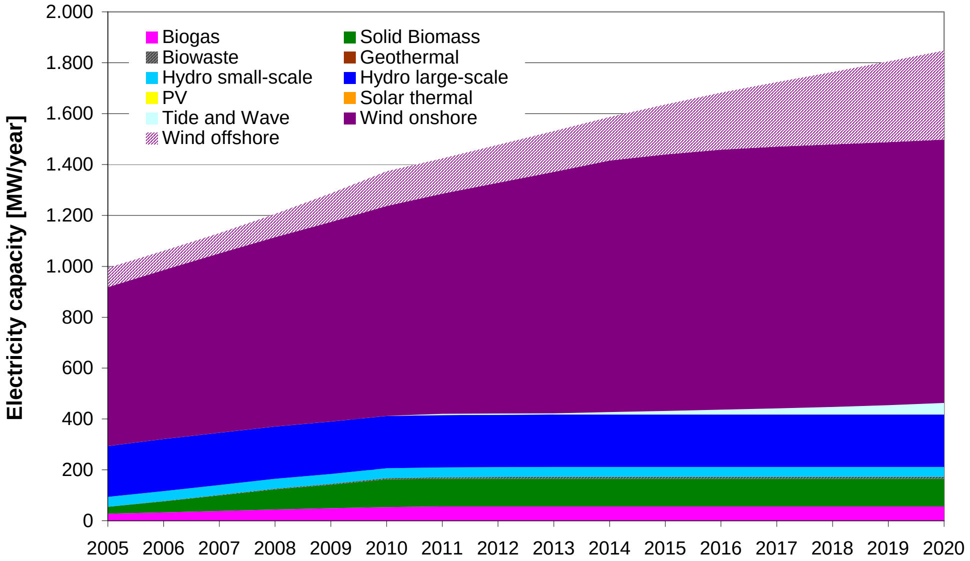


Figure 6-13 Development of RES-E generation 2005-2020 assuming a quota obligation with tradable green certificates and a RES-E target of 13.2% in 2010 and 15% in 2020.

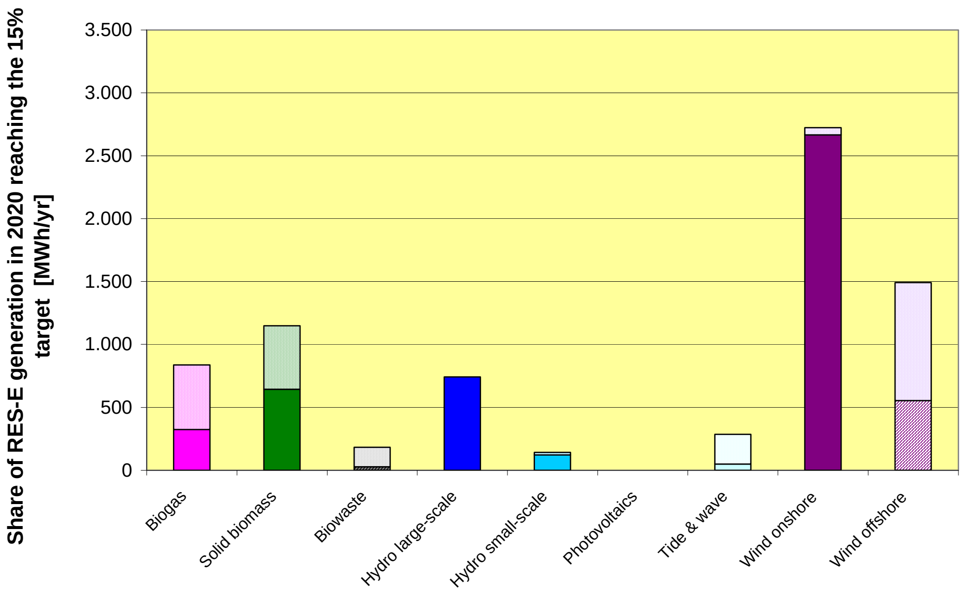


Figure 6-14 Portfolio of RES-E technologies reaching 15% target in 2020 (dotted area = spread due to different support mechanisms)

Costs for society are very sensitive with respect to the rate of return (measured by the WACC factor). This is especially true in the case of a quota obligation, where the premium support relative to BNE rises dramatically – from 1.9 to 7.3 €/MWh. It is notable that when all plants are included in the trading scheme (which normally raises the support considerably) but investors use a lower WACC, the support levels required are lower compared to when only new plant is included but the higher WACC factor is used. The WACC factor, however, is not a parameter that can be set by the Government – it can only be influenced by employing stable instruments and market conditions.[91] Different WACC factors influence the support required also in the case of a tender scheme, however in a less dramatic way.

Table 6-5 Comparison of different support mechanism for a 15% RES-E target in 2020 (and an interim target 13.2% in 2010 unless otherwise stated

		Electricity generation in 2020 from new plants 2006-2010 [GWh/yr]	Total transfer costs for society (2006-2020) due to new installed RES-E capacity in the period 2006-2010 [M€]	Additional financial support per MWh in 2020 (relative to BNE for new RES-E built in the period 2006-2020 [€/MWh]	Premium added to electricity price in 2020 due to RES-E policy 2006-2020 [€/MWh]
Quota obligation	amb. cofiring; WACC = 8.6%	3070	351	7,62	0,57
	default	3070	88	1,92	0,14
	default WACC = 8.6%	3070	335	7,27	0,54
	default WACC = 8.6%; duration 8 yr	3071	299	6,48	0,48
	default all plants	3071	276	6,00	0,00
FIT	amb. cofiring	3197	259	5,40	0,42
	Default	3309	251	5,05	0,40
Tender scheme	amb. cofiring	3211	85	1,76	0,14
	amb. cofiring, str. bidding	3211	218	4,53	0,35
	amb. cofiring (11.9% 2010)	3313	78	1,58	0,13
	amb. cofiring, str. bidding(11.9% 2010)	3313	147	2,97	0,24
	amb. cofiring, WACC = 8.6% (11.9% 2010)	2983	213	4,77	0,34
	amb. cof., WACC = 8.6%, str.b. (11.9% 2010)	2983	311	6,96	0,50
	default	3159	110	2,33	0,18
	default, strategic bidding	3159	251	5,30	0,40
	default (11.8% 2010)	3223	110	2,27	0,18
	default, strategic bidding (11.8% 2010)	3223	259	5,37	0,42
	default WACC = 8,6%	3084	314	6,78	0,51
	default, WACC = 8.6%, str. bidding	3084	536	11,60	0,86

Figure 6-15 compares the average additional support[96] of new RES-E under the different policy instruments using the default assumptions and testing the sensitivity of allowing ambitious co-firing. Assuming that investors use a WACC of 8.6%, under a quota obligation scheme again this instrument is less cost efficient from society's point-of-view compared to a tender scheme.[97] Surprisingly costs are actually marginally higher assuming the extensive implementation of co-firing in conventional power plants. The reason is that other "relatively efficient" technologies will not be developed in the period up to 2015, therefore they will not be mature enough to provide to a cost efficient portfolio beyond 2015. Therefore, despite using cost efficient co-firing options, total costs over the whole period are higher.

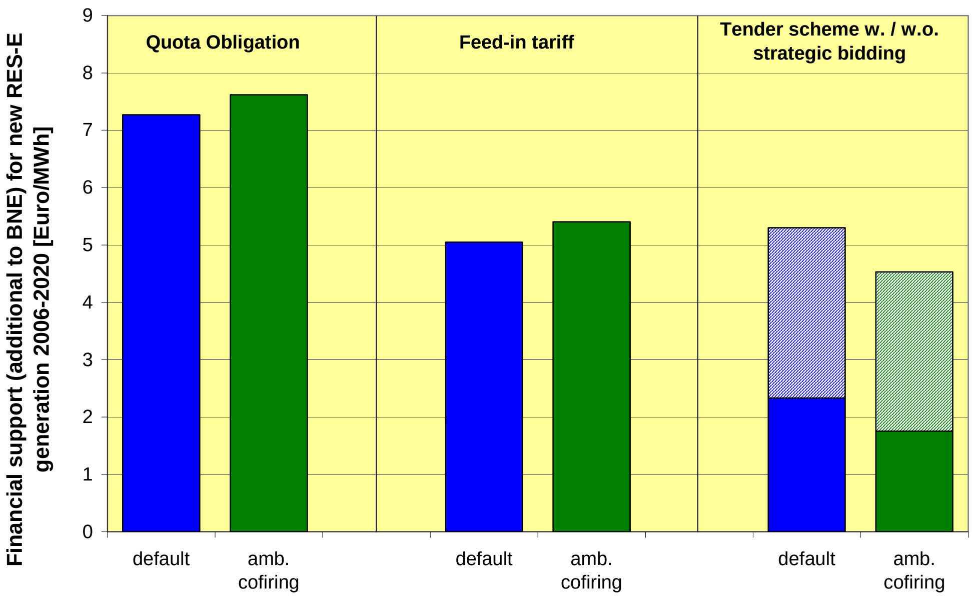


Figure 6-15 Average additional financial support per MWh in the year 2020 (relative to BNE) for new RES-E in the period 2006-2020 reaching 15% target in 2020

6.5 SCENARIO 4 - 25% RES-E TARGET 2020

In this scenario, the RES-E target for 2020 is 25% of gross electricity consumption. Assuming a quota obligation with tradable green certificates and a RES-E interim

[96] Note: The additional support per MWh (relative to BNE) for RES-E are 6.66-times higher (in this 15% target scenario) than the eventual cost premium for each MWh of electricity consumed.

[97] Even assuming the same WACC as for the other instruments, see Table 6-5.

[102] Generally it can be conclude that the inefficiency of a quota system increase with the target or, more precisely, with the non-homogeneously of the marginal generation costs (steeper marginal cost curve).

target of 15% in 2010, the development of RES-E generation 2005-2020 is depicted in Figure 6-16.

The scenario is characterised by a relatively stable increase in RES-E generation up to 2020, i.e. the additional yearly deployment beyond 2010 are similar to those in the period before 2010.

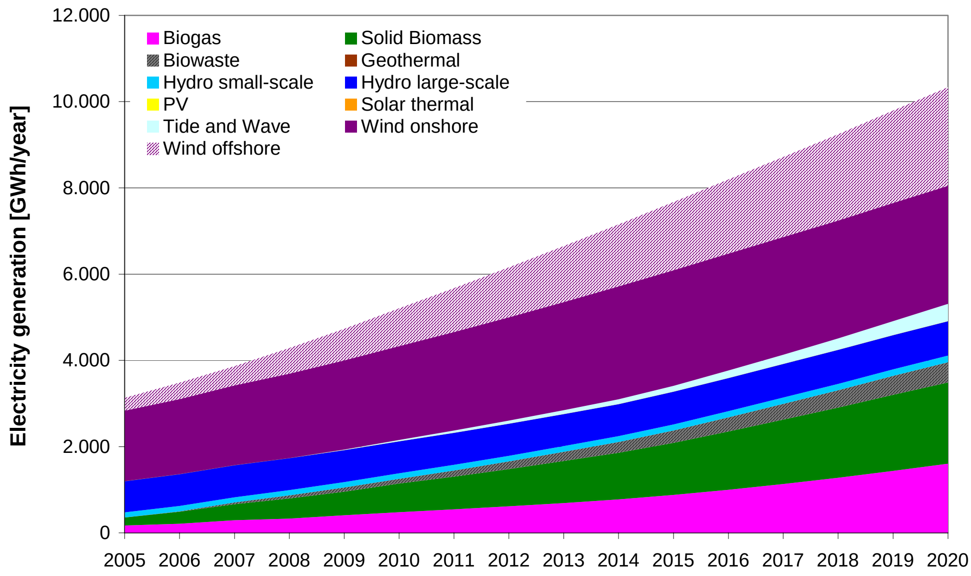


Figure 6-16 Development of RES-E generation 2005-2020 under a quota obligation with tradable green certificates and a RES-E target of 15% in 2010 and 25% in 2020.

The impact of the increased RES-E target in this scenario results in a more homogenous mix of the RES-E generation. This means, in contrast to low target scenarios – compare with 15% case for example – technologies other than on-shore wind are necessary to fulfil the goal. Again, however, there is significant variation in the portfolio make up, depending on the support mechanism chosen and the input sensitivity parameters.

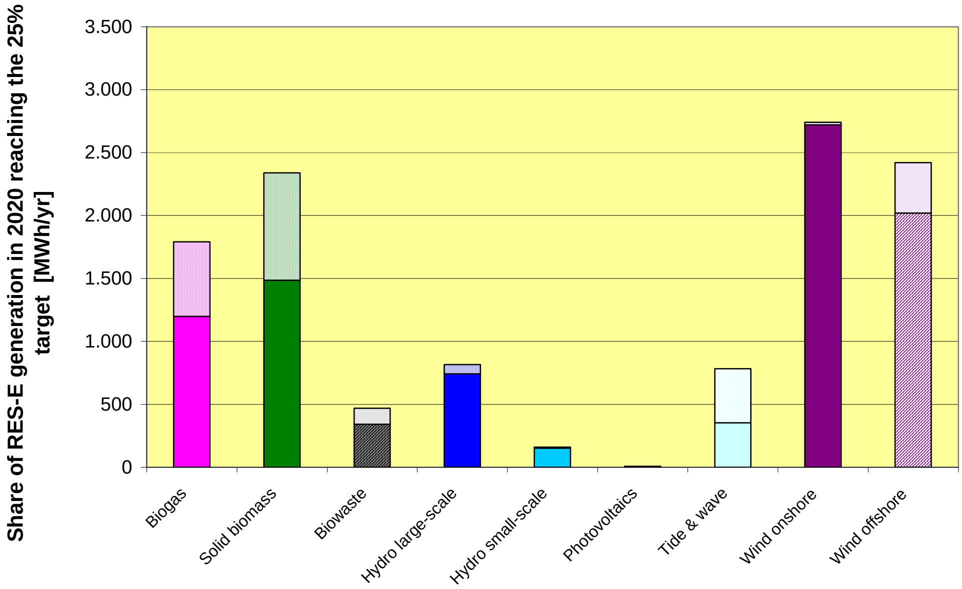


Figure 6-17 Portfolio of RES-E technologies reaching 25% target in 2020 (dotted area = spread due to different support mechanisms)

The deployment of biogas and solid biomass production in particular is very sensitive to the detailed policy framework, as shown in Figure 6-17. Note that the share of wave energy and - to a certain extent - biowaste also vary significantly depending on the detail of the support mechanism.

In contrast to the lower target scenarios, the WACC factor is of less importance here. This is evident from a comparison in Table 6-6 of the results for a WACC of 6.5% compared with 8.6%.

The poor efficiency of the quota system relative to either a feed-in tariff scheme or a tender procedure is also a feature of this high target scenario as is shown in Figure 6-18. This gap in the support level required for the quota system relative to the other two mechanisms grows as the target grows. The reason for this is that all new RES-E facilities, independent from their actual generation costs, can sell their TGC at the same price on the same market.[102]

In the case of a high RES-E target - 25% and more – individual targets for different RES-E technologies may be useful to address this – a separate quota obligation for electricity from wind energy for example. This would raise the trading volume and market transparency can be retained still under the assumption that a competitive market is available. The disadvantage of a non-standardised TGC is that a quota obligation for each (portfolio) of RES-E technologies must be set. However, one of the main advantages of a quota system will be diminished, namely the ability to find the most efficient RES-E technology portfolio via the market.

Table 6-6 Comparison of different scenarios 25% RES-E target 2020

	Electricity generation in	Total transfer costs for	Additional financial	Premium costs on

		2020 from new plants 2006-2020 [GWh/yr]	society (2006-2020) due to new installed RES-E capacity in the period 2006-2020 [M€]	support per MWh in 2020 relative to BNE for new RES-E built in the period 2006-2020 [€/MWh]	electricity price in 2020 due to RES-E policy 2006-2020 [€/MWh]
Quota obligation	amb. cofiring	7206	3325	30,76	5,36
	amb. cofiring; WACC = 8.6%	7206	4405	40,76	7,10
	default	7206	4720	43,67	7,61
	default WACC = 8.6%	7206	5127	47,44	8,27
FIT	amb. cofiring	7292	1494	13,66	2,41
	default	7181	1989	18,47	3,21
Tender scheme	amb. cofiring	7347	952	8,64	1,54
	amb. cofiring, strategic bidding	7347	2294	20,81	3,70
	amb. cofiring, WACC = 8.6%	7389	1531	13,81	2,47
	amb. cofiring, WACC = 8.6%, str. bidding	7389	3012	27,18	4,86
	default	7251	1233	11,33	1,99
	default, strategic bidding	7251	2494	22,93	4,02
	default WACC = 8,6%	7324	1928	17,55	3,11
	default, WACC = 8.6%, str. bidding	7324	3218	29,29	5,19

An alternative option is to offer additional support to those RES-E technologies with higher generation costs, for example tax relief. Again, economic disadvantages can occur, namely economic distortions take place among the different technologies.[103]

The comparison of a feed-in tariff scheme with a tender procedure shows that a tender system should be used only if strategic bidding can be (mostly) avoided. Assuming strategic behaviour is limited to a medium level, both instruments have the same efficiency from society's point-of-view. The efficiency of the tender procedure can be increased by calling for more technology specific tenders. However, under these assumptions similar problems occur, as in the case of separation of the quota obligations, i.e. a prescription of the capacity without exact knowledge of the costs associated with these technologies.

[103] Distortion occur if additional support is set to high for inefficient technologies, so efficient potentials - which would be available - will not be used.

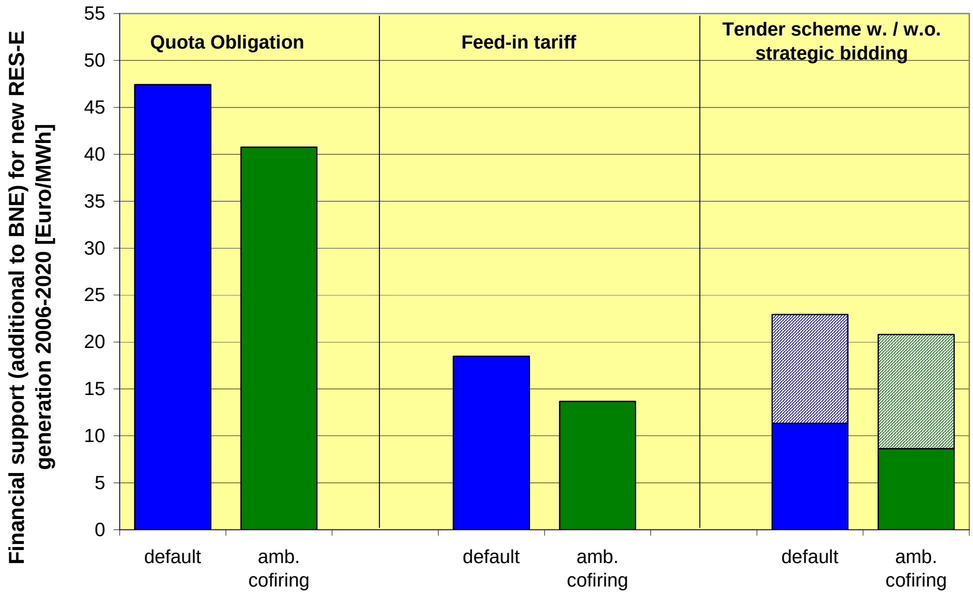


Figure 6-18 Average additional financial support per MWh in the year 2020 relative to BNE for new RES-E in the period 2006-2020 reaching a 25% target in 2020

6.6 SCENARIO 5 – 30% RES-E TARGET 2020

The 30% target represents the upper extreme case. Figure 6-19 illustrates the development of RES-E generation in the period 2005-2020 assuming a quota obligation with tradable green certificates and an interim RES-E target of 20% in 2010. Note, the 20% RES-E target in 2010 cannot be fulfilled (the detailed reasons are contained in Annex III of this report). The maximum amount that can be reached by 2010 is around 17.8%.[104]

The fulfilment of a 30% RES-E target in 2020 would require a huge effort from all sides – investors, society, policy makers, etc. Most of the available potential must be used. As a result, the spread of different portfolios is restricted and is not dependent on the choice of support mechanism, and is shown in Figure 6-20. In contrast to the other scenarios, solid biomass is the largest contributing RES-E resource, followed by on- and off-shore wind as well as biogas.

[104] And this is possible only under the following assumptions: (i) existing barriers are quickly overcome, (ii) a price cap is imposed on TGCs of 150 Euro/MWh. This avoids the intensive extension of the least cost efficient RES-E technologies like photovotaics.

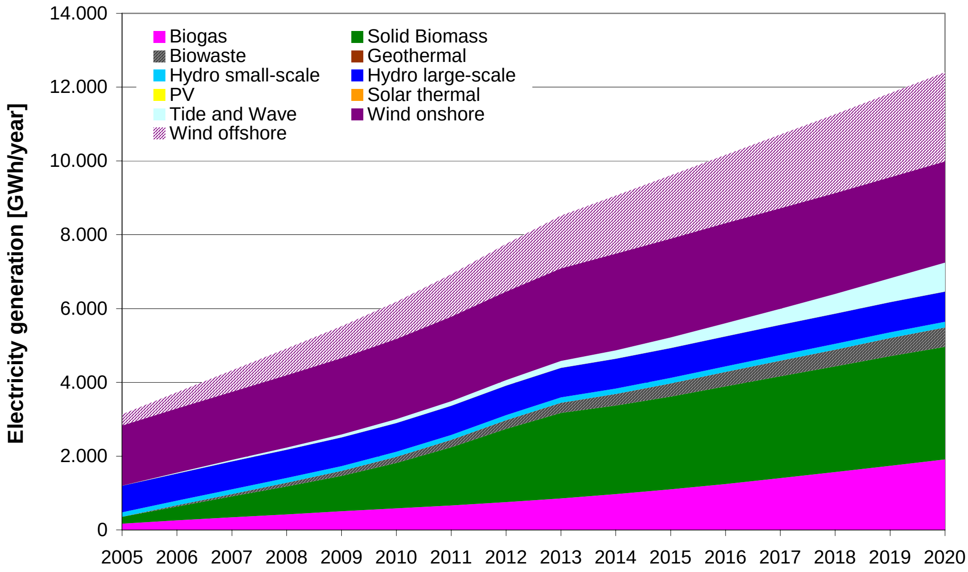


Figure 6-19 Development of RES-E generation 2005-2020 assuming a quota obligation with tradable green certificates and a RES-E target of 20% in 2010 and 30% in 2020.

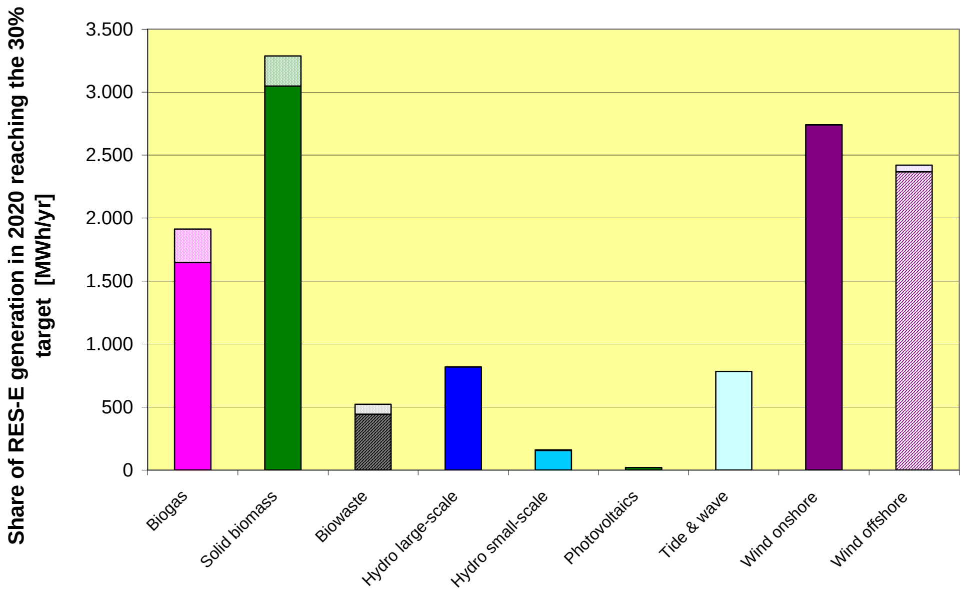


Figure 6-20 Portfolio of RES-E technologies reaching 30% target in 2020 (dotted area = spread due to different support mechanisms)

The key important results with respect to RES-E generation and costs are summarised in Table 6-7 and Figure 6-21, respectively. The results underpin the observation already made for the 25% target case, namely a quota system is inefficient from society's point-of view compared to a feed-in tariff and a tender scheme. If strategic bidding cannot be avoided in a comprehensive tendering scheme, a feed-in tariff comes out as the most cost effective solution.

Table 6-7 Comparison of different scenarios 30% RES-E target 2020

		Electricity generation in 2020 from new plants 2006-2020 [GWh/yr]	Total transfer costs for society due to new installed RES-E capacity 2006-2020 in the period 2006-2020 [M€]	Transfer costs for society new installed RES-E capacity 2006-2020 2010 in the period 2006- up to 2020 [M€]	Premium costs on electricity price in 2020 due to RES-E policy 2006-2020 [€/MWh]
Quota obliga-tion	amb. cofiring; WACC = 8.6%	9273	9327	6229	15,04
	default	9273	11080	6153	17,86
	default WACC = 8.6%	9273	11667	6440	18,81
FIT	amb. cofiring	9191	4593	2622	7,40
	default	9155	5279	3120	8,51
Tender scheme	amb. cofiring	9176	2340	1242	3,77
	amb. cofiring, strategic bidding	9176	6927	4034	11,17
	amb. cofiring, WACC = 8.6%	9165	2961	1637	4,77
	amb. cofiring, WACC = 8.6%, str. bidding	9163	7703	4535	12,42
	default	9242	2840	1370	4,58
	default, strategic bidding	9242	7441	3944	12,00
	default WACC = 8,6%	9229	3513	1728	5,66
	default, WACC = 8.6%, str. bidding[1]	9229	8228	4439	13,26

[1]…feed in tariff for PV

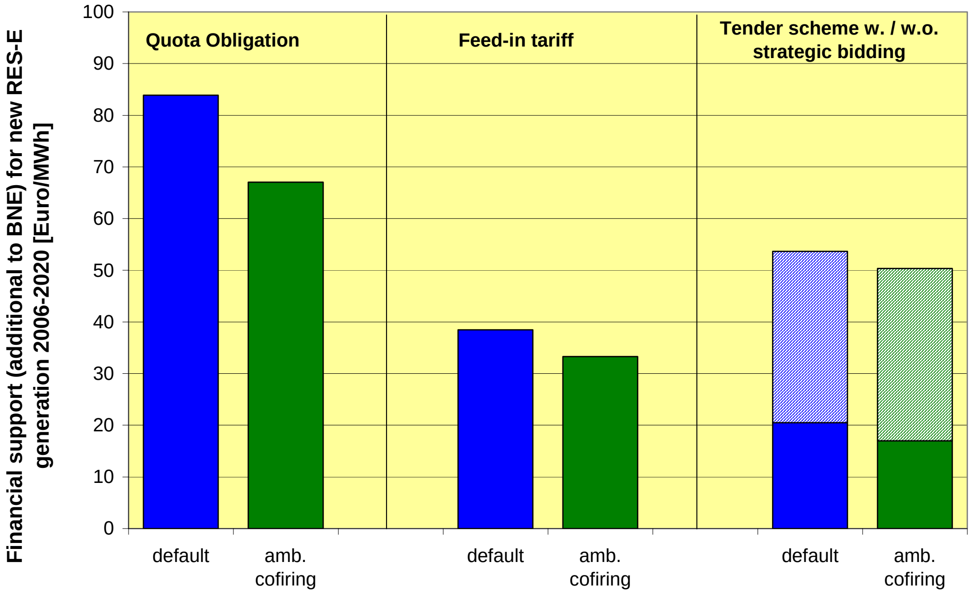


Figure 6-21 Average additional financial support per MWh in the year 2020 (relative to BNE) for new RES-E built in the period 2006-2020 reaching 30% target in 2020

7 DISCUSSION AND CONCLUSION

The main objective of this study was to quantify the impacts of different RES-E support schemes and targets on both RES-E development and society in Ireland.

Figure 7-1 shows total RES-E production and the technology mix in the year 2020, comparing different scenarios based on different set targets. All scenarios assume strengthening of RES-E support in the period 2006-2020.

Total on-shore wind power production is almost constant for all scenarios as additional capacity is cost efficient at the assumed levels of support within the RES-E basket. Electricity generation from off-shore wind plants increases continuously up to a RES-E target of 20% and remains constant for higher targets. In contrast to wind power, the share of biogas, solid biomass, biowaste and wave & tidal energy increase continuously with the RES-E target.

Note that Figure 7-1 shows the average contributions from technologies over all the considered support mechanisms and sensitivity analyses. The scenarios that include the possibility of ambitious co-firing obviously show a higher share of biomass even for lower target settings.

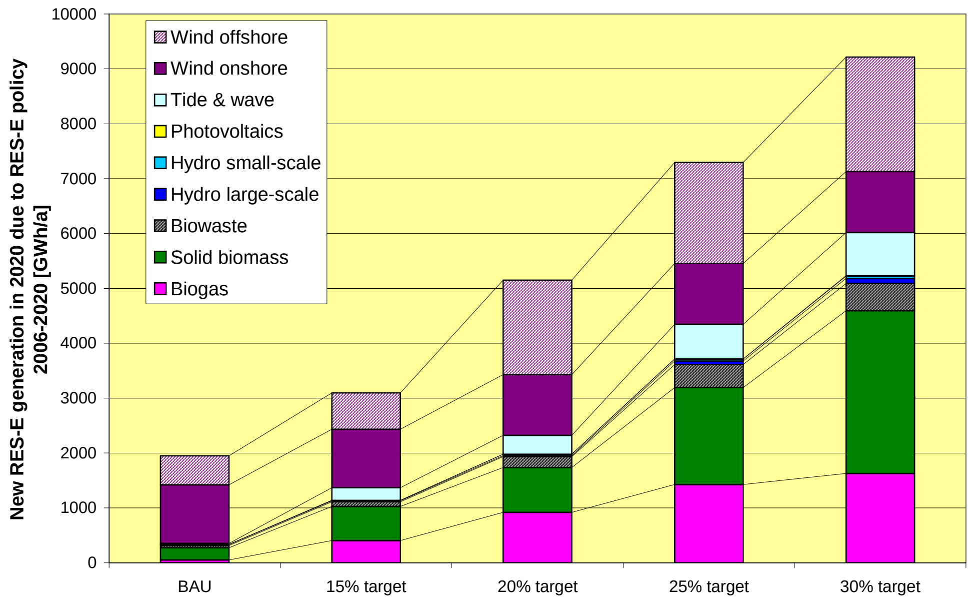
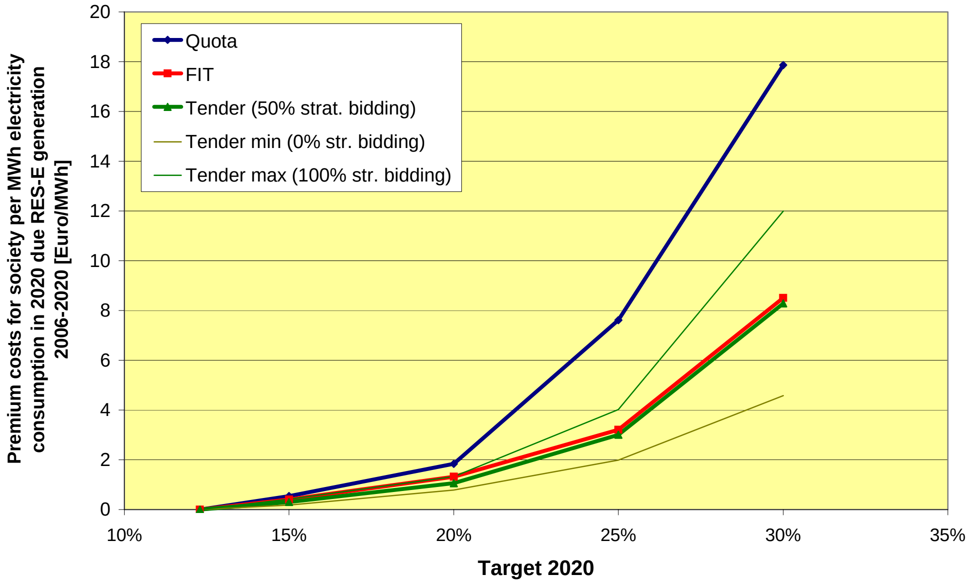


Figure 7-1 Comparison of RES-E generation in 2020 from capacities implemented in 2006-2020 (average numbers of various investigated scenarios)

Figure 7-2 depicts the costs for society of different policy instruments depending on the chosen RES-E level. The upper graph shows the costs without the possibility of comprehensive co-firing, the lower graph with co-firing. The following observations are notable:

- The quota system is inefficient in terms of increasing electricity costs for consumers for high RES-E targets. This is due to higher windfall profits occurring for cheaper RES-E technologies due to the presence of just one price signal. For lower targets this disadvantage disappears improving the efficiency gap to the other instruments. An additional support scheme for less-efficient RES-E technologies further reduces the transfer costs for society. However, administrative costs rise when applying a combined strategy.
- Under the assumption of full competition among RES-E investors in Ireland, a tender system is preferable over a feed-in tariff scheme, from the perspective of minimising the transfer costs from producer to consumer. Under oligopolic structure (with reduced competition) a feed-in tariff scheme is equal or even more efficient than a tender scheme.
- Including the possibility of biomass co-firing in RES-E strategies – e.g. TGCs can be issued, a feed-in tariff can be claimed or the co-firing part of electricity generation is allowed to participate in tender procedures - leads to lower costs for society as evident from a comparison between the two graphs in Figure 7-2.



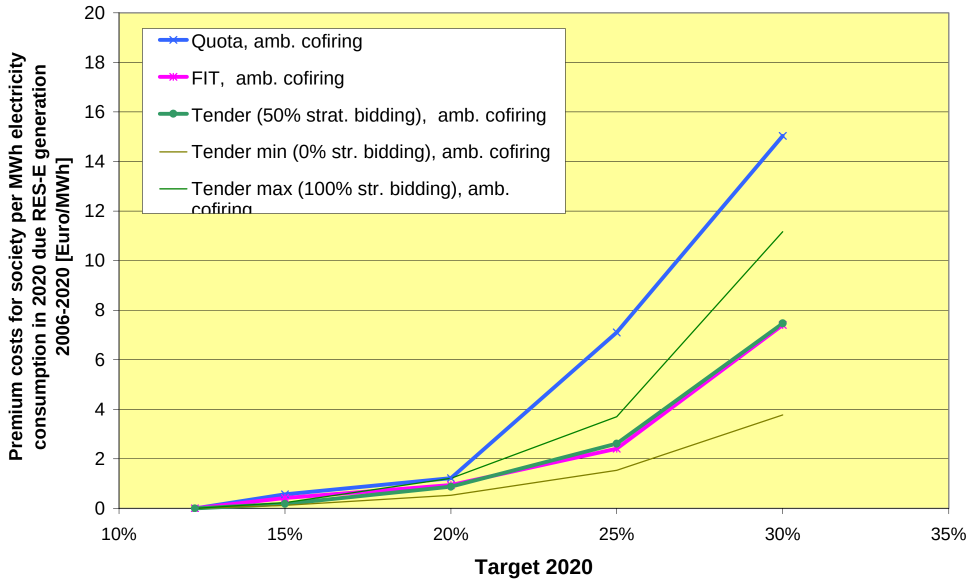


Figure 7-2 Average premium costs on electricity price in 2020 due to new RES-E 2006-2020 associated with different target scenarios, support mechanisms and co-firing scenarios

Investments resulting from additional RES-E policy are shown in Figure 7-3. Depending on the chosen strategy, it can be expected that investments in RES-E vary between 780 and 1060 M€ over the period 2006-2020. Increasing the target by one full percentage will increase the investments by approximately 150 to 170 M€.

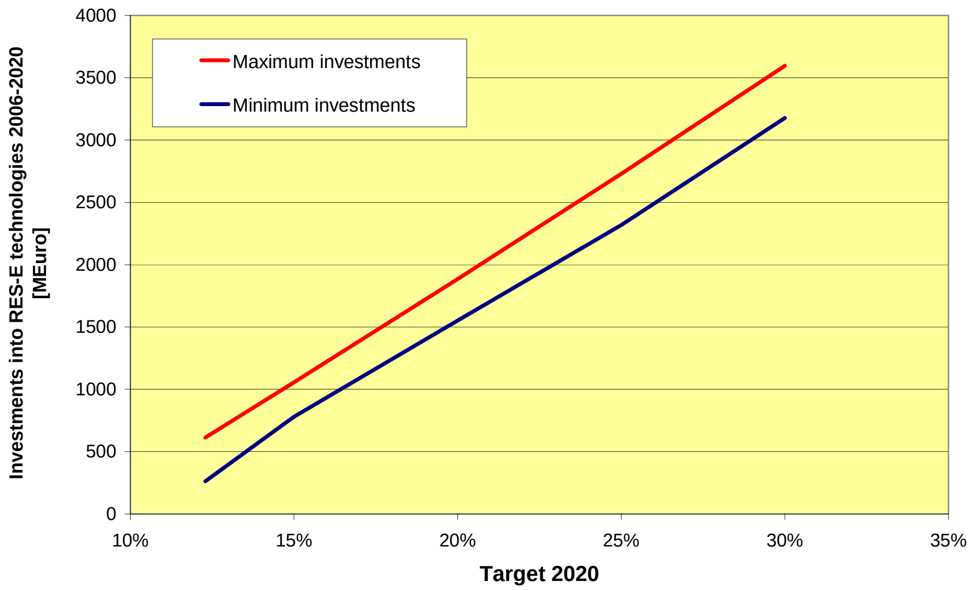


Figure 7-3 Investment in RES-E technologies caused by RES-E policy dependent on RES-E target 2020

The following conclusions are derived from both the impact analysis, theoretical investigations and the simulation results using the model ***Green*-X**.

7.1.1 General observations and conclusions

The following observations are made, which are independent of the chosen support mechanism.

- careful design detail is as important as the choice of policy tool to be implemented for example,
  - within any support mechanism, existing capacities and new capacities should not be mixed. Support should no longer be provided to plants that are fully depreciated or that were supported financially in the past;
  - the support (whatever the choice of mechanism) should be restricted to a certain time frame. The duration should depend on the policy scheme (e.g. development of the TGC price) and on the maximum annual additional costs that can be imposed on society.
- The RES-E support structure should also be directed to support small-scale projects, as these small-scale projects - with a relatively short lead-time - could be an important part of the solution to the capacity shortage in electricity supply.
- The effectiveness of various RES-E support schemes largely depends on the credibility of the system. Stable long-term planning is important in creating a sound investment climate and to lower social costs as a result of a lower risk premium.
- A continuous policy – avoiding a stop go nature - is important to build up a national RES-industry.
- Existing barriers for new RES-E generators should be rigorously removed;
  - the prospects for the development of a strong national renewable energy industry seem good, but aside from considerable growth in installed wind power capacity, very little development has taken place. The lack of a long-term policy perspective has been and still is the main barrier to a stronger deployment of renewable electricity in Ireland, inducing high investor uncertainty especially for independent power producers;
  - The mandates of Enterprise Ireland and the Industrial Development Authority could be examined in the light of the need to generate new skills in potential new RE industries. By including import-substitution of fossil fuels in their mandates for which companies they may support, new domestic or established international companies in these new industries would qualify for support;
  - Along with continued wind deployment, opportunities seem highest in the area of biomass. Co-firing of biomass in thermal power plants is one of the most commercially interesting options, but is so-far not included in the AER competitions and cannot compete with peat, given the current division of budgets and payments in the public service obligation;

- Integration of agriculture and energy policies is another element that might largely enhance the opportunities for biomass. If supported at the highest level, this could assist a more rapid deployment of affordable RE;

- The three support mechanisms investigated – fixed feed-in tariff scheme, Obligation plus TGC system and competitive tendering systems – all give priority rights to a certain amount of RES-E. This implies that the power market is split (divided) between a priority market and a “free” competitive market. The promotion of RES-E technologies will displace a corresponding amount of conventional power by lowering the demand for conventional power. The market price of power will decrease when support schemes for RES-E are introduced assuming a competitive market and increasing marginal cost of conventional power (Huber et. al., 2004);
  - In a closed economy like Ireland, with low international power trading, increased RES-E production will totally replace domestic conventional power and thus an equivalent emission reduction will be achieved
  - Moving to an open economy, i.e. with increased interconnections to Northern Ireland, UK (and France) and increased international power trading, national RES-E production does not automatically replace domestic conventional power. Hence, not all of the gained CO_2 emissions from the RES-E deployment in Ireland will be take place in Ireland itself. [105]

7.1.2 Quota system in combination with TGCs

The most important results with respect to a quota obligation are:

- A quota obligation system based on tradable green certificates leads to minimal investment needs for RES-E system, though not to minimal costs for society. This means, a TGC system is cost efficient with respect to the installed RES-E capacity but not with respect to the cost that must be borne by society;
- In the case of a flat RES-E supply curve – as is the case for low RES-E targets in Ireland – social costs are relatively low as well;
- In the case of higher targets, an additional technology specific support mechanism helps to reduce costs for consumer, i.e. windfall profits for cheap technologies remains lower. In this case, however, additional administrative costs appear due to the introduction of a second instrument;
- As TGC price developments are uncertain and difficult to forecast, investor risks are higher compared to a feed-in tariff or a tender procedure. The risk premium leads to higher costs for society. Risks can be reduced by a guaranteed floor price or allowing banking and borrowing of TGCs, but risks remain higher compared to other support schemes;

[105] In an open economy (no limitation of interconnection), the distribution of the national conventional electricity reduction is independent from the total national RES-E generation. The national conventional electricity production depends only from the conditions on the international spot market (marginal generation plant). As CO_2-emissions are related to the power generation, the same conclusion is valid for the national CO_2-reduction: How the total increase in RES-E generation by itself is distributed upon the countries has no influence upon the realised CO_2-reduction in each of the countries.

- One main advantage of a quota obligation is that the target will be reached with certainty. Thus, in contrast to a feed-in tariff scheme or a tender procedure, no adjustment is necessary in fulfilling targets;
- Non-compliance penalties should be significantly higher than the expected market price for TGCs, otherwise there is no incentive to fulfil the quota;
- Within an international TGC system, but not fully international power market (restricted by limited interconnections) distortions occur in the way that the RES-E deployment in countries with a high power price are favoured. The reason is that the total revenue from the purchase of the electricity from RES plants consists of the revenue from the (higher) power market and the internationally (constant) TGC price, thereby increasing the overall price signal for investments (marginal generation costs)

7.1.3 Feed-in tariff

The main conclusions with respect to application of the feed-in tariff system are:

- Feed-in tariffs have been successful for triggering substantial deployment of RES-E in many countries where they have been introduced;
- They remain the most proven and preferred national instrument for RES-E support. A guaranteed tariff is effective, flexible, fast and easy to install and has low administration costs;
- On the one hand, a feed-in tariff does not encourage competition between investors. Hence it does not force reductions in the unit electricity price. On the other hand, based on the German experience, a guaranteed tariff scheme (under the assumption that the tariff is guaranteed long enough) facilitates the implementation of high quality components compared to investments undertaken under full competition;
- An important result of the analysis is that feed-in tariffs are particularly efficient, if:
  - the feed-in tariff rates decrease over time, as experience is gained and in line with the expected learning curve;
  - a stepped feed-in tariff is used, so the guaranteed feed-in tariff rate is decreased as efficiency increases. While for wind power the full-load hours can be used as a benchmark for efficiency, a different tariff scheme for biomass should be based on the used biomass fraction.
- The power market structure has, in contrast to an international TGC system, no impact on the RES-E deployment in the case of a feed-in tariff scheme

7.1.4 Tender scheme

The effects of tender procedures can be summarised as follows:

- A tender procedure represents an efficient instrument, based on competition among RES-E investors;

- Continued calls for tender are important to stimulate RES-E deployment and to encourage competition;
- Costs for society are low if competition among the potential generators can be managed;
- In the case of less competitive market conditions the efficiency of this instrument is (significantly) reduced;
- Competitive tendering schemes have relatively low administrative costs. Administrative costs are mainly limited to staff time to run the tendering process and for monitoring the resulting projects. But transaction costs for the investor are high, as the project planning must be made before the tender takes place;
- Preventing or at least diminishing competition can be reduced by technology and location specific tenders, especially if the site, the size of the technology (e.g. off-shore wind plants) is already predefined and the grid connection agreement in place before the tender procedure starts. This system, however, is only readily applicable for certain technologies –off-shore wind, co-firing of biomass, and to a certain extent on-shore wind;
- If a tender system is applied, the RES-E developments are independent from the power market structure

7.1.5 Comparison of instruments

- A quota obligation based on TGCs is less efficient from a social point-of-view compared to other instruments analysed, as, first, a higher risk must be borne by the generator, and, second, the efficiency gain by implementing this instrument are absorbed by the producer (high producer surplus) and not by the consumer;
- Feed-in tariffs and tender schemes are useful in promoting a more homogeneous distribution among different technologies by setting technology specific guaranteed tariffs.[106] Such a policy can be employed to support the long-term technological development of various RES, which are currently not cost-effective. This arises from a dynamic process that can emerge for non-mature technologies (i.e. stimulation of additional research, own industrial development, etc.) which leads to a decrease in future generation costs and an increase of the available potential in the future (when the market is more mature). However, this positive effect must be compensated by economic distortions generated between the different RES-E technologies;
- A tender scheme is similar to a stepped feed-in tariff, but with the difference that the granted price for RES-E will be determined by the market itself and not by a regulatory authority. Under the assumption of a “perfect” market, the feed-in tariffs set by the authority is higher and thus inefficient from society’s point-of-view compared to a tender scheme. Considering, however, strategic bidding and the

[106] This can also be done for Quota by having separate quotas for individual technologies. A split of the quota into different sub quotas is feasible too. However, contradicting the advantages of a TGC system namely full competition and the promotion of least cost generation options.

higher administration costs of the tendering scheme, a feed-in tariff can be the more efficient solution.

7.2 FURTHER RESEARCH

The analysis provided in this report aimed to provide detailed information regarding the impacts of individual support mechanisms for different RES-E target scenarios. The study did not seek to recommend a particular target or the precise choice and design of a support mechanism.

The modelling tool used to compare effects of different policy scenarios is one of the most detailed tools available for such policy analysis, and the results shown indicate a high level of robustness with respect to cost impacts associated with the different support mechanisms. However, as with any modelling approach its results highly depend on the quality of input data and the assumptions made on future possible developments.

There is a large body of work that can be carried out based on the groundwork contained herein on targets, policy mechanisms and costs. The project team suggest the following analysis that would inform more deeply the decisions to be made in Ireland:

- Enhanced sensitivity analysis to the baseline price assumptions (such as BNE reference price assumptions[107]) or chosen policy scenarios to yield additional insights
- Analysing additional policy scenarios; of special interest could be a detailed analysis of biomass use in a wider energy and agricultural perspective
- More detailed analysis on the specific design of policy instruments, for instance with respect to the exact level of stepped feed-in tariffs or the design of technology-specific premium tariffs.
- Impact assessment on the interactions with international RES-E market developments and support mechanisms operated on these markets. This is of particular relevance in the context of the development of an All-Ireland Energy Framework.
- Extending the ***Green*-X** model runs covering conventional electricity generation and CO_2-emissions, interactions with the markets for renewable heat and renewable transport fuels, and the impact of demand-side measures (energy savings, efficiency improvements, etc.) on the costs of achieving renewable energy targets.
- Presentation of the modelling assumptions and results of the analysis to a wider group of policy makers and other stakeholders so as to enhance the quality of data assumptions and to discuss specific market sensitivities especially affecting investment requirements and the calculated costs for society.

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[107] The recent increase in BNE price associated largely with fuel price increases show how variable this is.

The amount of work arising from these follow-up activities will be dependent on the priorities and requirements of DCMNR and SEI.

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