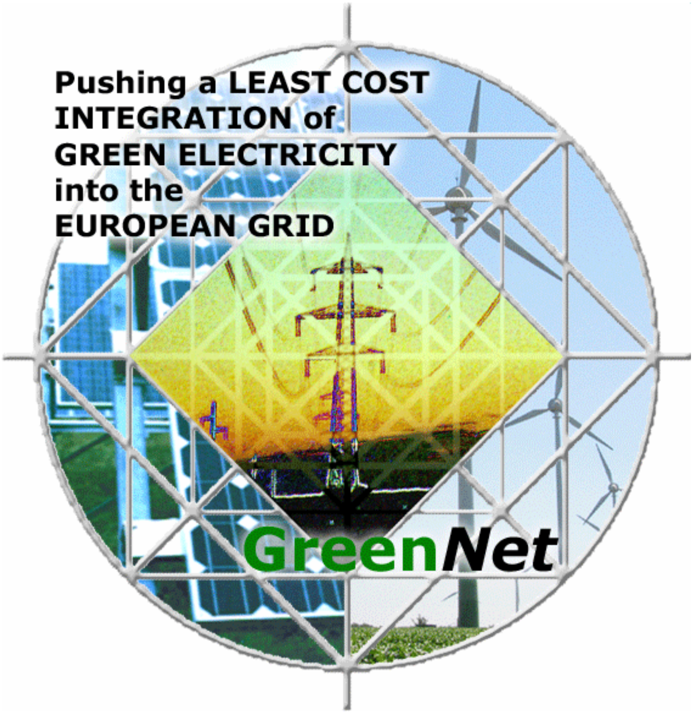
Report of the project

PUSHING A LEAST COST INTEGRATION OF GREEN ELECTRICITY INTO THE EUROPEAN GRID

GreenNet



Determination of the Potentials and Cost for RES-E Generation in the EU15 Member States and Analyses of the Interactions of Intermittent RES-E Generation with the Grid, Switchable Loads and Storage

Work Package 1

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

Contract N°: NNE5-2001-660

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This report is one of a series highlighting the potential for innovative non-nuclear energy technologies to become widely applied and to provide superior public services. The strategic aim of the European Commission is achieve cleaner, more efficient and more sustainable energy solutions. Throughout Europe, the scientific and engineering communities, policy-makers and key market players should fulfill this aim for their own benefit and for wider society.

The work is supported under the European Union's fifth-framework programme. Funding is within the 'Energie' sub-programme. The support covers research, technological development and demonstration (RTD), with associated dissemination, replication and market uptake. The whole process is for converting new ideas into practical solutions to meet real needs. 'Energie' publications, in print and electronic form, disseminate the results of actions carried out under this and previous framework programmes, including former JOULE-Thermie actions. Jointly managed by the European Commission's Directorates-General for Energy and Transport and for Research, Energie has a total budget of EUR 1.042 million over the period 1998-2002.

Delivery is organised principally around two key actions, 'Cleaner energy systems, including renewable energies' and 'Economic and efficient energy for a competitive Europe'. Both actions are within the theme 'Energy, environment and sustainable development', supplemented by coordination and cooperative activities of a sectoral and cross-sectoral nature. With targets guided by the Kyoto Protocol and associated policies, Energie's integrated activities are focused on new solutions which yield direct economic and environmental benefits to the energy user, and strengthen European competitive advantage by helping to achieve a position of leadership in the energy technologies of tomorrow. The resulting balanced improvements in energy, environmental and economic performance will help to ensure a sustainable future for Europe's citizens.

ENERGIE

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Directorate-General for Energy and Transport

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1 INTRODUCTION

1.1 Motivation

This report is part of the project "Pushing a Least Cost Integration of Green Electricity into the European Grid (**Green*Net***)", supported within the fifth-framework programme of the European Commission (Directorate-General for Energy and Transport). It mainly summarizes the potentials and cost of several renewable energy sources in the EU-15 countries and, furthermore, briefly addresses the basic interactions of RES-E (renewable energy sources for electricity generation) with the grid, switchable loads and storage. Please note, these interactions are comprehensively discussed in subsequent individual work package (WP) reports, this report just provides an introduction into different topics.

Furthermore, this report only partly represents the work that has been carried out in work package 1 (WP 1). The major objective of WP 1 is to collect empirical data and to create a corresponding data base on the potentials and costs for renewable energy sources for electricity generation (RES-E) in the EU-15 countries. Extracts of this comprehensive data base, which is finally used in the toolbox **Green*Net*** (work to be carried out in WP 8 and WP 9) are presented in chapter 3 of this report. Please note that data collection must be understood as an ongoing process being not finished yet. Not least this is due to the fact that insights from subsequent work packages – being completed at a later stage of the project **Green*Net*** – have to be considered when deriving final values. In addition, to guarantee robust and homogenous results, the results of other EC projects will be included and corresponding data harmonised.

Against this background this report summarizes work having been conducted in WP1 within the project **Green*Net***.

1.2 Overview on the project GreenNet

1.2.1 Objectives and problems to be solved

The core objective of the project **Green*Net*** is to enhance the proportion of electricity from renewable energy sources (RES-E) in the EU. This is done by applying a least-cost approach and utilising known technologies. Moreover, the costs and interactions of all important supply-side and demand-side options are considered. These options are:
- the technical constraints and the necessity of an update and/or extension of the grid for RES-E grid access and integration,
- the technical constraints and the opportunities of advanced storage technology integration and
- the technical constraints and the opportunities of load management and energy conservation by means of demand side measures.

These analyses will be conducted in a dynamic framework. Considering all these options it will be ensured that a certain quota of RES-E will be met with lowest costs for society.

1.2.2 The major product

The major product of this project will be the simulation software **Green*Net*** containing the following major features:
- A comprehensive database describing potentials and costs of:
  - different RES-E technologies in different EU countries,
  - the grid to accept RES-E integration (as well as potential and costs of an upgrade/ extension of the grid),
  - storage technology integration to support intermittent RES-E generation,
  - DSM (demand side management) measures for load reduction and energy conservation.

- Definition of different policy instruments related to supply and demand (i) across the EU as a whole, and (ii) within single countries. Both single and integrated technologies will be considered.
- Simulation of scenarios for supply-side and demand-side options. The simulation will be dynamic, i.e. allowing also changes of strategies and scenarios over time.
- Derivation of a least-cost priority list for the deployment of RES-E by policy, technology and country to meet targets.

Finally, based on the results of the simulation software **Green*Net*** comprehensive models for financial burden sharing of cost caused between different players in the European electricity market will be derived.

1.2.3 Expected results and exploitation plans

The major result of the project **Green*Net*** will be a least-cost time path for a continuous and significant increase of RES-E to meet targets. This includes a year by year recommendation for different measures (e.g. development of RES-E technologies, grid upgrade/extension, storage technology integration, and different DSM measures) for the whole EU and for single countries.

To underpin recommendations and to strengthen the decision making process for stakeholders several results of the simulation software **Green*Net*** will be available via the internet.

1.2.4 Project Structure

The working programme of the project **Green*Net*** has 13 different Work Packages (WPs), see Figure 1.1.

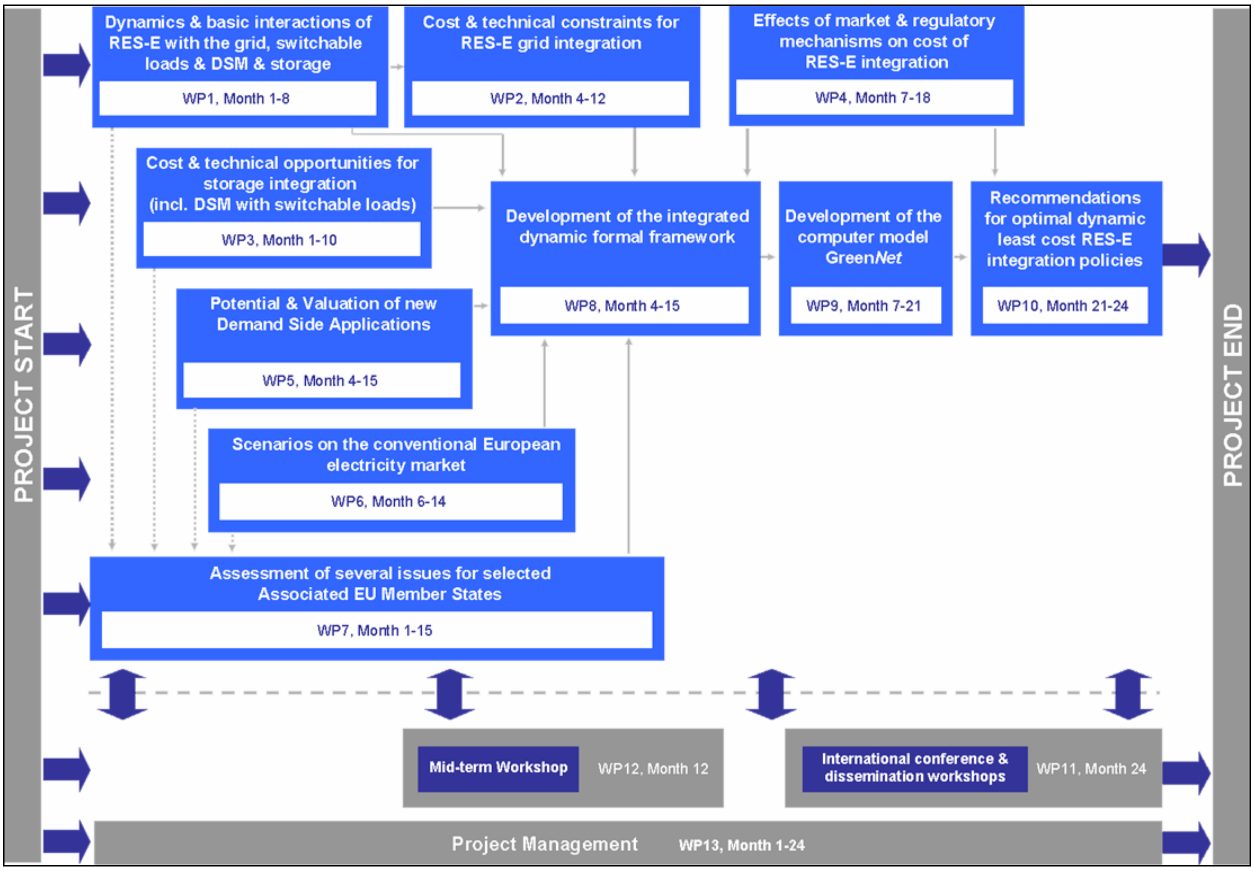

Figure 1.1. Structure of the project **Green*Net***

The major objectives of each Work Package (WP) are:

WP 1: Dynamics & basic interactions of RES-E with the grid, switchable loads & storage
The objective of WP 1 is to analyse the dynamics and basic interactions of RES-E technologies with the grid, switchable loads and storage technologies in various EU countries and to provide a database of cost curves for several RES-E technologies and different "RES-E grid access cases".

WP 2: Cost & technical constraints for RES-E grid integration
The objective of WP 2 is to derive the cost, the technical constraints and the additional measures necessary for integration of RES-E technologies into the Western European transmission and distribution grid.

WP 3: Cost & technical opportunities for storage integration (incl. switchable loads)
The objective of WP 3 is to derive the cost, the technical opportunities and the additional measures necessary for integration of storage technologies to support RES-E integration.

WP 4: Effects of market and regulatory mechanisms on the cost of RES-E integration
The objective of WP 4 is to assess the costs of intermittent RES-E in various balancing and settlement systems in the EU and to develop recommendations on policy, regulation and market design with respect to balancing and settlement mechanisms, priority dispatch and interconnection of RES-E to the grid.

WP 5: Potential, costs and economics of new Demand Side Applications
The objective of WP 5 is to assess the potential, costs and economics of new demand side measures and energy efficiency based on new information and communication technologies (ICT).

WP 6: Scenarios on the conventional European electricity market
The objective of WP 6 is to derive different scenarios on the development of the conventional European electricity market (mainly wholesale price level) being mainly responsible for the market penetration and competitiveness of RES-E integration, storage technologies and demand side applications.

WP 7: Assessment of several issues for selected Associated EU Member States
The objective of WP 7 is to assess several issues in WP 1, 2, 3, 5, 6 (RES-E potentials and cost; conditions and cost for grid access, storage and load management technology support as well as demand side applications; wholesale electricity price scenarios) for selected Associated EU Member States as there are Czech Republic, Poland, Slovakia and Hungary.

WP 8: Development of the integrated dynamic formal framework
The objective of WP 8 is to set up an integrated dynamic formal framework combining the dynamic interaction of RES-E generation and integration into the grid supported by storage technologies and load management as well as other measures for demand side management and energy efficiency.

WP 9: Development of the Computer model Green*Net*
The objective of WP 9 is to develop the computer model **Green*Net*** based on the dynamic analytical framework. Comprehensive testing, evaluation of the model results by simulating typical empirical case studies and finally conducting comprehensive quantitative analysis is also part of WP 9.

WP 10: Recommendations for optimal dynamic least cost RES-E integration policies
The objective of WP 10 is to extract recommendations for policy makers and stakeholders for a European-wide implementation of least cost strategies for integration of RES-E technologies into the grid supported by storage technologies and demand side applications.

WP 11: International conference and dissemination workshops
The objective of WP 11 is to organize the final international conference of the project **Green*Net*** and a series of international dissemination workshops on EU- as well as on Associated EU Member States level in order to comprehensively promote the final product: the software-toolbox **Green*Net***.

WP 12: Mid-term Feedback Workshop
The objective of WP 12 is to co-ordinate and to discuss the results of the WP's 1, 2, 3, 5, 7 and to discuss the preliminary results with key stakeholders in order to get useful feed-back for modelling and derivation of policy recommendations.

WP 13: Project Management
The objective of WP 13 is to manage the project **Green*Net*** - e.g. communication between the project partners, organisation of meetings, development of the project web-site as well as preparation of corresponding documents and report.

1.3 Outline of this report

The report is organized as follows:

In chapter 2 several renewable sources and RES-E generation technologies are clustered. Moreover, natural variability of renewable sources and RES-E technologies is discussed comprehensively. Furthermore, different DSM methods (such as switchable loads) enhancing intermittent RES-E generation are briefly discussed (comprehensive discussion in the WP 3 report addressing several aspects of intermittent RES-E generation and storage).

Chapter 3 is the essential part of this report. A comprehensive overview of potentials and costs of several RES-E generation technologies in the EU-15 countries is shown (historical developments, realized present potentials as well as futures potentials of renewable resources). Furthermore, the analytical framework to derive the dynamic cost-resource curves of RES-E generation is presented. Finally, empirical data of each of these cost-resource curves up to the year 2020 are shown.

Last but not least, in chapter 4 the basic principles of integrating RES-E technologies into the existing European transmission and distribution grids are discussed. In this context, also technical barriers as well as rough cost estimates are addressed briefly. Again, a detailed analysis as well as empirical cost data will be presented in the WP 2 report.

2 CLUSTERING OF RENEWABLE SOURCES AND RES-E GENERATION TECHNOLOGIES

2.1 Natural variability of renewable sources

2.1.1 Overview: Intensity and frequency characteristics of renewable sources

Renewable power is available in many environmental energy flows, as harnessed by a range of technologies. The parameters used to quantify and analyse the various forms are listed in Table 2.1, together with their intrinsic variation in magnitude and time.

Table 2.1. Intensity and frequency characteristics of renewable sources. Source: Twidell (2003).[1]

System	Major periods	Major variables	Power relationship	Comment	Approx time variation
Direct sunshine	24 h, 1 y	Solar beam irradiance G_b^* (W/m^2) Angle of beam from vertical q_z	$P \propto G_b^* \cos\theta_z$ $P_{max.}$ = 1kW/m^2	Daytime only! Highly fluctuating	hours to seconds
Diffuse sunshine	24 h, 1 y	Cloud cover, Perhaps air pollution	$P < \sim 300$ W/m^2	Significant energy, however	day
Biofuels	1 y	Soil condition, solar irradiation, water, plant species, wastes	Stored energy 10 MJ/kg^1	Very many variations. Linked to agriculture and forestry	year
Wind	1 y	Wind speed u_0 Height nacelle above ground z, height of anemometer mast h	$P \propto u_o^3$ $u_z/u_h = (z/h)^b$	Highly fluctuating $b \sim 0.15$	minutes to hours for windfarms
Wave	1 y	'Significant wave height' H_s wave period T	$P \propto H_s^2\ T$	High power density ~50 kW/m across wave front	week
Hydro	1 y	Reservoir height H water volume flow rate Q	$P \propto H\ Q$	Established resource	months
Tidal	12 h 25 min	Tidal range R; contained area A; estuary length L, depth h	$P \propto R^2\ A$	Enhanced tidal range if $L / \sqrt{h} = 36000\ m^{1/2}$	12 h
Geothermal	none	Temperature of aquifer or rock formation, hence temperature difference from ambient	$P \propto (\Delta T)^2$	Very few suitable locations for electricity generation	none

---

[1] The symbols are standard in the technologies.

The ability to integrate electricity into grid supplies as generated from renewables (i.e. RES-E generation) is governed by several general factors, including:

- variation of generated power with time
- extent of the variation (availability)
- predictability of that variation
- capacity of each generator
- dispersal of individual generators
- reliability of plant
- experience of use by operators
- technology for integration
- regulations and customs for embedded generation

Despite these many apparent difficulties, the experience of the last 25 years is that ever-increasing amounts of electricity from renewables can be integrated into grid supplies without significant financial penalty. The standard response of grid operators, used to large-scale centralised generation, is that intermittent and dispersed RES-E generation cannot be so integrated. However, given the requirement to accept specific RES-E generation, the technology and methods to accept that generation have followed successfully. Examples are:

- electrical safety equipment and grid-fault disconnectors
- grid linked inverters for photovoltaic, solar cell, power from buildings
- doubly-fed induction generators for variable speed wind turbines
- voltage reinforcement on rural power lines
- co-firing of steam boilers with biomass
- gas turbines for the output of gasifiers

The outstanding example of ever-increasing capacity of RES-E generation into the grid has occurred in Jutland, western Denmark. In the early 1980's, the limit for wind power exported to the grid was considered to be 20% of total supply. However, by 2003, about 40% of annual electricity supply was from wind and at times significant areas had 100% supplied by wind power. The reason for the change was the willing application of new technology and practices.

Nevertheless, there are fundamental limitations for any specific RES-E generation technology and plant; for instance, the sun never shines at night! So obviously, it is essential to integrate several RES-E generation options, together with control and storage, before the majority of power can be so supplied.

2.1.2 Individual description of renewable sources for RES-E generation

2.1.2.1 Biofuels

Biogas:

Biogas results from the natural decomposition of biomass. The biodegradable decomposition of organic substances causes the conversion of large molecular-mass organic bonds (fats, carbohydrates, etc.) into small molecular-mass compounds. If oxygen in the air is excluded (anaerobic conditions) then the biogas is produced. Biogas is predominantly methane and carbon dioxide in the proportions (excluding water vapour):

- 55 - 70% methane (CH_4);
- 38 - 23% carbon dioxide (CO_2);
- ~ max 7% various other trace gases.

Therefore the combustible content of biogas is predominantly methane. Per molecule, methane causes more climate change forcing than carbon dioxide. Hence burning methane in air produces less harmful products than the original gas. Moreover a dangerous and, often, smelly gas, is disposed of usefully. Therefore, the use of biogas as an energy source is welcome. To illustrate the global relevance: 280 Mio tonnes of unused biogas are currently produced in paddy fields per year, with a similar amount coming from livestock farming.

In principle, there are 3 possibilities for using biogas as a fuel:

- direct combustion for heat,

- combustion in an engine for motive power or electricity generation (with or without combined heat and power),
- pumping into pipelines with 'natural gas' as part of a grid network.

Biogas can be stored at atmospheric or larger pressure. Therefore variations in biogas production can be smoothed, say, for use in electricity generation. In practice, storage for more than a few weeks is likely to be expensive. Nevertheless, biogas provides a reliable fuel to use alongside intermittent generation, e.g. wind power. However, if the main requirement in combined heat and power is the heat, then the apparent flexibility of operation is lost.

Biomass:

Biomass represents a traditional resource for heating, especially in rural areas. It may be used directly as a fuel in combustion, or it can transform into other fuels, e.g. into biogas, pyrolytic fuels or transport biofuels. Electricity generation from biomass direct combustion is characterised by:

- *Various terminology occurs:* The generic-term 'biomass' is used to describe a broad set of different fuels; definitions in literature are not-harmonised between different organisations and countries.
- *Controlled power output:* as with fossil fuels, biomass is a fuel for thermal power plant. Therefore, controlling power production only depends on the operational strategy or plant-type (peak load plant vs. base load plant).
- *Unforeseen variable costs*: in practice, the cost of obtaining, transporting and storing biomass may be uncertain. In this respect, biomass is significantly different from most other forms of RES-E.
- *Advanced combustion:* apart from 'simple' combustion, various technological concepts exist for power production from biomass. In general, a distinction is made between biomass-fired CHP plant, biomass-fired power plant and co-firing with fossil fuel in conventional thermal plant.
- *Biomass represents a 'competitive resource':* In general, the use of biomass as a fuel is in competition to its use as a material or food. Furthermore, competition occurs within the energy sector, e.g. between the production of heat and electricity.

For the **Green*Net*** database it has been decided to follow the definition of biomass given by the 'RES-E directive' (EC, 2001). Five sub-categories have been defined:

- Forestry products (BM-FP),
- Forestry residues (BM-FR),
- Agricultural products (BM-AP),
- Agricultural residues (BM-AR),
- Biodegradable fraction of waste (BM-BW).

Moreover, within each sub-category, a further distinction between pure power production and CHP was applied. Based on this categorization, a separate assessment of the available potential has been undertaken for each sub-category. For the applied conversion technologies, differences between the sub-categories, with the exception of waste-treatment, are quite small. Therefore, the cost-assessment is based (a) on the set of conversion technologies, and (b) on an assessment of country-specific fuel prices.

Landfill gas:

Similar to biogas, landfill gas is the result of a natural decomposition process. The energetic content of landfill gas is directly linked to its methane content. From an ecological point-of-view – especially due to the high percentage of methane – the energetic use of this climate damaging side-product is highly recommended.

The source for this energy carrier is (the biodegradable fraction of) waste being deposited on landfill sites. Hence, recent developments regarding waste treatment regulations – e.g. given by the EU-directive on the landfill of waste (European Commission, 1999) – significantly influence the future potential of this energy source.

In principle, two possibilities exist for energetic utilisation: On the one hand, the combined production of heat and power (CHP) and, on the other hand, the pure production of electricity. Hence, for new plants the option of CHP has been neglected as default – due to the lack of heat consumers on-site. With respect to electricity generation it is important to mention that there is no seasonal dependence on resource availability as e.g. for hydropower.

Sewage gas:

The source for sewage gas is (the biodegradable fraction of) waste water or sewage, respectively, processed and refined in sewage purification plant. Similar to biogas, sewage gas is a result of a natural decomposition process. Hence, from an ecological point-of-view – especially due to the high percentage of methane – the energetic use of this climate damaging side-product is highly recommended.

In principle, two possibilities exist for the energetic utilisation: On the one hand, the combined production of heat and power (CHP) and, on the other hand, the pure production of electricity. With respect to electricity generation it is important to mention that there is no seasonal dependence on resource availability as e.g. for hydropower.

2.1.2.2 Geothermal energy

Electricity generation from geothermal energy is characterised by:

- *Low volatility of the power output:* Geothermal power represents an almost non-fluctuating source of energy.
- *High initial investment costs*: Substantial barriers for geothermal plants are high investment costs combined with a high level of uncertainty in the planning process of a project (i.e. the assessment of drilling costs).
- *Lack of high-temperature resources:* High-temperature geothermal resources as needed for the state-of-the-art of geothermal power generation are quite rare in Europe. Moreover, they are concentrated mainly in those countries where geothermal plants are already installed (e.g. Italy and Portugal). Of course, promising new technological options exist (e.g. hot-dry-rock) for future exploitation of low- to medium-temperature resources.

2.1.2.3 Hydro power

Electricity generation from large- and small-scale hydropower plants is characterised by:

- *High exploitation / proven technology:* Among all RES-E generation technologies, hydro power is the most explored sources, especially in EU countries like Austria or France. Several conversion technologies applied are common and well proven.
- *Low volatility of the power output:* Hydro power is a fluctuating source of energy. In contrast to wind and PV volatility of hydro power has time scales of seasons and years (see e.g. the Austrian case in Figure 2.1 below).
- *Low social acceptance:* Public resistance has been raised in most parts of Europe since the 80's when new large-scale hydro power projects have been discussed. For small-scale hydro power plant projects (i.e. installed capacity <10 MW) acceptance is even better.
- *High initial investment costs*: A substantial barrier for large-scale hydro power plants are high investment costs.
- *Run-of-river vs. storage plants:* In general, a standard classification of hydro power plants distinguishes between run-of-river- and storage power plants. In mountainous regions (large-scale) storage plants are operated to meet peak load demand. At proper river sites run-over-river plants generate base load electricity.
- *Pump-storage plants:* A further sub-category of storage plants is a pump-storage plant – in order to be able to store excessive base-load energy. Such plants are commonly used all over Europe to account for peak-load supply. Hence, the energy produced from such plants is not allocated to

renewables – see Article 2 of the 'RES-E Directive' (European Commission, 2001). Within the database of the toolbox **GreenNet**, electricity generation from existing pump-storage hydropower is excluded from the achieved potential and, hence, not considered in the potential assessment for new hydro plants!

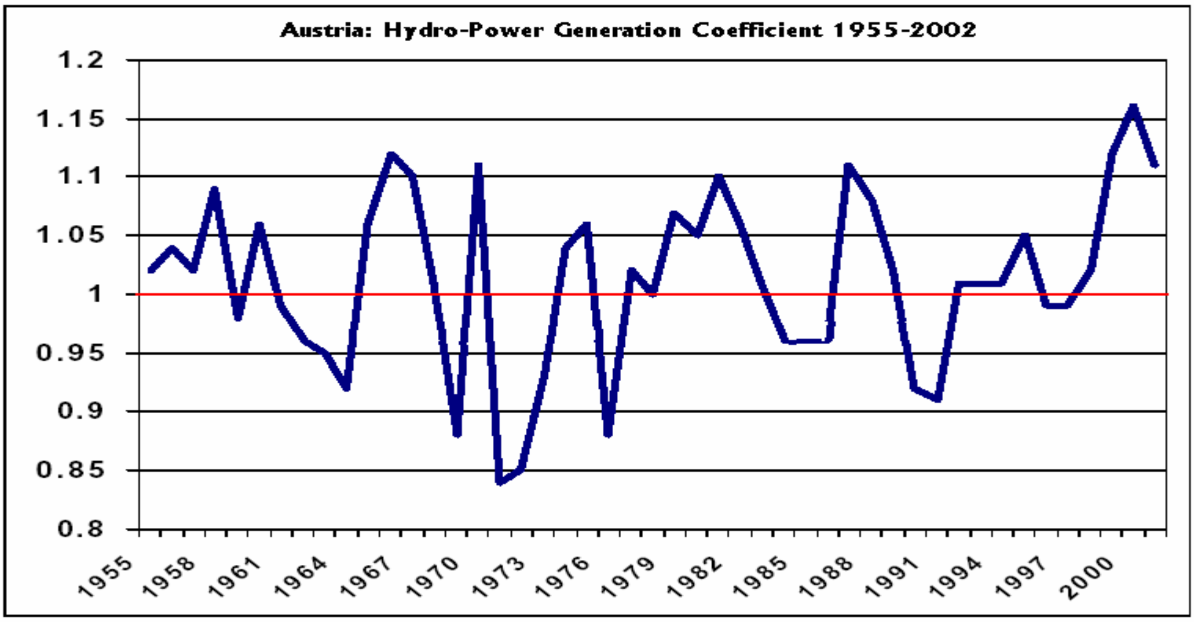

Figure 2.1. Annual hydro-power generation coefficient in Austria from 1955 to 2002. Source: EEG (2002).

2.1.2.4 Solar energy

Photovoltaics

Photovoltaic power cells use a specific spectrum of the sun light to produce electricity. In principle, there are four main applications for PV power systems:

- *Off-grid domestic systems* provide power in isolated remote areas.
- *Grid-connected distributed PV systems* are installed to supply power to a building or other loads (dwellings, commercial and industrial buildings) being also connected to the utility grid. These systems are increasingly integrated into the built environment and are likely to become common place in the future. Typically, for building integrated systems two different categories exist: A PV plant can either be installed on the roof ('PV on roof' - characterised by a higher load-factor), or on the facade ('PV on facade').
- *Off-grid non-domestic systems* provide power for a wide range of applications, such as telecommunications, water pumps, vaccine refrigeration, navigation aids, aeronautical warning lights and meteorological recording equipment. Energy storage is not required. This is an additional factor improving system efficiency and decreasing environmental impacts.
- *Grid-connected centralized PV systems* have been installed for two main purposes: as an alternative to centralized power generation from fossil fuels or nuclear energy, or for strengthening utility distribution grids.

Of course, for several investigations undertaken within this project, grid-connected PV systems are of relevance only.

Most important characteristics of grid-connected PV systems are:

- High volatility of power output: Due to the strong dependence of the power output on the availability of sun light there exist power fluctuations on several time scales: short-term, medium-term and long-term;

- Grid-connected distributed PV-systems contribute to reduced distribution losses;
- High initial investment costs.

Solar thermal

Solar thermal power plants have been considered as a promising new option for electricity generation for several years. Hence, up to now no solar power plant for electricity generation has gone ‘online’ in Europe (except demonstration facilities). But worldwide several (hybrid) solar thermal plants are operating well. In principle, the following technological concepts exist:

- *Parabolic through plant:* Large cylindrical parabolic mirrors concentrate the sunlight on a line of focus. Several of these collectors in a row form a solar field. Molten salt is used to transport heat to a (conventional) gas or steam turbine.
- *Solar power tower plant:* The solar field of a central receiver system (i.e. the power tower) is made up of several hundred mirrors concentrating the sun light to the central receiver. Similar to the system described above, air or molten salt is used to transport heat to a (conventional) gas or steam turbine.
- *Dish/Stirling Technology:* Parabolic dish concentrators are – in contrast to the systems above – rather small units (range of kilowatts).

Parabolic through plants and power tower plants are usually either equipped with a thermal storage block or a hybrid fossil burner in order to guarantee a non-fluctuating power supply.

In general, solar thermal plants can use direct irradiance only. Since there is a small proportion of direct irradiance in middle and northern Europe only, it does not make sense to install solar thermal electricity generation units based on the existing technology in these areas.

2.1.2.5 Wind

Among currently available and commercially viable renewable resources, wind is one of the cheapest possible sources of renewable energy. When considering the total capital investment costs of building new electric generation facilities, it is even competitive with conventional electric generation sources. Furthermore, also in several European countries wind power is characterised by rather high additional potentials still waiting to be exploited. This explains the keen interest power companies and private investors have had in wind energy in recent years.

In general, modern wind turbines use the energy content of wind to produce electricity. Thereby, electricity generation from wind power is characterised by:

- *High volatility of the power output:* Due to the strong dependence of the power output (P) on the wind speed (v) ($P \approx const. * v^3$) short-term as well as medium-term and long-term fluctuations appear. In this context, wind power prediction methods are developed to overcome the lack of planning awareness. The quality of a possible wind plant site can be determined by deriving the local wind climate, i.e. average annual wind speed and wind speed distribution. Compared to on-shore wind energy, wind conditions are more stable for off-shore plants. Therefore, higher full load-hours can be achieved and, hence, associated fluctuations of the power output appear in a smaller range.
- *Standardised and proven power conversion technology:* The stable growing demand for wind power starting in Europe within the early 90’s led especially Denmark and Germany become the leading countries with respect to the wind turbine manufacturing industry. Technological solutions differ in detail by manufacturer, but in general, the overall concepts are proven and well established. The various components are standardised and manufacturing is characterised by major competition. Nevertheless, the typical plant size increased rapidly within the 90’s, mainly driven by the growing demand for offshore-developments. Currently, the size of typical on-shore turbines is in a range between 1 to 2 MW. Nowadays, largest available turbines as used for off-shore appear in the 5 MW class.

2.1.2.6 Wave

Wave energy represents a promising future RES-E option. In principle, a distinction can be made with respect to its appliance, i.e. shoreline, near-shore and off-shore-devices. Hence, off-shore wave power is yet still in a R&D-stage[2].

2.1.2.7 Tidal

Tidal stream power has been recognized especially within the UK as a promising new option for power generation. In principle, a distinction between tidal barrage, near-shore and off-shore-devices occurs. Hence, off-shore wave power is still in a R&D-stage.[3]

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[2] See Michael (2002)

[3] See Michael (2002)

2.1.3 Clustering of RES-E generation technologies

Derived from the description of renewable energy sources qualified for electricity generation in the previous section in this section selected characteristics of several RES-E generation technologies addressed in toolbox **Green*Net*** are summarized briefly. In particular, the following categories of RES-E generation technologies are modelled in **Green*Net***: biogas, (solid) biomass, geothermal electricity, large-scale hydropower, small-scale hydropower, landfill gas, sewage gas, photovoltaics, solar thermal electricity generation, wind on-shore, wind off-shore, tidal and wave energy.

Please note, that there is an enormous variety of characteristics (indicators) which could be mentioned. In Table 2.2 a selection of corresponding indicators is shown as there are:

- Volatility (approximation of time variation), comprehensively described in chapter 2
- Resource availability, comprehensively described in chapter 3
- Range of generation cost, indicated in chapter 3
- Preferred voltage level of grid connection, indicated in chapter 3

Table 2.2. Different indicators for RES-E generation technologies

RES-E technology		**Volatility (approx. time variation)**	**Resource availability**	**Range of generation cost [€cent/kWh]**	**Preferred voltage level of grid connection**
Biogas		Year	High	5,18 – 26,34	1…30kV
Biomass		Year	High	2,87 – 9,46	1…30kV, except co-firing
Geothermal electricity		Year	Low: country-specific	3,34 – 6,49	10…110kV
Hydro power large	Run-of-River power plants	Months	Low	2,53 – 16,37	220…380kV
	Storage power plants	Months	Low	not considered	220…380kV
Hydro power small		Months	High	2,69 – 24,93	10…30kV
Landfill gas		Year	Low	2,50 – 3,91	1…30kV
Sewage gas		Year	Medium	2,85 – 6,24	1…30kV
Photovoltaic		Day, Hours, Seconds	High	47,56 – 165,32	<1kV
Solar thermal electricity		Day, Hours, Seconds	High: country-specific	12,48 – 66,97	1…30kV
Tidal		12 Hours	High	not considered	10…380kV
Wave		Weeks	High	9,38 – 45,16	10…380kV
Wind	On-shore	Hours, Minutes	High: country-specific	4,63 – 10,80	30…380kV
	Off-shore	Hours, Minutes	High: country-specific	6,09 – 13,39	110…380kV

Table 2.2 provides a coloured picture of electricity generation options based on renewable energy sources. In subsequent sections and chapters (in this report) as well as further workpackge reports of the project **Green*Net*** it is shown that individual characteristics of RES-E generation technologies a priori need not to be disadvantages (compared to competitive conventional electricity generation technologies). Moreover, intelligent scheduling of intermittent RES-E generation (incl. taking into account options for storage and load management on the demand side) even can trigger innovation (sustainable technological solutions) on both sides of the equation: electricity supply and demand.

2.2 DSM methods with the potential to enhance RES-E generation

2.2.1 Introduction

It is essential to appreciate that the instantaneous flow of electrical power into a circuit or grid must exactly equal the instantaneous output. We call the maintenance of this balance, ‘matching’. If the input is larger than the output, there are only two methods to establish a balance; either decrease the input or increase the output. If the output is too large, decrease the output or increase the input. So, in principle, both control of the output (the electrical load) and control of the input (generation) are available for matching.

The incorporation of ‘electricity storage’ does not change the requirement for matching. The store is merely a load that first absorbs power and later returns power to the circuit. In practice, such a store may be easier to control than other loads, however its cost is always a significant extra.

Traditional power engineering puts the emphasis for matching firmly on control of generation, and not on control of load. This is understandable with generation from fossil fuel, since the machinery uses negative feed-back control to operate and all control can be within centralised power stations. The negative feed-back control ensures that fuel use is minimised, as efficiency demands. However with renewable energy there is no cost-saving by intentionally reducing generation; indeed costs increase because there is less income to pay back the dominant capital expenditure. Moreover, renewable generation is predominantly dispersed and not centralised, so control of generation cannot be so localised.

Therefore, with significant amounts of RES-E feeding into grids, there is a strong case for considering how load can be altered to match the available generation. This is what we mean by ‘demand-side-management (DSM) for increasing RES-E’. We are aware the DSM usually means the control of loads and tariffs so consumers can decrease their expenditure on electricity. This aspect of DSM will always be important for consumers. However, DSM has a much larger and extended role for grid-power management, especially with RES-E. These ideas are explored below.

There is almost universal agreement that electricity generation from renewable sources should increase, subject to environmental, cost and service acceptability. This chapter assumes that the main opportunity for such increase is technological, with technological advance in tune with consumer satisfaction in a liberalised electricity market. Consumers want cheap, reliable service with the minimum of adverse impacts.

Renewable (green) energy is obtained from active flows of energy, i.e. power, already occurring in the environment. This is in marked contrast with fossil and nuclear (brown) energy, which is released from passive stores of potential energy. Many contrasting consequences arise from this fundamental difference between green and brown energy supply, e.g.:

- For renewables, the primary power source is essential free and usually dispersed, whereas for brown energy the primary source is expensive, yet concentrated. Consequently renewable power economics is *capital intensive*, with no economic savings obtained by switching off supply.
- The logical control system for brown electricity generation is *negative-feed-back* control, i.e. if generation is more than load, reduce generation. This saves expensive fuel and satisfies consumer service. Likewise, if load increases over generation, extra generation is increased. Consequently, the accepted grid operation practice is to control generation only, so maintaining constant voltage with constant frequency as the load varies.
- However, the logical control system for green electricity generation is *positive-feed-forward* control, i.e. if generation is more than load, increase load so constant voltage and frequency are maintained. If load is more than generation, then decrease load. This response optimises capital investment. And recognises that generation is set by the environment. However, great care is needed to maintain customer satisfaction as consumer loads are changed. Nevertheless, with carefully structured tariffs there is the possibility of both increasing generation income, whilst maintaining consumer satisfaction.

In practice, matters are more complicated than the principles above would suggest. For instance, nuclear power generation requires continuous operation, so reduced-cost, night-time, tariffs encourage a steady total load. A particular renewable supply, e.g. wind power, may cease entirely for a period, so a mix of generation is necessary to maintain electricity supply despite load reduction. Consequently, both brown and green systems benefit from forms of *energy storage*. Such storage either effectively stores electricity to be released later, or shifts demand in time. Storage allows greater flexibility for matching supply with load, despite inherent losses.

In this chapter, the suggested grid control strategy for increasing renewables depends on switching loads (including storage) within appropriate tariff regimes. There are many methods for this. The principle however depends on the load variation being in sympathy with the renewables generation, hence the terms *sympathetic loads* and *sympathetic tariffs*.

The suggestion of switching consumer loads on a large and dispersed scale is radical, despite the technology being available and there being many typical examples and case studies. The last hundred years has seen the growth of grid electricity to enormous technical and economic scales, therefore a reluctance to contemplate change is understandable. Yet, that growth has been based on a dominance of brown fuels, which now must change. Now that renewables generation is to increase, it is reasonable to consider how the electricity supply system should adapt.

2.2.2 Basics and definitions

2.2.2.1 Grid supplied electricity

The thickness, and hence cost, of conducting cable is inversely proportional to the voltage of the power, therefore large voltage is preferred for the electricity supply. The practical limits relate to safety, especially sparking and insulation at large voltage. In practice the voltage of long distance transmission is at 50 kV to 500 kV, local area distribution is at 10 to 50 kV, and supply to consumers at 100 to 500 V. Transforming between these voltages is easiest and cheapest with alternating current (AC to AC). Transforming between direct current (DC to DC) or between AC and DC is possible using electronic interfaces, which have become increasingly more reliable and cheaper, due to solid-state power-electronics.

Power transmission with AC has more loss per unit distance than with DC. Nevertheless, the ease of transformation means that the vast majority of power transmission is with AC.

Grid electricity is generated by either:
- moving wires in magnetic fields (Faraday Effect), or
- photovoltaic generation in sunlight.

To maintain constant voltage and frequency, both methods depend on matching instantaneously the load to the generation, see Figure 2.2.

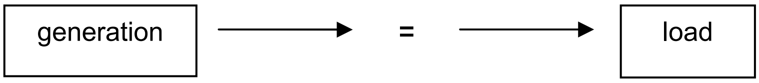

Figure 2.2. Matching instantaneously the load to the generation

Generation is distinguished by its economic and physical ability to be varied to match the load, e.g.
(1) base load generation (difficult or expensive to vary, e.g. nuclear power, large coal, large biomass)
(2) peaking generation (easier to vary quickly, but may be expensive, e.g. gas turbine)
(3) standby (easy to increase generation rapidly from being off or idling, e.g. diesel, gas turbine)
(4) intermittent (e.g. run-of-the-river hydro, wind, most renewables except biomass and geothermal).

Note that reservoir-hydro power may be treated as either base load (plenty of water) or peaking (limited water). Note also that ‘intermittency’ does not mean ‘unpredictable’.

2.2.2.2 Load

It is important to realise that users of electricity do not want the electricity *per se*. They want a *service*, such as lighting, water, motor movement, clean clothes, communication, warmth, cooked food, manufactured items etc. The success of the electricity supply has to be judged by the quality and cost of the services. Note that the quality of a service, e.g. heating or water supply tends to be measured by an *intensive parameter*, e.g. temperature or pressure, and the availability of that parameter. The cost of the service is measured by an *extensive parameter*, i.e. energy, kWh, linked to its availability.

The desire for the service presents a *demand* on the grid system, which the power engineers see as a *load*. Ordinary consumers always use the name of the service for the function, e.g. television, and never expect to use the word “load”. It is most meaningful to use the word “demand” as related to the desire of consumers for service, and the word “load” as related to the consequent electricity consumption. This subtle distinction will be maintained in this chapter.

Note that satisfactory service can be maintained without the continuous consumption of electricity. For instance, water at a satisfactory temperature can be supplied from a previously heated tank. If the value of the intensive parameter is maintained, e.g. shower temperature, then the consumer is satisfied even if electrical supply is interrupted. Such demand that is satisfied by intermittent power is an *interruptible load*, also called *switchable load.*

If load and tariff management is used to optimise a power system, e.g. to increase the penetration of renewable energy, it is here called *sympathetic.*

2.2.2.3 Demand Side Management (DSM)

Conventional operation of grid power systems depended on changing generation to match demand, and hence load, at all times. However increasingly various methods are used for the load to change according to the needs of generation, i.e. DSM. The most obvious example is a low price electricity tariff at night to maintain load for nuclear power and large, coal-burning stations. There several common options for implementing such night-timer tariffs, e.g.

- Consumer meters are switched to different registers, either by a local clock or by a radio signal (as in the UK, often named “Economy 7”), so allowing all load to change tariff. The consumers’ bills show energy consumed at each tariff and charge accordingly.
- Specific loads, e.g. storage heaters, water-tank heaters, are enabled by time clocks or by ripple control (a signal “down the wire”) (as common in Australia for water heaters and the UK for space heaters). These loads are wired on a separate circuit with a separate meter register.

The technology for remote switching (often called “ripple control”) is widely available, e.g. from *Landis+Gyr, Siemens,* etc. There are many ways to communicate such control (see e.g. Metering International (2002)), including the use of long wave radio, mobile telephone networks, and signals sent on the power lines. Modern digital electronics offers low cost and accurate communication for tariff information or direct control.

Also, modern communication methods allow *remote metering* to both measure and monitor electricity consumption at short intervals, e.g. minutes. Analysis of such information allows recommendations for DSM and reduced consumption, see Almeida et al (2003). The communication technologies for remote metering are similar to those needed for remote switching.

The range of options for DSM is large, with special expertise available for consultation, e.g. on cost benefits and implementing renewables wind power generation (see Hirst (2003)).

The short-term switching of loads is seen as significant potential benefit for managing the balance of generation with demand. Most attention is given to peak shaving, so avoiding the need for expense and rapid generation, e.g. gas turbines. A wide range of techniques, tariffs and other methods are lumped together as *demand response* (see e.g. Peak Load Management Alliance (2002) and Nordvik/ Lund (2003)), whereby consumers reduce electricity costs by responding over short periods to options offered by suppliers, e.g. on-site generation, interruptible loads, real-time pricing, peak pricing.

2.2.2.4 Storage

When demands for service are satisfied by intermittent power supply or generation, it is usually because there is *storage* in the system. There are many types of storage and an exact classification is not available.

In conventional terms, grid operators have to match supply to demand over a wide range of time periods, see Table 2.3. Each task may be associated with specific forms of generation, storage and load control (details will be discussed in chapter 4 of this WP1 report as well as in the WP2 report).

Table 2.3. Time characteristics required for storage applications

Task	**Period**
Output smoothing	Intermittent ~ second
Load-levelling	Daily 4-12 h Weekly 40-60 h Seasonal 3 month
Peak Shaving	180-10000 s
Spinning reserve	30-300 s
Voltage stabilisation, frequency regulation	0.5-120 s
Countermeasure against supply disruption	0.12-0.2 s
Improvement of stability	0.02-0.2 s

a) Storage for electricity regeneration (dedicated-storage)

These systems absorb electrical power from the grid, store the energy as a potential, and then release the energy to regenerate electrical power back into the grid, see Figure 2.3 below. The operation is usually a commercial enterprise. Examples are large-scale pumped hydro reservoirs, compressed gas accumulators, flywheel motor/generators, etc. We may call such systems *dedicated storage*. They are judged by their efficiency and cost of first absorbing electrical energy, and then regenerating electricity back into the grid when required, e.g. to meet peaks in demand.

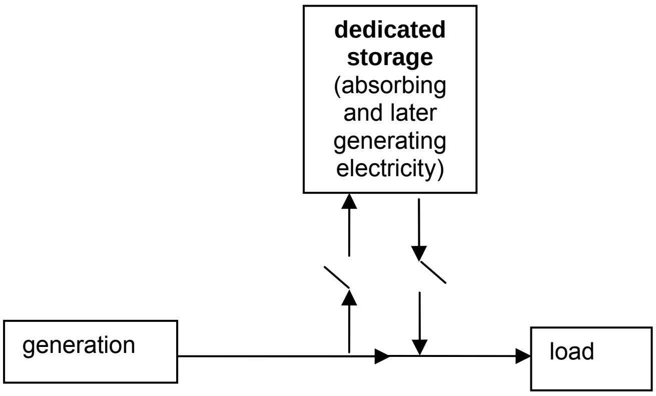

Figure 2.3. Basic principles of dedicated-storage

The use of dedicated-storage normally results in overall loss of energy, i.e. the electrical energy absorbed is more than the electrical energy regenerated. The electricity in/electricity out efficiency of dedicated storage is commonly about 80%. An exception is pumping into a tidal barrier reservoir at high tide, and regeneration at low tide, hence absorbed electricity is about 4 times less that re-injected electricity; however such overall gain is most unusual.

There is increasing interest in both large scale dedicated storage effecting transmission networks, and in lesser scale dedicated storage *embedded* in distribution networks. A major study for the UK identified significant cost benefits by having increased dedicated-storage throughout the grid supply system (see Campbell Carr (2000)).

The range of technologies for dedicated-storage is potentially wide (see Investire-Network (2003)), however pumped-hydro power installation is the most common and most experienced technology. Other technologies include: compressed air, flywheels, batteries (lead acid, advanced), fuel cells (including regenerative fuel cells, 'redox systems'), electrolysis (e.g. hydrogen for powering engine-generators or fuel cells), 'super-capacitors'.

Please note, that dedicated storage is analysed in detail in the WP 3 report.

b) Storage maintaining consumer service (demand-storage)

Householders have domestic hot water tanks, not to regenerate electricity, but to maintain a supply of hot water, i.e. to maintain a service function. Other services (e.g. refrigeration and deep-freezing, compressors, water pumping) may be associated inadvertently with storage, especially thermal storage. Likewise, a header tank may be used to maintain a water supply.

Electrical power for all these functions can be interrupted, whilst the service is maintained from the associated energy store, see Figure 2.4. The user experiences no alteration of the intrinsic parameter, e.g. hot water temperature or water pressure.

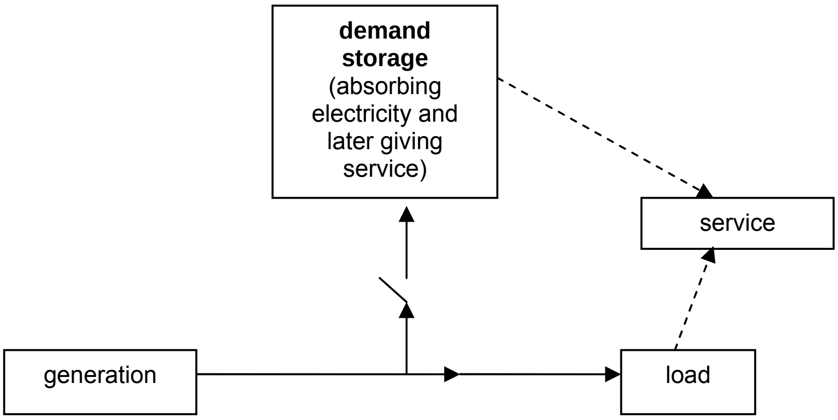

Figure 2.4. Basic principles of demand-storage

The interruption of electrical power to a service store may, or may not, be associated with overall increase of electrical energy consumption. Factors related to demand-*storage* include:

1) Distributed loads that have both storage capacity and the ability to be remotely switched, e.g. domestic water heaters, space heaters, refrigeration, water tank pumps, electric cars at recharge.
2) The energy capacities and time intervals likely to be available per type of switchable load (e.g. domestic water heaters ~ 2 hours at 2 kW (4 kWh/day) per consumer.
3) The number of such loads per consumer, and hence the storage available per consumer. (e.g. ~ 7 kWh/day time shifted).
4) The proportion of such demand-storage being available as a function of preferential tariff reduction (e.g. 50% at half-price tariff).
5) The total distributed demand-storage available per unit of generation (e.g. 1 MW wind may supply 500 households, each with 3 (kWh/day) virtual storage. So the ratio of accessible demand-storage per unit of generation = 1500 kWh/day per MW = 1.5 h/day time shifted. This is a smoothing time constant of 1.5 h.
6) Switching methods and switchable load identification (e.g. radio side band with random coded signals received by switches at individual load connection sockets; signals on the supply lines (i.e. forms of ripple control), telephone lines or mobile phone transmission).

2.2.2.5 *Time shifting (time-shifted service)*

Demand that is not required instantaneously, but can occur without loss of benefit at an advanced or delayed time, is termed here "time-shifted demand". For the grid system operator, this is "time-shifted load".

Time-shifted demand may, or may not, be associated with demand storage:

- Time-shifted demand, without storage and loses: clothes washing, drying, water pumping with no reservoir.
- Time-shifted demand, with storage: water heating, large thermal capacity building heat, water pumping to a reservoir.

2.2.2.6 *Interruptible (switchable loads) loads*

These include both demand-storage and time-shifted demand.

2.2.3 Overview of the portfolio of different DSM measures to mitigate intermittent RES-E generation

Finally, in Figure 2.5 the entire portfolio of different DSM measures to mitigate intermittent RES-E generation is summarized. So-called "sympathetic loads" applying the features of thermal storage in particular end-uses (e.g. hot water tank, space heating, refrigeration, etc.) are allocated between dedicated storage technologies and time-shifted loads. Comprehensive (empirical) analyses of several applications indicated in Figure 2.5 is conducted in WP 3, dealing with several aspects of electricity storage.

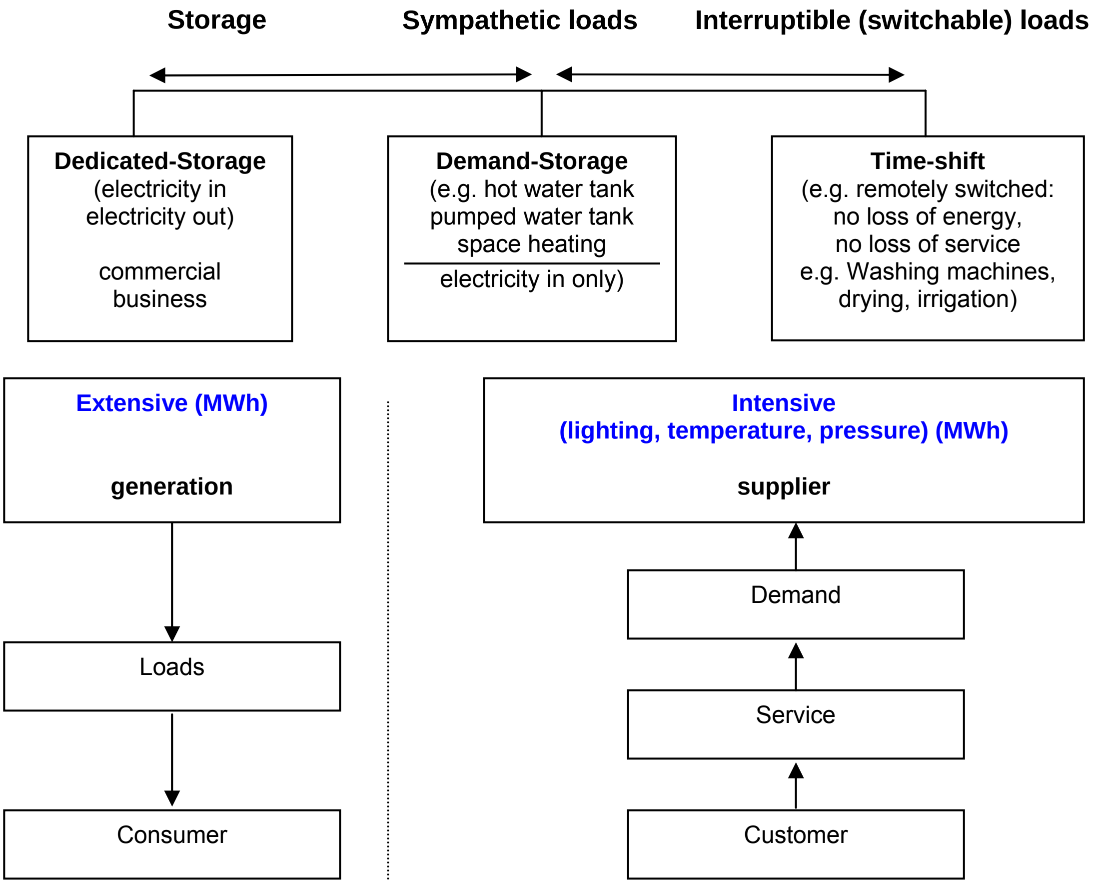

Figure 2.5. Overview of different DSM measures to mitigate intermittent RES-E generation

3 POTENTIALS AND COSTS FOR RES-E IN EU-15 COUNTRIES

A broad set of different technologies in the field of electricity generation based on renewables (RES-E technologies) exist today. Obviously, for a comprehensive investigation of the future development of RES-E in EU-15 countries it is of crucial importance to provide a detailed investigation of the country-specific situation, e.g. with respect to the potential of the certain RES-E in general as well as their regional distribution and the corresponding economic aspects. As a first result of such an EU-wide assessment being undertaken within WP 1 of the project **Green*Net*** – which is due to the limited time budget mainly based on existing literature – the background data regarding RES-E in EU-15 of the toolbox **Green*Net*** is presented in the following addressing in particular: (i) the general framework for model implementation in **Green*Net***, (ii) an overview of the status quo of already realized RES-E potentials in the EU15 countries and (iii) a brief description of the database on potentials and costs for each RES-E separately (cost-resource curves by RES-E).[4]

General Remarks

Calculation of electricity costs

In the model **Green*Net*** the calculation of electricity generation costs for the various generation options is done by a rather complex mechanism as described later – internalized within the overall set of modelling procedures. Thereby, band-specific data (e.g. investment costs, efficiencies, full load-hours, etc.) is linked to general model parameters like interest rate and depreciation time. The later parameters depend on a set of user input data like policy instrument settings, etc. Nevertheless, for a better illustration of the band-specific set of data presented in the following, marginal electricity generation costs are exemplarily depicted. Thereby, for long-run marginal generation costs (as applied for new plants) a default capital recovery factor is used – based on the following settings:

- Interest rate z = 6.5%
- Pay-back time PT = 15 years

Cost-data with respect to CHP-plants

In case of CHP, investments costs, etc. refer to the power plant only – i.e. costs for district heating network are not included. Hence, the assumed heat price in default size of 20 €/MWh must be seen as price according to the defined hand-over point. In this context, this price represents the additional revenue for the power producer due to selling of heat in case of combined heat production, but, of course, does not indicate the final consumer price for heat.

Preliminary default background data

The background data – describing the supply-side RES-E technologies and some default demand-side parameters – as presented in the following shall be seen as some kind of default settings – derived at an early stage of the project **Green*Net*** with its proposed duration until December 2004. Hence, further improvements and extensions will obviously occur until the model development is finished and, furthermore, by means of deriving scenario-calculations changes of these default settings are indispensable.

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[4] With respect to RES-E the following categories occur within the toolbox **Green*Net***: Biogas, (solid) biomass, geothermal electricity, large-scale and small-scale hydropower, landfill gas and sewage gas, solar electricity from photovoltaics and solar thermal, wind on-shore and off-shore, tidal and wave energy.

3.1 Model implementation - Analytic framework

In the model **Green*Net*** generation costs and corresponding potentials of all RES-E (for each EU country) are described by ‘dynamic cost-resource curves’ being subject to this section. Firstly, the calculation of electricity generation costs from RES will be explained, followed by a description of the potentials. Finally, the methodology used for the specification of dynamic ‘cost-resource curves’ is outlined.

3.1.1 Calculation of electricity generation costs

When calculating the generation costs a distinction must be made between already installed and potentially new plants. For existing plants, the running costs (short-term marginal costs) are relevant only for the economic decision whether or not to use the plant for electricity generation. On contrary, for new capacities the long-term marginal costs are important.

3.1.1.1 Existing plants

The annual running costs are split into two parts: fuel costs and operation/maintenance (O&M) costs. The fuel costs are a function of the fuel price of the primary energy carrier and the efficiency. In the toolbox **Green*Net***, the O&M-costs must refer to the electricity output. Hence, the O&M costs, referring to the energy unit in the database, must be coupled with the full-load hours.[5] In general, one average operation time (full-load hour) is taken for each technology band. Analytically, the generation costs for existing plants are given by:

$$C = C_{VARIABLE} = C_{FUEL} + \tilde{C}_{O\&M} - R_{HEAT} = \frac{p_{FUEL}}{\eta_{el}} + \frac{C_{O\&M}}{H} * 1000 - p_{HEAT} \frac{\eta_{heat}}{\eta_{el}} \cdot \frac{H_{heat}}{H_{el}} \qquad (1)$$

where:

C .... Generation costs per kWh [€/MWh]

$C_{VARIABLE}$ .... Running costs per energy unit [€/MWh]

C_{FUEL} .... Fuel costs per energy unit [€/MWh]

$\tilde{C}_{O\&M}$ .... Operation and maintenance costs per energy unit [€/MWh]

$C_{O\&M}$ .... Operation and maintenance costs per energy unit [€/(kW*a)]

R_{HEAT} .... Revenues gained from purchase of heat [€/MWh]

p_{FUEL} .... Fuel price primary energy carrier [€/$MWh_{primary}$]

p_{HEAT}................... Heat price [€/MWh_{heat}]

η_{el} .... Efficiency – electricity generation [1]

η_{heat} .... Efficiency – heat generation [1]

H_{el}....................... Full-load hours – electricity generation [h/a]

H_{heat}.................... Full-load hours – heat generation [h/a]

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[5] The full-load hours represent the equivalent time of full operation in a year. It is calculated for a certain power plant by dividing the amount of electricity generated per year by its nominal power capacity. For the theoretical cost-resource curves, this term reflects an important aspect, namely the suitability of sites (e.g. for wind energy). The full-load hours in the case of wind energy are determined by the wind speed distribution and the rated wind speed of the machines. Knowing the expected full-load hours, the quantity of electricity to be generated can be calculated. Hence, costs per unit are determined. ‘Full-load hours’ divided by the number of hours in a year (8765h on average) equals the dimensionless ‘capacity factor’.

General remarks:

- Apart from all kinds of biomass (biogas, solid biomass, sewage and landfill gas), renewables have zero fuel costs, so running costs are determined by operation & maintenance costs only. Therefore the running costs for RES-E are normally low compared to fossil fuels.
- In the toolbox **Green*Net***, primary fuel prices are given exogenously on a yearly basis. For the sensitivity analysis, however, these default values can be adapted.
- In the case of simultaneous electricity and heat generation (i.e. CHP), electricity generation costs are calculated by considering the revenues gained from the purchase of the heat.

3.1.1.2 New plants

The calculation of the generation costs of electricity consists of two parts, variable costs and fixed costs. In more detail, the generation costs are given by:

$$C = C_{VARIABLE} + \frac{C_{FIX}}{q_{el}} = \left(C_{FUEL} + \frac{C_{O\&M}}{H_{EL}} * 1000 - R_{HEAT} \right) + \frac{1000 * I * CRF}{H_{EL}} \tag{2}$$

where:

C	Electricity generation costs per kWh [€/MWh]
q_{el}	Quantity of electricity generation [MWh/a]
$C_{VARIABLE}$	Running costs per energy unit [€/MWh]
C_{FIX}	Fixed costs [€]
C_{FIX} / q_{el}	Fixed costs per energy unit [€/MWh]
C_{FUEL}	Fuel costs per energy unit [€/MWh]
$C_{O\&M}$	Operation and maintenance costs per energy unit [€/(kW*a)]
R_{HEAT}	Revenues gained from sales of heat[6] [€/MWh]
I	Investment costs per kW [€/kW]
CRF	Capital recovery factor: $CRF = \frac{z*(1+z)^{PT}}{\left[(1+z)^{PT}-1\right]}$
z	Interest rate [1]
PT	Payback time of the plant [a]
H_{EL}	Full-load hours electricity generation [h/a]

A more detailed description of the running costs is given in the previous chapter. Fixed costs occur independently whether or not the plant generates electricity. These costs are determined by investment costs (I) and the capital recovery factor (CRF).

- Investment Costs I

The investment costs differ by technology and energy source. In general, investment costs per unit capacity for RES-E are higher than for conventional technologies based on fossil fuels. Also differences occur between RES-E technologies, e.g. investment costs per unit capacity for small hydropower plants are generally at least twice those for wind turbines. Since most RES-E technologies (with the exception of (large-scale) hydropower) are still not mature, investment costs

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[6] In case of CHP, the calculation of the revenues gained from sales of heat is described in equation (1).

decrease over time. This evolution is taken into consideration in the toolbox **Green*Net***, i.e. investment costs are derived annually.[7]

Forecasting technology development is a crucial activity, especially for a long time horizon. Considerable efforts have been made recently to improve the modelling of technology development in energy models. A rather 'conventional' approach relies exclusively on exogenous forecasts based on expert judgements of technology development (e.g. efficiency improvements) and economic performance (i.e. described by investment and O&M-costs). Recently, within the scientific community, this has often been replaced by a description of technology-based cost dynamics which allow endogenous forecasts, at least to some extent, of technological change in energy models: This approach of so-called 'technological learning' or 'experience/learning curves' method takes into account the "learning by doing" effect.[8]

Within the model **Green*Net*** the approach chosen differs by technology. In principle, the database is prepared to include two different approaches: Standard cost forecasts or endogenous technological learning. Default settings have been applied as follows:

- For conventional power generation technologies – as well as some renewable energy technologies - it was decided to adopt well-accepted expert judgements.
- For a set of renewable energy technologies like, e.g. wind power or PV, it was decided to adopt the approach of technological learning. Learning rates were assumed at least for each decade[9] separately.

The default approach chosen to determine future investment costs is summarised by technology in Table 3.1.

Table 3.1. Overview of the methodology to derive investment costs for different technologies.

Dynamic cost development	**Methodology to derive investment costs year n**
Biogas	learning curve–approach or forecast
Biomass	Forecast
Geothermal electricity	Forecast
Small scale hydropower (<10 MW)	Forecast
Large scale hydropower (>10 MW)	Forecast
Landfill gas	learning curve–approach or forecast
Sewage gas	learning curve–approach or forecast
Photovoltaics	learning curve–approach
Solar thermal electricity	Forecast
Tidal energy	Forecast
Wave energy	Forecast
Wind on-shore	learning curve–approach
Wind off-shore	learning curve–approach
Nuclear power stations	Forecast
Steam	Forecast
Gas turbine	Forecast
Combined cycle power turbines	Forecast
Internal combustion engine plants	Forecast

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[7] The 'yearly' determination of the investment costs represents an important input to the data-tables described in chapter 3.3. In more detail, the following parameter must be derived for each country and technology according to the given situation for the year n-1 and the year n:

- quantitative values for investment costs over time.
- quantitative values for the development of efficiency over time.

[8] In principle the so-called 'learning effect' - being empirically observed in several fields of technological development – states that for each doubling of producing / installing a certain technology, a decline of the costs can be expected by a certain percentage, the learning rate. For a brief description of the learning / experience curve approach, see e.g. Wene et al., 2000.

[9] In many cases experience has shown that the rate of technological learning is often closely linked to the development stage of a certain technology – i.e. at an early stage of development, if a technology is 'brand new', high learning rates can be expected and later, as the technology matures, a slowdown occurs.

- Capital recovery factor CRF

The CRF allows investment costs incurred in the construction phase of a plant to be discounted. The amount depends on the interest rate and the payback time of the plant. For the standard calculation of the generation costs these factors are set for all technologies as follows:

  - payback time (PT) of all plants: 15 years
  - interest rate (z) equals 6.5%

Note, in the toolbox **Green*Net***, different interest rates will be applied. The interest rate depends on stakeholder behaviour and is a function of

  - guaranteed political planning horizon
  - promotion scheme
  - technology
  - investor category

General remarks:

- As the generation costs are calculated per energy output, the fixed costs must also be related to electricity generation q_{el}, compare equation (2). Hence, the fixed costs per unit output are lower if the operation time of the plant - characterised by the full load-hours - is high.
- Deriving the generation costs for CHP plants is similar to the calculation for plants producing electricity only. Beside the short-term marginal costs, i.e. the variable costs, fixed costs must be considered for new plants. Of course, equivalent to the case for existing plants, variable costs differ between CHP and conventional electricity plants, as the revenue from purchasing heat power must be considered in the first case.
- In general, no taxes are included in the various cost-components.

3.1.2 Determination of the (additional) mid-term potential

The starting point for deriving the dynamic potential is the determination of the additional mid-term potential for electricity generation for a specific technology in a specific country.[10] The additional mid-term potential is the maximal additional achievable potential assuming that all existing barriers can be overcome and all driving forces are active. The so-called ‘dynamic potential’ is the maximal achievable potential for the year n. This means advantage must have been taken of all existing promotion strategies both on the investor and the consumer side. To illustrate this more clearly, the connections between the different potential terms are depicted in Figure 3.1.

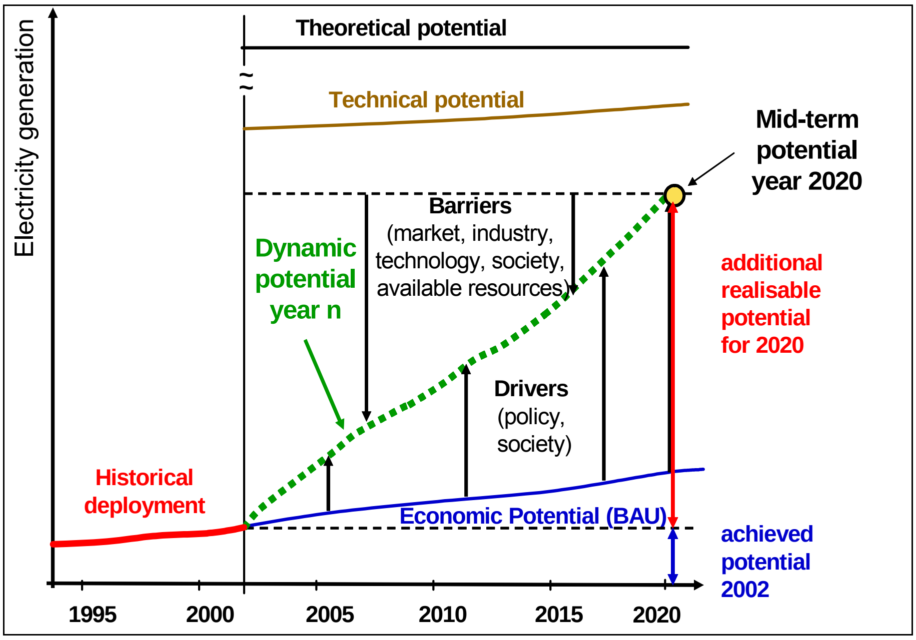

Figure 3.1. Methodology for the definition of different potentials

In the toolbox **Green*Net*** the additional mid-term potential for electricity generation refers to the year 2020. The methodology for the analysis of the potential varies significantly from one technology to another.

- In most cases a ‘top-down’ approach is used (e.g. for wind energy, photovoltaics). In a first step the technical potential for one technology in one country for 2020 has to be derived by determining the total useable energy flow of a technology. Secondly, based on step one, the mid-term potential for the year 2020 is determined by taking into consideration the technical feasibility, social acceptance, planning aspects, growth rate of industry and market distortions. The additional mid-term potential is given by the mid-term potential minus existing penetration plus decommissioning of existing plants.[11]
- For a few technologies, a ‘bottom-up’ approach has been more successful (e.g. for geothermal electricity), i.e. by looking at every single site (or band) where energy production seems possible and by considering various barriers, the additional mid-term potential is derived. The accumulated value of the single band yields the additional potential for one technology in one country.[12]

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[10] Note: While the additional mid-term potential represents an important input parameter in the database **Green*Net***, the additional annual potential (dynamic potential) is one of the essential output parameters of the cost curve development.

[11] To use the potential in the database of the toolbox **Green*Net***, the additional mid-term potential obtained on the technology level (in one country) must be broken down to the band level.

[12] For the toolbox **Green*Net*** the addition of the single band is not necessary as the information must be available on band level.

In this context, one specific problem occurs with respect to biomass. The total primary energy potential for biomass is restricted. The actual distribution among the different options - pure electricity generation, CHP generation, heat generation or biofuel - depends on the net economic condition. As for the economic assessment, various support schemes must be considered, the final decision as to which options will actually be implemented is only feasible after including this step. To solve this problem, the values and the different options are linked in the database.

3.1.3 Development of the 'static' cost-resource curve

A cost-resource curve shows the correlation between electricity generation costs per unit and the potential (in terms of capacity or electricity generation) for one specific technology in one country per annum. Hence, the development of a cost curve implies knowledge of the two items explained above:

- costs for electricity per unit;
- total quantity of electricity that can be generated or capacity that can be installed, respectively, per annum at certain cost levels. The cumulated sum of these amounts is equal to the totally available potential of a certain technology.

As already described, cost curves for one technology (and country) are divided into different bands, see Figure 3.2.

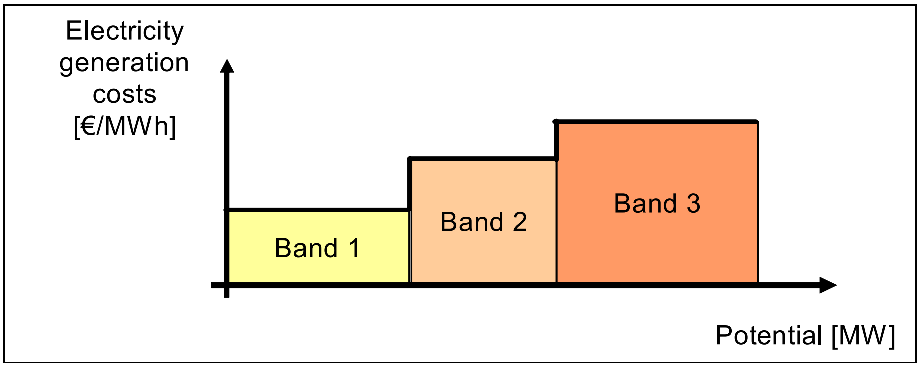

Figure 3.2. Relation between costs and potential for one technology

Bands are characterised by:

- same fuel input, e.g. biomass wood: forestry products (wood) – forestry residues (bark, sawmill by-products) – agricultural products (energy crops) – agricultural residues (straw etc.) – biogenic fraction of waste (MSW+ISW),
- same sub-technology and energy efficiency categories, e.g. photovoltaics systems: facade integrated systems – roof system,
- same range of full-load hours, e.g. wind energy onshore: 2600 h/a – 2500 h/a – 2400 h/a – 2100 h/a – …. – 1500 h/a.

Figure 3.3 depicts a characteristic run of a cost-resource curve. Thereby, all costs and potentials are threaded according to costs, i.e. the cheapest first and the most expensive last. It can be seen that it is helpful to show a separate development of the cost curve for already implemented capacities and for potential new plants.

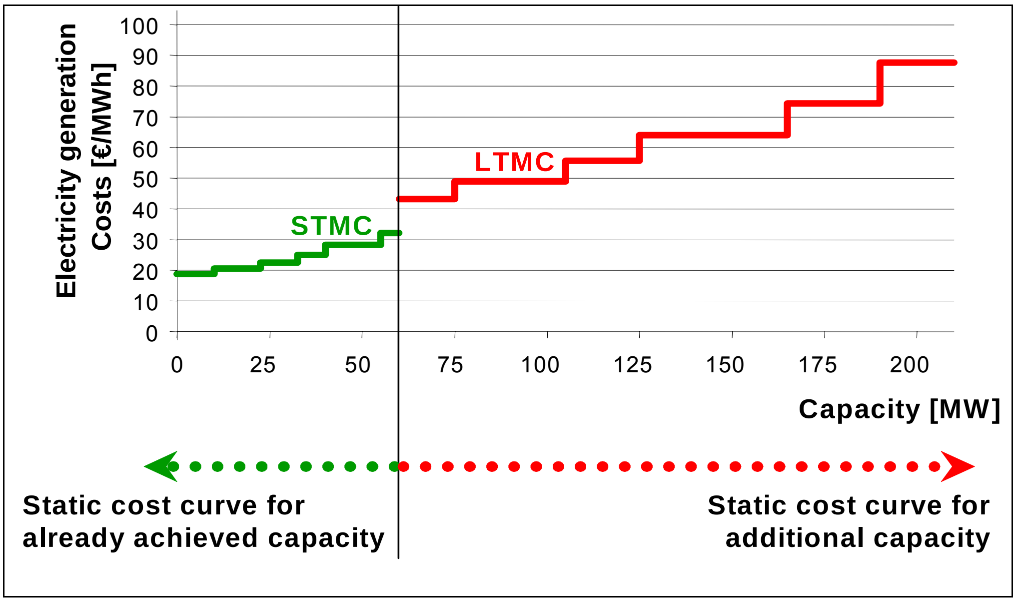

Figure 3.3. Cost curve for achieved and additional potential of technology x

3.1.3.1 Cost-resource curve – existing plants

A characteristic cost-resource curve for already achieved capacities is depicted in Figure 3.4. In this example the portfolio of existing plants of technology x consists of 4 different categories - bands B1 (efficient plant / good size) to B4 (inefficient plant / bad size). For each band the short-term marginal generation costs (STMC) and the long-term marginal generation costs (LTMC) are shown sorted by rising STMC.

The calculation of the STMC follows equation (1) explained above. The LTMC are derived according to equation (2), i.e. all cost parts, both investment and running costs, have to be taken into account. Note that the investment costs for existing plants refer to the year of installation and not to the year n.

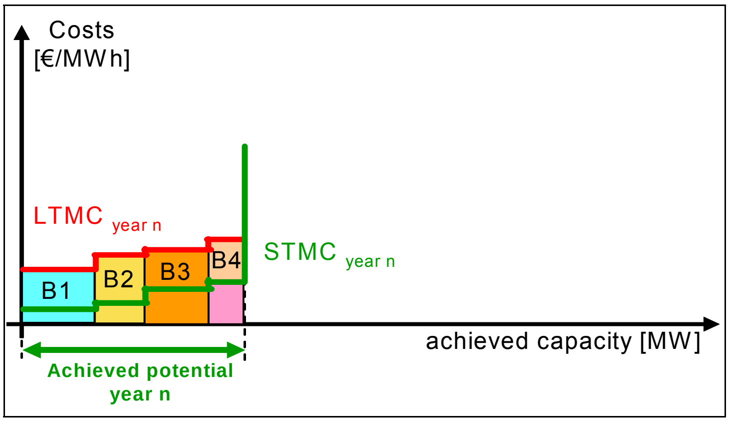

Figure 3.4. Cost curve for already achieved potential of technology x

As already mentioned, the short-term marginal generation costs (STMC) are relevant only for the economic decision whether or not to produce electricity with a certain capacity (represented in the model by the band). This is because for existing plants the investments in the capacity are already (irreversibly) sunk.[13]

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[13] It is assumed that the capacity cannot be rebuilt and sold to a third party.

Nevertheless the long-term marginal generation costs are still important for the calculation and evaluation of important results, e.g. the derivation of the producer's profit. More precisely, as long as the plant is not fully depreciated, the actual investment cost influences (significantly) the actual full generation costs and, hence, the producer's profit.

3.1.3.2 Cost-resource curve – new plants

As already mentioned, electricity generation costs for new installations are characterised by the long-term marginal costs. The costs are derived according to equation (1) and (2), respectively. In contrast to already existing plants, the investment costs decrease over time according to the derived learning curve of the technology for the year n. The stepped function depicted in Figure 3.5 indicates the different cost/potential levels (bands). For instance, in the case of wind energy, sites have a known average wind speed and wind availability, so the load factor (or full-load hours) and hence the costs can be predicted. In the example shown in Figure 3.5, seven different bands (characterised by different full-load hours) are defined starting with high wind speeds and hours (band B1) through to poor wind conditions (band B7).

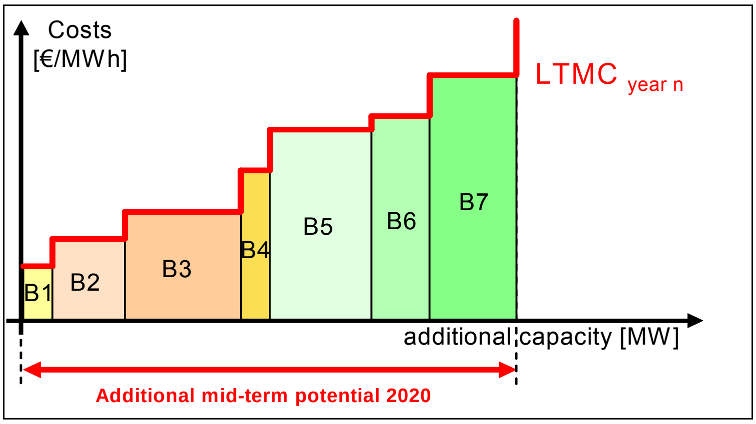

Figure 3.5. Cost curve for additional mid-term potential of technology x

Some technologies can be used either to produce electricity only or both electricity and heat. Therefore, information with respect to the mix of 'pure' electricity generation to combined heat and power production is of high relevance. In the toolbox **Green*Net***, the ratio of CHP plants to pure electricity generation plants depends on the competitiveness of each technology. To keep the simulation time short, it is assumed that the electricity to heat generation ratio is constant within one band. The power to heat ratio, however, differs among the bands of a certain CHP technology.[14]

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[14] An alternative option would be the assumption that the ratio of pure electricity generation plant to CHP plant is constant. In this approach, the ratio must not be derived in the computer model itself. Therefore, the implementation in the computer model requires much less methodological effort. The advantage is a shorter running time of the simulation compared to the other method and, subsequently, resulting in improved user-friendliness of the toolbox. The disadvantage of this approach is: Firstly, some divergences occur between the estimated and the actual possible ratio of pure electricity and combined heat and power generation.[14] Secondly, the grid connected heat demand (for CHP and heat plants) is given as an exogenous variable in the toolbox **Green*Net***. Hence a restriction of CHP plants (by heat demand) leads to a restriction of pure electricity generation, too. The reason is that the power to heat ratio is also restricted. This means, it is economically inefficient to produce a substantial electricity output and a low heat output with a CHP plant.

3.1.4 Development of the dynamic cost-resource curve

In general, in the toolbox **Green*Net*** dynamic effects will be considered covering the areas of:

- costs for new plants
- available / achievable potential for existing and new plants, respectively.

The dynamic adaptation of the costs (investment costs and operation/maintenance costs) will take place at the end of one simulated year, i.e. the investment costs for the year n will be determined at the end of the year n-1. The methodology used to derive the new investment costs has been already described before.

The dynamic assessment of the potential will take place at two different stages in the model. The evaluation of the available potential of existing plants for the year n will be made - similar to the cost evaluation – at the end of the simulation run in the previous year. For new plants, the assessment of the maximal achievable potential for the year n will be made after the creation of the static cost-resource curve in the year n. The reason this step cannot be carried out also at the end of the year n-1 – as for all other dynamic evaluation steps - is that information about assessment parameters is necessary which is only available at the beginning of the year n. In more detail the following inputs must be available:

- Input database supply
    - Input database – existing plants
    - Input database – new plants
- Stakeholder behaviour
    - Investor
    - Society
- Policy instruments
    - Supply-side strategies
    - Demand-side strategies

Based on the development of the static cost-resource curves for existing and new plants, dynamic cost curves will be derived by applying a dynamic parameter assessment.

3.1.4.1 Dynamic parameter assessment – new plant

As already mentioned, the starting point for deriving the dynamic potential is the additional mid-term potential for the year 2020. These data will be used directly from the 'input database – new plants'.

In a first step, the restricting factors of the dynamic potential for the year n must be analysed compared to the given additional mid-term potential, i.e. existing barriers must be determined. Secondly, the additional potential for the year n can be derived by applying a dynamic parameter assessment. More precisely, for each band, the available potential for the next year compared to the year 2020 will be evaluated taking various barriers into consideration.

In the toolbox **Green*Net*** the following obstacles are considered:

- Social barriers (social acceptance of additional generation)
  In some cases the acceptance is a function of the policy strategy, e.g. the acceptance of big wind projects (e.g. in Ireland) is more restricted knowing that most of the electricity generated will be exported (e.g. due to an international TGC market) rather than be consumed locally or at least domestically.
- Industrial barriers
  The availability of the technology in one country depends on the total global demand. This means that the total demand for a certain technology depends on the level of the worldwide (EU–wide) promotion scheme for this technology. If there is (suddenly), e.g. a high quota for wind energy in Europe (or worldwide) then the production of this technology (supply) cannot follow the demand because the growth of the industry is restricted. Hence, less capacity can be built in one country.
- Technical barriers (technical feasibility)

e.g. the need of additional grid extension measures.

- Market barriers (market and policy distortions)
  e.g. less transparency of subsidy scheme, no stable planning horizon.
- Administrative barriers (high bureaucracy)
  e.g. long commissioning time of a plant.
- Availability of the resources
  e.g. the available potential for biomass increases over time due to the time gap (delay) between cultivation (afforestation) and harvesting of the biomass. In the case of landfill gas, the potential decreases over time due to changes in waste management.

Table 3.2 gives an overview of the analysis of barriers and their consideration.

Table 3.2. Summary: characterisation of dynamic barriers

Dynamic parameter & their characterisation		**Techno-logy - specific**	**Country specific**	**Band-specific**	**Link to policy**	**Impact on costs**	**Impact on poten-tials**	**Methodology to implement**
Industrial constraints	Growth rate of industry	X					X	EU-wide limitation of annual installations…
	…							
Technical constraints	Grid constraints (i.e. extension necessary)	X	X	X		X	(X)	Band-specific limitation of annual installations
	…							
Market constraints	Market trans-parency	X	X				X	Increased interest rate
	Investors behaviour	X	X		X		X	Increased interest rate
	…							
Admini-strative constraints	Bureaucracy (	X	X		X		X	Country and technology specific limitation
Societal constraints	‘Willingness to accept‘	X	X	X	X		X	(Band-specific) limitation of annual realisable potential
	…							

$$P_{add\ n} = P_{add\ n\ 2020} * f_{barrier}(\text{Industry}, \text{Technique}, \text{Market}, \text{Society}, \text{Administration}) \quad (3)$$

where:

$P_{add\ n}$ .... Additional dynamic potential year n [GWh/a]

$P_{add\ n\ 2020}$ .... Additional remaining mid-term potential (2020) in year n [GWh/a]

$f_{barrier}$ .... Limitation factor [1]

Similar to the additional mid-term potential for the year 2020[15], the maximal actual achievable potential for the year n takes into consideration several described obstacles and drivers. The dynamic potential for the year n ($P_{add\ n}$) can be derived by multiplying the remaining additional mid-term potential in year n ($P_{add\_n\_2020}$) by a factor ($f_{barrier}$) indicating the maximum constraint of all considered obstacles, i.e. the residual potential is available for the year n.

This procedure is depicted in Figure 3.6; the red lines represent the additional mid-term potential, the blue lines the additional potential being available for the next year (year n) for each band. Of course, the actual availability can vary between the single bands.[16]

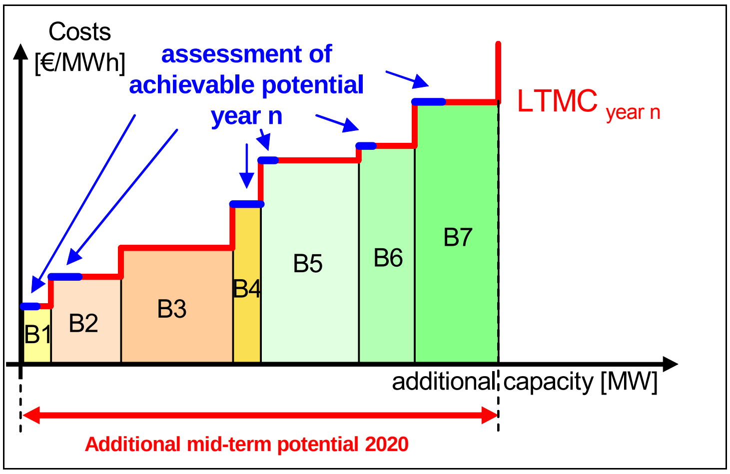

Figure 3.6. Cost curve assessment for additional potential year n of technology x

By adding the additional potential of each band for year n, the dynamic cost curve can be constructed. In the example, the blue lines in Figure 3.6 are put together with the available cost curve for the year n, see Figure 3.7.

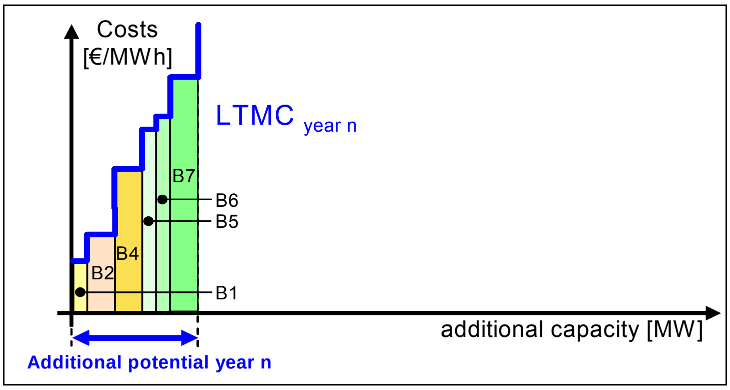

Figure 3.7. Cost curve for additional potential year n of technology x

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[15] Note, that the mid-term potential is equivalent to the dynamic potential for the year 2020 (since all barriers are already considered).

[16] E.g. in Figure 3.6 no additional potential for band 3 is available for the next year. Note, that the cost level of the individual bands remains not effected by the dynamic parameter assessment because the costs (referring to the mid-term as well as the dynamic potential) already refer to the year n for every cost curve.

3.1.4.2 Dynamic cost curves for the year n

The overall cost curve for the year n can be derived by horizontal addition of the already achieved potential (existing plants) and the available additional potential (new plants). This procedure is shown in Figure 3.8.

In general, it can be stated that generation costs of electricity from RES-E technologies are higher than those of conventional energy sources. Moreover, costs as well as achievable potentials differ widely among the specific RES-E technologies. The combination of the cost curves for potentially new and already achieved plants represents the output of the database 'dynamic cost curve'.

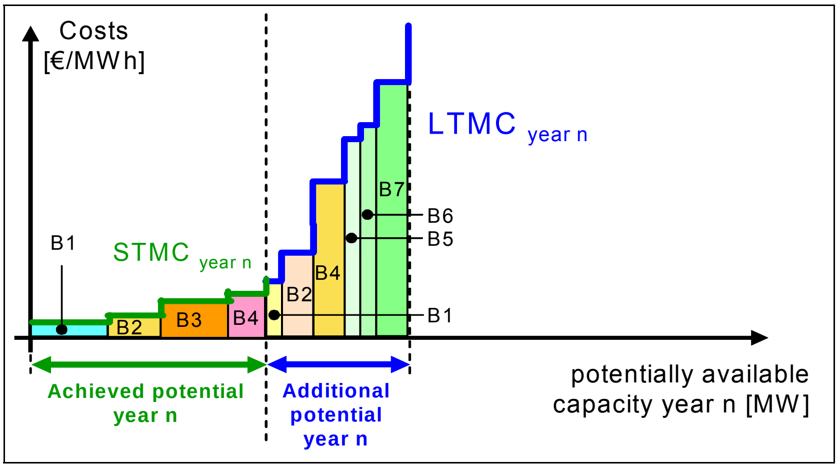

Figure 3.8. Combination of cost curve for already achieved and additional potential for the year n and technology x

Summing up, the future penetration of a certain technology depends on how it overcomes two categories of existing obstacles:

- economic barriers – they are reflected by the net generation costs, i.e. inclusive policy strategies.
- Other barriers as described above – they restrict the available potential of electricity generation in year n.

Penetration of a technology will only take place if both categories of barriers can be overcome. So, on the one hand, it does not help to support a certain technology via a quota obligation, a guaranteed feed-in tariff or a tender scheme without preparing the framework conditions to overcome remaining existing barriers, e.g. increasing the social acceptance using information campaigns, or decreasing administrative burdens for commissioning new plants, etc. In other words, low (net) generation costs, but a low existing potential, still results in less additional penetration.

On the other hand, providing a good environment at administrative, social, industrial and technical levels (i.e. admitting a huge potential) without economic incentives does not increase the future penetration rate of a certain technology. A high potential of electricity generation, but high generation costs, also results in a low market share.

Up to now, economic support schemes have not been considered in the toolbox **Green*Net***, i.e. the influence of the support schemes and policy framework on the economic cost for an investor and an enterprise has not yet been analysed. This important step will be carried out in the economic assessment. The costs will be adapted in such a way that they agree with the promotion schemes for renewables, conventional power, CHP environment and climate change policy. Note, the costs correspond after the economic support assessment to the market conditions, i.e. they represent the offered prices / bids on the market. In other words, a transition from generation costs to offer prices takes place by applying the economic assessment.

Note, the methodology of the economic evaluation will be described in work package 8 (WP 8).

3.2 Overview

3.2.1 Historical development – Achieved potential

Figure 3.9 compares for each EU country in 2001: (i) total electricity consumption, and (ii) amount of electricity generated from RES. Three countries, Austria, Sweden and Portugal, generate more than a third of electricity from these sources; others a much lower proportion.

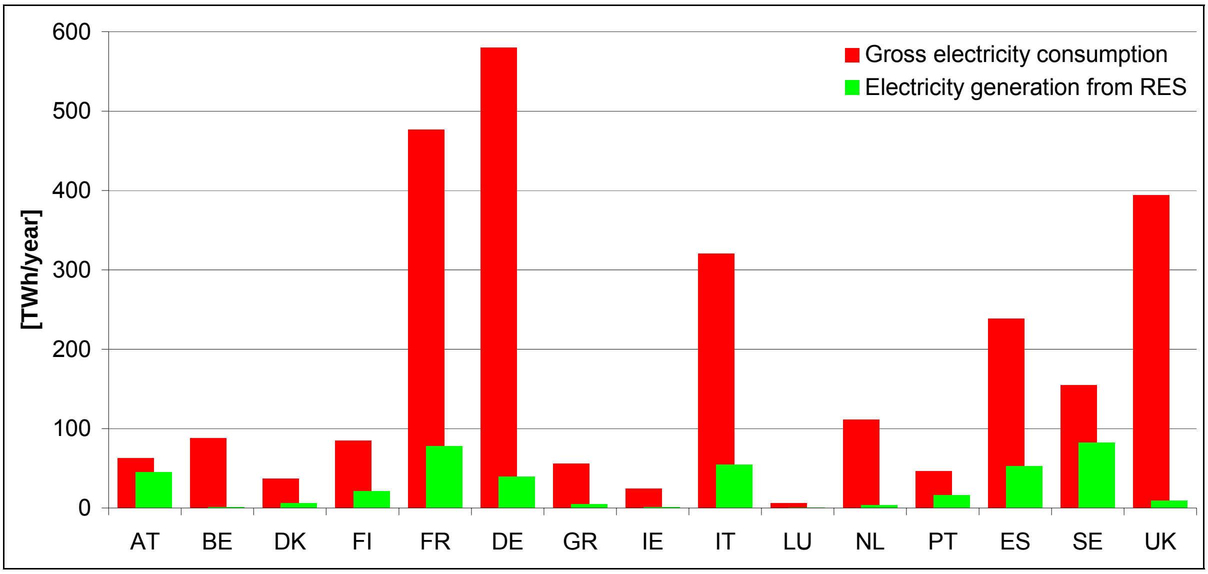

Figure 3.9. Electricity generation from RES versus total electricity consumption from RES in EU countries in 2001. Source: Own investigations; Eurostat, 2003.

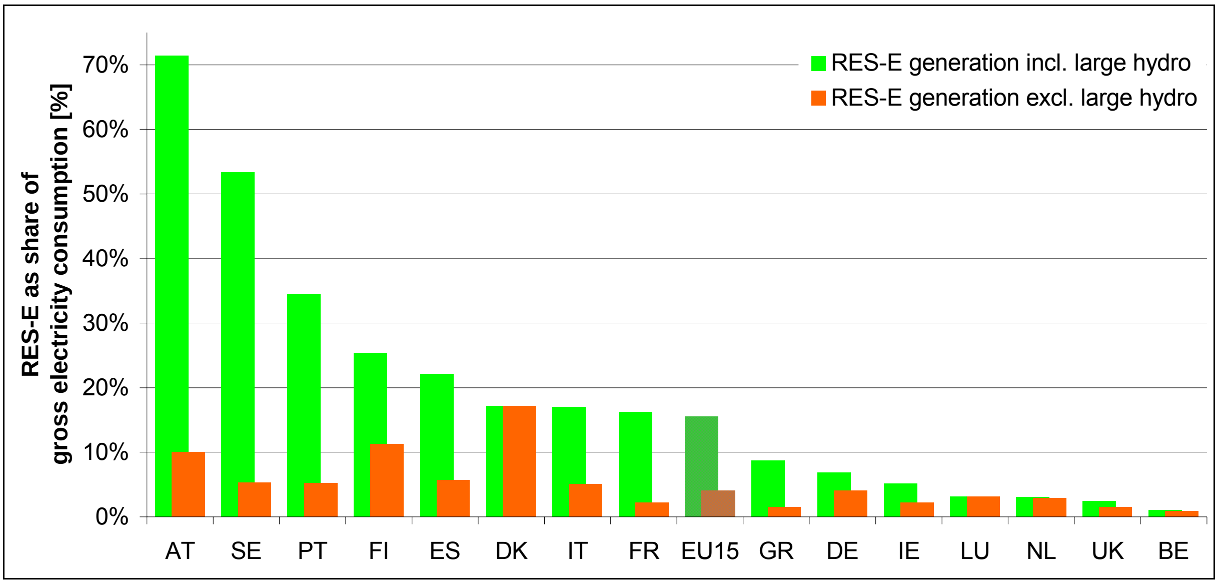

Figure 3.10. EU-15 countries ranked by the share of RES-E (with and without large hydro) on total electricity consumption in 2001. Source: Own investigations; Eurostat, 2003.

The largest share of RES is still 'large' (installed capacity >10 MW) hydropower, see Figure 3.10. Such plants have mostly been established before the post-1970's 'new renewables'. The shares of the other 'new renewable' technologies are depicted in detail in Figure 3.11. It shows that small hydro, biomass, municipal solid waste (MSW) and wind currently are the most important.

In Figure 3.11 of special interest are (i) the large proportions 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 3.12 shows the corresponding development of 'new renewables' over time (1990-2001), with (left-hand side) and without (right-hand side) hydropower.

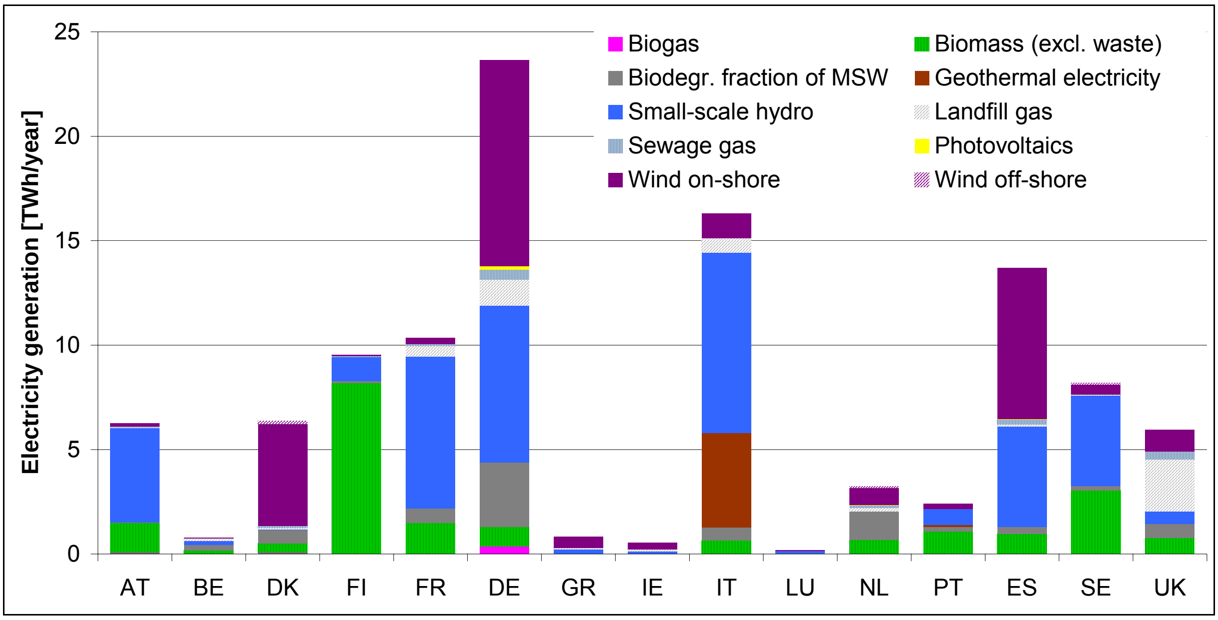

Figure 3.11. Electricity generation from various RES in EU countries in 2001. Source: Own investigations; Eurostat, 2003.

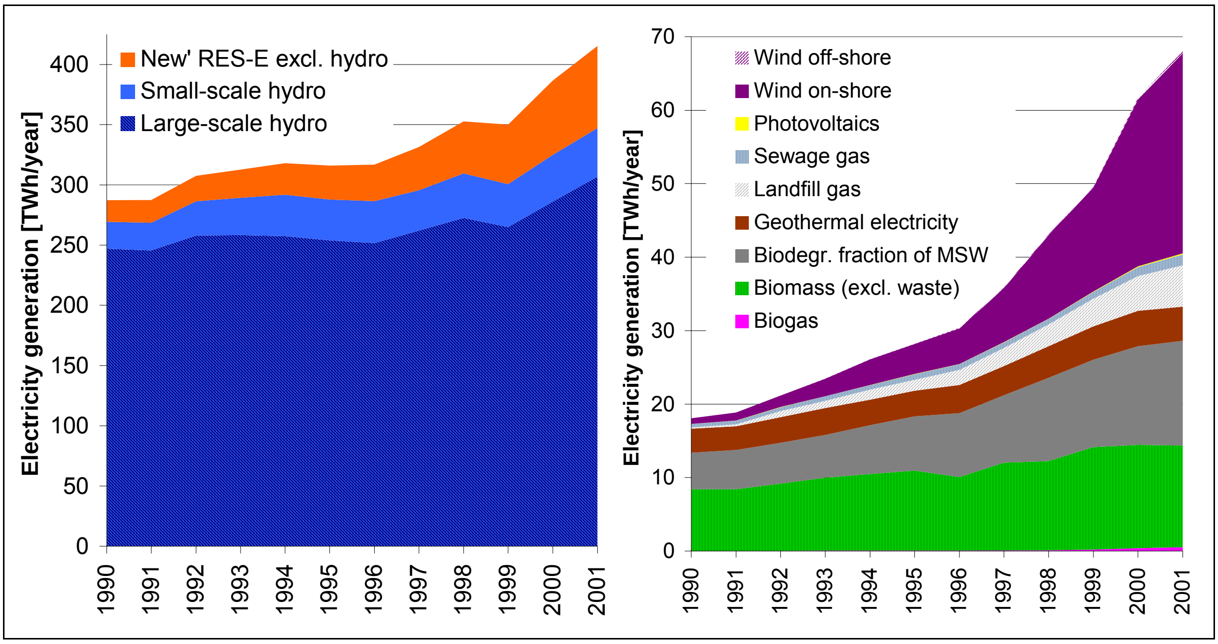

Figure 3.12. Electricity generation from RES in EU-15 countries from 1990 to 2001 – including (left-hand side) & excluding (right-hand side) hydro. Source: Own investigations; Eurostat, 2003.

Based on a comprehensive data-collection (Eurostat (2003), IEA (2002) and statistical information gained on national level) the database representing the achieved potential, i.e. the existing plant, for RES-E in EU-15 countries has been derived. Thereby, each band of the database for existing plant represents the generation potential of past annual installations within a country. In principle, it contains a set of information on costs (investment costs, O&M costs), potential (generation, full load-hours) and, of course, the construction year (derived by linking of time-series for annual installations – described by their electricity generation potential and the according capacity – with time-series for costs).

Table 3.3. Achieved potential (2001) of RES-E in EU-15 countries

RES-E: Achieved potential 2001 / Existing plant		AT	BE	DK	FI	FR	DE	GR	IE	IT	LU	NL	PT	ES	SE	UK	EU15
		Austria	Belgium	Denmark	Finland	France	Germany	Greece	Ireland	Italy	Luxembourg	Netherlands	Portugal	Spain	Sweden	United Kingdom	**European Union (15)**
Electricity generation potential [GWh]:																	
Category	*Short name*																
(Pure power generation & CHP)																	
Biogas	(BG)	49	0	70	0	0	385	0	0	8	8	0	0	2	0	0	**521**
(Solid) Biomass - Total	(BM)	1342	287	1650	8870	2249	3960	0	0	851	23	1496	1600	1553	3641	1718	**29240**
Forestry products	(BM-FP)	0	0	0	3511	0	0	0	0	0	0	0	0	0	1383	0	**4894**
Forestry residues	(BM-FR)	1310	0	668	5267	1572	816	0	0	218	0	91	1390	1234	2074	626	**15265**
Agricultural products	(BM-AP)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	313	**313**
Agricultural residues	(BM-AR)	0	0	334	1	0	21	0	0	5	0	11	1	12	0	104	**488**
Biodegradable fraction of waste	(BM-BW)	32	287	648	92	677	3122	0	0	629	23	1394	210	307	185	675	**8281**
Geothermal electricity	(GE)	7	0	0	0	21	0	0	0	6169	0	0	104	0	0	0	**6301**
Landfill gas	(LG)	96	99	71	10	505	1250	79	83	818	0	205	0	140	105	2301	**5761**
Sewage gas	(SG)	96	2	67	20	96	480	1	0	18	0	120	0	208	0	383	**1490**
(Pure power generation)																	
Hydropower - Total	(HY)	39206	317	27	13803	67155	19086	3582	824	43680	100	102	11207	34572	70731	4931	**309322**
Large-scale hydro	(HY-LS)	34869	133	0	12624	60935	11958	3407	721	35247	0	101	10560	31486	67363	4336	**273739**
Small-scale hydro	(HY-SS)	4338	184	27	1178	6219	7128	175	103	8433	100	1	647	3086	3369	595	**35583**
Solar energy - Total	(SO)	4	0	1	0	1	139	1	0	8	0	11	0	6	0	2	**173**
Photovoltaics	(SO-PV)	4	0	1	0	1	139	1	0	8	0	11	0	6	0	2	**173**
Solar thermal electricity	(SO-ST)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
Tidal stream	(TE)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
Wave energy	(WE)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
Wind energy - Total	(WI)	175	57	5351	72	300	14444	585	325	1289	33	1026	275	7988	593	1138	**33651**
Wind onshore	(WI-ON)	175	57	5197	72	300	14444	585	325	1289	33	968	275	7988	512	1138	**33357**
Wind offshore	(WI-OF)	0	0	155	0	0	0	0	0	0	0	58	0	0	81	0	**295**
TOTAL RES-E		**40975**	**762**	**7237**	**22775**	**70327**	**39744**	**4247**	**1231**	**52841**	**165**	**2961**	**13186**	**44468**	**75071**	**10471**	**386460**
Gross electricity consumption 2000	GWh	58615	86964	36893	81854	466213	571744	53128	23767	314355	6154	108511	44295	227211	150528	386310	**2616544**
Gross electricity consumption 2020	GWh	82167	107625	45768	99436	654170	656653	87903	39743	392953	9057	161839	72565	365327	175220	538024	**3488450**
RES-E as share of Gross electricity consumption 2000	%	69,9%	0,9%	19,6%	27,8%	15,1%	7,0%	8,0%	5,2%	16,8%	2,7%	2,7%	29,8%	19,6%	49,9%	2,7%	**14,8%**
RES-E as share of Gross electricity consumption 2020	%	49,9%	0,7%	15,8%	22,9%	10,8%	6,1%	4,8%	3,1%	13,4%	1,8%	1,8%	18,2%	12,2%	42,8%	1,9%	**11,1%**
Capacity potential [MW]:																	
Category	*Short name*																
(Pure power generation & CHP)																	
Biogas	(BG)	18	0	23	0	0	110	0	0	3	3	0	0	1	0	0	**158**
(Solid) Biomass - Total	(BM)	332	44	350	2209	497	690	0	0	152	4	240	380	359	893	365	**6514**
Forestry products	(BM-FP)	0	0	0	878	0	0	0	0	0	0	0	0	0	346	0	**1223**
Forestry residues	(BM-FR)	328	0	167	1317	393	204	0	0	54	0	23	347	308	518	156	**3816**
Agricultural products	(BM-AP)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	78	**78**
Agricultural residues	(BM-AR)	0	0	83	0	0	5	0	0	1	0	3	0	3	0	26	**122**
Biodegradable fraction of waste	(BM-BW)	5	44	100	14	104	480	0	0	97	4	215	32	47	28	104	**1274**
Geothermal electricity	(GE)	1	0	0	0	5	0	0	0	949	0	0	18	0	0	0	**973**
Landfill gas	(LG)	17	18	13	2	92	227	14	15	149	0	37	0	26	19	418	**1047**
Sewage gas	(SG)	18	0	15	4	21	107	0	0	4	0	27	0	46	0	85	**327**
(Pure power generation)																	
Hydropower - Total	(HY)	8551	104	10	2927	21142	3440	2465	233	13456	37	38	4330	18006	16271	1508	**92518**
Large-scale hydro	(HY-LS)	7680	43	0	2623	19468	2000	2402	199	11186	0	36	4049	16399	15496	1326	**82908**
Small-scale hydro	(HY-SS)	871	61	10	304	1674	1440	63	34	2270	37	2	281	1607	775	182	**9611**
Solar energy - Total	(SO)	5	0	1	0	1	178	1	0	8	0	16	0	5	0	2	**219**
Photovoltaics	(SO-PV)	5	0	1	0	1	178	1	0	8	0	16	0	5	0	2	**219**
Solar thermal electricity	(SO-ST)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
Tidal stream	(TE)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
Wave energy	(WE)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
Wind energy - Total	(WI)	95	31	2467	39	125	8754	272	125	697	15	542	125	3550	300	474	**17610**
Wind onshore	(WI-ON)	95	31	2417	39	125	8754	272	125	697	15	523	125	3550	277	474	**17518**
Wind offshore	(WI-OF)	0	0	50	0	0	0	0	0	0	0	19	0	0	23	0	**92**
TOTAL RES-E		**9037**	**198**	**2879**	**5181**	**21883**	**13506**	**2752**	**373**	**15419**	**59**	**900**	**4853**	**21993**	**17483**	**2852**	**119367**

3.2.2 Future potential

The following table and figures are presented in accordance with the cost-resource curve-database potentials of RES-E. In Table 3.4 the additional mid-term potentials are expressed for all RES-E and EU countries. Figure 3.13 and Figure 3.14 illustrate the various potential-terms by country. Especially, in Figure 3.15 and Figure 3.16 the RES-E shares (%) of achieved- and additional mid-term capacity potential for RES-E (by country) are depicted.

Table 3.4. Additional mid-term potential (up to 2020) for RES-E in EU-15 countries

RES-E: Additional mid-term potential 2020 / New plant		AT	BE	DK	FI	FR	DE	GR	IE	IT	LU	NL	PT	ES	SE	UK	EU15
		Austria	Belgium	Denmark	Finland	France	Germany	Greece	Ireland	Italy	Luxembourg	Netherlands	Portugal	Spain	Sweden	United Kingdom	European Union (15)
Electricity generation potential [GWh]:																	
Category	*Short name*																
(Pure power generation & CHP)																	
Biogas	(BG)	2505	4759	5196	952	18551	16057	774	4203	5846	125	8448	1696	12433	1790	11262	**94597**
in case of CHP …		*2422*	*4607*	*5030*	*921*	*17955*	*15541*	*748*	*4067*	*5658*	*121*	*8188*	*1640*	*12033*	*1732*	*10900*	***91565***
(Solid) Biomass (BM) - Total	(BM)	8704	4124	7539	16137	75598	61400	7322	3964	31665	434	4926	6715	54581	19788	28457	**331355**
in case of CHP …		*7463*	*3503*	*6555*	*14003*	*65401*	*52909*	*6321*	*3365*	*27187*	*377*	*4127*	*5782*	*45929*	*17069*	*24375*	***284366***
Forestry products	(BM-FP)	2548	266	375	6782	11574	14560	1268	396	3591	240	276	612	6327	7210	1834	**57860**
in case of CHP …		*2218*	*231*	*329*	*5934*	*10075*	*12675*	*1104*	*344*	*3126*	*209*	*241*	*533*	*5508*	*6308*	*1596*	***50431***
Forestry residues	(BM-FR)	1171	729	368	2924	5558	6271	558	302	3312	28	867	1027	2646	3466	3440	**32668**
in case of CHP …		*1019*	*635*	*322*	*2559*	*4838*	*5459*	*486*	*262*	*2883*	*24*	*755*	*894*	*2303*	*3033*	*2995*	***28467***
Agricultural products	(BM-AP)	2716	1658	4765	4321	35962	22966	3855	2004	15941	117	1901	4079	25072	5534	12893	**143783**
in case of CHP …		*2365*	*1443*	*4169*	*3781*	*31305*	*19992*	*3356*	*1740*	*13877*	*102*	*1655*	*3551*	*21825*	*4842*	*11223*	125225
Agricultural residues	(BM-AR)	1282	718	1715	1210	18970	12926	1178	550	5548	43	489	443	6812	1689	6848	**60421**
in case of CHP …		*1116*	*625*	*1501*	*1058*	*16513*	*11252*	*1025*	*478*	*4830*	*38*	*425*	*385*	*5930*	*1478*	*5962*	***52616***
Biodegradable fraction of waste	(BM-BW)	986	754	315	901	3534	4677	463	711	3273	5	1393	554	13725	1890	3442	**36623**
in case of CHP …		*745*	*569*	*235*	*671*	*2669*	*3531*	*350*	*541*	*2471*	*4*	*1052*	*418*	*10363*	*1408*	*2599*	***27627***
Geothermal electricity	(GE)	24	0	0	0	340	0	475	0	3500	0	0	407	204	0	0	**4950**
in case of CHP …		*21*	*0*	*0*	*0*	*297*	*0*	*416*	*0*	*3080*	*0*	*0*	*357*	*178*	*0*	*0*	***4350***
Landfill gas	(LG)	0	541	62	918	5320	3152	704	1108	2403	12	202	1308	14429	726	1593	**32479**
in case of CHP …		*0*	*525*	*60*	*890*	*5161*	*3059*	*683*	*1074*	*2331*	*11*	*196*	*1269*	*13996*	*705*	*1546*	***31506***
Sewage gas	(SG)	178	231	42	91	1289	1254	202	88	1204	11	241	209	575	198	921	**6735**
in case of CHP …		*166*	*216*	*39*	*85*	*1201*	*1170*	*188*	*82*	*1122*	*10*	*225*	*195*	*536*	*185*	*860*	***6279***
(Pure power generation)																	
Hydropower - Total	(HY)	4701	78	0	1119	3716	3657	237	179	1631	0	50	1546	2136	1391	157	**20600**
Large-scale hydro	(HY-LS)	0	0	0	732	0	2469	0	76	0	0	0	467	330	87	0	**4161**
Small-scale hydro	(HY-SS)	4701	78	0	388	3716	1188	237	103	1631	0	50	1080	1806	1304	157	**16439**
Solar energy - Total	(SO)	6569	8610	3661	7955	52333	52393	9666	3179	39052	725	12936	8223	46429	14018	43040	**308788**
Photovoltaics	(SO-PV)	6569	8610	3661	7955	52333	52393	7032	3179	31429	725	12936	5805	29220	14018	43040	**278903**
Solar thermal electricity	(SO-ST)	0	0	0	0	0	0	2634	0	7623	0	0	2418	17209	0	0	**29885**
Tidal stream	(TE)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
Wave energy	(WE)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
Wind energy - Total	(WI)	4752	7744	18086	11635	84295	114510	10865	16219	29075	181	23698	14848	44776	22336	92405	**495423**
Wind onshore	(WI-ON)	4752	4172	3384	7615	54995	39260	8285	7707	26728	181	4319	8385	30631	9073	26805	**236291**
Wind offshore	(WI-OF)	0	3572	14702	4020	29300	75250	2580	8512	2347	0	19379	6463	14145	13263	65600	**259132**
TOTAL RES-E		**27433**	**26087**	**34585**	**38807**	**241442**	**252423**	**30245**	**28940**	**114376**	**1487**	**50500**	**34953**	**175563**	**60247**	**177837**	**1294926**
in case of CHP …		***23672***	***20675***	***28401***	***35687***	***212404***	***227698***	***28375***	***24098***	***103478***	***1304***	***41232***	***32219***	***153981***	***55703***	***162384***	***1151311***
Gross electricity consumption 2000	GWh	58615	86964	36893	81854	466213	571744	53128	23767	314355	6154	108511	44295	227211	150528	386310	**2616544**
Gross electricity consumption 2010	GWh	70244	98457	40027	92833	568053	616806	75830	33121	352929	8315	134185	57825	304637	159572	452636	**3065472**
Gross electricity consumption 2020	GWh	82167	107625	45768	99436	654170	656653	87903	39743	392953	9057	161839	72565	365327	175220	538024	**3488450**
RES-E as share of Gross electricity consumption 2000	%	46,8%	30,0%	93,7%	47,4%	51,8%	44,1%	56,9%	121,8%	36,4%	24,2%	46,5%	78,9%	77,3%	40,0%	46,0%	**49,5%**
in case of CHP …	*%*	*40,4%*	*23,8%*	*77,0%*	*43,6%*	*45,6%*	*39,8%*	*53,4%*	*101,4%*	*32,9%*	*21,2%*	*38,0%*	*72,7%*	*67,8%*	*37,0%*	*42,0%*	*44,0%*
RES-E as share of Gross electricity consumption 2020	%	33,4%	24,2%	75,6%	39,0%	36,9%	38,4%	34,4%	72,8%	29,1%	16,4%	31,2%	48,2%	48,1%	34,4%	33,1%	37,1%
in case of CHP …	*%*	*28,8%*	*19,2%*	*62,1%*	*35,9%*	*32,5%*	*34,7%*	*32,3%*	*60,6%*	*26,3%*	*14,4%*	*25,5%*	*44,4%*	*42,1%*	*31,8%*	*30,2%*	*33,0%*
Capacity potential [MW]:																	
Category	*Short name*																
(Pure power generation & CHP)																	
Biogas	(BG)	494	882	963	181	3481	3013	153	798	1097	23	1466	334	2333	336	2113	**17668**
in case of CHP …		*478*	*854*	*932*	*175*	*3368*	*2915*	*148*	*772*	*1061*	*23*	*1421*	*323*	*2257*	*325*	*2044*	***17095***
(Solid) Biomass (BM) - Total	(BM)	1347	638	1167	2497	11700	9502	1133	613	4901	67	762	1039	8447	3062	4404	**51281**
in case of CHP …		*1795*	*822*	*1617*	*3437*	*16096*	*12891*	*1547*	*790*	*6561*	*94*	*932*	*1406*	*10495*	*4133*	*5846*	***68460***
Forestry products	(BM-FP)	394	41	58	1050	1791	2253	196	61	556	37	43	95	979	1116	284	**8955**
in case of CHP …		*555*	*58*	*82*	*1484*	*2519*	*3169*	*276*	*86*	*781*	*52*	*60*	*133*	*1377*	*1577*	*399*	***12608***
Forestry residues	(BM-FR)	181	113	57	453	860	971	86	47	513	4	134	159	409	536	532	**5056**
in case of CHP …		*255*	*159*	*81*	*640*	*1210*	*1365*	*121*	*65*	*721*	*6*	*189*	*224*	*576*	*758*	*749*	***7117***
Agricultural products	(BM-AP)	420	257	737	669	5566	3554	597	310	2467	18	294	631	3880	856	1995	**22252**
in case of CHP …		*591*	*361*	*1042*	*945*	*7826*	*4998*	*839*	*435*	*3469*	*25*	*414*	*888*	*5456*	*1211*	*2806*	31306
Agricultural residues	(BM-AR)	198	111	265	187	2936	2000	182	85	859	7	76	68	1054	261	1060	**9351**
in case of CHP …		*279*	*156*	*375*	*265*	*4128*	*2813*	*256*	*119*	*1207*	*9*	*106*	*96*	*1482*	*369*	*1490*	***13154***
Biodegradable fraction of waste	(BM-BW)	153	117	49	139	547	724	72	110	507	1	216	86	2124	293	533	**5668**
in case of CHP …		*115*	*88*	*36*	*104*	*413*	*547*	*54*	*84*	*382*	*1*	*163*	*65*	*1604*	*218*	*402*	***4276***
Geothermal electricity	(GE)	4	0	0	0	58	0	81	0	600	0	0	70	35	0	0	**849**
in case of CHP …		*4*	*0*	*0*	*0*	*57*	*0*	*80*	*0*	*675*	*0*	*0*	*69*	*34*	*0*	*0*	***919***

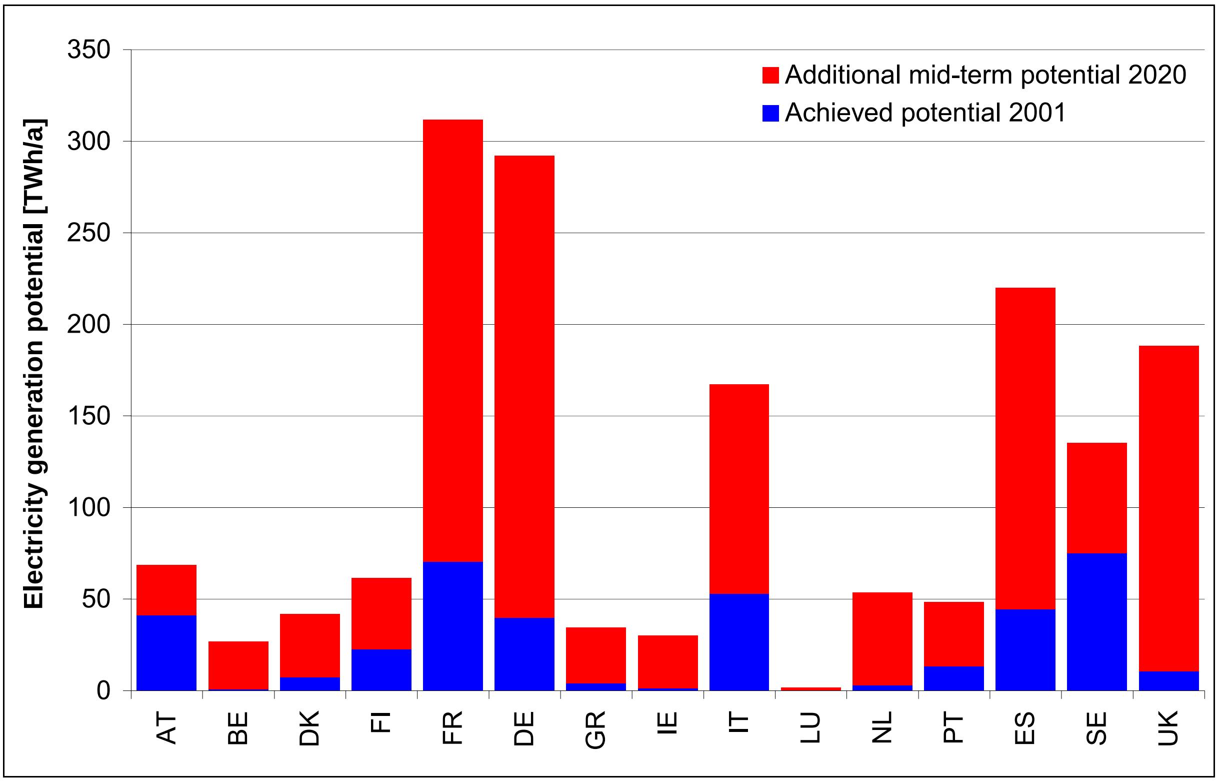

Figure 3.13. Achieved (2001) & additional mid-term electricity potential (up to 2020) for RES-E in EU-15 countries

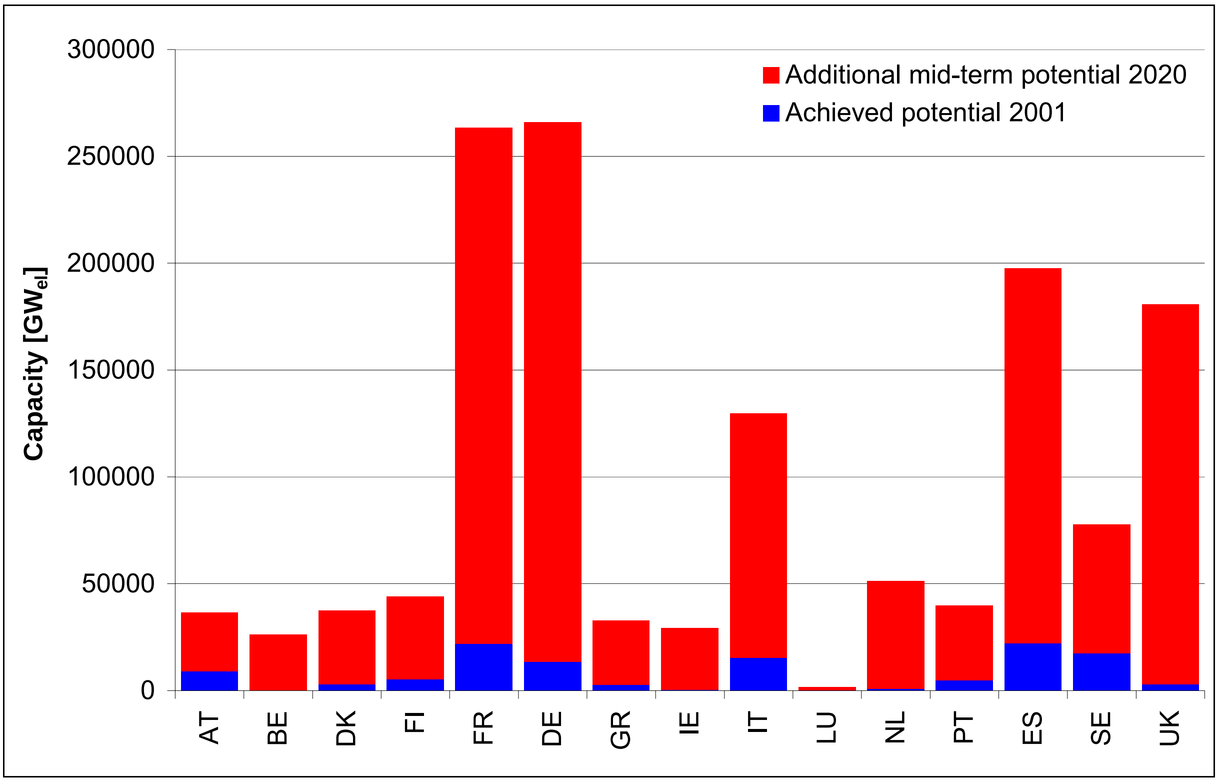

Figure 3.14. Achieved (2001) & additional mid-term capacity potential (up to 2020) for RES-E in EU-15 countries

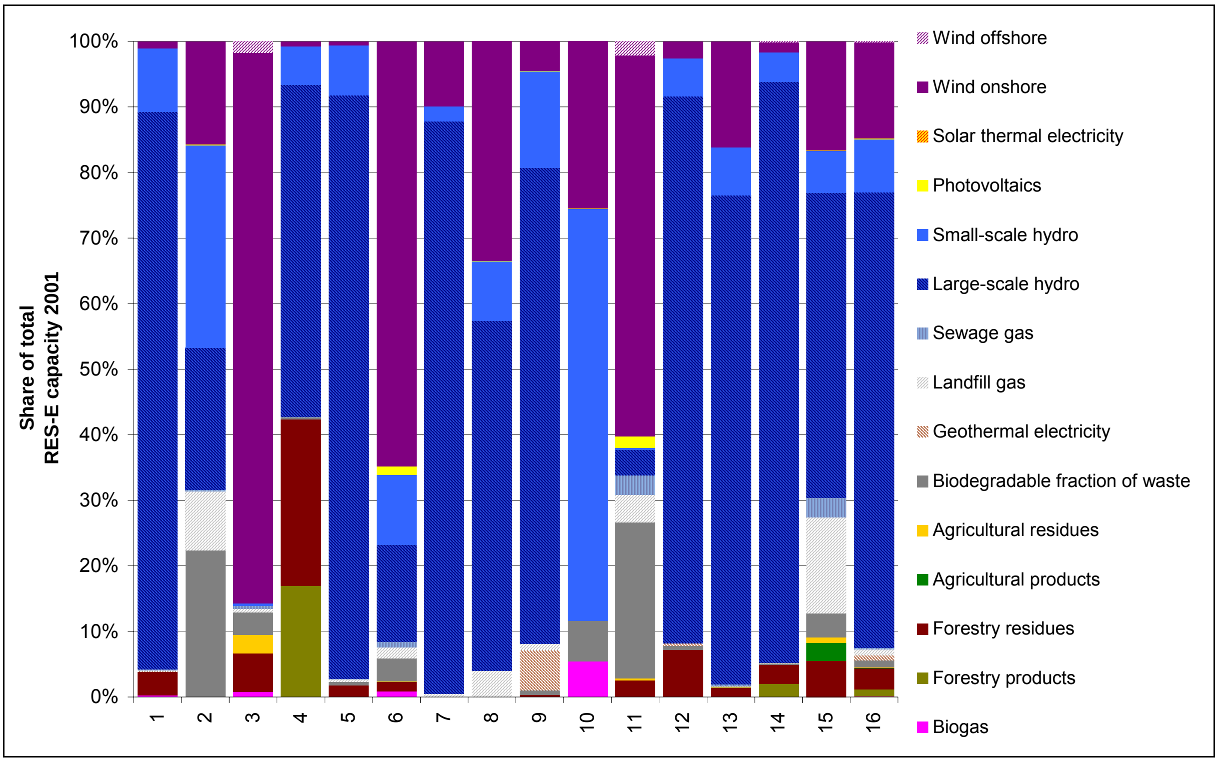

Figure 3.15. RES-E shares (%) of achieved mid-term capacity potential for RES-E in EU-15 countries

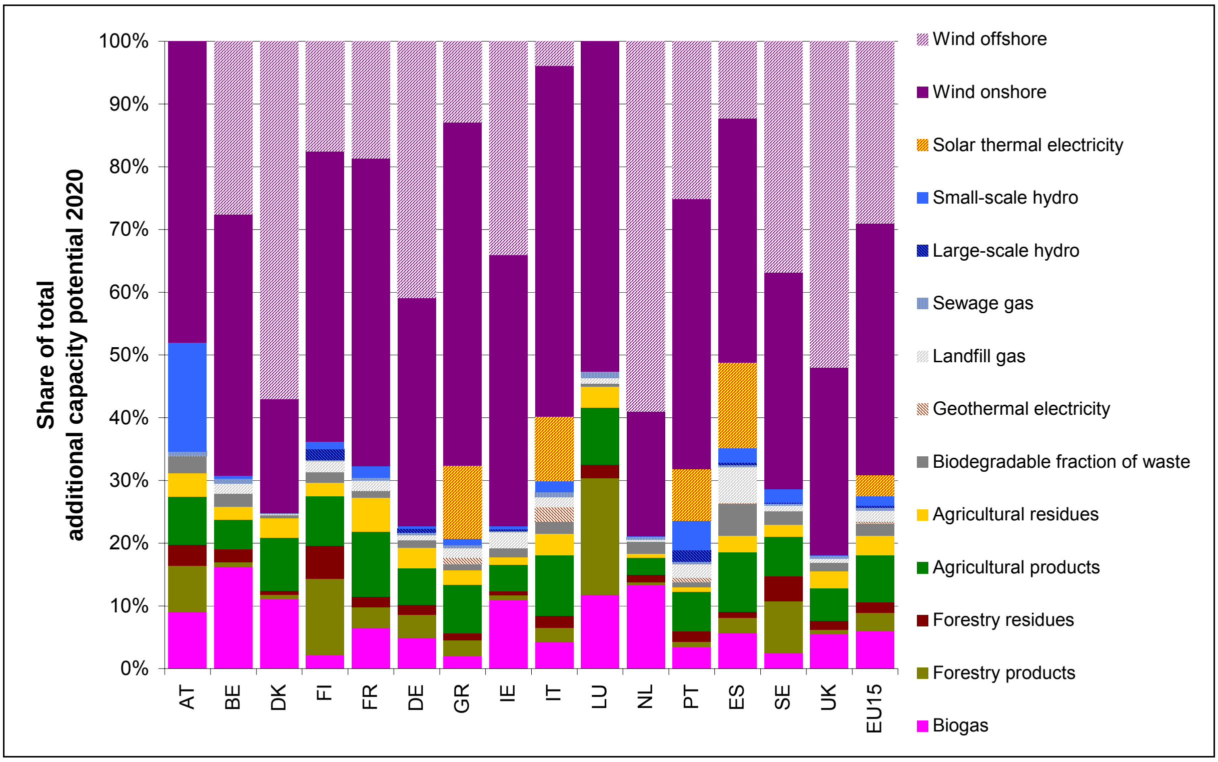

Figure 3.16. RES-E shares (%) of additional mid-term capacity potential for RES-E (excl. PV) in EU-15 countries

3.2.3 Economics

In accordance with the database long-run and short-run marginal generation costs for new RES-E are expressed in the following, see Figure 3.17 to Figure 3.19. These costs refer to the starting year of the simulation, i.e. 2002 and, hence, are expressed in €$_{2002}$. The broad range of cost for several RES-E represents the country-specific differences occurring at present.

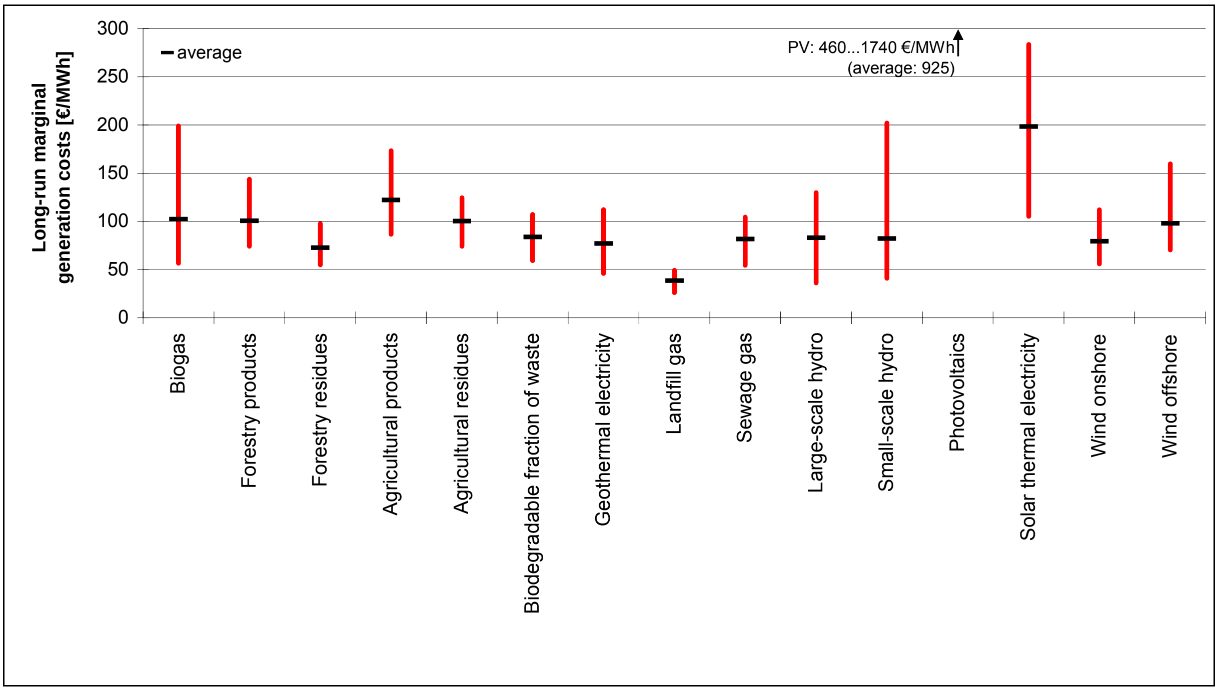

Figure 3.17. Overview of long-run marginal generation costs for RES-E in EU-15 countries

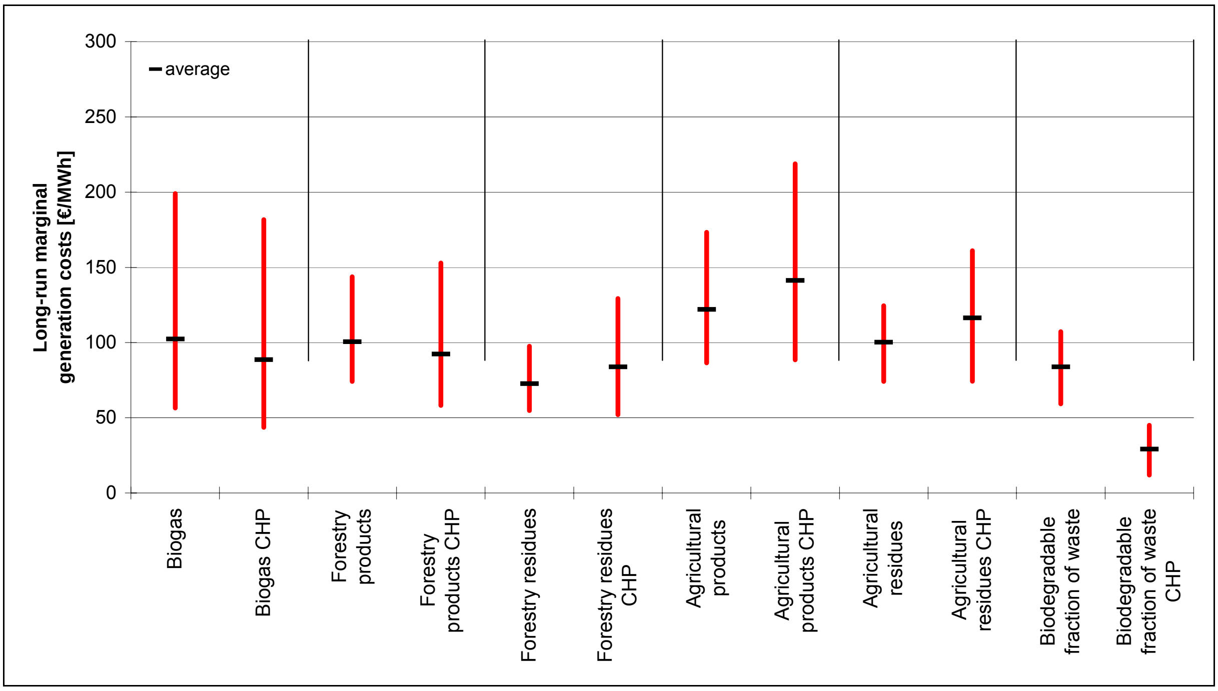

Figure 3.18 Comparison of long-run marginal generation costs for biomass: CHP vs. pure power generation

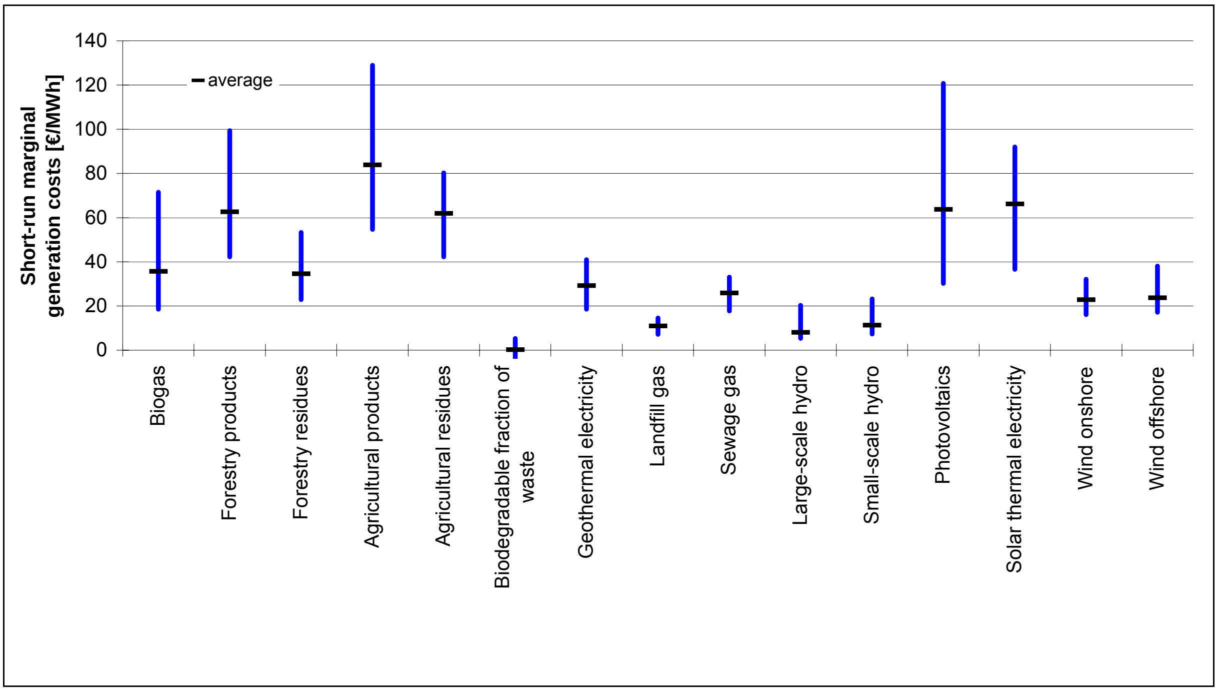

Figure 3.19 Overview of short-run marginal generation costs for RES-E in EU-15 countries

3.3 Cost-resource curves by RES-E

3.3.1 Biogas

3.3.1.1 Methodology for the development of cost-resource curves

Within the toolbox **Green*Net*** the RES-E category biogas is used to describe electricity generation resulting from an anaerobic digestion process of biological deposits. Thereby, following primary resource categories are covered:

- Farm slurries,
- Agricultural residues (e.g. from sugar beet production),
- Residues from pasture land; and
- Separately-collected biodegradable fractions of municipal waste.

Please note, on contrary to the categorization given by Eurostat or IEA, biogas described in **Green*Net*** does not cover landfill and sewage gas!

Future potential

The approach for the assessment of the additional mid-term potential is as follows:

1. First, an assessment of the mid-term primary energy potential has been undertaken.
2. Second, electricity potentials are calculated by linking of plant-specific conversion efficiencies to the primary potentials derived above.

In the following, the approach for the derivation of the primary potential figures is explained in more detail. In principle, four different fuel categories are considered:

- Farm slurries: Based on country-specific statistical agricultural data (Eurostat, 2002a), i.e. livestock of cows, swine and poultry by country, biogas production is calculated by applying typical values for the specific amount of excrements and related biogas produced. Obviously the technical potential of biogas from farm slurries depends on the number of total livestock. Therefore, to calculate the mid-term potential, country-specific shares of availability of the different slurries are applied.
- Agricultural residues: The cultivation of a set of plants as used in agriculture (e.g. sugar beet) produces a large amount of residues for digestion. Agricultural statistics (taken from Eurostat, 2002a) are used to estimate the biogas potential. In this context, it is assumed that only 15% of these residues can be used for biogas production.
- Pasture residues: A 5% availability of the total amount of pasture residues is assumed for each country. In accordance with the specific output per ha and total available area biogas potential is calculated.
- Separated biodegradable fraction of municipal wastes: It is assumed that roughly 100 kg per capita and year can be used for biogas production. The typical gas output of this fuel fraction is in size of 100 m^3/t.

Based on this primary energy potential assessment, the potential for electricity from biogas is calculated by applying an average gas energy content of 21,6 MJ/m^3 (see e.g. Neubarth et. al., 2000) and an electrical conversion efficiency of 26%. Finally, capacity potentials are derived by applying plant-specific full-load hours.

Costs

Table 3.5 provides an overview on cost-data for new biogas plant of the toolbox **Green*Net***. Please note, investment as well as O&M-costs are given in $€_{2002}$ and refer to the start year of the simulations (i.e. 2002).

Table 3.5. Overview on cost-data for new plant (biogas – pure power production & CHP)

Cost - data for new plant

	category	plant-type: unit	**ELE large** (new 1)	**ELE medium** (new 2)	**ELE small** (new 3)	**CHP large** (new 1)	**CHP medium** (new 2)	**CHP small** (new 3)
technical-specification	*plant-size*	*MW_{el}*	0,500	0,250	0,100	0,500	0,250	0,100
	efficiency electricity	%	34%	32%	28%	33%	31%	27%
	efficiency heat	%				55%	56%	59%
	efficiency TOTAL	%	34%	32%	28%	88%	87%	86%
	power-to-heat-ratio	1	0,00	0,00	0,00	1,67	1,81	2,19
	life time	a	25	25	25	25	25	25
cost-specification (general)	lifetime	a	15	15	15	15	15	15
	interest rate	*%*	*6,5%*	*6,5%*	*6,5%*	*6,5%*	*6,5%*	*6,5%*
	c.r.f	*1*	*0,1064*	*0,1064*	*0,1064*	*0,1064*	*0,1064*	*0,1064*
	Share of HARMONISED investment costs	%	100%	100%	100%	100%	100%	100%
	investment costs TOTAL (average)	**€/kW_{el}**	**2.500,00**	**3.200,00**	**4.200,00**	**2.700,00**	**3.400,00**	**4.400,00**
	investment costs HARMONISED	€/kW_{el}	2.500,00	3.200,00	4.200,00	2.700,00	3.400,00	4.400,00
	investment costs NON-HARMONISED (average)	€/kW_{el}	0,00	0,00	0,00	0,00	0,00	0,00
	Share of HARMONISED O&M costs	%	100%	100%	100%	100%	100%	100%
	O&M costs TOTAL (average)	**€/(kW_{el}*a)**	**130,00**	**180,00**	**250,00**	**135,00**	**185,00**	**255,00**
	O&M costs TOTAL (average) as share of investment costs	**%**	**5,2%**	**5,6%**	**6,0%**	**5,0%**	**5,4%**	**5,8%**
	O&M costs HARMONISED	€/(kW_{el}*a)	130,00	180,00	250,00	135,00	185,00	255,00
	O&M costs NON-HARMONISED (average)	€/(kW_{el}*a)	0,00	0,00	0,00	0,00	0,00	0,00

The total investment costs of biogas plants are at present in a range between 2100 and 3570 €/kW (compare e.g. Fischer et. al. (2002), Resch et. al. (2001)), depending on site-specific conditions (i.e. plant-size, etc.). Cost differences with respect to related technologies like landfill gas occur due to the fact that for a landfill site gas collection as well as a gas treatment is prescribed by law. Therefore, this cost intensive investments can not be allocated to the power plant.

The achievable full-load hours of a biogas gas plant highly depend on plant specific conditions, especially with respect to the planning process. If the power unit is constructed too large, achievable full load hours would be rather low. In general, achievable full-load hours decrease with the age of the plant even if waste depositing is kept constant over time. *E-Control (2002)* states with respect to existing plant about 4600 h/a on average, a quite moderate figure. To meet the existing uncertainty – full-load hours are assumed to be in a range between 2500 and 4500 h/a. Hence, in case of CHP due to the lacking demand for heat on-site achievable full load-hours with respect to heat generation are assumed to be lower: 2000 h/a for small plant and 3500 h/a for large plant.

In general, biogas gas represents a zero-cost fuel source, as it appears as a kind of side-product of the purification process.

Cost-resource curves

To define the cost-resource curves for biogas (in case of pure power generation) for each country the following considerations have to be taken into account:

- The typical farm size given by country-specific statistical agricultural data (taken from Eurostat, 2020a) is used to determine the shares of different plant categories, i.e. if in country A, the current farm size is quite large, many large biogas plant can be constructed; therefore the share of large scale plant ‘new 1’ (see Table 3.5) is assumed to be high. Thus the total potential of biogas by country is divided to the different plant categories.
- For each plant category two different full-load hour levels are applied.
- As a consequence the cost range is equal for all countries, whereas the average electricity generation costs vary by country.

In case of CHP the procedure was similar to above. In this context, please note that the potential for CHP and pure power production are linked within the model – i.e. the potential can not be used twice.[17]

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[17] In more detail: Bands for CHP and pure power generation referring to the same primary energy potential are linked to each other within the model. That means that if e.g. a certain part of potential of the CHP-band no.1 will be implemented the potential of band no.1 for pure power generation will be reduced accordingly. This

3.3.1.2 Resulting cost-resource curves

An overview on potential and costs for electricity from biogas in EU-15 countries is provided in Table 3.6 (for both pure power production and CHP). In addition, a comparison of the achieved and the additional mid-term potential is given in Figure 3.20 (for both pure power production and CHP).

Table 3.6. Overview on potential and costs for electricity from biogas (pure power production & CHP) in EU-15 countries

Biogas (BG)		**AT**	**BE**	**DK**	**FI**	**FR**	**DE**	**GR**	**IE**	**IT**	**LU**	**NL**	**PT**	**ES**	**SE**	**UK**	**EU15**
Potential - existing & new plant:																	
Achieved potential:																	
electricity generation pot.	GWh	49	0	70	0,1	0	385	0	0	8	8	0	0	2	0	0	**521**
capacity potential	MW	18	0	23	0,0	0	110	0	0	3	3	0	0	1	0	0	**158**
full load-hours (average)	h/a	2700		3000	3000		3500			2500	2500			2500			**3291**
Additional mid-term potential:																	
electricity generation pot.	GWh	2505	4759	5196	952	18551	16057	774	4203	5846	125	8448	1696	12433	1790	11262	**94597**
in case of CHP …	GWh	2422	4607	5030	921	17955	15541	748	4067	5658	121	8188	1640	12033	1732	10900	**91565**
capacity potential	MW	494	882	963	181	3481	3013	153	798	1097	23	1466	334	2333	336	2113	**17668**
in case of CHP …	MW	478	854	932	175	3368	2915	148	772	1061	23	1421	323	2257	325	2044	**17095**
full load-hours (average)	h/a	5070	5395	5395	5265	5330	5330	5047	5265	5330	5330	5762	5070	5330	5330	5330	**5354**
in case of CHP …	h/a	5072	5397	5397	5267	5332	5332	5049	5267	5332	5332	5763	5072	5332	5332	5332	**5356**
Costs of electricity - new plant:																	
Long-run marginal costs (LRMC):																	
minimum	€/MWh	56,6	56,6	56,6	56,6	56,6	56,6	56,6	56,6	56,6	56,6	56,6	56,6	56,6	56,6	56,6	**56,6**
maximum	€/MWh	199,1	199,1	199,1	199,1	199,1	199,1	199,1	199,1	199,1	199,1	199,1	199,1	199,1	199,1	199,1	**199,1**
average (weighted)	€/MWh	117,7	100,6	100,6	106,6	103,6	103,6	119,3	106,6	103,6	103,6	83,2	117,7	103,6	103,6	103,6	**102,3**
in case of CHP …																	
minimum	€/MWh	43,6	43,6	43,6	43,6	43,6	43,6	43,6	43,6	43,6	43,6	43,6	43,6	43,6	43,6	43,6	**43,6**
maximum	€/MWh	181,6	181,6	181,6	181,6	181,6	181,6	181,6	181,6	181,6	181,6	181,6	181,6	181,6	181,6	181,6	**181,6**
average (weighted)	€/MWh	102,4	87,0	87,0	92,4	89,7	89,7	103,9	92,4	89,7	89,7	71,4	102,4	89,7	89,7	89,7	**88,6**
Short-run marginal costs (SRMC):																	
minimum	€/MWh	18,6	18,6	18,6	18,6	18,6	18,6	18,6	18,6	18,6	18,6	18,6	18,6	18,6	18,6	18,6	**18,6**
maximum	€/MWh	71,4	71,4	71,4	71,4	71,4	71,4	71,4	71,4	71,4	71,4	71,4	71,4	71,4	71,4	71,4	**71,4**
average (weighted)	€/MWh	41,5	35,0	35,0	37,2	36,1	36,1	42,1	37,2	36,1	36,1	28,4	41,5	36,1	36,1	36,1	**35,6**
in case of CHP …																	
minimum	€/MWh	2,6	2,6	2,6	2,6	2,6	2,6	2,6	2,6	2,6	2,6	2,6	2,6	2,6	2,6	2,6	**2,6**
maximum	€/MWh	47,9	47,9	47,9	47,9	47,9	47,9	47,9	47,9	47,9	47,9	47,9	47,9	47,9	47,9	47,9	**47,9**
average (weighted)	€/MWh	22,1	17,5	17,5	19,1	18,3	18,3	22,6	19,1	18,3	18,3	12,9	22,1	18,3	18,3	18,3	**18,0**

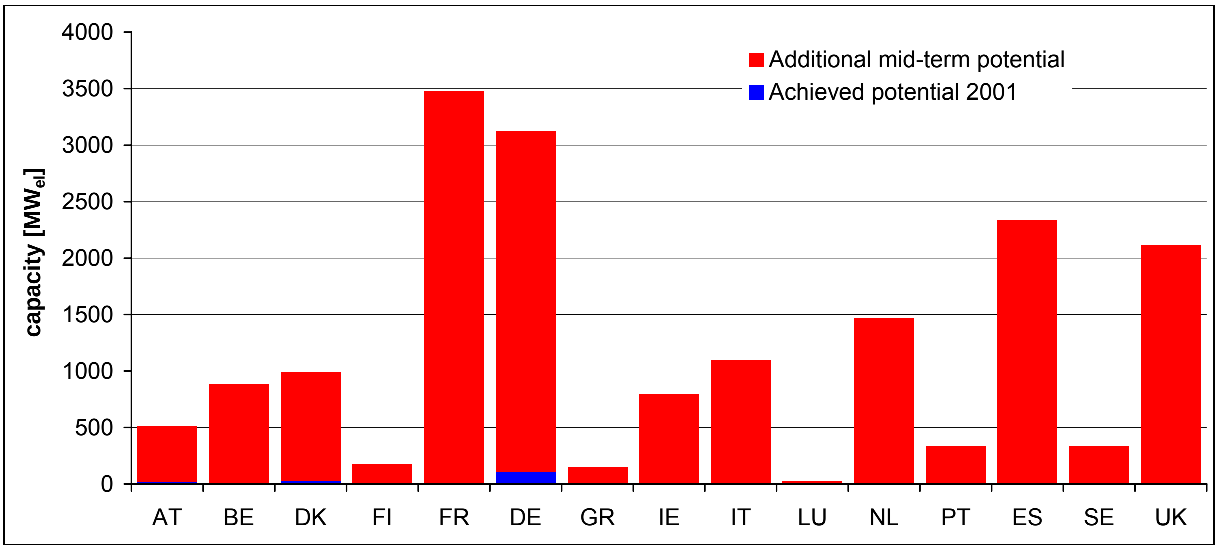

Figure 3.20. Achieved potential (2001) & additional mid-term potential for electricity from biogas (pure power production) in EU-15 countries

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procedure is internalised into the model, as part of the band-specific data linkages can be applied to a maximum of four different options.

Dynamic aspects of cost development

As default, within the model **Green*Net*** the future development of investment costs for biogas plant is based using cost forecasts where a percentage decrease of costs is indicated for each year.

3.3.2 (Solid) Biomass

3.3.2.1 Methodology for the development of cost-resource curves

For the database of the toolbox **Green*Net*** it has been decided to treat electricity generation from solid biomass as follows:

Following the definition of biomass given by the 'RES-E directive' (EC, 2001) five sub-categories have been defined:

- Forestry products (BM-FP),
- Forestry residues (BM-FR),
- Agricultural products (BM-AP),
- Agricultural residues (BM-AR),
- Biodegradable fraction of waste (BM-BW).

Based on this categorization, for each sub-category a separate assessment of the available potential has been undertaken. With respect to the applied conversion technologies, differences between the sub-categories – with the exception of waste-treatment – are quite small. Therefore, the cost-assessment is based, on the one hand, on a definition of a set of conversion technologies, and, on the other hand, on an assessment of fuel prices, where finally for each sub-category country-specific fuel prices are derived.

Future potential

In general, solid biomass represents an energy source with a more or less strong limited potential – depending on country-specific conditions. Thereby, not only the primary energy potential is restricted. Moreover, the energetic use of biomass competes with material use and, in addition, competition occurs within the energetic fraction: Solid biomass like wood represents a traditional resource for heating, especially in rural areas.

The approach for the assessment of its electricity generation potential was as follows:

1. First, an assessment of the primary energy potential – more precisely, the additional realisable primary mid-term potential – has been undertaken. Thereby, for each pre-defined fuel-based sub-category country-specific potentials were derived.
2. Second, within each sub-category electricity potentials were calculated by linking of plant-specific conversion efficiencies to primary potentials derived above. In this context, the conversion efficiency for electricity highly depends on the technological concept applied. In general, for small units and CHP-plants the electrical efficiency is lower than for pure power production.

The following figures illustrate the development as described above and, in addition, provide an overview on the various additional mid-term potentials of solid biomass. Figure 3.21 indicates the mid-term potential in terms of primary energy (for whole EU-15 some 1242 TWh/a of solid biomass might be used for electricity production). This would generate roughly 346 TWh_{el} if generation is based on power stations without heat recovery, see Figure 3.22. On contrary, an amount of 284 TWh_{el} could be produced in case of CHP, see Figure 3.23.[18]

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[18] Note, the rough overall figure of 284 TWh_{el} in case of CHP does not take into account dynamic as well as country-specific restrictions which especially appear for Southern European countries due to a quite small demand for (grid-connected) heat. In general, in the model **Green*Net*** demand restrictions for CHP-heat are considered within the process of dynamic assessment and, in case of biomass, not by applying a 'simple' static limitation of the CHP-potential for each fuel-category.

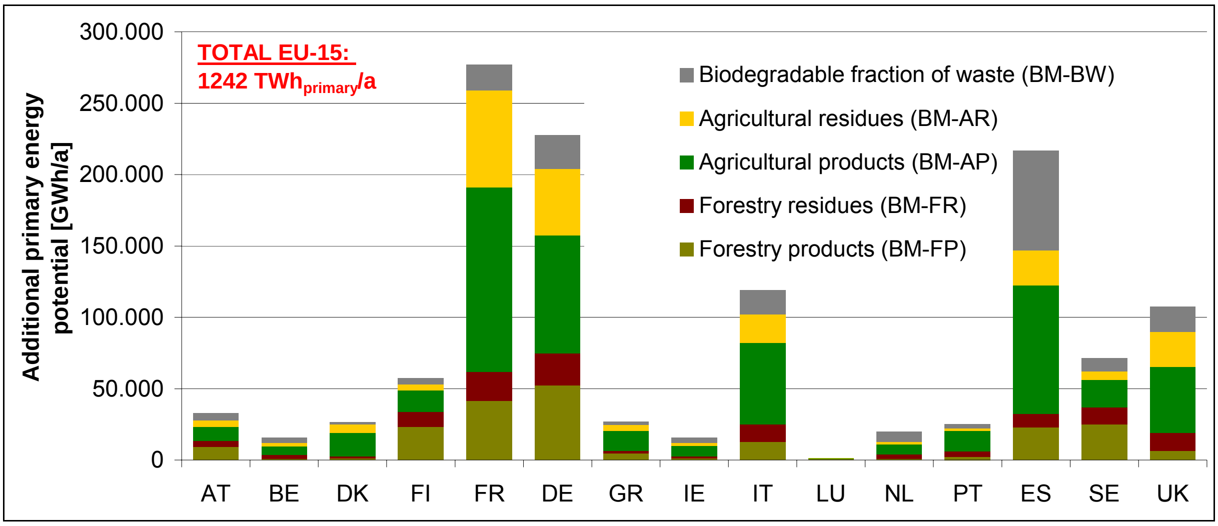

Figure 3.21 Additional mid-term primary energy potential for solid biomass in EU-15 countries

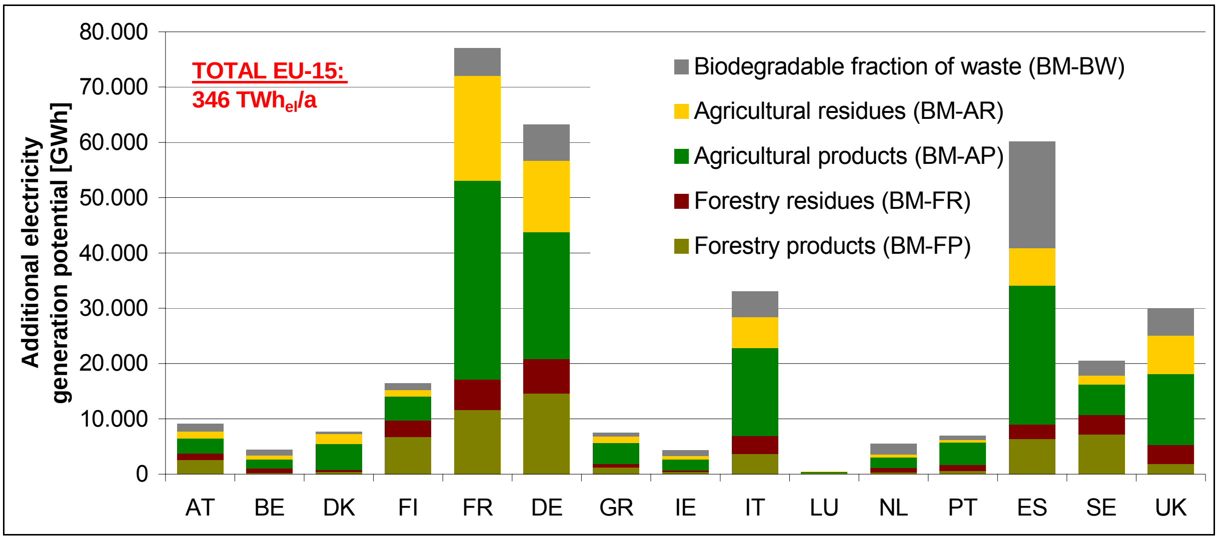

Figure 3.22 Additional mid-term potential for electricity from solid biomass in EU-15 countries – in case of pure power production

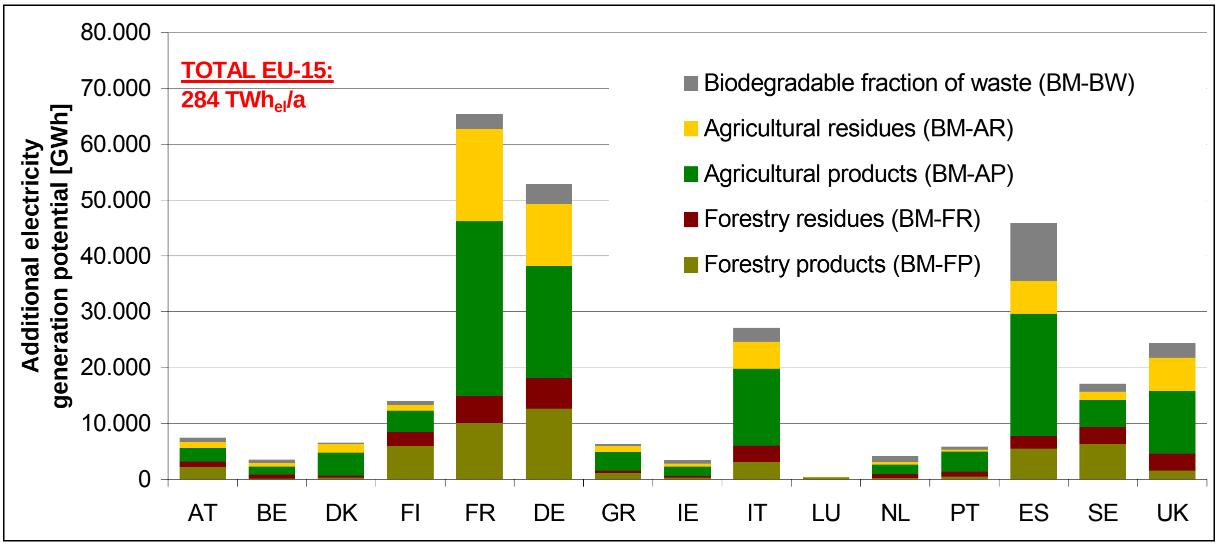

Figure 3.23 Additional mid-term potential for electricity from solid biomass in EU-15 countries – in case of CHP

In order to provide more insights into the process of potential assessment, the derivation of the primary energy potential (i.e. the additional primary energy mid-term potential) is described in the following for each sub-category:

Note, in general, the assessment is mainly based on processing of statistical data taken from Eurostat (2002a) and FAOSTAT (2002) – in order to get a homogenous set of data for all EU countries.

Forestry products (BM-FP):

This sub-category covers all forms of wood (e.g. wood chips) directly harvested from forests. The additional potential is derived from the unused net annual increment of forests which are marked as available for wood supply. The *unused* net increment represents the difference between the net annual increment and the amount of fellings harvested.[19] Hence, by applying a usability factor (roughly 70%) and density as well as specific heat value, the primary energy potential is calculated. Note, in general the growing stock of forests increases year by year.

Forestry residues (BM-FR):

The sub-category by itself includes the following fuel sources:

Forestry wastes: Only a certain percentage of wood occurring in the forests in the process of harvesting should be removed (considering seriously environmental impacts). It is assumed that this amounts 5% of total annual felling.

Solid industrial by-products (bark, waste from sawmill- , wood- and paper industry production): Almost none of these by-products are currently available additionally – due to their cheap price. By considering an average growth rate (1% per year) a small amount of this fraction will be available in 2020.

Wood waste: The annual potential of matured timber stands in statistical correlation to population. Hence, according to statistics it is assumed that an amount of 85kg occurs on average per capita. Combining this figure with a usability of 50% the potential can be assumed.

Agricultural products (BM-AP):

The primary energy potential of energy crops is in strong interdependence with agricultural policy. Hence, as default figure it is assumed that 10% of the current arable land would be available for cultivation of energy crops in 2020. Crop yields differ by country due to different climatic conditions (in a range from 11 - 15 dry tonnes/ha/year).

Agricultural residues (BM-AR):

Straw represents an EU-wide common agricultural residue which can be used for combustion. The potential assessment is based on current production of cereals, yields differ by country in accordance with actual production data (3 – 6.7 t/ha). It is planned to extent this fuel-category with non-harmonised country-specific residues (e.g. solid residues in the extraction process of olive oil as typical for Spain and Greece).

Biodegradable fraction of waste (BM-BW):

In accordance with the definition of RES-E presented in the 'RES-E directive' (EC, 2001) the biodegradable part of waste is accounted as a renewable energy source. Hence, so far only the potential of municipal waste is represented in the database. In order to derive the additional mid-term potential the amount of waste to be generated in the year 2020 has been estimated – by applying country-specific similar growth rates as observed in the past (taken from Eurostat, 2002a). Next, country-specific current waste treatment (incineration vs. recovery operations vs. landfilling) as well as implemented policy regulations (e.g. the EU-directive on landfilling of waste (EC, 1999)) has to be taken into account in order to provide stable forecasts of the future waste treatment. Finally, the potential for waste incineration occurs as residuum from other options. The biodegradable fraction has been estimated in accordance with the PRETIR-study (Harmelink et. al., 2002).

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[19] Note, in general the growing stock of forests increases in Europe year by year. Of course, differences occur between countries – but the methodology applied takes into consideration of country-specifics and, moreover, aims to derive potentials meeting the objective of sustainability.

Costs

Table 3.7 provides an overview on cost-data for new biomass-fired plants of the toolbox **Green*Net***. Please note, investment as well as O&M-costs are given in €$_{2002}$ and refer to the start year of the simulations (i.e. 2002).

Table 3.7. Overview on cost-data for new plant (solid biomass – pure power production & CHP)

Cost - data for new plant — data for: BM-FP, BM-FR, BM-AP & BM-AR

	category	plant-type: unit	ELE large (new 1)	ELE medium (new 2)	ELE small (new 3)	CHP large (new 1)	CHP medium (new 2)	CHP small (new 3)
technical-specification	*plant-size (average)*	*MW_{el}*	50,000	10,000	1,000	50,000	10,000	1,000
	efficiency electricity	%	31%	28%	26%	27%	25%	22%
	efficiency heat	%				63%	64%	66%
	efficiency TOTAL	%	31%	28%	26%	90%	89%	88%
	power-to-heat-ratio	1	0,00	0,00	0,00	2,33	2,56	3,00
	life time	a	25	25	25	25	25	25
cost-specification (general)	depreciation time	a	15	15	15	15	15	15
	interest rate	*%*	*6,5%*	*6,5%*	*6,5%*	*6,5%*	*6,5%*	*6,5%*
	c.r.f	*1*	*0,1064*	*0,1064*	*0,1064*	*0,1064*	*0,1064*	*0,1064*
	Share of HARMONISED investment costs	%	100%	100%	100%	100%	100%	100%
	investment costs TOTAL (average)	**€/kW$_{el}$**	**2.100,00**	**2.300,00**	**2.500,00**	**2.450,00**	**3.050,00**	**4.200,00**
	investment costs HARMONISED	€/kW$_{el}$	2.100,00	2.300,00	2.500,00	2.450,00	3.050,00	4.200,00
	investment costs NON-HARMONISED (average)	€/kW$_{el}$	0,00	0,00	0,00	0,00	0,00	0,00
	Share of HARMONISED O&M costs	%	100%	100%	100%	100%	100%	100%
	O&M costs TOTAL (average)	**€/(kW$_{el}$*a)**	**70,00**	**85,00**	**135,00**	**75,00**	**90,00**	**165,00**
	O&M costs TOTAL (average) as share of investment costs	**%**	**3,3%**	**3,7%**	**5,4%**	**3,1%**	**3,0%**	**3,9%**
	O&M costs HARMONISED	€/(kW$_{el}$*a)	70,00	85,00	135,00	75,00	90,00	165,00
	O&M costs NON-HARMONISED (average)	€/(kW$_{el}$*a)	0,00	0,00	0,00	0,00	0,00	0,00

Cost - data for new plant — data for: BM-BW

	category	plant-type: unit	ELE large (new 1)	ELE medium (new 2)	ELE small (new 3)	CHP large (new 1)	CHP medium (new 2)	CHP small (new 3)
technical-specification	*plant-size (average)*	*MW_{el}*	50,000	10,000	1,000	50,000	10,000	1,000
	efficiency electricity	%	22%	20%	18%	16%	15%	14%
	efficiency heat	%				64%	65%	66%
	efficiency TOTAL	%	22%	20%	18%	80%	80%	80%
	power-to-heat-ratio	1	0,00	0,00	0,00	4,00	4,33	4,71
	life time	a	25	25	25	35	35	35
cost-specification (general)	depreciation time	a	15	15	15	15	15	15
	interest rate	*%*	*6,5%*	*6,5%*	*6,5%*	*6,5%*	*6,5%*	*6,5%*
	c.r.f	*1*	*0,1064*	*0,1064*	*0,1064*	*0,1064*	*0,1064*	*0,1064*
	Share of HARMONISED investment costs	%	100%	100%	100%	100%	100%	100%
	investment costs TOTAL (average)	**€/kW$_{el}$**	**4.250,00**	**5.000,00**	**5.750,00**	**4.500,00**	**5.200,00**	**6.000,00**
	investment costs HARMONISED	€/kW$_{el}$	4.250,00	5.000,00	5.750,00	4.500,00	5.200,00	6.000,00
	investment costs NON-HARMONISED (average)	€/kW$_{el}$	0,00	0,00	0,00	0,00	0,00	0,00
	Share of HARMONISED O&M costs	%	100%	100%	100%	100%	100%	100%
	O&M costs TOTAL (average)	**€/(kW$_{el}$*a)**	**90,00**	**130,00**	**165,00**	**100,00**	**145,00**	**180,00**
	O&M costs TOTAL (average) as share of investment costs	**%**	**2,1%**	**2,6%**	**2,9%**	**2,2%**	**2,8%**	**3,0%**
	O&M costs HARMONISED	€/(kW$_{el}$*a)	90,00	130,00	165,00	100,00	145,00	180,00
	O&M costs NON-HARMONISED (average)	€/(kW$_{el}$*a)	0,00	0,00	0,00	0,00	0,00	0,00

If no incineration of municipal waste is considered, the total investment costs of biomass-fired CHP-plants are at present in a range between 2450 and 4200 €/kW (compare e.g. Haas et. al., 2001), Fischer et. al., 2001)), depending on plant-size and the technological concept applied. Hence, for pure power generation investment needs decrease. Nevertheless, the cheapest option represents co-firing where investment costs amount to 550 €/kW on average.

Fuel costs:

Default figures for fuel costs with respect to the various fractions of solid biomass (except municipal waste) are illustrated in Figure 3.24. Hence, for municipal price a default price of 20€/MWh was used. This negative price represents a revenue for the power producer, i.e. a 'gate fee' for the waste treatment. Note, these prices refer to start year of the simulation, i.e. 2002. Their future development is internalised in the overall model – linked to fossil fuel prices as well as the available additional potentials.

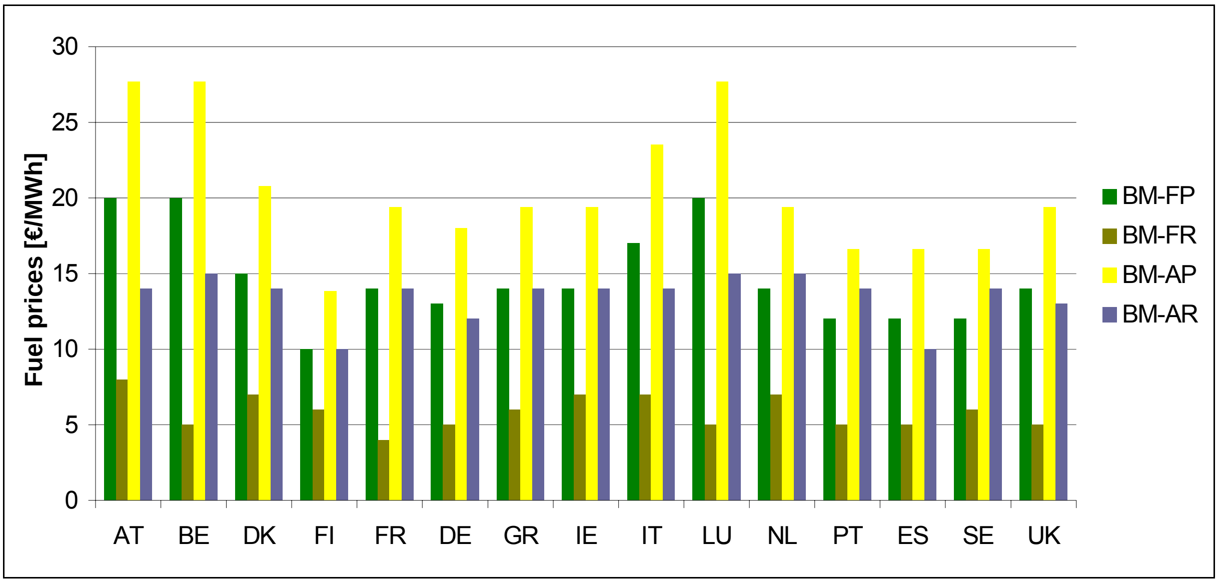

Figure 3.24. Fuel prices for various fractions of solid biomass in EU-15 countries

Cost-resource curves

To define the cost curves for various sub-categories of solid biomass for each country the following procedure has been applied:

- The additional mid-term potential (within each sub-category) was subdivided and linked to the defined plant-categories according to country-specific considerations (e.g. population density in case of CHP, regional distribution of resources).
- For each plant category two different full load-hour levels are applied.
- Co-firing is not considered in this general approach. Its potential is assessed in accordance with the existing conventional power plants by country.
- As a consequence the cost range is equal for all countries, whereas the average electricity generation costs vary by country.

Again, as explained for biogas, CHP and pure power generation are each linked to the overall same primary energy potentials. That means that no pre-separation of the primary potential has been undertaken. Of course, the same primary potential can not be used twice – i.e. for both CHP and pure power production. This is guaranteed by an internal linkage of the according bands.[20]

In a similar way the option of co-firing is modelled where its potential depends on the existing (coal-fired) conventional power plant of a certain country.

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[20] In detail: Bands for CHP and pure power generation referring to the same primary energy potential are linked to each other within the model. That means that if e.g. a certain part of potential of the CHP-band no.1 will be implemented the potential of band no.1 for pure power generation will be reduced in a similar amount. This procedure is internalised into the model, as part of the band-specific data linkages can be applied to a maximum of four different options.

3.3.2.2 Resulting cost-resource curves

The following tables and figures provide an overview on the derived set of data on potential and costs for electricity from solid biomass in EU-15 countries, see e.g. Table 3.8. Thereby, a comparison of the achieved and the additional mid-term potential is given in Figure 3.25.[21]

Table 3.8. Overview on potential and costs for electricity from biomass in EU-15 countries (by fuel-category – new plant)

(Solid) Biomass - Forestry products (BM-FP)		**AT**	**BE**	**DK**	**FI**	**FR**	**DE**	**GR**	**IE**	**IT**	**LU**	**NL**	**PT**	**ES**	**SE**	**UK**	**EU15**
Potential - existing & new plant:																	
Achieved potential:																	
electricity generation pot.	GWh	0	0	0	3511	0	0	0	0	0	0	0	0	0	1383	0	**4894**
capacity potential	MW	0	0	0	878	0	0	0	0	0	0	0	0	0	346	0	**1223**
full load-hours (average)	h/a	4000	4000	4000	4000	4000	4000	4000	4000	4000	4000	4000	4000	4000	4000	4000	**4000**
Additional mid-term potential:																	
electricity generation pot.	GWh	2548	266	375	6782	11574	14560	1268	396	3591	240	276	612	6327	7210	1834	**57860**
in case of CHP …	GWh	2218	231	329	5934	10075	12675	1104	344	3126	209	241	533	5508	6308	1596	**50431**
capacity potential	MW	394	41	58	1050	1791	2253	196	61	556	37	43	95	979	1116	284	**8955**
in case of CHP …	MW	555	58	82	1484	2519	3169	276	86	781	52	60	133	1377	1577	399	**12608**
full load-hours (average)	h/a	6462	6462	6462	6462	6462	6462	6462	6462	6462	6462	6462	6462	6462	6462	6462	**6462**
in case of CHP …	h/a	4000	4000	4000	4000	4000	4000	4000	4000	4000	4000	4000	4000	4000	4000	4000	**4000**
Costs of electricity - new plant:																	
Long-run marginal costs (LRMC):																	
minimum	€/MWh	106,4	106,4	90,3	74,2	87,1	83,8	87,1	87,1	96,7	106,4	87,1	80,6	80,6	80,6	87,1	**74,2**
maximum	€/MWh	143,7	143,7	124,5	105,3	120,7	116,8	120,7	120,7	132,2	143,7	120,7	113,0	113,0	113,0	120,7	**143,7**
average (weighted)	€/MWh	125,8	125,8	102,7	85,3	104,2	100,6	104,2	106,9	115,0	125,8	104,2	97,1	97,1	92,3	104,2	**100,6**
in case of CHP …																	
minimum	€/MWh	95,3	95,3	76,8	58,3	73,1	69,4	73,1	73,1	84,2	95,3	73,1	65,7	65,7	65,7	73,1	**58,3**
maximum	€/MWh	152,9	152,9	130,1	107,4	125,6	121,0	125,6	125,6	139,2	152,9	125,6	116,5	116,5	116,5	125,6	**152,9**
average (weighted)	€/MWh	122,1	122,1	92,3	72,5	97,3	93,2	97,3	102,1	109,7	122,1	97,3	89,0	89,0	80,4	97,3	**92,3**
Short-run marginal costs (SRMC):																	
minimum	€/MWh	74,5	74,5	58,4	42,3	55,2	51,9	55,2	55,2	64,8	74,5	55,2	48,7	48,7	48,7	55,2	**42,3**
maximum	€/MWh	99,4	99,4	80,2	61,0	76,3	72,5	76,3	76,3	87,9	99,4	76,3	68,7	68,7	68,7	76,3	**99,4**
average (weighted)	€/MWh	87,5	87,5	65,6	48,3	65,9	62,3	65,9	67,9	76,7	87,5	65,9	58,7	58,7	55,2	65,9	**62,5**
in case of CHP …																	
minimum	€/MWh	55,5	55,5	36,9	18,4	33,2	29,5	33,2	33,2	44,4	55,5	33,2	25,8	25,8	25,8	33,2	**18,4**
maximum	€/MWh	80,2	80,2	57,5	34,7	52,9	48,4	52,9	52,9	66,6	80,2	52,9	43,8	43,8	43,8	52,9	**80,2**
average (weighted)	€/MWh	67,2	67,2	43,0	23,2	42,4	38,3	42,4	44,2	54,8	67,2	42,4	34,2	34,2	31,1	42,4	**38,8**

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[21] Please note, these generation costs are calculated by applying a standardised interest rate of 6.5% and a depreciation time of 15 years to investment and O&M-costs as implemented in the database for new plant. Thereby, costs refer to the start year of the simulation (i.e. 2002).

Table 3.8 ff. Overview on potential and costs for electricity from biomass in EU-15 countries (by fuel-category – new plant)

(Solid) Biomass - Forestry residues (BM-FR)		**AT**	**BE**	**DK**	**FI**	**FR**	**DE**	**GR**	**IE**	**IT**	**LU**	**NL**	**PT**	**ES**	**SE**	**UK**	**EU15**
Potential - existing & new plant:																	
Achieved potential:																	
electricity generation pot.	GWh	1310	0	668	5267	1572	816	0	0	218	0	91	1390	1234	2074	626	**15265**
capacity potential	MW	328	0	167	1317	393	204	0	0	54	0	23	347	308	518	156	**3816**
full load-hours (average)	h/a	4000	4000	4000	4000	4000	4000	4000	4000	4000	4000	4000	4000	4000	4000	4000	**4000**
Additional mid-term potential:																	
electricity generation pot.	GWh	1171	729	368	2924	5558	6271	558	302	3312	28	867	1027	2646	3466	3440	**32668**
in case of CHP …	GWh	1019	635	322	2559	4838	5459	486	262	2883	24	755	894	2303	3033	2995	**28467**
capacity potential	MW	181	113	57	453	860	971	86	47	513	4	134	159	409	536	532	**5056**
in case of CHP …	MW	255	159	81	640	1210	1365	121	65	721	6	189	224	576	758	749	**7117**
full load-hours (average)	h/a	6462	6462	6462	6462	6462	6462	6462	6462	6462	6462	6462	6462	6462	6462	6462	**6462**
in case of CHP …	h/a	4000	4000	4000	4000	4000	4000	4000	4000	4000	4000	4000	4000	4000	4000	4000	**4000**
Costs of electricity - new plant:																	
Long-run marginal costs (LRMC):																	
minimum	€/MWh	67,7	58,0	64,5	61,3	54,8	58,0	61,3	64,5	64,5	58,0	64,5	58,0	58,0	61,3	58,0	**54,8**
maximum	€/MWh	97,6	86,0	93,7	89,9	82,2	86,0	89,9	93,7	93,7	86,0	93,7	86,0	86,0	89,9	86,0	**97,6**
average (weighted)	€/MWh	82,7	71,9	74,9	71,4	68,3	71,9	75,5	81,3	79,1	71,9	79,1	71,9	71,9	71,4	71,9	**72,7**
in case of CHP …																	
minimum	€/MWh	66,9	55,7	63,2	59,4	52,0	55,7	59,4	63,2	63,2	55,7	63,2	55,7	55,7	59,4	55,7	**52,0**
maximum	€/MWh	129,3	115,6	124,7	120,2	111,1	115,6	120,2	124,7	124,7	115,6	124,7	115,6	115,6	120,2	115,6	**129,3**
average (weighted)	€/MWh	96,8	84,4	80,7	76,8	80,3	84,4	88,5	99,0	92,7	84,4	92,7	84,4	84,4	76,8	84,4	**83,9**
Short-run marginal costs (SRMC):																	
minimum	€/MWh	35,8	26,1	32,6	29,4	22,9	26,1	29,4	32,6	32,6	26,1	32,6	26,1	26,1	29,4	26,1	**22,9**
maximum	€/MWh	53,3	41,7	49,4	45,6	37,9	41,7	45,6	49,4	49,4	41,7	49,4	41,7	41,7	45,6	41,7	**53,3**
average (weighted)	€/MWh	44,3	33,5	37,9	34,4	29,9	33,5	37,1	42,2	40,7	33,5	40,7	33,5	33,5	34,4	33,5	**34,6**
in case of CHP …																	
minimum	€/MWh	1,7	-9,4	-2,0	-5,7	-13,1	-9,4	-5,7	-2,0	-2,0	-9,4	-2,0	-9,4	-9,4	-5,7	-9,4	**-13,1**
maximum	€/MWh	17,6	4,0	13,1	8,5	-0,6	4,0	8,5	13,1	13,1	4,0	13,1	4,0	4,0	8,5	4,0	**17,6**
average (weighted)	€/MWh	8,2	-4,2	1,2	-2,8	-8,4	-4,2	-0,1	5,5	4,0	-4,2	4,0	-4,2	-4,2	-2,8	-4,2	**-2,9**

(Solid) Biomass - Agricultural products (BM-AP)		**AT**	**BE**	**DK**	**FI**	**FR**	**DE**	**GR**	**IE**	**IT**	**LU**	**NL**	**PT**	**ES**	**SE**	**UK**	**EU15**
Potential - existing & new plant:																	
Achieved potential:																	
electricity generation pot.	GWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0	313	**313**
capacity potential	MW	0	0	0	0	0	0	0	0	0	0	0	0	0	0	78	**78**
full load-hours (average)	h/a	4000	4000	4000	4000	4000	4000	4000	4000	4000	4000	4000	4000	4000	4000	4000	**4000**
Additional mid-term potential:																	
electricity generation pot.	GWh	2716	1658	4765	4321	35962	22966	3855	2004	15941	117	1901	4079	25072	5534	12893	**143783**
in case of CHP …	GWh	2365	1443	4169	3781	31305	19992	3356	1740	13877	102	1655	3551	21825	4842	11223	**125225**
capacity potential	MW	420	257	737	669	5566	3554	597	310	2467	18	294	631	3880	856	1995	**22252**
in case of CHP …	MW	591	361	1042	945	7826	4998	839	435	3469	25	414	888	5456	1211	2806	**31306**
full load-hours (average)	h/a	6462	6462	6462	6462	6462	6462	6462	6462	6462	6462	6462	6462	6462	6462	6462	**6462**
in case of CHP …	h/a	4000	4000	4000	4000	4000	4000	4000	4000	4000	4000	4000	4000	4000	4000	4000	**4000**
Costs of electricity - new plant:																	
Long-run marginal costs (LRMC):																	
minimum	€/MWh	131,2	131,2	108,9	86,6	104,4	100,0	104,4	104,4	117,8	131,2	104,4	95,5	95,5	95,5	104,4	**86,6**
maximum	€/MWh	173,3	173,3	146,7	120,1	141,4	136,0	141,4	141,4	157,3	173,3	141,4	130,7	130,7	130,7	141,4	**173,3**
average (weighted)	€/MWh	153,5	153,5	122,7	98,7	123,6	118,6	123,6	126,6	138,6	153,5	123,6	113,7	113,7	108,3	123,6	**122,1**
in case of CHP …																	
minimum	€/MWh	139,8	139,8	114,1	88,5	109,0	103,9	109,0	109,0	124,4	139,8	109,0	98,8	98,8	98,8	109,0	**88,5**
maximum	€/MWh	218,8	218,8	187,3	155,9	181,0	174,7	181,0	181,0	199,9	218,8	181,0	168,4	168,4	168,4	181,0	**218,8**
average (weighted)	€/MWh	178,2	178,2	135,4	107,9	143,8	138,1	143,8	151,3	161,0	178,2	143,8	132,4	132,4	118,9	143,8	**141,4**
Short-run marginal costs (SRMC):																	
minimum	€/MWh	99,3	99,3	77,0	54,7	72,5	68,1	72,5	72,5	85,9	99,3	72,5	63,6	63,6	63,6	72,5	**54,7**
maximum	€/MWh	129,0	129,0	102,4	75,8	97,1	91,7	97,1	97,1	113,0	129,0	97,1	86,4	86,4	86,4	97,1	**129,0**
average (weighted)	€/MWh	115,1	115,1	85,7	61,6	85,3	80,3	85,3	87,6	100,2	115,1	85,3	75,3	75,3	71,2	85,3	**83,8**
in case of CHP …																	
minimum	€/MWh	74,6	74,6	49,0	23,4	43,9	38,8	43,9	43,9	59,3	74,6	43,9	33,6	33,6	33,6	43,9	**23,4**
maximum	€/MWh	107,1	107,1	75,7	44,2	69,4	63,1	69,4	69,4	88,2	107,1	69,4	56,8	56,8	56,8	69,4	**107,1**
average (weighted)	€/MWh	89,5	89,5	55,8	28,3	55,2	49,5	55,2	57,8	72,4	89,5	55,2	43,8	43,8	39,3	55,2	**53,6**

Table 3.8 ff. Overview on potential and costs for electricity from biomass in EU-15 countries (by fuel-category – new plant)

(Solid) Biomass - Agricultural residues (BM-AR)		**AT**	**BE**	**DK**	**FI**	**FR**	**DE**	**GR**	**IE**	**IT**	**LU**	**NL**	**PT**	**ES**	**SE**	**UK**	**EU15**
Potential - existing & new plant:																	
Achieved potential:																	
electricity generation pot.	GWh	0	0	334	1	0	21	0	0	5	0	11	1	12	0	104	**488**
capacity potential	MW	0	0	83	0	0	5	0	0	1	0	3	0	3	0	26	**122**
full load-hours (average)	h/a	4000	4000	4000	4000	4000	4000	4000	4000	4000	4000	4000	4000	4000	4000	4000	**4000**
Additional mid-term potential:																	
electricity generation pot.	GWh	1282	718	1715	1210	18970	12926	1178	550	5548	43	489	443	6812	1689	6848	**60421**
in case of CHP …	GWh	1116	625	1501	1058	16513	11252	1025	478	4830	38	425	385	5930	1478	5962	**52616**
capacity potential	MW	198	111	265	187	2936	2000	182	85	859	7	76	68	1054	261	1060	**9351**
in case of CHP …	MW	279	156	375	265	4128	2813	256	119	1207	9	106	96	1482	369	1490	**13154**
full load-hours (average)	h/a	6462	6462	6462	6462	6462	6462	6462	6462	6462	6462	6462	6462	6462	6462	6462	**6462**
in case of CHP …	h/a	4000	4000	4000	4000	4000	4000	4000	4000	4000	4000	4000	4000	4000	4000	4000	**4000**
Costs of electricity - new plant:																	
Long-run marginal costs (LRMC):																	
minimum	€/MWh	87,1	90,3	87,1	74,2	87,1	80,6	87,1	87,1	87,1	90,3	90,3	87,1	74,2	87,1	83,8	**74,2**
maximum	€/MWh	120,7	124,5	120,7	105,3	120,7	113,0	120,7	120,7	120,7	124,5	124,5	120,7	105,3	120,7	116,8	**124,5**
average (weighted)	€/MWh	104,2	107,8	99,2	85,3	104,2	97,1	104,2	106,9	104,2	107,8	107,8	104,2	89,9	99,2	100,6	**100,1**
in case of CHP …																	
minimum	€/MWh	89,1	92,8	89,1	74,3	89,1	81,7	89,1	89,1	89,1	92,8	92,8	89,1	74,3	89,1	85,4	**74,3**
maximum	€/MWh	156,6	161,1	156,6	138,4	156,6	147,5	156,6	156,6	156,6	161,1	161,1	156,6	138,4	156,6	152,0	**161,1**
average (weighted)	€/MWh	121,6	125,7	108,5	92,7	121,6	113,3	121,6	128,5	121,6	125,7	125,7	121,6	105,1	108,5	117,5	**116,3**
Short-run marginal costs (SRMC):																	
minimum	€/MWh	55,2	58,4	55,2	42,3	55,2	48,7	55,2	55,2	55,2	58,4	58,4	55,2	42,3	55,2	51,9	**42,3**
maximum	€/MWh	76,3	80,2	76,3	61,0	76,3	68,7	76,3	76,3	76,3	80,2	80,2	76,3	61,0	76,3	72,5	**80,2**
average (weighted)	€/MWh	65,9	69,5	62,2	48,3	65,9	58,7	65,9	67,9	65,9	69,5	69,5	65,9	51,5	62,2	62,3	**61,9**
in case of CHP …																	
minimum	€/MWh	23,9	27,6	23,9	9,1	23,9	16,5	23,9	23,9	23,9	27,6	27,6	23,9	9,1	23,9	20,2	**9,1**
maximum	€/MWh	44,9	49,4	44,9	26,7	44,9	35,8	44,9	44,9	44,9	49,4	49,4	44,9	26,7	44,9	40,3	**49,4**
average (weighted)	€/MWh	32,9	37,1	28,9	13,1	32,9	24,7	32,9	35,1	32,9	37,1	37,1	32,9	16,4	28,9	28,8	**28,3**

(Solid) Biomass - Biodegradable fraction of waste (BM-BW)		**AT**	**BE**	**DK**	**FI**	**FR**	**DE**	**GR**	**IE**	**IT**	**LU**	**NL**	**PT**	**ES**	**SE**	**UK**	**EU15**
Potential - existing & new plant:																	
Achieved potential:																	
electricity generation pot.	GWh	32	287	648	92	677	3122	0	0	629	23	1394	210	307	185	675	**8281**
capacity potential	MW	5	44	100	14	104	480	0	0	97	4	215	32	47	28	104	**1274**
full load-hours (average)	h/a	6500	6500	6500	6500	6500	6500	6500	6500	6500	6500	6500	6500	6500	6500	6500	**6500**
Additional mid-term potential:																	
electricity generation pot.	GWh	986	754	315	901	3534	4677	463	711	3273	5	1393	554	13725	1890	3442	**36623**
in case of CHP …	GWh	745	569	235	671	2669	3531	350	541	2471	4	1052	418	10363	1408	2599	**27627**
capacity potential	MW	153	117	49	139	547	724	72	110	507	1	216	86	2124	293	533	**5668**
in case of CHP …	MW	115	88	36	104	413	547	54	84	382	1	163	65	1604	218	402	**4276**
full load-hours (average)	h/a	6462	6462	6462	6462	6462	6462	6462	6462	6462	6462	6462	6462	6462	6462	6462	**6462**
in case of CHP …	h/a	6462	6462	6462	6462	6462	6462	6462	6462	6462	6462	6462	6462	6462	6462	6462	**6462**
Costs of electricity - new plant:																	
Long-run marginal costs (LRMC):																	
minimum	€/MWh	59,2	59,2	59,2	59,2	59,2	59,2	59,2	59,2	59,2	59,2	59,2	59,2	59,2	59,2	59,2	**59,2**
maximum	€/MWh	107,2	107,2	107,2	107,2	107,2	107,2	107,2	107,2	107,2	107,2	107,2	107,2	107,2	107,2	107,2	**107,2**
average (weighted)	€/MWh	84,4	84,4	77,9	77,9	84,4	84,4	84,4	87,8	84,4	84,4	84,4	84,4	84,4	77,9	84,4	**83,9**
in case of CHP …																	
minimum	€/MWh	11,9	11,9	11,9	11,9	11,9	11,9	11,9	11,9	11,9	11,9	11,9	11,9	11,9	11,9	11,9	**11,9**
maximum	€/MWh	44,9	44,9	44,9	44,9	44,9	44,9	44,9	44,9	44,9	44,9	44,9	44,9	44,9	44,9	44,9	**44,9**
average (weighted)	€/MWh	29,5	29,5	24,6	24,6	29,5	29,5	29,5	32,1	29,5	29,5	29,5	29,5	29,5	24,6	29,5	**29,1**
Short-run marginal costs (SRMC):																	
minimum	€/MWh	-5,3	-5,3	-5,3	-5,3	-5,3	-5,3	-5,3	-5,3	-5,3	-5,3	-5,3	-5,3	-5,3	-5,3	-5,3	**-5,3**
maximum	€/MWh	5,3	5,3	5,3	5,3	5,3	5,3	5,3	5,3	5,3	5,3	5,3	5,3	5,3	5,3	5,3	**5,3**
average (weighted)	€/MWh	0,3	0,3	-1,2	-1,2	0,3	0,3	0,3	1,1	0,3	0,3	0,3	0,3	0,3	-1,2	0,3	**0,2**
in case of CHP …																	
minimum	€/MWh	-61,7	-61,7	-61,7	-61,7	-61,7	-61,7	-61,7	-61,7	-61,7	-61,7	-61,7	-61,7	-61,7	-61,7	-61,7	**-61,7**
maximum	€/MWh	-55,5	-55,5	-55,5	-55,5	-55,5	-55,5	-55,5	-55,5	-55,5	-55,5	-55,5	-55,5	-55,5	-55,5	-55,5	**-55,5**
average (weighted)	€/MWh	-58,6	-58,6	-58,6	-58,6	-58,6	-58,6	-58,6	-58,6	-58,6	-58,6	-58,6	-58,6	-58,6	-58,6	-58,6	**-58,6**

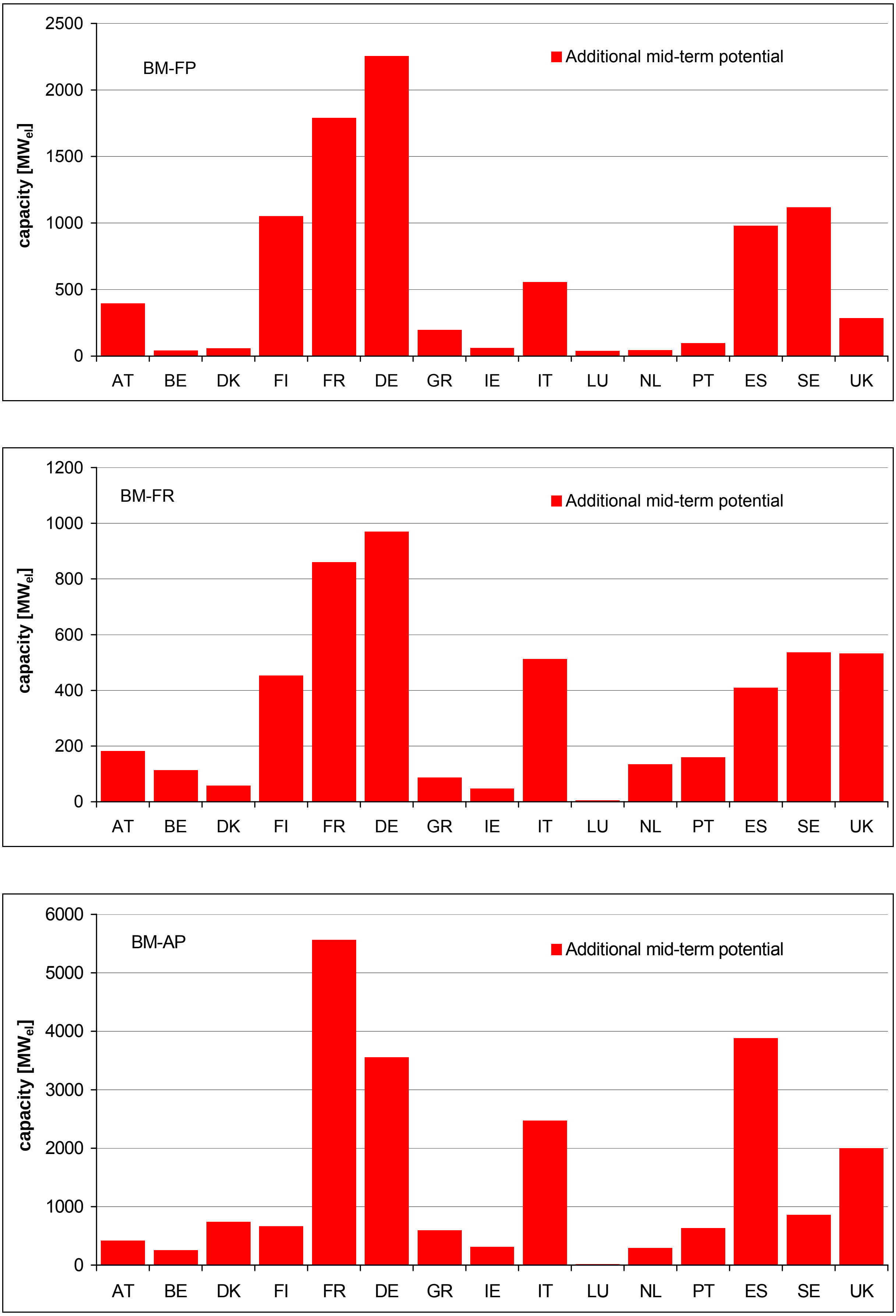
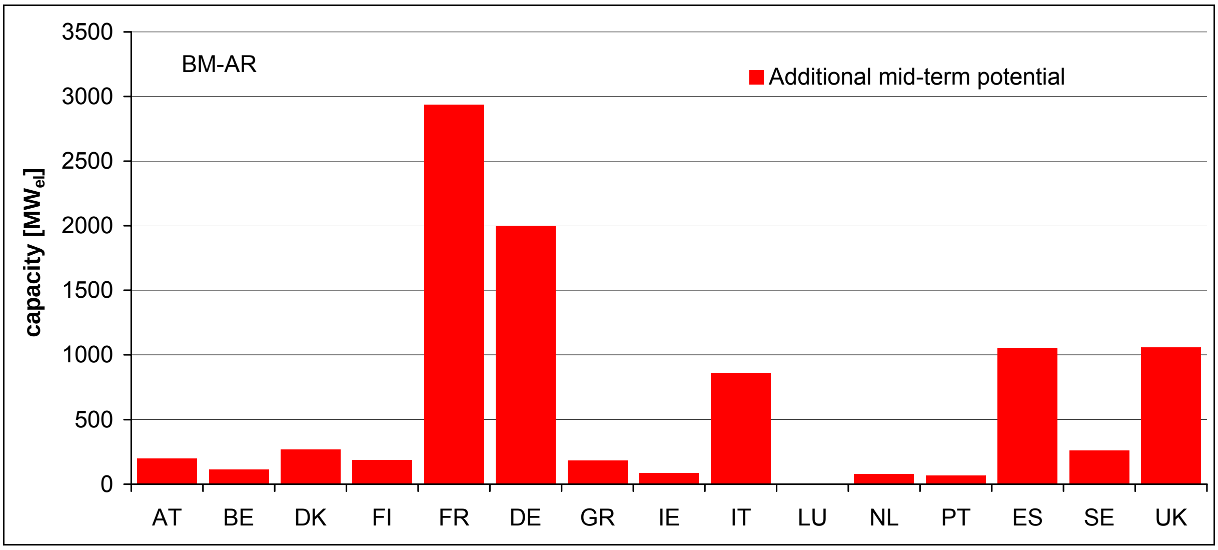


Figure 3.25. Additional mid-term potential for electricity from biomass (in total) in EU-15 countries



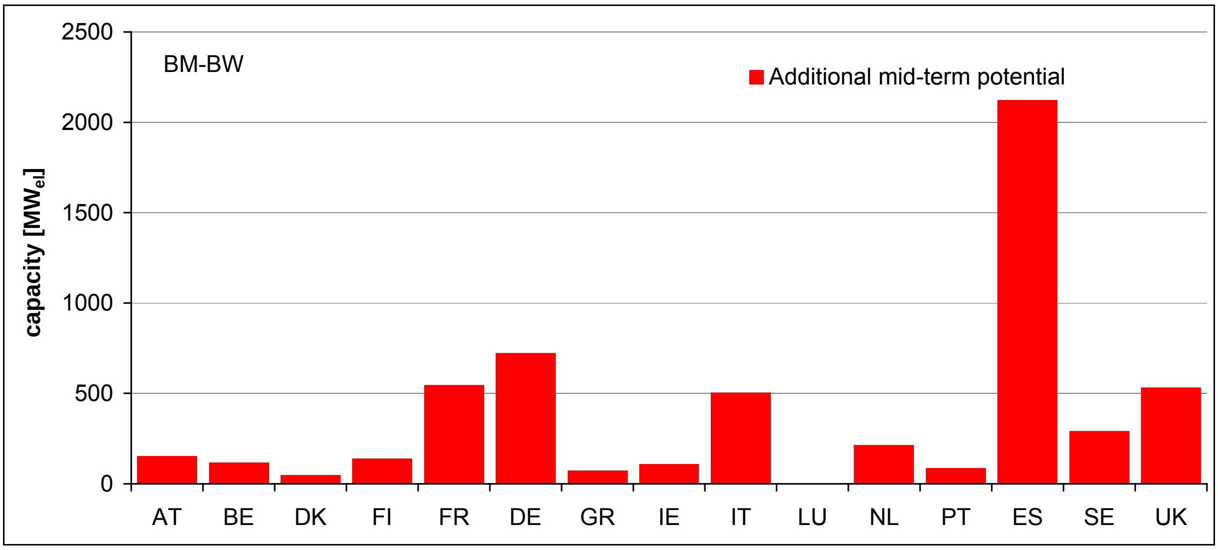


Figure 3.25ff. Additional mid-term potential for electricity from biomass (in total) in EU-15 countries

Dynamic aspects of cost development

As default, within the model **GreenNet** the future development of investment costs for biomass-fired plant is based using cost forecasts where a percentage decrease of costs is indicated for each year.

3.3.3 Geothermal electricity

3.3.3.1 Methodology for the development of cost-resource curves

Future potential

The potential assessment is mainly based on ESD/DGXVII, 1996. Thereby, corrections have been undertaken after consultation with project partners and own investigations. In this context, please note that new options for the exploitation of low-temperature geothermal resources are on the way and for instance already discussed and investigated in certain countries (e.g. Germany) – but hence, as far as no common set of data necessary to assess the potential for the whole EU-15, it has been decided to leave this new options aside.

Costs

Table 3.9 provides an overview on cost-data for new geothermal plant of the toolbox **Green*Net***. Please note, investment as well as O&M-costs are given in €$_{2002}$ and refer to the start year of the simulations (i.e. 2002).

Table 3.9. Overview on cost-data for new plant (Geothermal electricity)

Cost - data for new plant

	category	plant-type: unit	**ELE large** (new 1)	**ELE medium** (new 2)	**ELE small** (new 3)	**CHP large** (new 1)	**CHP medium** (new 2)	**CHP small** (new 3)
technical-specification	*plant-size*	*MW$_{el}$*	50,000	20,000	5,000	50,000	20,000	5,000
	efficiency electricity	%	26%	25%	24%	23%	22%	21%
	efficiency heat	%				61%	63%	64%
	efficiency TOTAL	%	26%	25%	24%	84%	85%	85%
	power-to-heat-ratio	1	0,00	0,00	0,00	2,65	2,86	3,05
	life time	a	25	25	25	25	25	25
cost-specification (general)	lifetime	a	15	15	15	15	15	15
	interest rate	*%*	*6,5%*	*6,5%*	*6,5%*	*6,5%*	*6,5%*	*6,5%*
	c.r.f	*1*	*0,1064*	*0,1064*	*0,1064*	*0,1064*	*0,1064*	*0,1064*
	Share of HARMONISED investment costs	%	100%	100%	100%	100%	100%	100%
	investment costs TOTAL (average)	**€/kW$_{el}$**	**1.800,00**	**2.250,00**	**3.350,00**	**1.950,00**	**2.400,00**	**3.550,00**
	investment costs HARMONISED	€/kW$_{el}$	1.800,00	2.250,00	3.350,00	1.950,00	2.400,00	3.550,00
	investment costs NON-HARMONISED (average)	€/kW$_{el}$	0,00	0,00	0,00	0,00	0,00	0,00
	Share of HARMONISED O&M costs	%	100%	100%	100%	100%	100%	100%
	O&M costs TOTAL (average)	**€/(kW$_{el}$*a)**	**130,00**	**155,00**	**205,00**	**145,00**	**170,00**	**220,00**
	O&M costs TOTAL (average) as share of investment costs	**%**	**7,2%**	**6,9%**	**6,1%**	**7,4%**	**7,1%**	**6,2%**
	O&M costs HARMONISED	€/(kW$_{el}$*a)	130,00	155,00	205,00	145,00	170,00	220,00
	O&M costs NON-HARMONISED (average)	€/(kW$_{el}$*a)	0,00	0,00	0,00	0,00	0,00	0,00

At present, the total investment costs of geothermal plants are in a range between 1800 and 3550 €/kW (compare e.g. Resch et. al. (2001)) – depending on site-specific conditions, i.e. plant-size, availability of the resource, applied technology, etc.

Full load-hours, of course, depend on the resource availability – hence, on average a rather constant supply (5000 - 7000 h/a) could be achieved.

In general, geothermal energy represents a zero-cost fuel source, additional cost efforts are considered in the O&M costs.

Cost-resource curves

To define the cost-resource curves for geothermal electricity by country the following approach was chosen:

- The total country-specific potential as well as the typical field size is used to share out the potential between the different plant categories. I.e., if in country A the total potential as well as the typical field size is quite large, a lot of large geothermal power plant can be constructed.
- Common for all plant categories two full load-hour levels are applied to – varying between 5000 and 7000 h/a in case of pure power production.

As the geothermal energy is used to drive – in most cases – a conventional steam turbine, also the option of CHP has been taken into account. Hence, as explained in case of biomass or biogas both options – CHP and pure power production stand in competition for the same potential of primary energy. This procedure is internalized into the model calculations.

3.3.3.2 Resulting cost-resource curves

Table 3.10 provides an overview on potential and costs for electricity from geothermal energy in EU-15 countries. In this context, a comparison of the achieved and the additional mid-term potential is given in Figure 3.26.[22]

Table 3.10. Overview on potential and costs for electricity from geothermal energy in EU-15 countries

Geothermal electricity (GE)		**AT**	**BE**	**DK**	**FI**	**FR**	**DE**	**GR**	**IE**	**IT**	**LU**	**NL**	**PT**	**ES**	**SE**	**UK**	**EU15**
Potential - existing & new plant:																	
Achieved potential:																	
electricity generation pot.	GWh	7	0	0	0	21	0	0	0	6169	0	0	104	0	0	0	**6301**
capacity potential	MW	1	0	0	0	5	0	0	0	949	0	0	18	0	0	0	**973**
full load-hours (average)	h/a	7000	0	0	0	4000	0	0	0	6500	0	0	5800	0	0	0	**6474**
Additional mid-term potential:																	
electricity generation pot.	GWh	24	0	0	0	340	0	475	0	3500	0	0	407	204	0	0	**4950**
in case of CHP …	GWh	21	0	0	0	297	0	416	0	3080	0	0	357	178	0	0	**4350**
capacity potential	MW	4	0	0	0	58	0	81	0	600	0	0	70	35	0	0	**849**
in case of CHP …	MW	4	0	0	0	57	0	80	0	675	0	0	69	34	0	0	**919**
full load-hours (average)	h/a	5833	0	0	0	5833	0	5833	0	5833	0	0	5833	5833	0	0	**5833**
in case of CHP …	h/a	5652	0	0	0	5202	0	5202	0	4563	0	0	5202	5202	0	0	**4734**
Costs of electricity - new plant:																	
Long-run marginal costs (LRMC):																	
minimum	€/MWh	80,2	0,0	0,0	0,0	56,3	0,0	56,3	0,0	45,9	0,0	0,0	56,3	56,3	0,0	0,0	**45,9**
maximum	€/MWh	112,3	0,0	0,0	0,0	112,3	0,0	112,3	0,0	112,3	0,0	0,0	112,3	112,3	0,0	0,0	**112,3**
average (weighted)	€/MWh	96,2	0,0	0,0	0,0	88,8	0,0	88,8	0,0	71,9	0,0	0,0	88,8	88,8	0,0	0,0	**76,9**
in case of CHP …																	
minimum	€/MWh	49,7	0,0	0,0	0,0	37,2	0,0	37,2	0,0	25,3	0,0	0,0	37,2	37,2	0,0	0,0	**25,3**
maximum	€/MWh	76,8	0,0	0,0	0,0	76,8	0,0	76,8	0,0	76,8	0,0	0,0	76,8	76,8	0,0	0,0	**76,8**
average (weighted)	€/MWh	63,3	0,0	0,0	0,0	59,0	0,0	59,0	0,0	47,3	0,0	0,0	59,0	59,0	0,0	0,0	**50,7**
Short-run marginal costs (SRMC):																	
minimum	€/MWh	29,3	0,0	0,0	0,0	22,1	0,0	22,1	0,0	18,6	0,0	0,0	22,1	22,1	0,0	0,0	**18,6**
maximum	€/MWh	41,0	0,0	0,0	0,0	41,0	0,0	41,0	0,0	41,0	0,0	0,0	41,0	41,0	0,0	0,0	**41,0**
average (weighted)	€/MWh	35,1	0,0	0,0	0,0	32,9	0,0	32,9	0,0	27,7	0,0	0,0	32,9	32,9	0,0	0,0	**29,2**
in case of CHP …																	
minimum	€/MWh	-8,4	0,0	0,0	0,0	-19,5	0,0	-19,5	0,0	-20,8	0,0	0,0	-19,5	-19,5	0,0	0,0	**-20,8**
maximum	€/MWh	1,3	0,0	0,0	0,0	1,3	0,0	1,3	0,0	1,3	0,0	0,0	1,3	1,3	0,0	0,0	**1,3**
average (weighted)	€/MWh	-3,5	0,0	0,0	0,0	-6,1	0,0	-6,1	0,0	-11,3	0,0	0,0	-6,1	-6,1	0,0	0,0	**-9,8**

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[22] Please note, these generation costs are calculated applying a standardised interest rate of 6.5% and a depreciation time of 15 years to investment and O&M-costs as implemented in the database for new plants. Thereby, costs refer to the start year of the simulation (i.e. 2002).

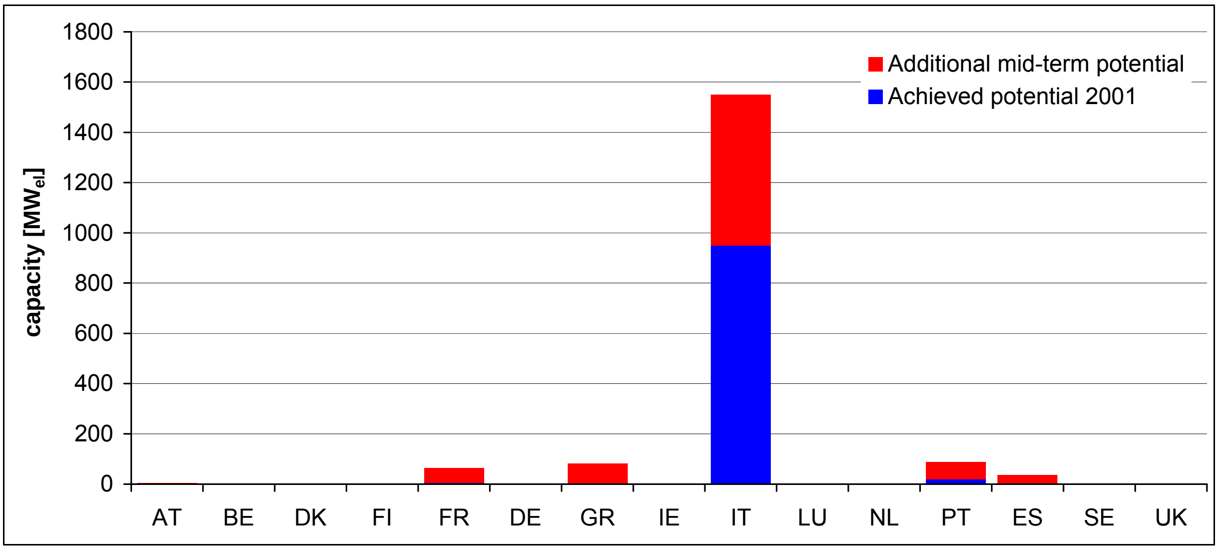

Figure 3.26. Achieved potential (2001) & additional mid-term potential for electricity from geothermal energy in EU-15 countries

Dynamic aspects of cost development

As default, within the model **Green*Net*** the future development of investment costs for biomass-fired plant is based using cost forecasts where a percentage decrease of costs is indicated for each year.

3.3.4 Hydro power – Large-scale plant

3.3.4.1 Methodology for the development of cost-resource curves

Note, within the database of the toolbox **Green*Net***, electricity generation from existing pump-storage hydropower is excluded from the achieved potential and, hence, not considered in the potential assessment for new hydro plant! Pump-storage plants will be considered within WP 3 (“storage”)!

Future potential

An additional realisable mid-term potential for large-scale hydro power is difficult to predict – due to above mentioned constraints, i.e. the missing public acceptance. Although hydro power is well exploited in Europe, the technical as well as the economic potential in some countries still is quite high – compared with other RES-E. Hence, the approach to assess the future potential is as follows:

Default potential data was based on ESD/DGXVII, 1996. Further corrections have been undertaken after consultation with project partners and own investigations. Especially, for those countries which have proposed future targets for large hydro, these figures have been taken into account – in order to derive a proper set of data.

In this context, it is important to mention that potential for upgrading or refurbishment of existing plant is not expressed in the database for new plant. Of course, it is considered in the overall model **Green*Net*** – but internalised into the model calculations.[23]

Costs

Table 3.11 provides an overview on cost-data for new large-scale hydropower plant of the toolbox **Green*Net***. Please note, investment as well as O&M-costs are given in €$_{2002}$ and refer to the start year of the simulations (i.e. 2002).

Table 3.11 Overview on cost-data for new plant (large hydro) – *harmonised costs only*

Cost - data for new plant

	category	plant-type: unit	ELE large (new 1)	ELE medium (new 2)	ELE small (new 3)
technical-specification	*plant-size (average)*	*MW $_{el}$*	250,000	75,000	20,000
	efficiency electricity	%	100%	100%	100%
	efficiency heat	%			
	efficiency TOTAL	%	100%	100%	100%
	power-to-heat-ratio	1	0,00	0,00	0,00
	life time	a	20	20	20
cost-specification (general)	depreciation time	a	15	15	15
	interest rate	*%*	*6,5%*	*6,5%*	*6,5%*
	c.r.f	*1*	*0,1064*	*0,1064*	*0,1064*
	Share of HARMONISED investment costs	%	50%	50%	50%
	investment costs TOTAL (average)	**€/kW $_{el}$**	**1.200,00**	**1.750,00**	**2.300,00**
	investment costs HARMONISED	€/kW $_{el}$	600,00	875,00	1.150,00
	investment costs NON-HARMONISED (average)	€/kW $_{el}$	600,00	875,00	1.150,00
	Share of HARMONISED O&M costs	%	100%	100%	100%
	O&M costs TOTAL (average)	**€/(kW $_{el}$*a)**	**35,00**	**35,00**	**35,00**
	O&M costs TOTAL (average) as share of investment costs	**%**	**2,9%**	**2,0%**	**1,5%**
	O&M costs HARMONISED	€/(kW $_{el}$*a)	35,00	35,00	35,00
	O&M costs NON-HARMONISED (average)	€/(kW $_{el}$*a)	0,00	0,00	0,00

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[23] Note, as explained in chapter 2, existing plants at the end of their lifetime are shifted to the database for new plants – for most technologies representing a cheaper option compared to other new plants. In case of hydropower a similar approach will be implemented – although, more complexity occurs due to the fact that the terminology ‘lifetime’ does not really indicate that the plant will stop operation as historical evidence has proven – e.g. as described in Lorenzoni (2001) 47% of all small-scale hydro plant are older than 60 years.

Investment costs for large-scale hydropower plant are site-specific, depending on geographic conditions as well as on additional (country-specific) efforts (acceptance barrier, planning process, etc.).

Therefore the range of investment costs differs largely between and within the countries, e.g. in Portugal costs vary from 1100 up to 2450 €/kW.

Country-specific average full load-hours – derived from further investigations (i.e. based on energy capability factors combined with actual generation figures as expressed e.g. in UCTE, 2002) are applied for new plant – representing the hydrologic and climatic conditions

Cost-resource curves

By linking the cost-data – specified for different plant-types – with the potential assessment, cost-resource curves are derived.

3.3.4.2 Resulting cost-resource curves

Table 3.12 shows the overall set of data regarding costs and potentials for large hydro. In addition, a comparison of the achieved and the additional mid-term potential is given in Figure 3.27.[24]

Table 3.12. Overview on potential and costs for electricity from large hydropower in EU-15 countries

Hydropower - large-scale plant (HY-LS)		**AT**	**BE**	**DK**	**FI**	**FR**	**DE**	**GR**	**IE**	**IT**	**LU**	**NL**	**PT**	**ES**	**SE**	**UK**	**EU15**
Potential - existing & new plant:																	
Achieved potential:																	
electricity generation pot.	GWh	34869	133	0	12624	60935	11958	3407	721	35247	0	101	10560	31486	67363	4336	**273739**
capacity potential	MW	7680	43	0	2623	19468	2000	2402	199	11186	0	36	4049	16399	15496	1326	**82908**
full load-hours (average)	h/a	4540	3092	0	4813	3130	5979	1418	3622	3151	0	2844	2608	1920	4347	3270	**3302**
Additional mid-term potential:																	
electricity generation pot.	GWh	0	0	0	732	0	2469	0	76	0	0	0	467	330	87	0	**4161**
capacity potential	MW	0	0	0	152	0	413	0	21	0	0	0	179	172	20	0	**957**
full load-hours (average)	h/a	0	0	0	4813	0	5979	0	3622	0	0	0	2608	1920	4347	0	**4348**
Costs of electricity - new plant:																	
Long-run marginal costs (LRMC):																	
minimum	€/MWh	0,0	0,0	0,0	42,8	0,0	63,5	0,0	43,5	0,0	0,0	0,0	53,0	56,9	36,2	0,0	**36,2**
maximum	€/MWh	0,0	0,0	0,0	65,8	0,0	124,1	0,0	129,8	0,0	0,0	0,0	125,9	109,5	75,5	0,0	**129,8**
average (weighted)	€/MWh	0,0	0,0	0,0	53,4	0,0	92,5	0,0	83,0	0,0	0,0	0,0	85,8	81,4	54,6	0,0	**83,0**
Short-run marginal costs (SRMC):																	
minimum	€/MWh	0,0	0,0	0,0	6,6	0,0	5,3	0,0	8,8	0,0	0,0	0,0	12,2	16,6	7,3	0,0	**5,3**
maximum	€/MWh	0,0	0,0	0,0	8,1	0,0	6,5	0,0	10,7	0,0	0,0	0,0	14,9	20,3	8,9	0,0	**20,3**
average (weighted)	€/MWh	0,0	0,0	0,0	7,3	0,0	5,9	0,0	9,7	0,0	0,0	0,0	13,4	18,2	8,1	0,0	**8,0**

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[24] Please note, these generation costs are calculated by applying a standardised interest rate of 6.5% and a depreciation time of 15 years to investment and O&M-costs as implemented in the database for new plant. Thereby, costs refer to the start year of the simulation (i.e. 2002).

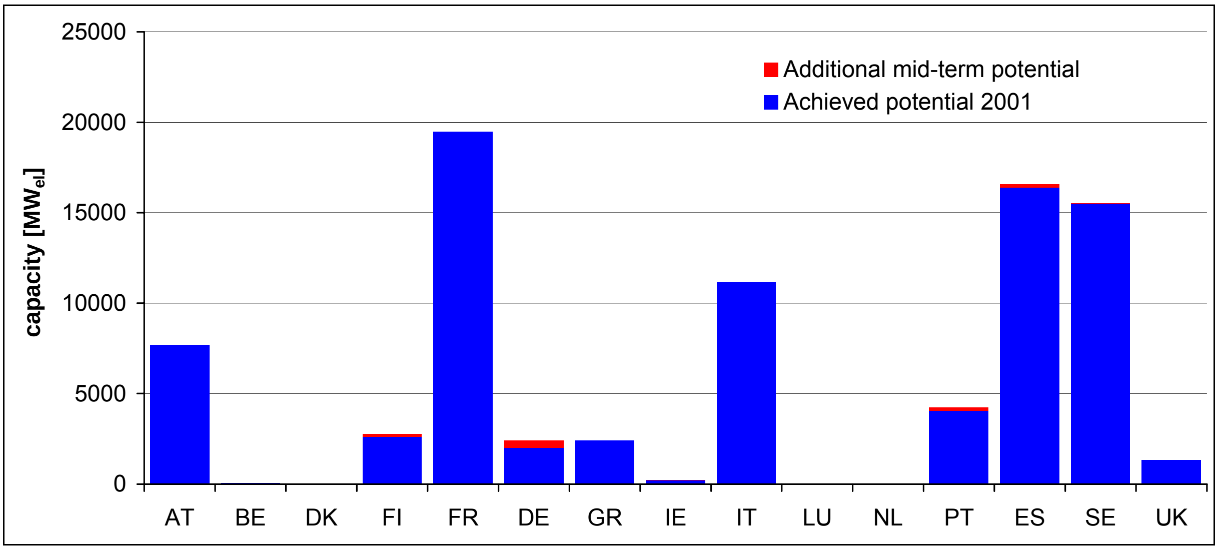

Figure 3.27. Achieved potential (2001) & additional mid-term potential for electricity from large hydropower in EU-15 countries

Dynamic aspects of cost development

As default, within the model **Green*Net*** the future development of investment costs for large hydropower plant is based using cost forecasts where a percentage decrease or increase, respectively, of costs is indicated for each year. Hence, in general for large-scale hydropower lower costs for turbine, generator, etc. have to be compared to increasing efforts related to environmental regulations.

3.3.5 Hydro power – Small-scale plant

3.3.5.1 Methodology for the development of cost-resource curves

Note, within the database of the toolbox **Green*Net***, electricity generation from existing pump-storage hydropower is excluded from the achieved potential and, hence, not considered in the potential assessment for new hydro plant! Pump-storage plants will be considered within WP 3 ("storage")!

Future potential

In contrast to large hydro, data with respect to realisable potentials – considering also environmental constraints – have been well-assessed in the past. A homogenous approach was undertaken within the project 'BlueAge' – where national experts derived in accordance with the applied approach of potential definitions reliable set of data representing country-specific potentials under consideration of economic and environmental constraints.[25] Hence, these figures are used and, of course, updated according to recent developments, to derive the mid-term potentials.

In this context, it is important to mention that potential for upgrading or refurbishment of existing plants is not expressed in the database for new plants. Of course, it is considered in the overall model **Green*Net*** – but internalised into the model calculations.[26]

Costs

Table 3.13 provides an overview on cost-data for new large-scale hydropower plants of the toolbox **Green*Net***. Please note, investment as well as O&M-costs are given in $€_{2002}$ and refer to the start year of the simulations (i.e. 2002).

Table 3.13. Overview on cost-data for new plants (small hydro)

Cost - data for new plant

	category	plant-type: unit	**ELE large** (new 1)	**ELE medium** (new 2)	**ELE small** (new 3)
technical-specification	*plant-size (average)*	*MW_{el}*	9,999	2,000	0,250
	efficiency electricity	%	100%	100%	100%
	efficiency heat	%			
	efficiency TOTAL	%	100%	100%	100%
	power-to-heat-ratio	1	0,00	0,00	0,00
	life time	a	20	20	20
cost-specification (general)	depreciation time	a	15	15	15
	interest rate	*%*	*6,5%*	*6,5%*	*6,5%*
	c.r.f	*1*	*0,1064*	*0,1064*	*0,1064*
	Share of HARMONISED investment costs	%	50%	50%	50%
	investment costs TOTAL (average)	**$€/kW_{el}$**	**1.600,00**	**2.050,00**	**2.500,00**
	investment costs HARMONISED	$€/kW_{el}$	800,00	1.025,00	1.250,00
	investment costs NON-HARMONISED (average)	$€/kW_{el}$	800,00	1.025,00	1.250,00
	Share of HARMONISED O&M costs	%	100%	100%	100%
	O&M costs TOTAL (average)	**$€/(kW_{el}*a)$**	**40,00**	**40,00**	**40,00**
	O&M costs TOTAL (average) as share of investment costs	**%**	**2,5%**	**2,0%**	**1,6%**
	O&M costs HARMONISED	$€/(kW_{el}*a)$	40,00	40,00	40,00
	O&M costs NON-HARMONISED (average)	$€/(kW_{el}*a)$	0,00	0,00	0,00

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[25] For details see Lorenzoni, 2001 (especially, section 3.3 of the report).

[26] Note, that existing plants at the end of their lifetime are shifted to the database for new plants – for most technologies representing a cheaper option compared to other new plants. In case of hydropower a similar approach will be implemented – although, more complexity occurs due to the fact that the terminology 'lifetime' does not really indicate that the plants will stop operation as historical evidence has proven – e.g. as described in Lorenzoni (2001) 47% of all small-scale hydro plants are older than 60 years.

Investment costs for small-scale hydropower plants are site-specific, depending on geographic conditions as well as on additional (country-specific) efforts (acceptance barrier, planning process, etc.). Compared to large-scale hydropower costs are in a similar range (economies of scale are in contrast to higher necessary environmentally driven expenditures).

The range of investment costs differs largely between and within the countries, e.g. in Austria costs vary from 2900 up to 4500 €/kW (compare e.g. Lorenzoni, 2001).

Country-specific average full load-hours – derived from further investigations (i.e. based on energy capability factors combined with actual generation figures as expressed e.g. in UCTE, 2002) are applied for new plants – representing the hydrologic and climatic conditions. Hence, to take site-specific conditions into account, a range of +/-10% has been applied.

Cost-resource curves

By linking the cost-data – specified for different plant-categories – with the potential assessment, cost-resource curves are derived.

3.3.5.2 Resulting cost-resource curves

Table 3.14 indicates the overall set of data with respect to costs and potentials for small hydropower. In addition, a comparison of the achieved and the additional mid-term potential is given in Figure 3.28.[27]

Table 3.14. Overview on potential and costs for electricity from small hydropower in EU-15 countries

Hydropower - small-scale plant (HY-SS)		AT	BE	DK	FI	FR	DE	GR	IE	IT	LU	NL	PT	ES	SE	UK	EU15
Potential - existing & new plant:																	
Achieved potential:																	
electricity generation pot.	GWh	4338	184	27	1178	6219	7128	175	103	8433	100	1	647	3086	3369	595	**35583**
capacity potential	MW	871	61	10	304	1674	1440	63	34	2270	37	2	281	1607	775	182	**9611**
full load-hours (average)	h/a	4980	3014	2812	3876	3716	4950	2784	3025	3715	2711	500	2302	1920	4347	3270	**3702**
Additional mid-term potential:																	
electricity generation pot.	GWh	4701	78	0	388	3716	1188	237	103	1631	0	50	1080	1806	1304	157	**16439**
capacity potential	MW	944	26	0	100	1000	240	85	34	439	0	17	469	941	300	48	**4643**
full load-hours (average)	h/a	4980	3014	0	3876	3716	4950	2784	3025	3715	0	3000	2302	1920	4347	3270	**3541**
Costs of electricity - new plant:																	
Long-run marginal costs (LRMC):																	
minimum	€/MWh	48,1	117,9	0,0	59,3	41,0	81,6	47,8	60,0	48,8	0,0	118,5	70,4	69,3	41,7	70,3	**41,0**
maximum	€/MWh	121,6	201,0	0,0	86,2	105,8	153,4	103,0	161,2	109,0	0,0	201,9	150,2	118,5	79,5	167,2	**201,9**
average (weighted)	€/MWh	79,6	151,6	0,0	71,7	70,9	115,9	73,6	106,3	76,5	0,0	152,3	106,1	92,2	59,4	114,6	**82,3**
Short-run marginal costs (SRMC):																	
minimum	€/MWh	7,3	12,1	0,0	9,4	9,8	7,3	13,1	12,0	9,8	0,0	12,1	15,8	18,9	8,4	11,1	**7,3**
maximum	€/MWh	8,9	14,7	0,0	11,5	12,0	9,0	16,0	14,7	12,0	0,0	14,8	19,3	23,1	10,2	13,6	**23,1**
average (weighted)	€/MWh	8,0	13,3	0,0	10,3	10,8	8,1	14,4	13,2	10,8	0,0	13,3	17,4	20,8	9,2	12,2	**11,3**

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[27] Please note, these generation costs are calculated by applying a standardised interest rate of 6.5% and a depreciation time of 15 years to investment and O&M-costs as implemented in the database for new plants. Thereby, costs refer to the start year of the simulation (i.e. 2002).

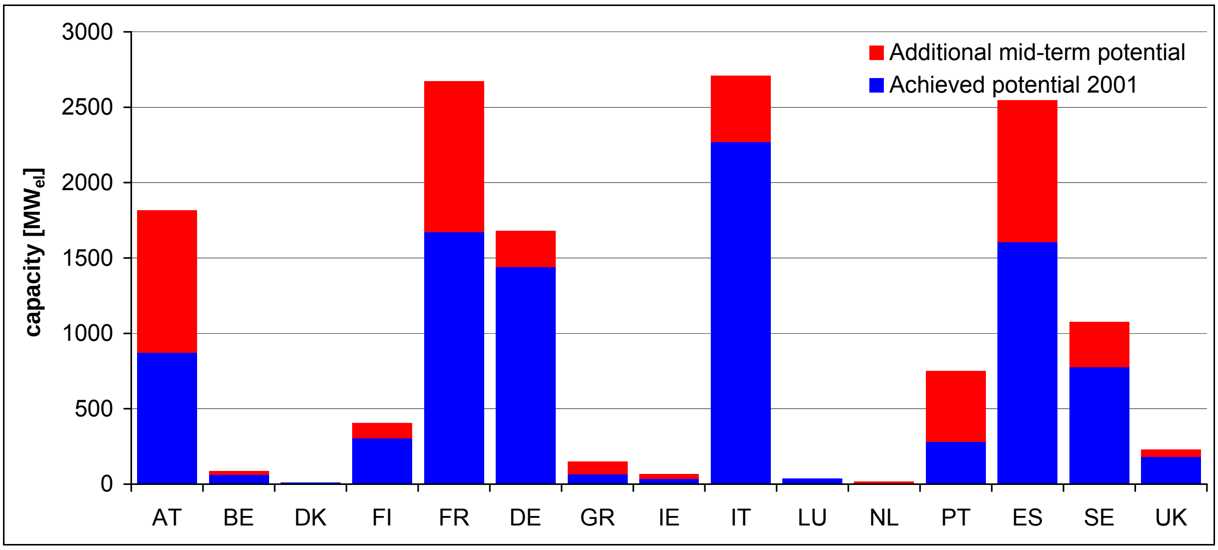

Figure 3.28. Achieved potential (2001) & additional mid-term potential for electricity from small hydropower in EU-15 countries

Dynamic aspects of cost development

As default, within the model **Green*Net*** the future development of investment costs for small-scale hydropower plant is based on the appliance of cost forecasts where a percentage decrease or increase, respectively, of costs is indicated for each year. Hence, similar to large scale hydropower, costs for turbine, generator, etc. have to be compared to increasing efforts related to environmental regulations.

3.3.6 Landfill gas

3.3.6.1 Methodology for the development of cost-resource curves

Future potential

The future potential of landfill gas is highly influenced by recent developments regarding waste treatment regulations as e.g. given EU-wide by the EU-directive on the landfill of waste (European Commission, 1999). In general, the waste treatment option of land-filling is restricted in the future. In accordance with these regulations as implemented on a national level, primary potentials have been assessed. In more detail, the approach was as follows:

First, in order to derive the additional mid-term potential the amount of waste to be generated in the year 2020 has been estimated – by applying country-specific similar growth rates as observed in the past (taken from Eurostat, 2002a). Next, in accordance with the above mentioned waste treatment regulation, a country-specific certain percentage of waste to be land-filled has been assumed. By applying figures with respect to gas rise, usability, energy content, plant efficiency, etc. the potential for electricity from landfill gas was derived by country. In order to determine the additional available mid-term potential, the already achieved level of use (electricity generation of existing plant) has to be taken into account. Of course, as explained for e.g. biogas – both options with respect to the energetic use have been considered – CHP vs. pure power production. As default setting, due to the lack of heat consumers on-site, the option of CHP has been neglected.

Costs

Table 3.15 provides an overview on cost-data for new landfill gas plant of the toolbox **Green*Net***. Please note, investment as well as O&M-costs are given in €$_{2002}$ and refer to the start year of the simulations (i.e. 2002).

Table 3.15. Overview on cost-data for new plant (landfill gas)

Cost - data for new plant

	category	plant-type: unit	ELE large (new 1)	ELE medium (new 2)	ELE small (new 3)	CHP large (new 1)	CHP medium (new 2)	CHP small (new 3)
technical-specification	*plant-size*	MW_{el}	8,000	3,000	0,750	8,000	3,000	0,750
	efficiency electricity	%	36%	34%	32%	35%	33%	31%
	efficiency heat	%	0%	0%	0%	50%	52%	54%
	efficiency TOTAL	%	36%	34%	32%	85%	85%	85%
	power-to-heat-ratio	1	0,00	0,00	0,00	1,43	1,58	1,74
	life time	a	25	25	25	25	25	25
cost-specification (general)	lifetime	a	15	15	15	15	15	15
	interest rate	*%*	*6,5%*	*6,5%*	*6,5%*	*6,5%*	*6,5%*	*6,5%*
	c.r.f	*1*	*0,1064*	*0,1064*	*0,1064*	*0,1064*	*0,1064*	*0,1064*
	Share of HARMONISED investment costs	%	100%	100%	100%	100%	100%	100%
	investment costs TOTAL (average)	**€/kW$_{el}$**	**1.250,00**	**1.500,00**	**1.800,00**	**1.400,00**	**1.650,00**	**1.950,00**
	investment costs HARMONISED	€/kW$_{el}$	1.250,00	1.500,00	1.800,00	1.400,00	1.650,00	1.950,00
	investment costs NON-HARMONISED (average)	€/kW$_{el}$	0,00	0,00	0,00	0,00	0,00	0,00
	Share of HARMONISED O&M costs	%	100%	100%	100%	100%	100%	100%
	O&M costs TOTAL (average)	**€/(kW$_{el}$*a)**	**50,00**	**60,00**	**80,00**	**55,00**	**65,00**	**85,00**
	O&M costs TOTAL (average) as share of investment costs	**%**	**4,0%**	**4,0%**	**4,4%**	**3,9%**	**3,9%**	**4,4%**
	O&M costs HARMONISED	€/(kW$_{el}$*a)	50,00	60,00	80,00	55,00	65,00	85,00
	O&M costs NON-HARMONISED (average)	€/(kW$_{el}$*a)	0,00	0,00	0,00	0,00	0,00	0,00

At present, the total investment costs of landfill gas plants are in a range between 1250 and 1950 €/kW (compare e.g. Haas et. al. (2001), Resch et. al. (2001)) – depending on site-specific conditions, i.e. plant-size, etc. Cost differences with respect to related technologies as biogas or sewage gas occur due to the fact that for a landfill site a gas collection as well as a gas treatment is prescribed by law. Therefore, this cost intensive investments can not be charged to the power plant.

The achievable full-load hours of a landfill gas plant highly depend on plant specific conditions, especially with respect to the planning process. If the power unit is constructed too large, achievable full load hours would be rather low. In general, achievable full-load hours decrease with the age of the plant even if waste depositing is kept constant over time. Empirical data indicates in general rather low figures in size of 2.800 h/a on average. With respect to new plant 5750 h/a on average occur to be more realistic. For further calculations undertaken within this project – to meet the existing uncertainty – full-load hours are assumed to be in a range between 5500 and 6500 h/a.

In general, landfill gas represents a zero-cost fuel source, as it appears as a kind of side-product of the purification process.

Cost-resource curves

By linking the cost-data – specified for different plant-sizes (i.e. large-, medium- and small-scale) – with the potential assessment, cost-resource curves are derived. In this context, for the overall realisable potential the share of different plant-sizes is assumed. To overcome uncertainty with respect to the achievable full-load hours three discrete values have been applied for each plant-type.

3.3.6.2 Resulting cost-resource curves

An overview on potential and costs for electricity from landfill gas in EU-15 countries is provided in Table 3.16. In addition, a comparison of the achieved and the additional mid-term potential is given in Figure 3.29.[28]

Table 3.16. Overview on potential and costs for electricity from landfill gas in EU-15 countries.

Landfill gas (LG)		**AT**	**BE**	**DK**	**FI**	**FR**	**DE**	**GR**	**IE**	**IT**	**LU**	**NL**	**PT**	**ES**	**SE**	**UK**	**EU15**
Potential - existing & new plant:																	
Achieved potential:																	
electricity generation pot.	GWh	96	99	71	10	505	1250	79	83	818	0	205	0	140	105	2301	**5761**
capacity potential	MW	17	18	13	2	92	227	14	15	149	0	37	0	26	19	418	**1047**
full load-hours (average)	h/a	5500	5500	5500	5500	5500	5500	5500	5500	5500	0	5500	0	5500	5500	5500	**5500**
Additional mid-term potential:																	
electricity generation pot.	GWh	0	541	62	918	5320	3152	704	1108	2403	12	202	1308	14429	726	1593	**32479**
in case of CHP …	GWh	0	525	60	890	5161	3059	683	1074	2331	11	196	1269	13996	705	1546	**31506**
capacity potential	MW	0	87	10	151	865	508	116	183	392	2	32	215	2351	118	256	**5287**
in case of CHP …	MW	0	84	10	146	839	493	113	177	380	2	32	208	2280	115	249	**5128**
full load-hours (average)	h/a	0	6213	6213	6099	6150	6200	6061	6061	6137	6086	6213	6087	6137	6137	6213	**6143**
in case of CHP …	h/a	0	6213	6213	6100	6150	6201	6061	6061	6138	6086	6213	6087	6138	6138	6213	**6144**
Costs of electricity - new plant:																	
Long-run marginal costs (LRMC):																	
minimum	€/MWh	0,0	26,1	26,1	26,1	26,1	26,1	26,1	26,1	26,1	26,1	26,1	26,1	26,1	26,1	26,1	**26,1**
maximum	€/MWh	0,0	49,4	49,4	49,4	49,4	49,4	49,4	49,4	49,4	49,4	49,4	49,4	49,4	49,4	49,4	**49,4**
average (weighted)	€/MWh	0,0	36,0	36,0	40,1	38,2	36,5	41,5	41,5	38,7	40,5	36,0	40,6	38,7	38,7	36,0	**38,5**
in case of CHP …																	
minimum	€/MWh	0,0	21,0	21,0	21,0	21,0	21,0	21,0	21,0	21,0	21,0	21,0	21,0	21,0	21,0	21,0	**21,0**
maximum	€/MWh	0,0	46,8	46,8	46,8	46,8	46,8	46,8	46,8	46,8	46,8	46,8	46,8	46,8	46,8	46,8	**46,8**
average (weighted)	€/MWh	0,0	31,9	31,9	35,6	33,9	32,4	36,9	36,9	34,4	36,0	31,9	36,1	34,4	34,4	31,9	**34,2**
Short-run marginal costs (SRMC):																	
minimum	€/MWh	0,0	7,1	7,1	7,1	7,1	7,1	7,1	7,1	7,1	7,1	7,1	7,1	7,1	7,1	7,1	**7,1**
maximum	€/MWh	0,0	14,5	14,5	14,5	14,5	14,5	14,5	14,5	14,5	14,5	14,5	14,5	14,5	14,5	14,5	**14,5**
average (weighted)	€/MWh	0,0	10,1	10,1	11,5	10,9	10,3	12,0	12,0	11,1	11,6	10,1	11,7	11,1	11,1	10,1	**11,0**
in case of CHP …																	
minimum	€/MWh	0,0	-0,3	-0,3	-0,3	-0,3	-0,3	-0,3	-0,3	-0,3	-0,3	-0,3	-0,3	-0,3	-0,3	-0,3	**-0,3**
maximum	€/MWh	0,0	9,1	9,1	9,1	9,1	9,1	9,1	9,1	9,1	9,1	9,1	9,1	9,1	9,1	9,1	**9,1**
average (weighted)	€/MWh	0,0	3,5	3,5	4,4	4,0	3,6	4,8	4,8	4,1	4,5	3,5	4,6	4,1	4,1	3,5	**4,1**

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[28] Please note, these generation costs are calculated by applying a standardised interest rate of 6.5% and a depreciation time of 15 years to investment and O&M-costs as implemented in the database for new plants. Thereby, costs refer to the start year of the simulation (i.e. 2002).

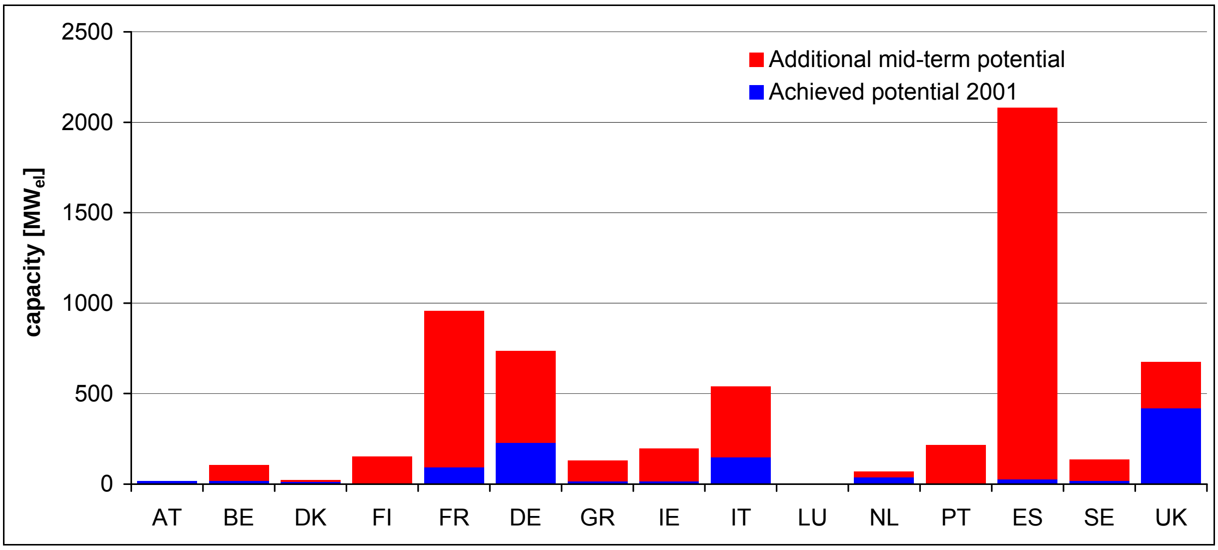

Figure 3.29. Achieved potential (2001) & additional mid-term potential for electricity from landfill gas in EU-15 countries

Dynamic aspects of cost development

As default, within the model **Green*Net*** the future development of investment costs for landfill gas plant is based using cost forecasts where a percentage decrease of costs is indicated for each year.

3.3.7 Sewage gas

3.3.7.1 Methodology for the development of cost-resource curves

Future potential

The approach to assess the future potential of sewage gas is follows:

Water disposal per capita and/or the amount of sewage sludge (in total per country) have been used as indicator to determine the potential of sewage gas. In this context, statistical data was taken from Eurostat, 2000a on a European level. Hence, if newer data was available, also country-specific sources have been taken into account. Next, the potential for electricity from sewage gas has been calculated by applying specific energy content and an average conversion efficiency. In order to determine the additional available mid-term potential, the already achieved level of use (electricity generation of existing plant) has to be taken into account. Of course, as explained for e.g. biogas – both options with respect to the energetic use have been considered – CHP vs. pure power production.

Costs

Table 3.17 provides an overview on cost-data for new sewage gas plants of the toolbox **Green*Net***. Please note, investment as well as O&M-costs are given in €$_{2002}$ and refer to the start year of the simulations (i.e. 2002).

Table 3.17. Overview on cost-data for new plant (sewage gas)

Cost - data for new plant

	category	plant-type: unit	ELE large (new 1)	ELE medium (new 2)	ELE small (new 3)	CHP large (new 1)	CHP medium (new 2)	CHP small (new 3)
technical-specification	*plant-size*	*MW_{el}*	0,600	0,200	0,100	0,600	0,200	0,100
	efficiency electricity	%	32%	30%	28%	30%	28%	26%
	efficiency heat	%	0%	0%	0%	54%	56%	58%
	efficiency TOTAL	%	32%	30%	28%	84%	84%	84%
	power-to-heat-ratio	1	0,00	0,00	0,00	1,80	2,00	2,23
	life time	a	25	25	25	25	25	25
cost-specification (general)	lifetime	a	15	15	15	15	15	15
	interest rate	*%*	*6,5%*	*6,5%*	*6,5%*	*6,5%*	*6,5%*	*6,5%*
	c.r.f	*1*	*0,1064*	*0,1064*	*0,1064*	*0,1064*	*0,1064*	*0,1064*
	Share of HARMONISED investment costs	%	100%	100%	100%	100%	100%	100%
	investment costs TOTAL (average)	**$€/kW_{el}$**	**2.250,00**	**3.000,00**	**3.350,00**	**2.400,00**	**3.150,00**	**3.500,00**
	investment costs HARMONISED	$€/kW_{el}$	2.250,00	3.000,00	3.350,00	2.400,00	3.150,00	3.500,00
	investment costs NON-HARMONISED (average)	$€/kW_{el}$	0,00	0,00	0,00	0,00	0,00	0,00
	Share of HARMONISED O&M costs	%	100%	100%	100%	100%	100%	100%
	O&M costs TOTAL (average)	**$€/(kW_{el}*a)$**	**115,00**	**145,00**	**165,00**	**125,00**	**155,00**	**175,00**
	O&M costs TOTAL (average) as share of investment costs	**%**	**5,1%**	**4,8%**	**4,9%**	**5,2%**	**4,9%**	**5,0%**
	O&M costs HARMONISED	$€/(kW_{el}*a)$	115,00	145,00	165,00	125,00	155,00	175,00
	O&M costs NON-HARMONISED (average)	$€/(kW_{el}*a)$	0,00	0,00	0,00	0,00	0,00	0,00

At present, the total investment costs of sewage gas plants are in a range between 2500 and 3500 €/kW (compare e.g. Haas et.al. (2001), Fischer et. al. (2002)), depending on site-specific conditions. On contrary to landfill gas, costs are on a higher level mainly due to smaller plant-sizes.

The achievable full-load hours of a sewage gas plant highly depend on plant specific conditions, especially with respect to the planning process. If the power unit is constructed too large, achievable full load hours would be rather low. In general, achievable full-load hours decrease with the age of the plant even if waste depositing is kept constant over time. Empirical data indicate in general rather low figures in size of 2900 h/a on average. With respect to new plants 5750 h/a on average occur to be more realistic. For further calculations undertaken within this project – to meet the existing uncertainty – full-load hours are assumed to be in a range between 5000 and 6500 h/a.

In general, sewage gas represents a zero-cost fuel source, as it appears as a kind of side-product of the purification process.

Cost-resource curves

By linking the cost-data – specified for different plant-sizes (i.e. large-, medium- and small-scale) – with the potential assessment, cost-resource curves are derived. In this context, for the overall realisable potential the share of different plant-sizes is assumed. To overcome uncertainty with respect to the achievable full-load hours three discrete values have been applied for each plant-type.

3.3.7.2 Resulting cost-resource curves

An overview on potential and costs for electricity from sewage gas in EU-15 countries is provided in Table 3.18. In addition, a comparison of the achieved and the additional mid-term potential is given in Figure 3.30.[29]

Table 3.18. Overview on potential and costs for electricity from sewage gas in EU-15 countries.

Sewage gas (SG)		**AT**	**BE**	**DK**	**FI**	**FR**	**DE**	**GR**	**IE**	**IT**	**LU**	**NL**	**PT**	**ES**	**SE**	**UK**	**EU15**
Potential - existing & new plant:																	
Achieved potential:																	
electricity generation pot.	GWh	96	2	67	20	96	480	1	0	18	0	120	0	208	0	383	**1490**
capacity potential	MW	18	0	15	4	21	107	0	0	4	0	27	0	46	0	85	**327**
full load-hours (average)	h/a	5500	4500	4500	4500	4500	4500	4500		4500		4500		4500		4500	**4553**
Additional mid-term potential:																	
electricity generation pot.	GWh	178	231	42	91	1289	1254	202	88	1204	11	241	209	575	198	921	**6735**
in case of CHP …	GWh	166	216	39	85	1201	1170	188	82	1122	10	225	195	536	185	860	**6279**
capacity potential	MW	32	40	7	16	228	220	36	16	214	2	42	37	102	35	161	**1190**
in case of CHP …	MW	29	38	7	15	213	205	34	15	199	2	39	35	95	33	151	**1109**
full load-hours (average)	h/a	5634	5710	5710	5596	5647	5698	5558	5558	5634	5583	5710	5584	5634	5634	5710	**5659**
in case of CHP …	h/a	5635	5711	5711	5597	5648	5698	5558	5558	5635	5584	5711	5584	5635	5635	5711	**5660**
Costs of electricity - new plant:																	
Long-run marginal costs (LRMC):																	
minimum	€/MWh	54,5	54,5	54,5	54,5	54,5	54,5	54,5	54,5	54,5	54,5	54,5	54,5	54,5	54,5	54,5	**54,5**
maximum	€/MWh	104,3	104,3	104,3	104,3	104,3	104,3	104,3	104,3	104,3	104,3	104,3	104,3	104,3	104,3	104,3	**104,3**
average (weighted)	€/MWh	78,3	78,3	78,3	85,9	82,7	79,0	88,6	88,6	83,3	87,2	78,3	86,6	83,3	83,3	78,3	**81,6**
in case of CHP …																	
minimum	€/MWh	39,1	39,1	39,1	39,1	39,1	39,1	39,1	39,1	39,1	39,1	39,1	39,1	39,1	39,1	39,1	**39,1**
maximum	€/MWh	87,1	87,1	87,1	87,1	87,1	87,1	87,1	87,1	87,1	87,1	87,1	87,1	87,1	87,1	87,1	**87,1**
average (weighted)	€/MWh	62,0	62,0	62,0	68,3	65,6	62,5	70,5	70,5	66,2	69,4	62,0	68,8	66,2	66,2	62,0	**64,7**
Short-run marginal costs (SRMC):																	
minimum	€/MWh	17,7	17,7	17,7	17,7	17,7	17,7	17,7	17,7	17,7	17,7	17,7	17,7	17,7	17,7	17,7	**17,7**
maximum	€/MWh	33,0	33,0	33,0	33,0	33,0	33,0	33,0	33,0	33,0	33,0	33,0	33,0	33,0	33,0	33,0	**33,0**
average (weighted)	€/MWh	24,8	24,8	24,8	27,2	26,2	25,0	28,0	28,0	26,4	27,5	24,8	27,4	26,4	26,4	24,8	**25,8**
in case of CHP …																	
minimum	€/MWh	-0,2	-0,2	-0,2	-0,2	-0,2	-0,2	-0,2	-0,2	-0,2	-0,2	-0,2	-0,2	-0,2	-0,2	-0,2	**-0,2**
maximum	€/MWh	12,7	12,7	12,7	12,7	12,7	12,7	12,7	12,7	12,7	12,7	12,7	12,7	12,7	12,7	12,7	**12,7**
average (weighted)	€/MWh	5,8	5,8	5,8	6,7	6,3	5,8	7,1	7,1	6,4	6,9	5,8	6,8	6,4	6,4	5,8	**6,2**

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[29] Please note, these generation costs are calculated by applying a standardised interest rate of 6.5% and a depreciation time of 15 years to investment and O&M-costs as implemented in the database for new plants. Thereby, costs refer to the start year of the simulation (i.e. 2002).

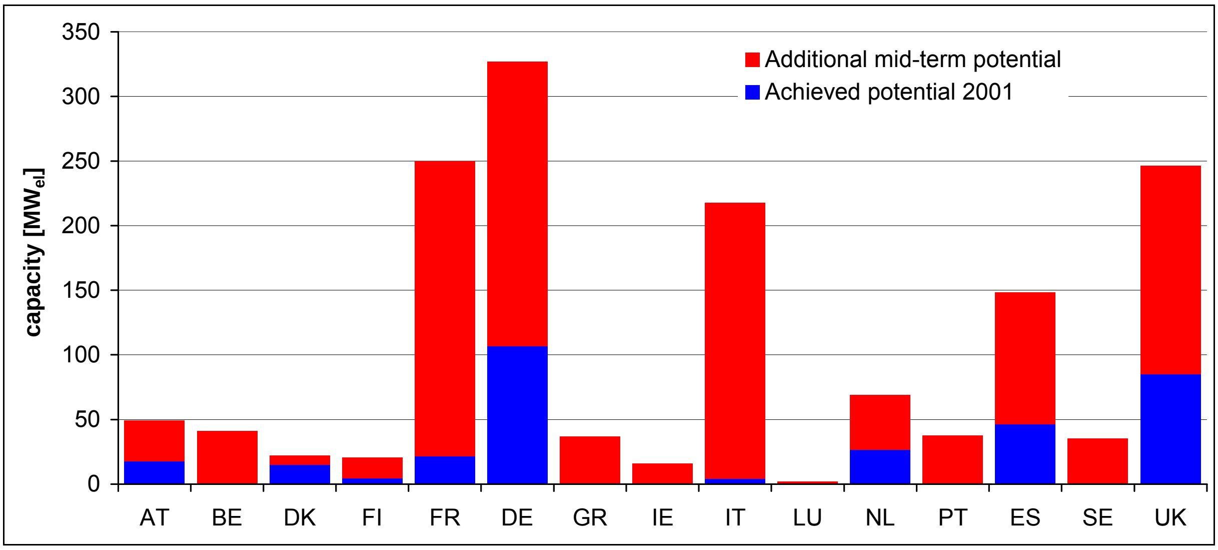

Figure 3.30. Achieved potential (2001) & additional mid-term potential for electricity from sewage gas in EU-15 countries

Dynamic aspects of cost development

As default, within the model **Green*Net*** the future development of investment costs for sewage gas plant is based using cost forecasts where a percentage decrease of costs is indicated for each year.

3.3.8 Solar electricity - Photovoltaics

3.3.8.1 Methodology for the development of cost-resource curves

Future potential

In general, PV represents an energy source characterised by a large realisable potential from a technical point-of-view. The approach for the assessment of the (additional) realisable mid-term potential is based on the following categorisation of PV plant:

- PV on roofs (building integrated),
- PV on facades (building integration),
- PV on fields (no building integration).

In principle, for *building integrated PV* (PV on roofs, PV on facades) the electricity generation potential can be calculated by linking the average figures of solar-architecturally suitable area per capita to country-specific features (mainly population size and annual solar irradiation).

In more detail, the chosen approach for the potential assessment was is follows:

1. Assessment of the capacity potential: For building integrated PV the methodology for the assessment of the capacity potential based on Gutschner et al (2001) is illustrated in Figure 3.31 (upper part). Thereby, in a first step, a country-specific (per capita) ground floor area is aggregated.[30] Applying the corresponding overall utilisation factor of 0.4 for roofs and 0.15 for facades (for the building stock), the solar-architecturally suitable building roof and facade areas per capita are calculated. Multiplied with population, solar irradiance (i.e. 1kW/m2) and conversion efficiency the capacity potential is derived.

   For *non-building integrated PV* (PV on 'free field') the capacity potential is derived by assuming that a maximum of 0.05% of agricultural area are available for PV installations. Again, by applying solar irradiance, conversion efficiency, potential for PV is defined.

2. Total *potential for electricity from PV* is calculated by applying country-specific as well as category-specific full-load hours. In this context, the achievable full-load hours of a PV plant represent the site-specific solar conditions as well as the location where the solar modules are installed, i.e. on roof, on facade or on free-field. In more detail, the calculation was as follows: The annual solar irradiation (country-specific!) multiplied with a factor representing the solar yield by category (i.e. 0.46 for facade, 0.73 for roof-systems and 0.78 for 'free field'-systems) results in achievable full-load hours. They appear on average in a range between 460 (PV on facades) and 760 h/a (PV on 'free fields') for Northern European countries (e.g. United Kingdom, Sweden) and in a range between 730 (PV on facades) and 1330 h/a (PV on 'free fields') for Southern European countries (e.g. Spain).

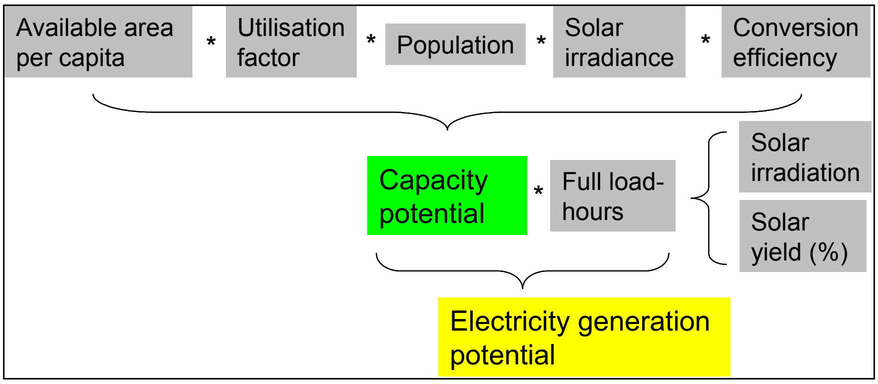

Figure 3.31. Methodology for the assessment of the building-integrated PV potential

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[30] Compare Gutschner et al (2001): "A typical statistical building for a person living in Central Western Europe has about 45 m2 of ground floor area. Half of it is used for residential purposes, 7 m2 for the primary sector, 6 m^2 each for the secondary sector and for the tertiary sector and the rest for other purposes."

3. A further restriction is applied in order to consider aspects of grid integration. Assuming no radical changes with respect to the existing grid, as (a rather high) constraint the in maximum achievable potential of electricity from PV is limited to 8% of expected gross electricity consumption in 2020 (BAU-forecast of Capros, 2003).
4. Finally, the additional mid-term potential is calculated by subtraction the already achieved potential (i.e. the electricity generation potential of existing plant) – which, in general, is rather small compared to the overall mid-term potential

Costs

Table 3.19 provides an overview on cost-data for new PV plant of the toolbox **Green*Net***. Please note, investment as well as O&M-costs are given in €$_{2002}$ and refer to the start year of the simulations (i.e. 2002).

Table 3.19. Overview on cost-data for new plant (PV)

Cost - data for new plant

	category	plant-type: unit	ELE large (new 1)	ELE medium (new 2)	ELE small (new 3)
technical-specification	*plant-size (average)*	*MW_{el}*	0,050	0,020	0,005
	efficiency electricity	%	11%	11%	11%
	efficiency heat	%			
	efficiency TOTAL	%	11%	11%	11%
	power-to-heat-ratio	1	0,00	0,00	0,00
	life time	a	20	20	20
cost-specification (general)	depreciation time	a	15	15	15
	interest rate	*%*	*6,5%*	*6,5%*	*6,5%*
	c.r.f	*1*	*0,1064*	*0,1064*	*0,1064*
	Share of HARMONISED investment costs	%	100%	100%	100%
	investment costs TOTAL (average)	**€/kW_{el}**	**5.400,00**	**5.900,00**	**6.300,00**
	investment costs HARMONISED	€/kW_{el}	5.400,00	5.900,00	6.300,00
	investment costs NON-HARMONISED (average)	€/kW_{el}	0,00	0,00	0,00
	Share of HARMONISED O&M costs	%	100%	100%	100%
	O&M costs TOTAL (average)	**€/(kW_{el}*a)**	**40,00**	**45,00**	**50,00**
	O&M costs TOTAL (average) as share of investment costs	**%**	**0,7%**	**0,8%**	**0,8%**
	O&M costs HARMONISED	€/(kW_{el}*a)	40,00	45,00	50,00
	O&M costs NON-HARMONISED (average)	€/(kW_{el}*a)	0,00	0,00	0,00

In principle, total investment costs for grid-connected PV plants include module-costs and costs for balance-of-systems (BOS), including costs for inverters, grid connection, etc. At present total costs are in a range between 5.400 and 6.300 €/kW (compare e.g. Haas et al (2001), Kaltschmitt et al (2003), EEG (2002)) – depending on the plant-size.

Cost-resource curves

By linking the cost-data – specified for different plant-sizes (i.e. large-, medium- and small-scale) – with the potential assessment, cost-resource curves are derived. In this context, for each potential-category (i.e. PV on roofs, PV on facades, PV on 'free field') the share of the different plant-sizes is assumed. This approach causes 9 different bands – i.e. 3 potential categories times 3 plant-sizes – representing the additional mid-term potential for electricity from PV within a country.

3.3.8.2 Resulting cost-resource curves

An overview on potential and costs for electricity from PV in EU-15 countries is provided in Table 3.20. In addition, a comparison of the achieved and the additional mid-term potential is given in Figure 3.32.[31]

Table 3.20 Overview on potential and costs for electricity from PV in EU-15 countries

Solar energy - Photovoltaics (SO-PV)		**AT**	**BE**	**DK**	**FI**	**FR**	**DE**	**GR**	**IE**	**IT**	**LU**	**NL**	**PT**	**ES**	**SE**	**UK**	**EU15**
Potential - existing & new plant:																	
Achieved potential:																	
electricity generation pot.	GWh	4	0	1	0	1	139	1	0	8	0	11	0	6	0	2	**173**
capacity potential	MW	5	0	1	0	1	178	1	0	8	0	16	0	5	0	2	**219**
full load-hours (average)	h/a	852	710	710	639	852	781	1065	710	923	710	710	1207	1136	639	710	**791**
Additional mid-term potential:																	
electricity generation pot.	GWh	6569	8610	3661	7955	52333	52393	7032	3179	31429	725	12936	5805	29220	14018	43040	**278903**
capacity potential	MW	8213	13046	5473	13315	65217	71929	7016	4674	36384	1093	19606	5098	26938	23505	64844	**366351**
full load-hours (average)	h/a	800	660	669	597	802	728	1002	680	864	663	660	1139	1085	596	664	**761**
Costs of electricity - new plant:																	
Long-run marginal costs (LRMC):																	
minimum	€/MWh	656,3	787,6	787,6	875,1	656,3	716,0	525,0	787,6	605,8	787,6	787,6	463,3	492,2	875,1	787,6	**463,3**
maximum	€/MWh	1304,4	1565,3	1565,3	1739,2	1304,4	1423,0	1043,5	1565,3	1204,1	1565,3	1565,3	920,7	978,3	1739,2	1565,3	**1739,2**
average (weighted)	€/MWh	880,1	1072,6	1050,5	1181,1	875,8	970,0	701,5	1023,3	816,4	1065,1	1073,0	616,6	642,9	1184,4	1063,1	**925,5**
Short-run marginal costs (SRMC):																	
minimum	€/MWh	42,7	51,3	51,3	57,0	42,7	46,6	34,2	51,3	39,4	51,3	51,3	30,2	32,1	57,0	51,3	**30,2**
maximum	€/MWh	90,6	108,7	108,7	120,8	90,6	98,8	72,5	108,7	83,6	108,7	108,7	63,9	67,9	120,8	108,7	**120,8**
average (weighted)	€/MWh	60,5	73,9	72,1	81,2	60,1	66,8	48,2	70,0	56,1	73,3	73,9	42,3	44,0	81,5	73,1	**63,6**

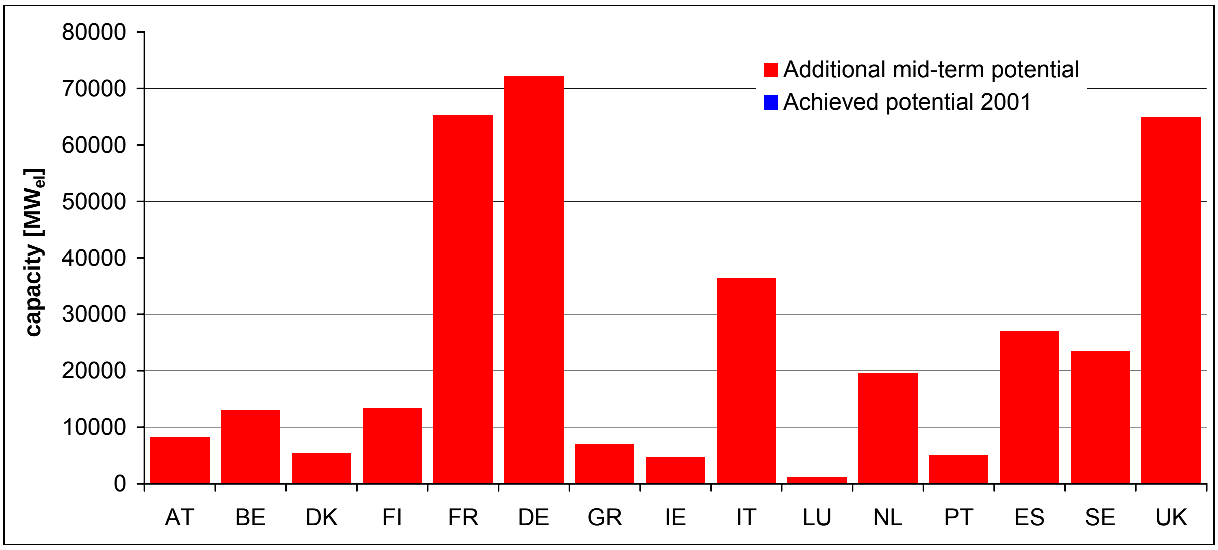

Figure 3.32. Achieved potential (2001) & additional mid-term potential for electricity from PV in EU-15 countries

Dynamic aspects of cost development

As default, within the model **Green*Net*** the future development of investment costs for PV plants is predicted using the experience curve approach. As default figure – in accordance with Alsema (2003) – a constant learning rate of 20% is assumed for the total investigated period (up 10 2020). In the initial phase of model-runs this learning rate is linked to the development of PV within EU-15 market.

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[31] Please note, these generation costs are calculated by applying a standardised interest rate of 6.5% and a depreciation time of 15 years to investment and O&M-costs as implemented in the database for new plants. Thereby, costs refer to the start year of the simulation (i.e. 2002).

3.3.9 Solar electricity – Solar thermal electricity

3.3.9.1 Methodology for the development of cost-resource curves

Solar thermal power plants have been considered as promising new option for power generation – since several years. Hence, up to now – beside from demonstration facilities – no solar power plant has gone 'online' within Europe. Worldwide several (hybrid) solar thermal plants are operating well. In principle, several technological concepts appear:

- *Parabolic through plant:* Large cylindrical parabolic mirrors concentrate the sunlight. Several of these collectors in a row form a solar field. Hence, molten salt is used to transport the heat to a (conventional) gas or steam turbine.
- *Solar power tower plant:* The solar field of a central receiver system (i.e. the power tower) is made up of several hundred mirrors concentrating the sun light to the central receiver. Similar to above, air or molten salt is used to transport the heat to a (conventional) gas or steam turbine.
- *Dish/Stirling Technology:* Parabolic dish concentrators are - on contrary to above - rather small units (in the range of kilowatts).

Parabolic through and *power tower plants* are usually equipped either with a thermal storage block or a hybrid fossil burner in order to guarantee a non-fluctuating power supply.

In general, solar thermal plants can use direct irradiance only. Hence, as in middle and northern Europe there is only a small proportion of direct irradiance. It does not make sense to install solar thermal power units based on current technology there.

The following assessment approach is based on a non-hybrid power station. Hence, thermal storage units are taken into calculation in order to guarantee a more constant supply. The size of the storage units determines beside plant-size, plant-concept the overall costs.

Future potential

In general, based on assumptions on land use (0.5% of agricultural area, area factor) and country-specific data for solar irradiation (direct irradiance) primary energy potentials have been assessed for Southern European countries (i.e. Greece, Spain, Portugal and Italy). Next, electricity generation potentials are derived by applying plant-specific conversion efficiencies.

Costs

All cost-data is derived from a literature survey – e.g. based on ETSU/DGXVII (1997), Nowak et al (2001), DLR (2002). Table 3.21 provides an overview on cost-data for new solar thermal plant as implemented in the toolbox **Green*Net***. Please note, investment as well as O&M-costs are given in €$_{2002}$ and refer to the start year of the simulations (i.e. 2002).

Table 3.21. Overview on cost-data for new plants (solar thermal electricity)

Cost - data for new plant

	category	plant-type: unit	ELE large (new 1)	ELE medium (new 2)	ELE small (new 3)
technical-specification	*plant-size (average)*	*MW_{el}*	50,000	20,000	2,000
	efficiency electricity	%	38%	35%	33%
	efficiency heat	%			
	efficiency TOTAL	%	38%	35%	33%
	power-to-heat-ratio	1	0,00	0,00	0,00
	life time	a	20	20	20
cost-specification (general)	depreciation time	a	15	15	15
	interest rate	*%*	*6,5%*	*6,5%*	*6,5%*
	c.r.f	*1*	*0,1064*	*0,1064*	*0,1064*
	Share of HARMONISED investment costs	%	100%	100%	100%
	investment costs TOTAL (average)	**€/kW_{el}**	**2.900,00**	**3.500,00**	**4.500,00**
	investment costs HARMONISED	€/kW_{el}	2.900,00	3.500,00	4.500,00
	investment costs NON-HARMONISED (average)	€/kW_{el}	0,00	0,00	0,00
	Share of HARMONISED O&M costs	%	100%	100%	100%
	O&M costs TOTAL (average)	**€/(kW_{el}*a)**	**165,00**	**190,00**	**230,00**
	O&M costs TOTAL (average) as share of investment costs	**%**	**5,7%**	**5,4%**	**5,1%**
	O&M costs HARMONISED	€/(kW_{el}*a)	165,00	190,00	230,00
	O&M costs NON-HARMONISED (average)	€/(kW_{el}*a)	0,00	0,00	0,00

For investment costs a range between 2900 and 4500 €/kW has been assumed – mainly depending on the solar conditions determining the size of the thermal storage unit applied. O&M costs in size of 135 to 250 €/(kW*a) have been applied – in dependence of the plant-concept.

Full load-hours depend on the technological concept applied (hybrid vs. thermal storage) and, of course, also reflect the solar conditions. Hence, fuel costs appear for hybrid systems only.

Cost-resource curves

Cost curves for solar thermal electricity are determined by variation of full-load hours (in order to consider the influence of solar irradiation) and plant-types (investment (incl. storage), operation & maintenance costs).

By linking the cost-data – specified for different plant-types – with the potential assessment, cost-resource curves are derived. In this context, the overall potential is equally shared on the different plant categories.

3.3.9.2 Resulting cost-resource curves

An overview on potentials and costs for electricity from solar thermal plants in EU-15 countries is provided in Table 3.22. In addition, a comparison of the achieved and the additional mid-term potentials is given in Figure 3.33.[32]

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[32] Please note, these generation costs are calculated by applying a standardised interest rate of 6.5% and a depreciation time of 15 years to investment and O&M-costs as implemented in the database for new plants. Thereby, costs refer to the start year of the simulation (i.e. 2002).

Table 3.22. Overview on potential and costs for electricity from solar thermal plant in EU-15 countries

Solar energy - Solar thermal electricity (SO-ST)		**AT**	**BE**	**DK**	**FI**	**FR**	**DE**	**GR**	**IE**	**IT**	**LU**	**NL**	**PT**	**ES**	**SE**	**UK**	**EU15**
Potential - existing & new plant:																	
Achieved potential:																	
electricity generation pot.	GWh	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
capacity potential	MW	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
full load-hours (average)	h/a	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
Additional mid-term potential:																	
electricity generation pot.	GWh	0	0	0	0	0	0	2634	0	7623	0	0	2418	17209	0	0	**29885**
capacity potential	MW	0	0	0	0	0	0	897	0	2642	0	0	817	5597	0	0	**9953**
full load-hours (average)	h/a	0	0	0	0	0	0	2937	0	2886	0	0	2961	3074	0	0	**3003**
Costs of electricity - new plant:																	
Long-run marginal costs (LRMC):																	
minimum	€/MWh	0,0	0,0	0,0	0,0	0,0	0,0	105,2	0,0	124,9	0,0	0,0	105,2	105,2	0,0	0,0	**105,2**
maximum	€/MWh	0,0	0,0	0,0	0,0	0,0	0,0	283,4	0,0	283,4	0,0	0,0	283,4	283,4	0,0	0,0	**283,4**
average (weighted)	€/MWh	0,0	0,0	0,0	0,0	0,0	0,0	195,8	0,0	225,3	0,0	0,0	195,7	187,0	0,0	0,0	**198,3**
Short-run marginal costs (SRMC):																	
minimum	€/MWh	0,0	0,0	0,0	0,0	0,0	0,0	36,7	0,0	42,2	0,0	0,0	36,7	36,7	0,0	0,0	**36,7**
maximum	€/MWh	0,0	0,0	0,0	0,0	0,0	0,0	92,0	0,0	92,0	0,0	0,0	92,0	92,0	0,0	0,0	**92,0**
average (weighted)	€/MWh	0,0	0,0	0,0	0,0	0,0	0,0	65,8	0,0	74,2	0,0	0,0	65,7	62,9	0,0	0,0	**66,2**

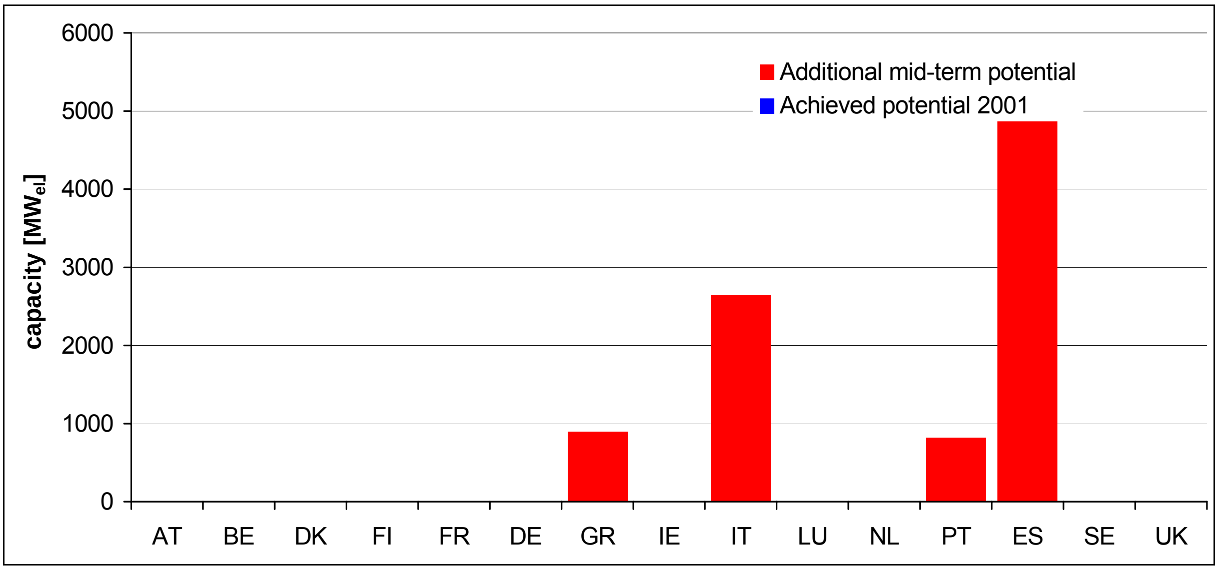

Figure 3.33. Achieved potential (2001) & additional mid-term potential for electricity from solar thermal plant in EU-15 countries

Dynamic aspects of cost development

As default, within the model **Green*Net*** the future development of investment costs for solar thermal plants is based using cost forecasts where a percentage decrease of costs is indicated for each year.

3.3.10 Tidal stream

3.3.10.1 Methodology for the development of cost-resource curves

Tidal stream power has been recognized especially within the UK as a promising new option for power generation. In principle, a distinction between tidal barrage, near-shore and off-shore-devices occurs. Hence, off-shore wave power is still in a R&D-stage.[33]

Future potential

The assessment of the future potential of tidal stream is accompanied by a set of difficulties. As the technological development is focussed on UK, for other parts of Europe no overall in-depth resource assessment has been conducted so far. Therefore, technological experts have been contacted by partners *IT Power* and *EEG* in the **Green*Net***-consortium to provide a 'best guess' of the resource potential. In addition, an overall methodology is discussed to provide a first EU-wide harmonised assessment of its potential.

Costs

In accordance with the location of a plant (i.e. tidal barrage, near-shore, offshore), three different plant- and cost-categories have been defined. So far, reliable figures can be provided for 'near-shore' devices only!

Investment costs are – in accordance with DTI/ETSU (2001) – around 1850 €/kW. A 25 year lifetime can be expected for commercial operating plants with a size of 5 MW. Note, in general, an uncertainty with respect to median value of costs of ± 20% must be taken into account (see Thorpe, 1999).

O&M costs in a range of 60 €/(kW*a) are expected.

3.3.10.2 Resulting cost-resource curves

So far, no reliable cost-resource curves can be provided. *IT Power* and *EEG* are in close cooperation to provide a first EU-wide assessment of potentials. As soon as this task will be completed cost-resource curves for tidal stream power will be included into the toolbox **Green*Net***.

Dynamic aspects of cost development

As default, within the model **Green*Net*** the future development of investment costs for tidal stream is based using cost forecasts where a percentage decrease of costs is indicated for each year. As default, the following figures will be applied: 'Renewable Electricity Entry Scenario' (OXERA Environmental, 2001) notes that under a scenario agreed with the UK Cabinet Office, investment costs are expected to fall by 5-10% p.a. 2004-2014 and 1% p.a. 2014-2020.

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[33] See Michael (2002)

3.3.11 Wave energy

3.3.11.1 Methodology for the development of cost-resource curves

Wave energy represents a promising future RES-E option.

In principle, a distinction can be undertaken by device, i.e. shoreline, near-shore and off-shore-devices. Hence, off-shore wave power is still in a R&D-stage.[34]

Future potential

The future potential of wave energy is indicated in many studies as significant depending on the 'roughness' of the sea etc.. Nevertheless, the technology is still not recognized by many countries. Therefore EU-wide future projections of realisable potentials up to 2020 are difficult to provide. Recent assessments as provided e.g. by Thorpe (1999) have concentrated on the UK only.

Costs

In accordance with the scale of a wave power plant, which correlates to typical technology-specific site-conditions three different plant-categories and cost-categories are defined, see Table 3.23. Please note, investment as well as O&M-costs are given in €$_{2002}$ and refer to the start year of simulations (i.e. 2002). Note, the figures presented in the following must be seen as preliminary – mainly based on Boud (2003) and DTI (2002).

Table 3.23. Overview on cost-data for new plants (wave power)

Cost - data for new plant

	category	plant-type: unit	**shoreline** (new 1)	**nearshore** (new 2)	**offshore** (new 3)
technical-specification	*plant-size (average)*	*MW $_{el}$*	0,500	1,000	10,000
	efficiency electricity	%			
	efficiency heat	%			
	efficiency TOTAL	%			
	power-to-heat-ratio	1	0,00	0,00	0,00
	life time	a	20	20	20
cost-specification (general)	depreciation time	a	15	15	15
	interest rate	*%*	*6,5%*	*6,5%*	*6,5%*
	c.r.f	*1*	*0,1064*	*0,1064*	*0,1064*
	Share of HARMONISED investment costs	%	100%	100%	100%
	investment costs TOTAL (average)	**€/kW$_{el}$**	**1.580,00**	**1.620,00**	**1.750,00**
	investment costs HARMONISED	€/kW$_{el}$	1.580,00	1.620,00	1.750,00
	investment costs NON-HARMONISED (average)	€/kW$_{el}$	0,00	0,00	0,00
	Share of HARMONISED O&M costs	%	100%	100%	100%
	O&M costs TOTAL (average)	**€/(kW$_{el}$*a)**	**60,00**	**60,00**	**60,00**
	O&M costs TOTAL (average) as share of investment costs	**%**	**3,8%**	**3,7%**	**3,4%**
	O&M costs HARMONISED	€/(kW$_{el}$*a)	60,00	60,00	60,00
	O&M costs NON-HARMONISED (average)	€/(kW$_{el}$*a)	0,00	0,00	0,00

For investment costs a range between 1580 and 1750 €/kW has been assumed – depending on the plant-concept, plant-size and the plant-category (i.e. shoreline, near shore, offshore), respectively. Note, in general, an uncertainty with respect to median value of costs in size of ± 20% must be taken into account (see Thorpe, 1999).

O&M costs around 60 €/(kW*a) occur on average.

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[34] See Michael (2002)

3.3.11.2 Resulting cost-resource curves

So far, no reliable cost-resource curves can be provided. *IT Power* and *EEG* are in close cooperation, to provide a first EU-wide assessment of potentials. As far as this task will be completed, cost-resource curves for wave power will be included into the toolbox **Green*Net***.

Dynamic aspects of cost development

As default, within the model **Green*Net*** the future development of investment costs for wave energy is based using cost forecasts where a percentage decrease of costs is indicated for each year. In this context – similar to tidal stream, 'Renewable Electricity Entry Scenario' (OXERA Environmental, 2001) states that under a scenario agreed with the UK Cabinet Office, investment costs are expected to fall by 5-10% p.a. 2004-2014 and 1% p.a. 2014-2020.

3.3.12 Wind energy – wind on-shore

3.3.12.1 Methodology for the development of cost-resource curves

Future potential

The technical potential for on-shore wind energy is high in various EU countries, namely France, UK – but several barriers have to be overcome, e.g. public acceptance, power grid constraints.

Realisable potentials are assumed 'step-by-step' – after consultation within the project and discussion with other experts, keeping in mind important 'constrain indicators' like e.g. 'percentage of wind power on total electricity consumption', 'wind power (capacity) potential per capita', "wind power (capacity) potential per land area'.

First, in accordance with data regarding land use, overall area-potentials have been assessed by country. Next, wind maps (mainly taken from RISOE, 1998) have been applied to the define areas characterised by certain 'wind characteristics' (i.e. mean wind speed, roughness class) Finally, electricity potentials have been derived. Note, these calculations are based by appliance of a power curve for a – at present and in near future – common on-site turbine in size of 2 MW.

In this context, a set of bands – characterised by same wind conditions (i.e. described by full load-hours) – have been derived for each country – describing the overall mid-term generation potential from on-shore wind. Thereby, in order to meet the model requirements[35] and hence, to produce a set of reliable data, discrete values for full load-hours have been defined. Finally, the already achieved potential (i.e. existing plant) has been taken into account. Therefore, the additional realisable mid-term potential represents the residuum of the overall mid-term potential and the achieved potential.

For a better illustration of the final approach, Figure 3.34 illustrates the mid-term potential for on-shore wind in Germany related to discrete full load-hours.

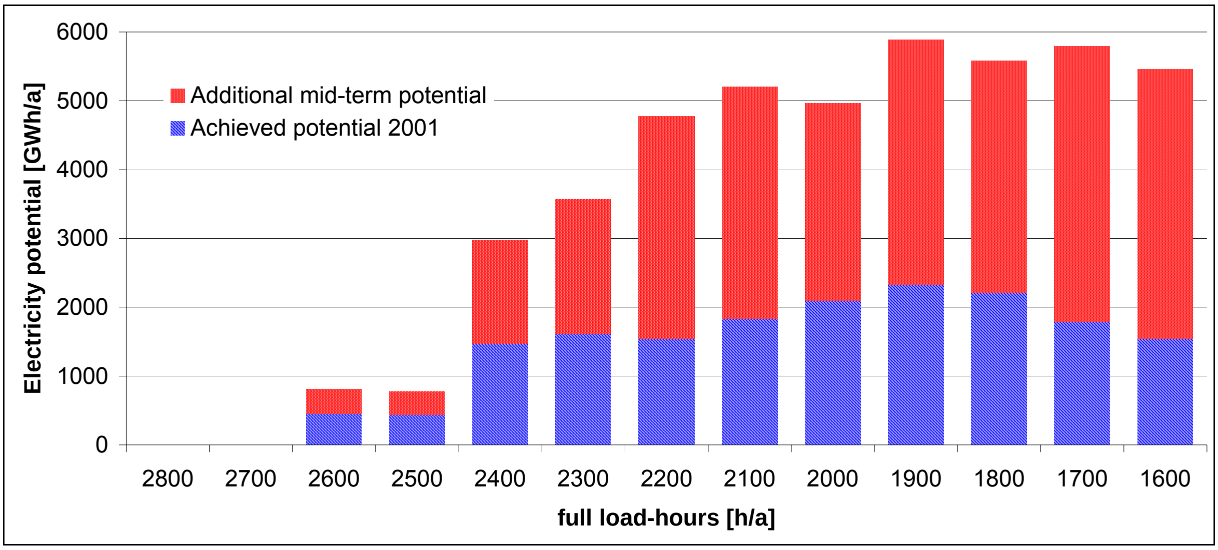

Figure 3.34. Mid-term potential of electricity from wind on-shore in Germany related to full load-hours.

Costs

Table 3.23 provides an overview on cost-data for new wind power plants as implemented in the toolbox **Green*Net***. Please note, investment as well as O&M-costs are given in €$_{2002}$ and refer to the start year of the simulations (i.e. 2002).

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[35] To be able to model policy instruments like 'stepped feed-in tariffs' in a proper way, a discrete set of full load-hours was required.

Table 3.24. Overview on cost-data for new plant (wind on-shore)[36]

Cost - data for new plant

	category	plant-type: unit	**ELE large** (new 1)
technical-specification	*plant-size (average)*	*MW$_{el}$*	2,000
	efficiency electricity	%	100%
	efficiency heat	%	
	efficiency TOTAL	%	100%
	power-to-heat-ratio	1	0,00
	life time	a	20
cost-specification (general)	depreciation time	a	15
	interest rate	*%*	*6,5%*
	c.r.f	*1*	*0,1064*
	Share of HARMONISED investment costs	%	100%
	investment costs TOTAL (average)	**€/kW$_{el}$**	**1.050,00**
	investment costs HARMONISED	€/kW$_{el}$	1.050,00
	investment costs NON-HARMONISED (average)	€/kW$_{el}$	0,00
	Share of HARMONISED O&M costs	%	100%
	O&M costs TOTAL (average)	**€/(kW$_{el}$*a)**	**45,00**
	O&M costs TOTAL (average) as share of investment costs	**%**	**4,3%**
	O&M costs HARMONISED	€/(kW$_{el}$*a)	45,00
	O&M costs NON-HARMONISED (average)	€/(kW$_{el}$*a)	0,00

The total investment costs of modern wind power plants are at present[37] in a range between 850 and 1150 €/kW (compare e.g. Neij (2003), Resch et.al. (2002)) – depending on country-specific as well as site-specific conditions (costs for grid connection, planning, etc.) and the chosen technological turbine-type. With respect to the cost curve database total investment costs are assumed to be 1.090 €/kW on average.

O&M costs occur at present in a range between 40 and 50 €/(kW*a). Hence, on average a cost-figure of 45 €/(kW*a) has been assumed.

Cost-resource curves

By linking the cost-data with the potential assessment (i.e. the potentials assessed for each discrete full load-hour level), cost-resource curves are derived.

3.3.12.2 Resulting cost-resource curves

An overview on potential and costs for electricity from on-shore wind in EU-15 countries is provided in Table 3.25. In addition, a comparison of the achieved and the additional mid-term potential is given in Figure 3.35.[38]

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[36] Note, as default setting, it has been chosen to define an average plant-type for model implementation only due to the fact that country-specific cost differences – as currently observed – will be already represented in the modelling of policy instruments within the overall model.

[37] Note, cost data refer to the start year of the simulation, i.e. 2002.

[38] Please note, these generation costs are calculated by applying a standardised interest rate of 6.5% and a depreciation time of 15 years to investment and O&M-costs as implemented in the database for new plants. Thereby, costs refer to the start year of the simulation (i.e. 2002).

Table 3.25. Overview on potential and costs for electricity from wind on-shore in EU-15 countries

Wind energy - onshore (WI-ON)		**AT**	**BE**	**DK**	**FI**	**FR**	**DE**	**GR**	**IE**	**IT**	**LU**	**NL**	**PT**	**ES**	**SE**	**UK**	**EU15**
Potential - existing & new plant:																	
Achieved potential:																	
electricity generation pot.	GWh	175	57	5197	72	300	14444	585	325	1289	33	968	275	7988	512	1138	**33357**
capacity potential	MW	95	31	2417	39	125	8754	272	125	697	15	523	125	3550	277	474	**17518**
full load-hours (average)	h/a	1850	1850	2150	1850	2400	1650	2150	2600	1850	2200	1850	2200	2250	1850	2400	**1904**
Additional mid-term potential:																	
electricity generation pot.	GWh	4752	4172	3384	7615	54995	39260	8285	7707	26728	181	4319	8385	30631	9073	26805	**236291**
capacity potential	MW	2606	2269	1583	3961	26375	22246	4228	3175	14303	105	2177	4275	15950	4673	11526	**119452**
full load-hours (average)	h/a	1824	1839	2138	1922	2085	1765	1959	2427	1869	1720	1984	1961	1920	1941	2326	**1978**
Costs of electricity - new plant:																	
Long-run marginal costs (LRMC):																	
minimum	€/MWh	65,3	62,7	56,0	60,3	56,0	60,3	60,3	56,0	62,7	65,3	60,3	60,3	60,3	60,3	56,0	**56,0**
maximum	€/MWh	111,9	111,9	111,9	111,9	111,9	111,9	111,9	111,9	111,9	111,9	111,9	111,9	111,9	111,9	111,9	**111,9**
average (weighted)	€/MWh	85,9	85,2	73,3	81,5	75,1	88,8	80,0	64,5	83,8	91,1	79,0	79,9	81,6	80,7	67,4	**79,2**
Short-run marginal costs (SRMC):																	
minimum	€/MWh	18,8	18,0	16,1	17,3	16,1	17,3	17,3	16,1	18,0	18,8	17,3	17,3	17,3	17,3	16,1	**16,1**
maximum	€/MWh	32,1	32,1	32,1	32,1	32,1	32,1	32,1	32,1	32,1	32,1	32,1	32,1	32,1	32,1	32,1	**32,1**
average (weighted)	€/MWh	24,7	24,5	21,0	23,4	21,6	25,5	23,0	18,5	24,1	26,2	22,7	22,9	23,4	23,2	19,3	**22,7**

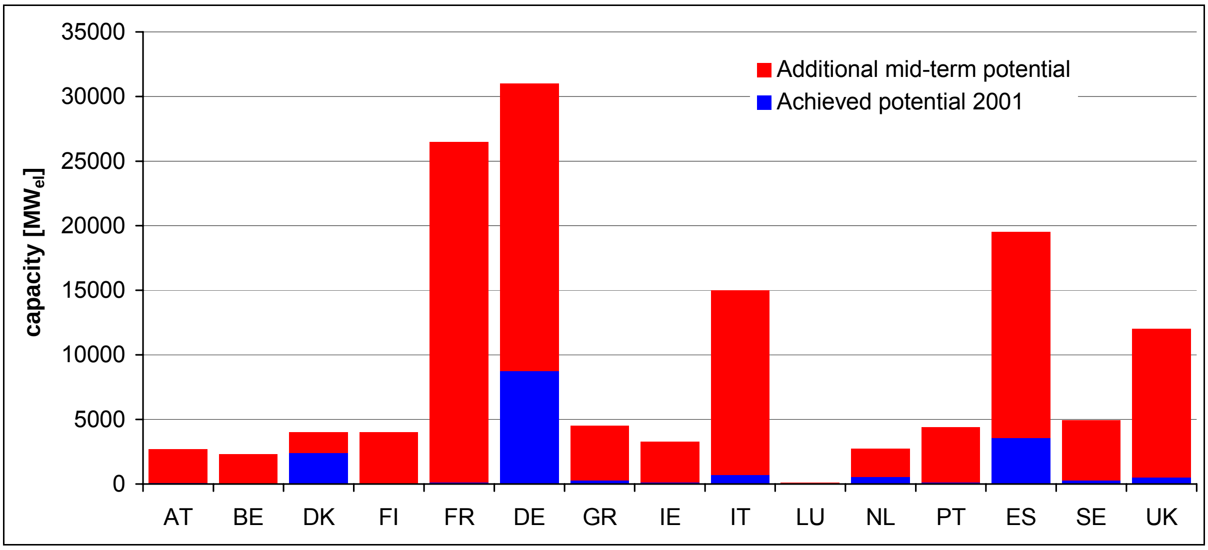

Figure 3.35. Achieved potential (2001) & additional mid-term potential for electricity from wind on-shore in EU-15 countries

Dynamic aspects of cost development

As default, within the model **Green*Net*** the future development of total investment costs for wind power plants is predicted using the experience curve approach. As default figure – in accordance with Neij (2003) – a learning rate of 18% is assumed. In the initial phase of model-runs this learning rate is linked to the development of wind energy within EU-15's market.

3.3.13 Wind energy – wind off-shore

3.3.13.1 Methodology for the development of cost-resource curves

Future potential

The overall technical potential for off-shore wind energy seems to be substantial in parts of Europe, especially in the North Sea (compare e.g. Greenpeace, 2001) but several barriers have to be overcome, e.g. public acceptance, power grid constraints.

Realisable potentials are assumed 'step-by-step' – after consultation within the project and discussion with other experts, keeping in mind important 'constrain indicators' like e.g. 'percentage of wind power on total electricity consumption', 'wind power (capacity) potential per capita'.

First, in accordance with geographical data, overall area-potentials have been assessed by country. Next, wind maps or wind data-sources, respectively (mainly taken from Greenpeace, 2001 and RISOE, 1998) have been applied to the define areas characterised by certain 'wind characteristics' (i.e. mean wind speed, roughness class). This finally enabled the derivation electricity potentials. Note, these calculations are based using an assumed power curve (based on data for a 4.5 MW turbine) for a – in near future – common off-site turbine in size of 5 MW.

A further distinction has been undertaken in order to be able to derive correct economic data: Area-classes have been defined with respect to the distance from the coastline: near shore (Zone 0), 5-30 km from coast (Zone 1), 30-50 km from coast (Zone 2) and more than 50 km (Zone 4).

For each area-class a set of bands – characterised by same wind conditions (i.e. described by full load-hours) – has been derived for each country describing the overall mid-term generation potential from off-shore wind. Thereby, in order to meet the model requirements[39] and hence, to produce a set of reliable data, discrete values for full load-hours have been defined. Finally, the already achieved potential (i.e. existing plants) has been taken into account. Hence, the additional realisable mid-term potential represents the residuum of the overall mid-term potential and the achieved potential. In the final version of the toolbox **Green*Net***, planned offshore projects will be included as separate bands.

For a better illustration of the final approach, Figure 3.36 illustrates the mid-term potential for off-shore wind in Germany related to discrete full load-hours.

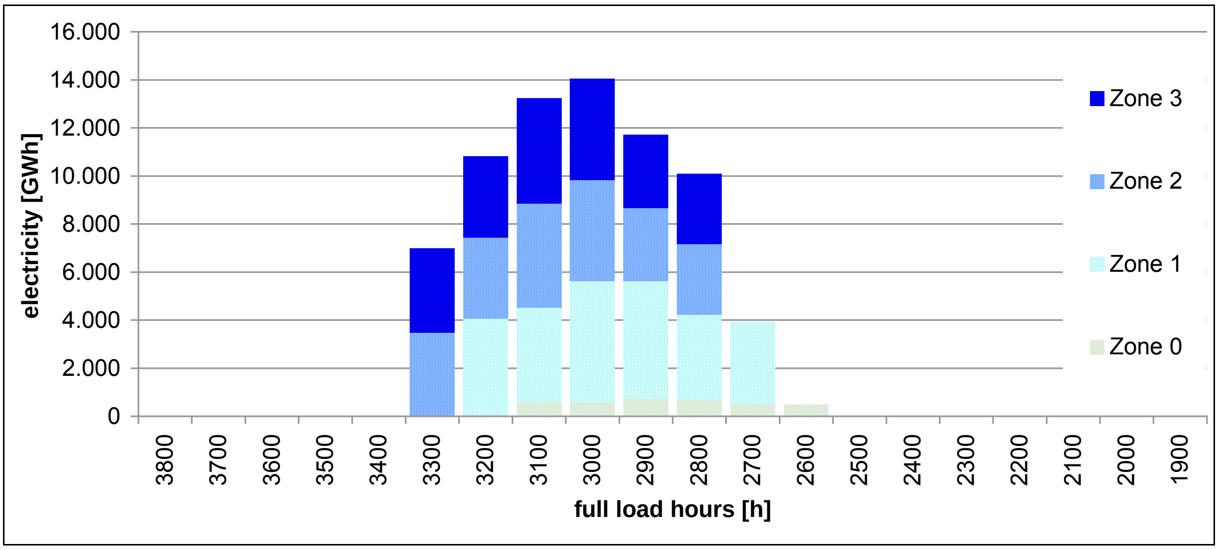

Figure 3.36. Mid-term potential of electricity from wind off-shore in Germany related to full load-hours

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[39] To be able to model policy instruments like 'stepped feed-in tariffs' in a proper way, a discrete set of full load-hours is required.

Costs

Table 3.26 provides an overview on cost-data for new offshore wind power plant as implemented in the toolbox **Green*Net***. Please note, investment as well as O&M-costs are given in €$_{2002}$ and refer to the start year of the simulations (i.e. 2002).

Table 3.26. Overview on cost-data for new plant (wind off-shore)[40]

Cost - data for new plant

	category	plant-type: unit	nearshore (new 1)	5..30km (new 2)	30..50km (new 3)	50.. km (new 4)
technical-specification	*plant-size (average)*	MW_{el}	5,000	5,000	5,000	5,000
	efficiency electricity	%	100%	200%	300%	400%
	efficiency heat	%				
	efficiency TOTAL	%	100%	200%	300%	400%
	power-to-heat-ratio	1	0,00	0,00	0,00	0,00
	life time	a	20	20	20	20
cost-specification (general)	depreciation time	a	15	15	15	15
	interest rate	*%*	*6,5%*	*106,5%*	*206,5%*	*306,5%*
	c.r.f	*1*	*0,1064*	*1,0650*	*2,0650*	*3,0650*
	Share of HARMONISED investment costs	%	100%	100%	100%	100%
	investment costs TOTAL (average)	**€/kW$_{el}$**	**1.750,00**	**1.950,00**	**2.150,00**	**2.400,00**
	investment costs HARMONISED	€/kW$_{el}$	1.750,00	1.950,00	2.150,00	2.400,00
	investment costs NON-HARMONISED (average)	€/kW$_{el}$	0,00	0,00	0,00	0,00
	Share of HARMONISED O&M costs	%	100%	100%	100%	100%
	O&M costs TOTAL (average)	**€/(kW$_{el}$*a)**	**60,00**	**65,00**	**75,00**	**80,00**
	O&M costs TOTAL (average) as share of investment costs	**%**	**3,4%**	**3,3%**	**3,5%**	**3,3%**
	O&M costs HARMONISED	€/(kW$_{el}$*a)	60,00	65,00	75,00	80,00
	O&M costs NON-HARMONISED (average)	€/(kW$_{el}$*a)	0,00	0,00	0,00	0,00

The absolute level of investment costs of offshore wind power is closely linked to some parameters – i.e. the distance from the coast and the water depth. The farer going offshore, the higher costs occur. On contrary, with increasing distance from the coast wind conditions get more stable and, hence, higher full load-hours can be achieved. The current range of turnkey cost lies between about 1750 and roughly 2100 €/kW.

O&M costs occur at present in a range between 60 and 80 €/(kW*a). Hence, on average a cost-figure of 70 €/(kW*a) has been assumed.

Cost-resource curves

By linking the cost-data with the potential assessment (i.e. the potentials assessed for each discrete full load-hour level), cost-resource curves are derived.

3.3.13.2 Resulting cost-resource curves

An overview on potential and costs for electricity from off-shore wind in EU-15 countries is provided in Table 3.27. In addition, a comparison of the achieved and the additional mid-term potential is given in Figure 3.37.[41]

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[40] Note, as default setting, it has been chosen to define an average plant-type for model implementation only due to the fact that country-specific cost differences – as currently observed – will be already represented in the modelling of policy instruments within the overall model.

[41] Please note, these generation costs are calculated by applying a standardised interest rate of 6.5% and a depreciation time of 15 years to investment and O&M-costs as implemented in the database for new plants. Thereby, costs refer to the start year of the simulation (i.e. 2002).

Table 3.27. Overview on potential and costs for electricity from wind off-shore in EU-15 countries

Wind energy - offshore (WI-OF)		**AT**	**BE**	**DK**	**FI**	**FR**	**DE**	**GR**	**IE**	**IT**	**LU**	**NL**	**PT**	**ES**	**SE**	**UK**	**EU15**
Potential - existing & new plant:																	
Achieved potential:																	
electricity generation pot.	GWh	0	0	155	0	0	0	0	0	0	0	58	0	0	81	0	**295**
capacity potential	MW	0	0	50	0	0	0	0	0	0	0	19	0	0	23	0	**92**
full load-hours (average)	h/a	0	0	3100	0	0	0	0	0	0	0	3100	0	0	3500	0	**3201**
Additional mid-term potential:																	
electricity generation pot.	GWh	0	3572	14702	4020	29300	75250	2580	8512	2347	0	19379	6463	14145	13263	65600	**259132**
capacity potential	MW	0	1500	4950	1500	10000	25000	1000	2500	1000	0	6481	2500	5000	4977	20000	**86408**
full load-hours (average)	h/a	0	2381	2970	2680	2930	3010	2580	3405	2347	0	2990	2585	2829	2665	3280	**2999**
Costs of electricity - new plant:																	
Long-run marginal costs (LRMC):																	
minimum	€/MWh	0,0	82,0	79,4	87,9	79,4	79,4	91,2	70,3	98,4	0,0	79,4	91,2	82,0	87,9	74,6	**70,3**
maximum	€/MWh	0,0	124,2	119,7	134,1	119,7	119,7	145,8	101,6	159,6	0,0	119,7	134,1	124,2	128,9	108,1	**159,6**
average (weighted)	€/MWh	0,0	100,1	98,2	107,1	99,6	100,0	116,0	82,5	127,5	0,0	97,6	115,1	105,2	109,5	88,9	**97,9**
Short-run marginal costs (SRMC):																	
minimum	€/MWh	0,0	20,0	19,4	21,4	19,4	19,4	22,2	17,1	24,0	0,0	19,4	22,2	20,0	21,4	18,2	**17,1**
maximum	€/MWh	0,0	29,6	28,6	32,0	28,6	28,6	34,8	24,2	38,1	0,0	28,6	32,0	29,6	30,8	25,8	**38,1**
average (weighted)	€/MWh	0,0	24,2	23,7	25,8	24,1	24,2	28,0	19,8	30,8	0,0	23,6	27,8	25,4	26,5	21,5	**23,7**

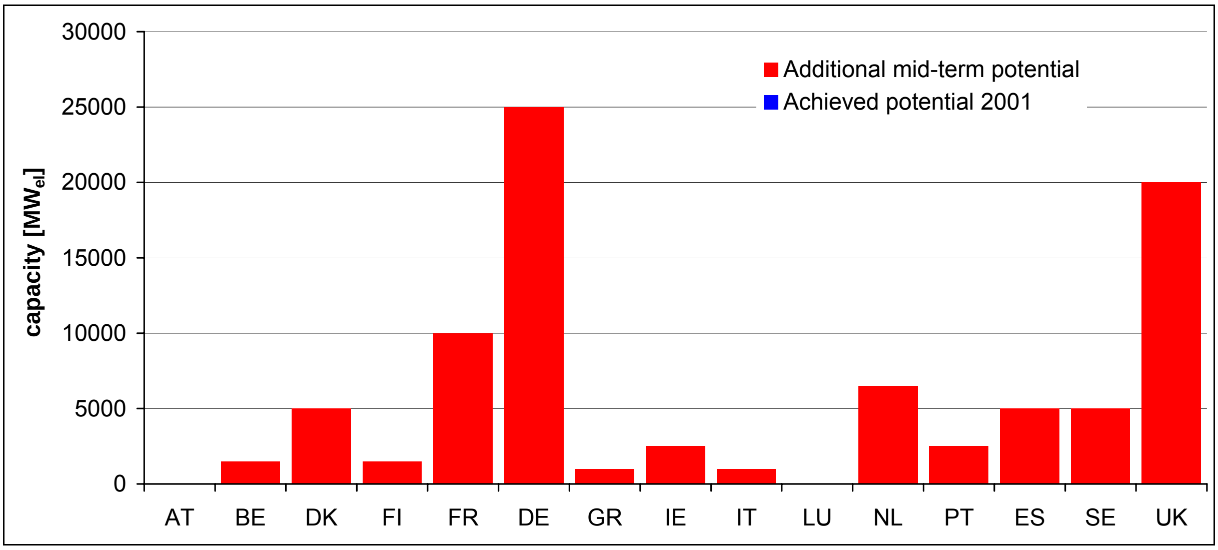

Figure 3.37. Achieved potential (2001) & additional mid-term potential for electricity from wind off-shore in EU-15 countries

Dynamic aspects of cost development

As default, within the model **Green*Net*** the future development of total investment costs for wind power plant is predicted using the experience curve approach. As default figure – in accordance with Neij (2003) – a learning rate of 18% is assumed. In the initial phase of model-runs this learning rate is linked to the development of wind energy within EU-15's market.

4 INTEGRATION OF RES-E TECHNOLOGIES INTO THE EXISTING EUROPEAN TRANSMISSION AND DISTRIBUTION GRID

4.1 Basic principles of grid-integration of RES-E technologies

4.1.1 Electricity grids

Electricity grids can be split into two major subsections: the *transmission grid* and the *distribution grid*.

The *transmission grid* consists of high voltage power lines designed to transfer bulk power from major generators to areas of demand. In general, the higher the voltage level the larger the transfer capacity. Only the very largest customers are connected to the transmission grid. Transmission voltage levels are typically above 100 kV. They are designed to be extremely robust, i.e. they can continue to fulfil their function even in the event of several simultaneous failures of the network. In liberalised electricity markets they are operated by organisations termed “Transmission System Operators” (TSOs) or “Independent System Operators” (ISOs). This simply defines the function of operating the network: responsibility for constructing or owning the network may belong to other organisations.

Distribution grids are usually below 100 kV and their purpose is to distribute power from the transmission grid to the customers. At present little generation is connected to distribution grid, but it is growing rapidly. Generation connected to distribution grids is termed “distributed generation”, “embedded generation”, etc. Distribution grids are less robust than transmission grids and their reliability decreases as voltage level decreases, e.g. a connection at 30 kV could expect to lose only a few minutes of connection per year on average, whereas a low voltage connection at 230 volts for an individual domestic consumer in a rural area would, on average, expect to lose – lets say – at least an hour.

There is very little so-called “active” management of distribution grids. Rather, they are designed and configured on the basis of extreme combinations of circumstances (for example, maximum demand in conjunction with high ambient temperatures, which reduce the capacity of overhead lines), to ensure that even in these extreme circumstances the grid conditions experienced by customers are still within the agreed limits. The addition of “distributed generation” (or “embedded generation”) to these distribution grids creates problems, for the following principal reasons:

- the “distributed generation” adds a further set of circumstances (full generation/no generation) with which the grid must cope, without negatively affecting the quality of supply seen by other customers;
- the direction and quantity of real and reactive power flows changes, which may affect operation of grid control and protection equipment;
- design and operating practices are no longer suitable and need modification.

Distribution grids may become more “actively managed”. This implies cost, and requires the development of suitable equipment and design principles but there may also be benefits for the distribution grid operator.

4.1.2 Integration of RES-E technologies

When connecting any new electricity generation source to the grid the “strength” of the grid near to the location of the generation plant must be known. One way of defining the “strength” of a grid is by finding the fault level of the grid. The fault level of a grid is a measure of the flow of current that will occur when a fault develops on the grid. A grid with a high fault level is generally an interconnected grid in an area like a city centre or large industrial area whereas a grid with a low fault level is generally a long electrical circuit. In general the higher the value of the voltage transmission level the stronger the system.

Many transmission and distribution grids are “weak” or have a low fault level (due to low voltage levels). Low voltage lines (e.g. medium voltage level of 30kV and 10kV) are most abundant in rural or isolated areas – the location for many renewable energy sources.

Integrating RES-E generation technologies such as hydro, biomass, etc. are less of a problem than wind, solar, tidal or wave. Hydro, biomass, etc. are not much different to that of traditional power stations where a constant output can be maintained and regulated. It is relatively straightforward to control the power output by controlling the quantities of fuel used to generate the electricity.

The unreliability and intermittency of other RES-E generation technologies such as wind and solar can cause problems with the power output from them variable and unpredictable (tidal and wave are predictable to a certain extent). So the problems occurring from them have to be considered.

The voltage variations caused by this continuous varying power output on the grid is commonly known as “Flicker”. Flicker is only usually a problem when the local network is “weak” and the voltage change is large (details on this issue will be addressed in the report of WP 2). Also “harmonics” can be created by intermittent RES-E generation. Variable speed wind turbines can cause harmonic voltage disturbances to appear on the grid. Harmonics on a grid can create problems, as they will disturb consumers by causing some connected equipment to overheat or malfunction.

Besides these factors mentioned above many others must be investigated when considering connecting a renewable energy source to the grid. Again, details will be discussed in the report of WP2.

Finally, of course, the cost of a RES-E project must be given careful consideration and can vary from scheme to scheme. Variations can arise due to the required voltage level for connection and also for the equipment required at the point of connection to the transmission and distribution grid. There are many cost components such as switchgears, cables, transformers and other equipment within the system. On large wind farms consideration may also be needed for reinforcing the grid at remote locations.

4.2 Technical barriers of RES-E technology grid integration

4.2.1 Grid connection

4.2.1.1 Preferred voltage level of grid connection of different RES-E technologies

In the past, for many decades the electric power system has been driven by the paradigm where most of the electricity is generated in big conventional power plants, sent to the consumption areas through *Extra High Voltage (EHV)* transmission lines, and delivered to the consumers through a passive distribution infrastructure that involves *High Voltage (HV)*, *Medium Voltage (MV)*, and *Low Voltage (LV)* grids. In this paradigm, power flows only in one direction: from the power station to the grid and to the consumer (see Joerss et al (2002)).

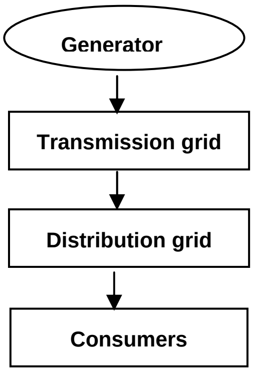

Figure 4.1. Paradigm 1 – Power flows in the past decades. Source: Joerss et al (2002).

The above paradigm is about to change due to a large scale of distributed generation coming back to either the medium (MV) or at the low (LV) levels. Electricity is now again going to be produced closer to the consumers, see Figure 4.2.

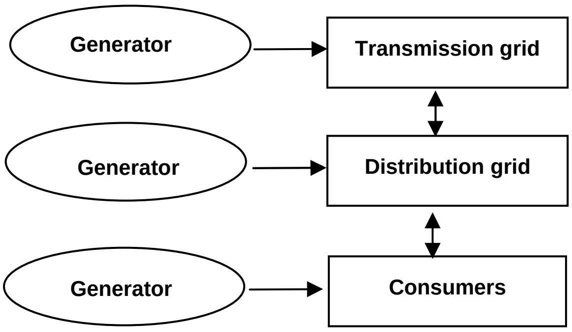

Figure 4.2. Paradigm 2 – Power flows in the future: Source: Joerss et al (2002).

Several main impacts can be identified in the operation of a distribution system with a large amount of distributed generation:

- Voltage profiles change along the grid, depending on the power produced by the generation units and on the consumption levels, leading to a behaviour different from the typical one,
- Voltage transients will appear as a result of connection and disconnection of generators or even as a result of their operation,
- Short-circuit levels increase,
- Losses changes as a function of the production and load levels,
- Congestion in system branches is a function of the production and load levels,
- Power quality and reliability may be affected,
- Utility protection need to be coordinated with the ones installed in the generator's side.

In solving these problems it is important to keep in mind, that the existing grid design standards and regulatory framework is still based on paradigm 1, see Figure 4.1. The corresponding framework for paradigm 2 currently is being established.
Finally, Table 4.1 gives an overview on the preferred voltage levels of grid connection for several decentralised RES-E generation technologies. Technology-specific details addressing grid connection issues will be discussed in the report of WP2.

Table 4.1. Preferred voltage level of grid connection of different RES-E technologies

Generation technology	380/220kV	110kV	10-30kV	1kV	<1kV
Conventional generators	↔				
Large Hydro	↔	↔			
Small Hydro			↔		
Biomass			↔	↔	
Biogas			↔	↔	
Geothermal Electricity		↔	↔		
Landfill Gas			↔	↔	
Sewage Gas			↔	↔	
Photovoltaic				↔	↔
Solar Thermal Electricity			↔	↔	
Tidal	↔	↔	↔		
Wave	↔	↔	↔		
Wind On-shore	↔	↔	↔		
Wind Off-shore	↔	↔			

4.2.1.2 *RES-E technology connection cases*

As already mentioned above, the unreliability and intermittency of both wind and solar energy can cause problems with the power output and, subsequently, with grid operation (tidal and wave are predictable to a certain extent). So the problems occurring with wind and solar energy only are considered in this WP1-report. Again, grid connection and grid operation issues of remaining RES-E technologies are comprehensively addressed in the WP2 report.

4.2.1.2.1 *Wind*

Wind turbines have developed rapidly from unit sizes below 20 kV (fixed speed, stall control) in the seventies to the present size of more than 2 MW. In order to withstand the mechanical stress most wind turbines above 1 MW are equipped with a variable speed system incorporating power electronics in combination with pitch control. If advanced enough these systems are capable of decoupled “active” and “reactive” power control on the grid side and of decoupled “torque” and “generator” excitation control on the generator side.

Single units can normally be connected to the distribution grid (e.g. medium voltage level at 10-30 kV). The present trend though is that larger wind farms (onshore) are increasingly connected to higher voltage levels on the transmission grid (>100kV). Moreover, already in the near future big shares of offshore wind power are planned to be connected in Europe.

For such big wind farms the transmission system operators in several European countries have started to implement new connection rules. These rules imply that a wind farm must oblige virtually to the same kind of rules, as the traditional generator does. It must for example offer services like: active power regulation, frequency regulation, voltage regulation, and not least to be able to survive prolonged periods with low grid voltage. A detailed discussion in this respect will also be continued in the WP2 report.

In the following, on-shore and off-shore wind energy connection is addressed separately.

a) On-shore connection

In recent years onshore wind turbines either have been connected on a medium voltage (MV) turn off (where also customers are supplied) or on a free MV feeder (i.e. separate MV wind grid), see Figure 4.3 below:

- *Case 1:* Connection on a MV turn off (where also customers are supplied) substantially reduces transmission and distribution losses and, therefore, is an economic solution. But small capacities can be connected only in order not to influence customer supply. Line 1 exclusively supplies customers whereas line 3 exclusively transmits wind energy to the transformer station. Since line 3 accepts higher capacities than line 2 this option is increasingly used in practice to connect small wind capacities.
- *Case 2:* Case 2 shows a separate wind grid on the medium voltage (MV) level tailor-made for wind energy purposes being connected to the high voltage level on 110 kV. No consideration for customer supply purposes needs to be made.

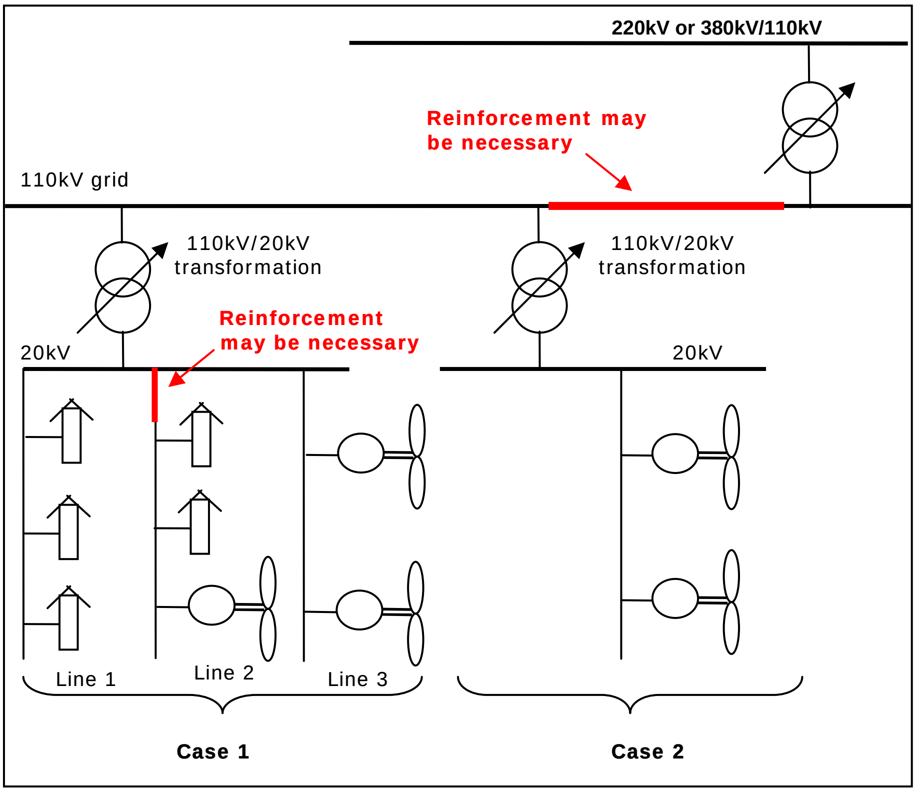

Figure 4.3. Connection of wind turbines on the medium voltage (MV) level

Large onshore wind farms are increasingly connected to the high voltage grid (>100 kV). These connection cases are discussed on the example of offshore wind below.

b) Off-shore connection

Offshore wind generation is increasingly growing in importance. It is seen as a large and untapped power resource which presently offers the best potential for large scale renewable generation. Offshore wind farms are also exposed to higher average wind speeds with less variation than onshore schemes, leading to greater yields.

Currently, more than 10 offshore wind farms are already in operation worldwide and more than 70 offshore wind projects are being firmly planned.[42] In Europe, offshore wind projects are mainly concentrated in the northern part of Europe, see Figure 4.4.

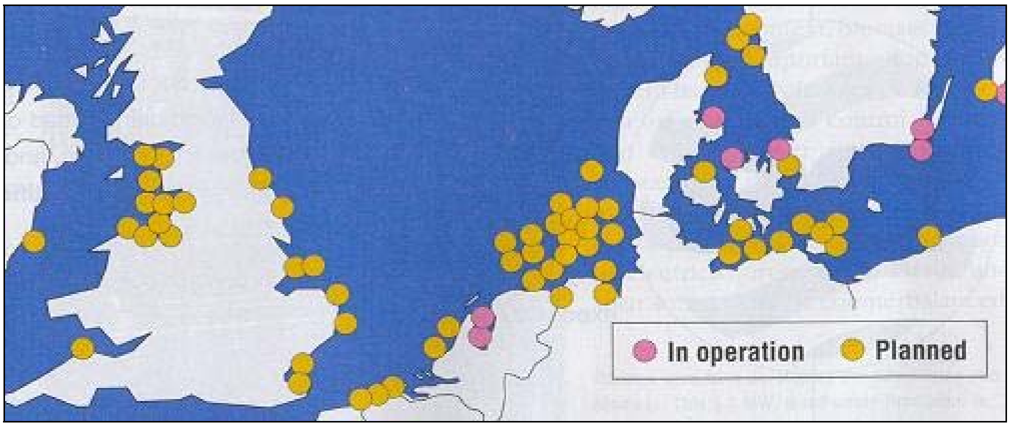

Figure 4.4. Offshore wind energy projects in Europe. Source: Renewable Energy World (2003).

In Germany, an offshore wind energy capacity of at least 20.000 MW is supposed to be installed in the German parts of the North Sea and Baltic Sea by 2030 (according to the German government).[43] Countries like the UK, Belgium, Denmark and the Netherlands are also supporting the development of offshore wind energy. However, many challenges in the field of planning, design, installation, logistics at sea and grid connection will need to be solved before the installation of large schemes.

<u>General requirements:</u>
The requirements of offshore electrical systems differ from those applicable to onshore wind generation and other existing offshore electrical networks, such as oil and gas platforms. Nevertheless, there are also a number of similarities and consequently some lessons to be learned from both areas. There are three main issues: (i) the requirements of the electrical equipment, (ii) the network topography and associated issues, and (iii) factors affecting the connection to the grid.

High volume, low cost solutions are fundamental to the electrical systems of any wind generation scheme. However, they are emphasised because of the large number of turbines needed in offshore projects. The modularisation of equipment and system design is essential to reduce costs. It also aids in keeping the operation and maintenance procedures simple and effective.

Reliability requirements of equipment for both individual turbines and entire farms have to be carefully optimised. Optimisation is a balancing act between improved availability, reduced maintenance visits, increased mean time to failure and associated financial benefits accruing from increased energy output and reduced maintenance cost, set against higher equipment and installation capital cost. The key focus areas for high reliability and system designs are:

- High power density equipment and systems such as onshore and offshore grid connections, and turbine group feeder configurations – rather than lower power density equipment such as individual turbine connections.
- Critical equipment and systems that cannot be doubled for redundancy.

<u>Electrical infrastructure:</u>
Key factors in the design of the internal electrical infrastructure are:

- interconnection voltage,
- the number of turbines per circuit,
- capability of the network configurations to tolerate component failure,
- protection and control requirements, and

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[42] Lehmann K.-P., Övermöhle K.: “Fascination Offshore – report 2002”, Hamburg, Germany, June 2002.

[43] Deutsche Bundesregierung: Strategie zur Nutzung der Windenergie auf See, Berlin, Germany, January, 2002.

- availability of space on each turbine platform for the equipment needed to provide the fault tolerant system

The predominant infrastructure connection method to date for offshore wind farms is a number of radial feeders with several turbines "daisy-chained" to form each radial circuit, as illustrated in Fig. 4.5.

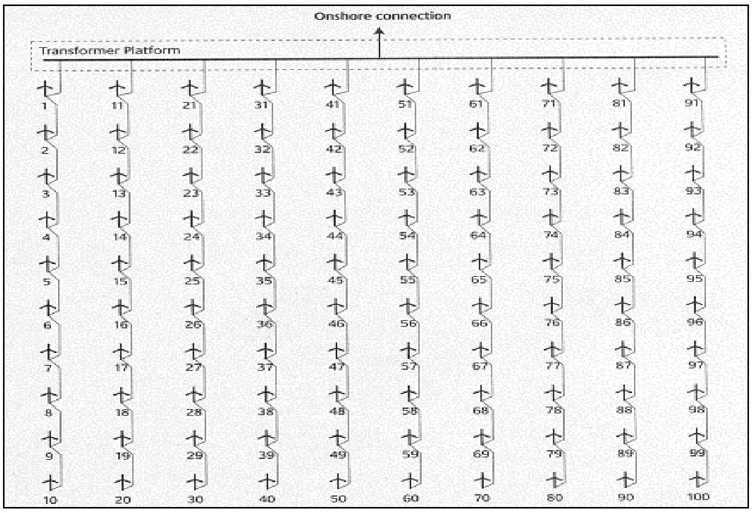

Figure 4.5. Illustration of radial feeder connected offshore wind farm with an evenly spaced matrix.

However, where there is more than one connection to the shore, some grouping could be considered. There are other configurations that may offer better lifetime financial advantage, especially in the future, as the megawatt ratings of offshore turbines increase, or as access becomes more difficult. Access problems could be caused by increased distance from the maintenance base or longer periods of adverse weather, for example. Increase in megawatt ratings may also lead to the use of higher voltages. It may be feasible to develop a medium voltage direct current (MVDC) system for turbine interconnection through the use of local power converters at each turbine. However, this would represent a significant technological step in turbine design for the majority of manufacturers. So, AC systems are likely to be used for turbine interconnections for the foreseeable future.

Shore connection options:
The options for connection to the grid on the shore include:
- AC transmission at a suitable voltage
- Conventional (line communicated) HVDC technology
- Voltage sourced converter (VSC) HVDC technology

The typical maximum power levels and connection distance of each of these technologies is illustrated in Figure 4.6. There are, of course, variations depending on the various factors pertinent to each project and boundaries are always shifting as technologies and associated costs change. The level of power transfer and connection distance for an AC connection is limited by a number of factors:
- Potential resonance within the AC transmission system – especially true if rectifier/inverter equipment is used in the turbines – possibly affecting the harmonic response of the wider system.
- Cable charging current – limits the feasible connection distance.
- Cable losses, which may be significant at high power transfer levels.
- Voltage and frequency variations in the onshore transmission system may impact on the AC connected offshore system.

The use of HVDC transmission is more suitable for high power transfer levels and/or long connection distances. Conventional HVDC technology is based on line commutated converters and requires a strong AC onshore connection for effective operation. It is also bulky and expensive and so is unlikely to be used. In recent years a new technology, known as HVDC-light and based on the voltage sourced converters (VSC) has become available and is probably more suitable for offshore wind. VSC converters can cope better with weak AC onshore systems, such as those in a number of coastal areas in Europe. Based on present semiconductor technology, VSC converter units are available in ratings of up to 330 MW, although it would be possible to increase this power transfer level by connecting modules in parallel, see Figure 4.7.

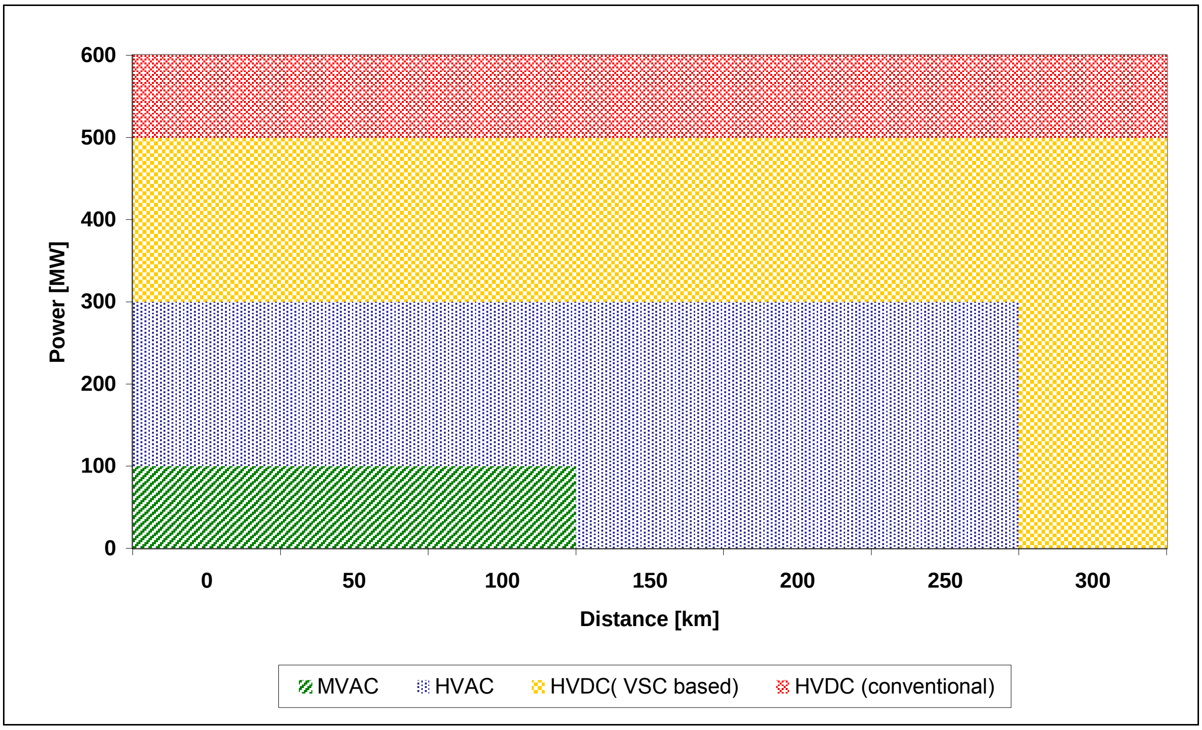

Figure 4.6. Estimated range for AC and DC transmission systems as a function of installed capacity and distance of an offshore wind farm to shore. Source: Wright et al (2002).

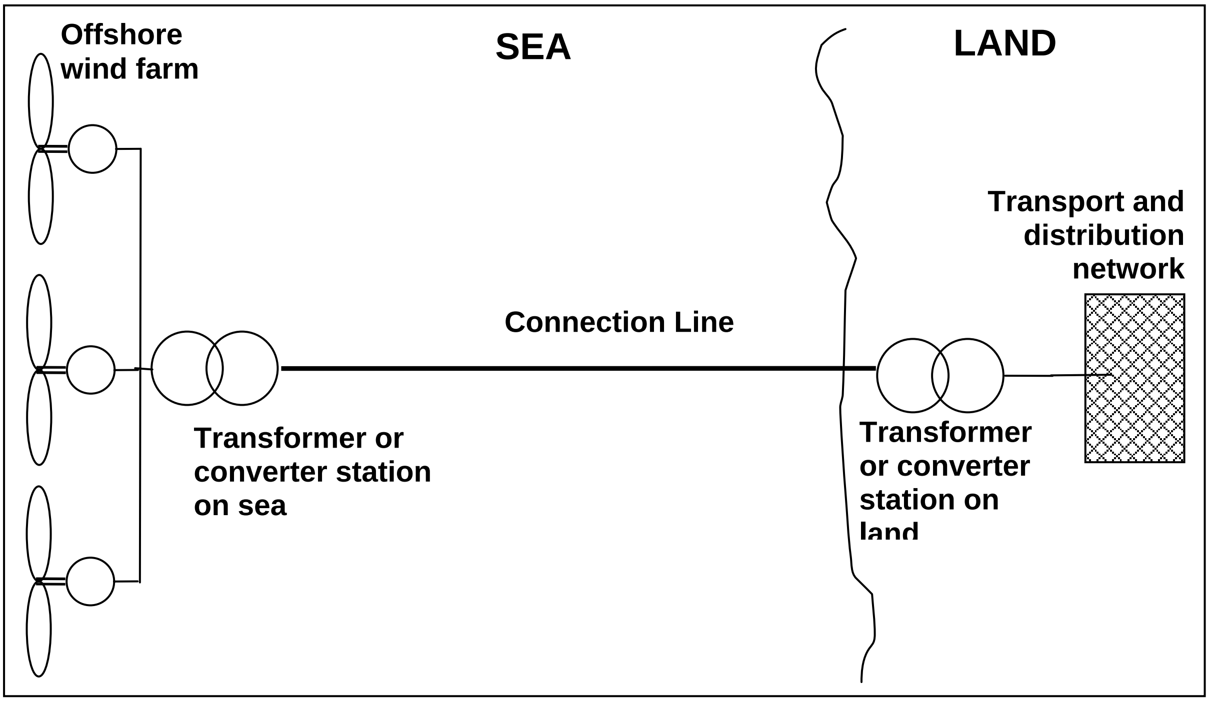

Figure 4.7. DC connection of a large offshore wind farm with “HVDC Light” VSC technology from ABB. Source: Häusler (2002).

The advantages offered by HVDC compared to AC transmission include: (i) much longer connection distance, (ii) reduced power losses, (iii) decoupling of the wind farm and the onshore AC system, (iv) independent control of active and reactive power, and (v) the potential to provide ancillary services to AC onshore network, such as reactive power capabilities, frequency response and control within the capabilities of the available output.

The significant converter costs for HVDC lead to higher investment costs compared to AC transmission for connection distances below 150 km, as illustrated in Figure 4.8.

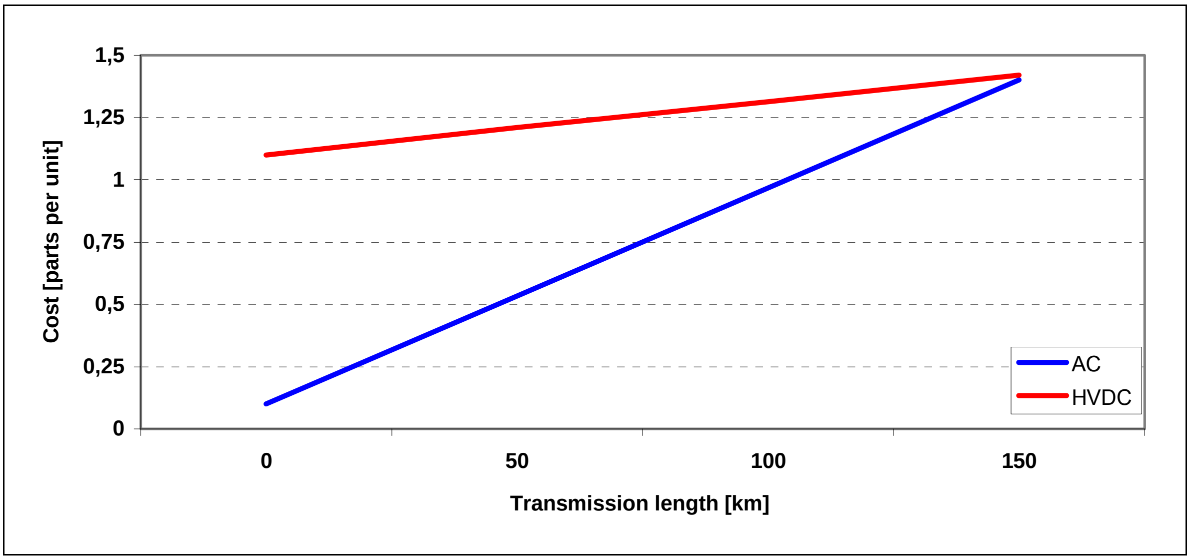

Figure 4.8. Investment costs for HVDC and AC submarine transmission and grid connection. Source: McLeay et al (2003).[44]

However, if the reduced losses associated with HVDC are taken into account, the break-point between HVDC and AC is reduced to about 100 km, as illustrated in Figure 4.9.

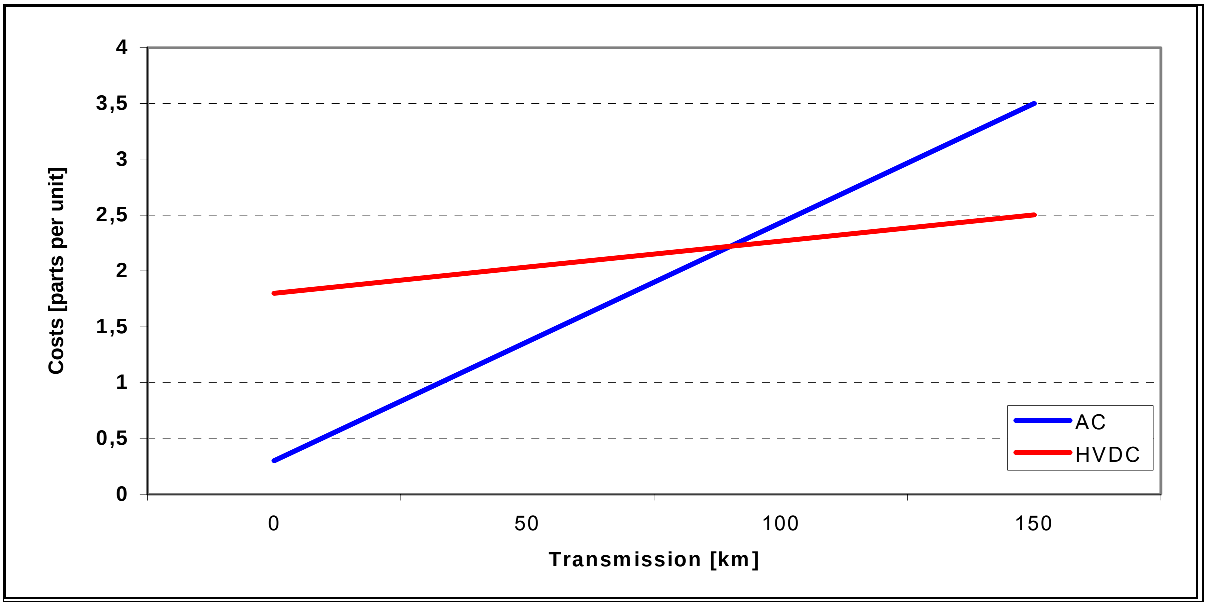

Figure 4.9. Comparison of investment costs and capitalized losses for HVDC and AC submarine transmission and grid connection. Source: McLeay et al (2003).[45]

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[44] Note, investment costs for HDVC for a connection distance of 0 km is taken as 1 part per unit [pu].

[45] See footnote 44 above.

The number of parallel connections to shore also has to be considered. Typical offshore connections to oil and gas platforms consist of a single connection only, because the additional installed cost of cables is usually considered excessive and because cable repairs are normally achievable within a few days. The application of this single connection design philosophy to an offshore generation connection would need to be reviewed on an individual project basis dependent on a number of factors, such as: (i) generation location and size, (ii) potential lost revenues, (iii) contractual liabilities and penalties, and (iv) likelihood of cable failure and time needed for repairs depending on seabed conditions and the laying method employed.

Typical studies for offshore wind:

The typical studies that should be undertaken for an offshore wind farm are indicated in Table 4.2. These are largely similar to those that are carried out within utilities and industry. Details in this context will be also discussed in the WP2 report.

Table 4.2. Typical power system studies required for assessing technical issues of offshore wind.

Study type	**Objectives**
Load flow	* Equipment thermal ratings * Optimisation of system losses * Voltage profile and operating limits * reactive power requirements
Short Circuit	* Equipment short-circuit ratings * Short-circuit current flows used in protection setting & co-ordination studies
Transient Stability	* Responses to grid disturbances (fault ride through, voltage and frequency variations, etc.) * Internal disturbances (turbine trip, cable fault, turbine start-up/short-down, power level fluctuations, etc.)
Harmonics	* System resonance and harmonic distortion calculation and effects * Identification, assessment and optimisation of remedial measures
Protection	* Functional requirements and characteristics of systems to protect personnel and plant under fault conditions * Co-ordination of protection systems to isolate the minimal amount of equipment under fault conditions
Fast Transient	* Lightning, energisation and switching transients effects and mitigation measures
Reliability/Availability	* Reliability and availability based on internal and external factors * Failure mode and effect analysis to minimise failure modes

4.2.1.2.2 *Photovoltaics*

As already shown in Figure 4.1, in traditional electricity systems generated power is fed in at highest voltage levels and electricity is mainly consumed on low voltage levels. However, with the growth of decentralised (embedded) generation power flow becomes more complicated.

Investigations of PV access and their effects on the electricity grid can be limited to the medium (MV) and low voltage levels (LV). Normally, no consideration of the high voltage level (HV) is necessary. Only when a large amount of PV power is fed into the grid, the HV grid must be considered as well. In such cases, the range of the automatic tap changers of the HV/MV transformers needs to be reviewed. When accessing PV systems to the grid, it is necessary to build reception networks in areas with a high density of PV to avoid interference with other grids, see Figure 4.10.

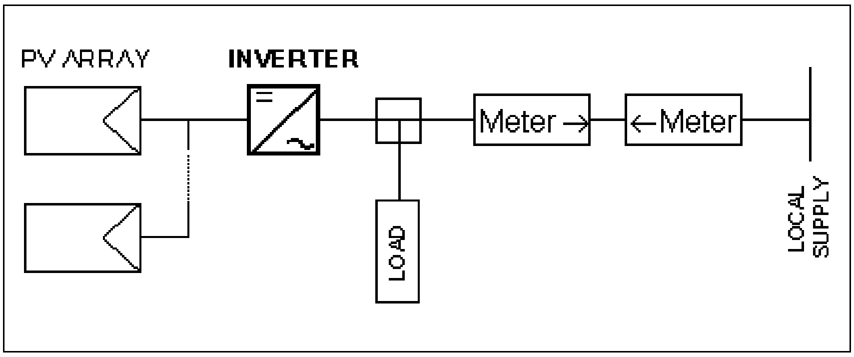

Figure 4.10. Typical grid connected PV system. Source: ESRU (2002).

The major components of a PV system are (see Figure 4.10):

- PV array or generator: A number of PV panels connected in series and/or in parallel providing a DC output according to incident irradiance.
- Inverter: A power converter inverting DC power from PV panels into AC power. The characteristics of the output signal should match voltage, frequency & power quality limits in the distribution grid.
- Load: Represents appliances connected to the grid in the building being fed from the inverter, or, alternatively, from the grid.
- Meters: They account for the energy being drawn from or fed into then local distribution grid.
- Local supply grid: A single or three-phase grid managed by a supplier. The distribution grid acts both as a sink for energy surplus in the building or as a backup for low local generation periods.

A typical case of integration of PV systems into the LV grid is shown in Figure 4.11, the corresponding equivalent grid for calculation of voltage changes under different conditions is indicated in Figure 4.12.

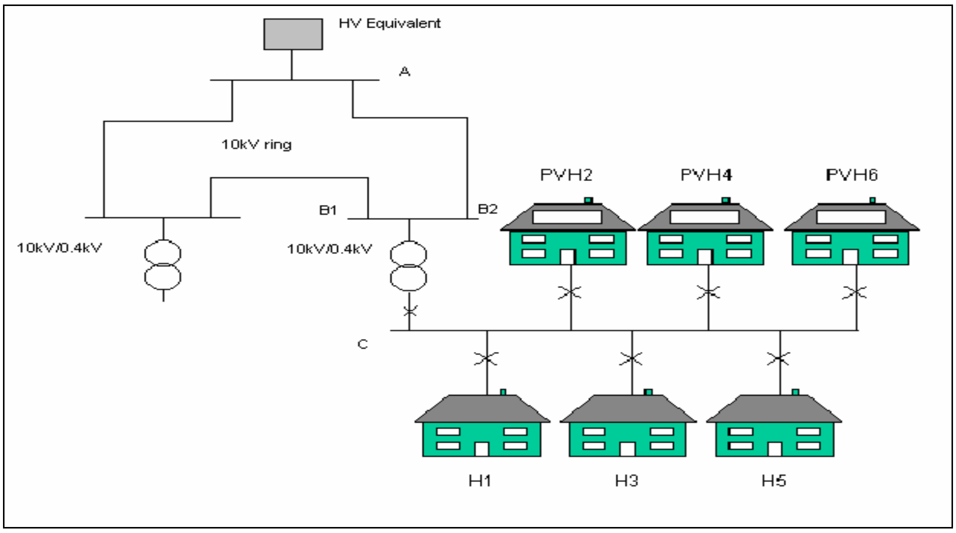

Figure 4.11. Integration of PV systems into a LV grid. Source: IEA (2002).

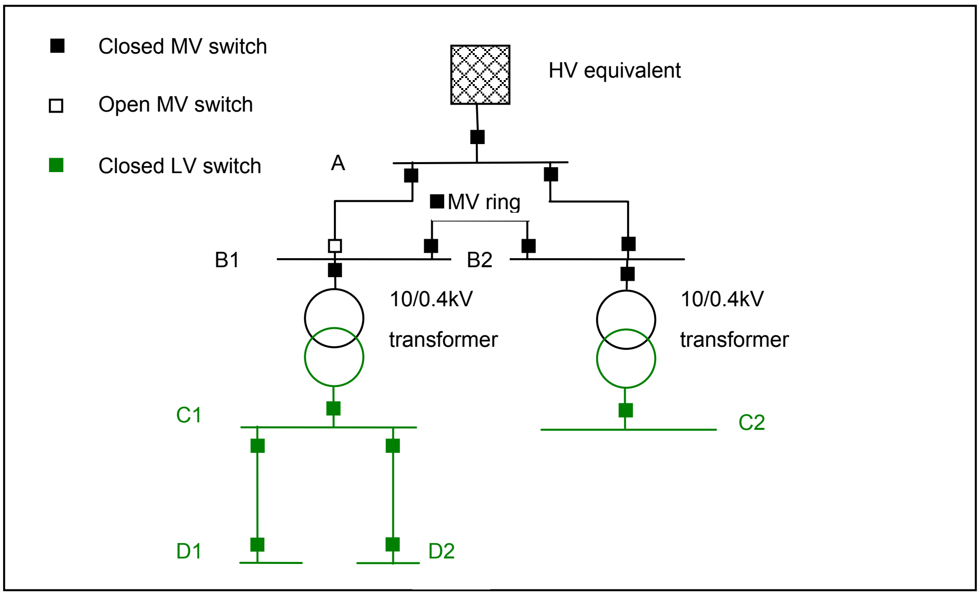

Figure 4.12. Equivalent network for calculation of voltage changes because of PV penetration. Source: IEA (2002).

The most important effect of PV generation on the MV/LV network is the change in the voltage level depending on load and available supply of electricity from PV. Normally, the manual off-load tap changer of an MV/LV transformer is set once in a fixed position. The selected position is to ensure that the voltage limits are respected at both minimum and maximum load, see Figure 4.13 and Figure 4.14 below.

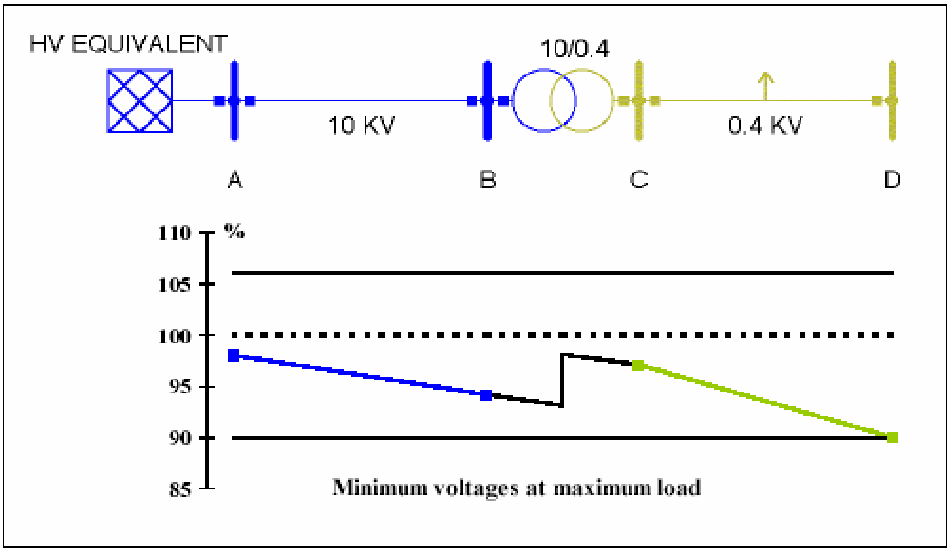

Figure 4.13. Minimum voltages at maximum load in the simplified power system.[46] Source: IEA (2002).

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[46] The voltage at the beginning of the MV line (A) is kept close to 100% by the automatic tap changer of the HV/MV transformer. To allow for a variation equal to ± 1 step in tap changer position, the voltage is set to 98% at maximum load and 102% at minimum load. Of course, the voltage curves from A to B and from C to D are not straight lines if the loads are evenly distributed along the power lines. They are parabolas. However, the shapes of the curves have no influence on the results of the analyses as long as the voltages at the beginning and the end of the lines are correct.

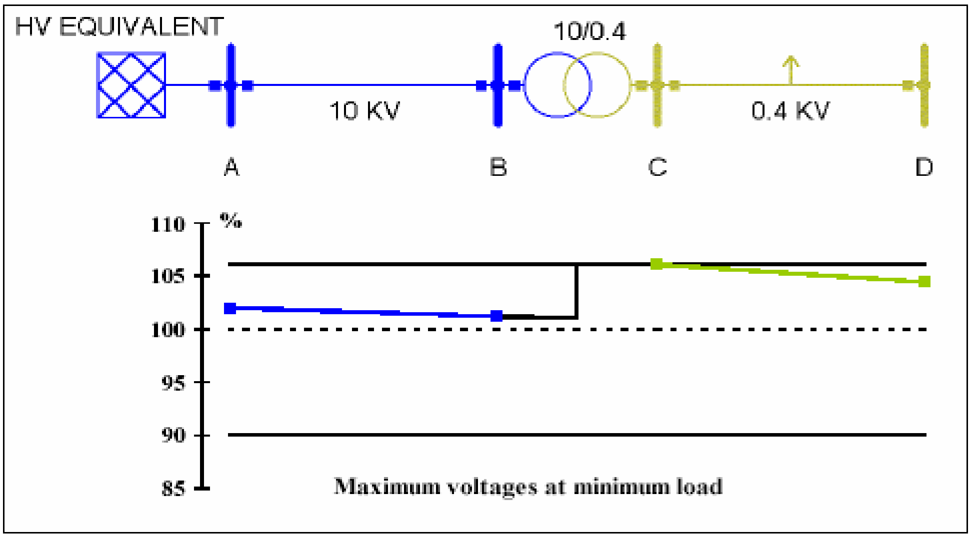

Figure 4.14. Maximum voltages at minimum load in the simplified power system. Source: IEA (2002).

Therefore, PV is fitting into electricity systems where PV generation coincides with high loads in order to avoid too high voltage levels in the LV grid. Such conditions are typical in areas with significant use of air-conditioning (e.g. Italy, Spain, and Greece and so on). PV penetration is less suitable for areas such as the northern European countries where the use of air-conditioning is limited. In such countries PV penetration often coincides with low power demands from both households and industry due to holiday seasons.

A comprehensive investigation of different case studies on connection and operation of PV systems on the MV/LV network will be carried out in the WP2 report.

4.2.2 Grid operation

In the context of intermittent RES-E generation corresponding requirements and cost addressing grid operation can be broken down into its constituent parts:

- system balancing and
- capacity for system security.

Moreover, the impact of intermittent RES-E generation is analysed in detail through:

- Quantifying the additional requirements and costs of balancing the system in the operational time-scale (from several minutes to several hours), primarily driven by fluctuations in wind generation output, and
- Quantifying the capacity and cost of conventional plant required to maintain adequate security of supply in a system supplied by a considerable contribution of intermittent RES-E sources.

The intermittency many RES-E generation technologies in general, and wind particular, is the single largest driver of additional system requirements and corresponding cost. Balancing comprises measures of e.g. response, synchronised reserve, standing reserve, start-up and wind curtailment. Capacity requirements relate to the limited contribution that wind can make to system security, because of the correlation of output across generators and the risk of low wind speeds across the whole country for prolonged periods. The role of each of these elements of balancing as well as capacity requirements is briefly described in below in section 4.2.2.1 and 4.2.2.2, respectively.

4.2.2.1 System balancing requirements caused by intermittent RES-E generation

The key driver for the requirements and costs associated with system balancing is the amount of random power fluctuation, caused by unpredictable changes in load and generation that needs to be accommodated. In order to maintain a secure and stable operation of the electricity system, demand and generation must be continuously balanced. System frequency is the direct measurement of the balance between generation and system demand at any one instant and must be maintained continuously within narrow statutory limits around 50 Hz. Frequency falls when demand is greater than generation and rises when generation is greater than demand.

In order to manage frequency effectively, system operators utilise a range of balancing (ancillary) services that operate at different time horizons. In order to continuously maintain system frequency in the time scale of several seconds to several minutes, conventional generators are equipped with appropriate governing systems that control their outputs to neutralise frequency fluctuations – which may arise from changes in demand and generation. This service, known as dynamic response, is automatically delivered by synchronised generators specially selected to operate in frequency-sensitive mode and is primarily provided by pumped storage and part-loaded thermal plants. Big generators are required to contribute to this service in accordance with the grid code. Similar requirements although less demanding, are now being imposed on large wind generators by a number of European utilities.

Over the time horizon of several minutes to several hours, the balance between supply and demand is achieved through a number of reserve services, such as synchronised reserve and standing reserve.

Fluctuations in the output of renewable generation (such as wind) will place an additional duty on the remaining generating plant and increase the requirements for both response and reserve capacity. The amount of additional resource required to manage unscheduled wind generation will not be on a "megawatt for megawatt" basis. The key factor here is the density – the phenomenon of natural aggregation on individual wind farm outputs. The output of individual wind turbines is generally not highly correlated, particularly when wind farms are located in different regions.

It is important to stress that response and reserve requirements are not assigned to back up a particular plant type (wind), but to deal with the overall uncertainty in the balance between demand and generation! The uncertainty to be managed is driven by the combined effect of the fluctuations in demand and conventional and renewable generation. These individual fluctuations are generally not correlated, which has an overall smoothing effect with a consequent beneficial impact on the cost. In assessing the additional resources required to manage the balance between generation and demand in systems with a large penetration of renewables two distinct time horizons have to be selected:

- Half hour – relevant for determining response requirements
- Four hours – relevant for determining reserve requirements

Response

One of the factors determining the amount of response required is system interia, which controls the initial rate of change of frequency following a disturbance, such a loss of plant. The amount of response required increases with reductions in system demand, as the amount of interia reduces and the relative impact of disturbance increases. Furthermore, the overall response requirements will be driven by the interia of generating plant running on the system.

The amount of dynamic response that a conventional generating unit should provide is specified by the grid code. In order for synchronised conventional plant to provide dynamic response (and reserve) it must run part-loaded. Thermal units operate less efficiently when part-loaded, with an efficiency loss of between 10% and 20%. Since some of the generating units will be part loaded to provide response, some other units will need to be brought on the system to supply energy that was originally allocated to responsive plant. This usually means that plant with higher marginal cost will need to run, and this is another source of cost. Both of these factors are taken into consideration in the assessment of cost related with providing response services.

Reserve

Reserve requirements are met by both synchronised and standing reserves.[47] Synchronised reserve is provided by part-loaded thermal plants (e.g. coal or CCGT (Combined Cycle Gas Turbines), while

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[47] In general, some electricity generation plant is held in a *´warm´*state in which it can increase electricity output at short notice. Thermal power plants (like coal fired power stations) take several hours to warm up from cold. To ensure that there is sufficient capacity available to respond rapidly to a sudden increase in electricity demand, some thermal power stations are kept in a condition known as *´spinning reserve´*. These plants are burning fuel

standing reserve is provided by higher fuel cost thermal plants, such as e.g. OCGTs (Open Cycle Gas Turbines) or pump hydro storage plants (if available in the system). Following the simplifications adopted, the total requirement for reserve (synchronised and standing) is assumed to be driven by the overall system fluctuations of demand and generation over the four-hour time horizon.

The allocation of reserve between synchronised and standing plant is a trade-off between the cost of efficiency losses of part-loaded synchronised plant (plant with relatively low marginal cost) and the cost of running standing plant with relatively high marginal cost. The balance between synchronised and standing reserve is optimised to achieve minimum overall reserve cost.

Based on Dany/Haubrich (2000) manual minute reserve of around 20% of total peak load is necessary in a system with small penetrations of wind, regardless of the wind forecasting error. If installed wind capacity is above 20% of peak load in a system demand for manual minute reserve increases with increasing forecasting error, see Figure 4.15.

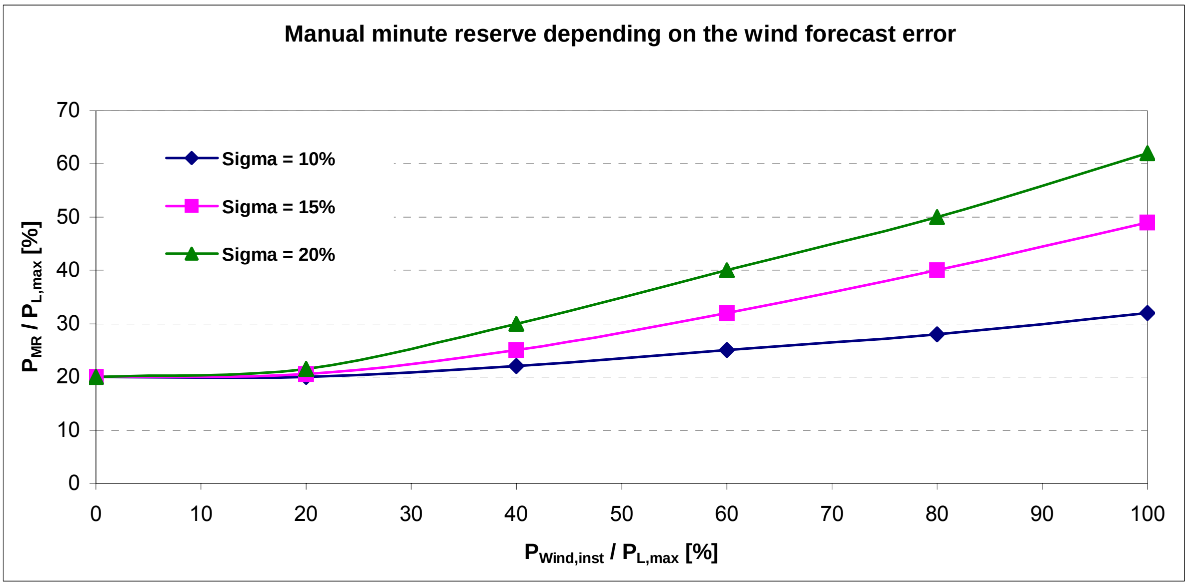

Figure 4.15. Manual minute reserve depending on the wind forecast error. Source: Dany/Haubrich (2000).

Curtailment Cost

When renewable generation reaches 20% or 30% of demand, there will be occasions (generally during low demand days over summer at least in central and northern Europe) when the number of conventional units needed to supply the remaining load will be so few, that adequate levels of response and reserve could not be maintained. In extreme situations renewable generation could exceed the demand during some periods. These conditions could generally occur during the periods of low demand coinciding with high output of wind generation. A number of actions that may be available to deal with such surpluses of generation are identified and prioritised with respect to cost. The least costly options would be to increase demand, e.g. also by additional pumping at the pumped storage facilities or hydrogen production in the future.

If these options are exhausted and the amount of conventional plant on the system is still insufficient to provide adequate response and reserve, wind generation could be de-loaded in order to take part in frequency regulation and reserve tasks. It can be assumed that wind generators will be able to provide response and reserve at the level of 10% of their output. If there were still some surplus generation left, renewable generation would need to be constrained off, starting with the technologies with the highest marginal cost, such as biomass.

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and are generating electricity, but are not running at full load. Keeping a certain amount of power plant as *´spinning reserve´* is necessary to ensure that electricity supply can maintained should there be an unexpected loss of generation capacity.

4.2.2.2 System capacity requirements caused by intermittent RES-E generation

The objective of analyses is to determine the contribution of intermittent renewable sources to system security or, other words, to determine the amount of capacity of conventional plant that can be displaced by intermittent renewables whilst maintaining the same degree of security.

In this context, system capacity requirements and corresponding costs to a large extent relate to the limited contribution that wind can make to system security, because of the correlation of output across generators and the risk of low wind speeds across the whole country for prolonged periods. Although wind makes some contribution to capacity at peak, this contribution is significantly less than for equivalent conventional generation or non-intermittent renewables. New technological developments in storage, fuel cells or load management in the future may reduce the cost of providing this additional capacity. However, it is often argued that wind may be unable to contribute to system security at all, because of the risk of periods with hardly any wind at times close to maximum system demand. Details in this context are briefly discussed below and comprehensively in the report of WP2 (“grid”) and WP3 (“storage”).

Nevertheless, the relevant parameter in estimating the system capacity requirement is the capacity credit. Capacity credit is calculated by determining the reductions of installed conventional power capacity so that the probability of loss of load in winter peaks is not increased. Or, in other words, how much conventional power plant could be “replaced” by wind power, without making the system less reliable. For low levels of penetration of wind power into the grid, the capacity credit for wind energy is about the same as the installed capacity multiplied by the load factor. However, as the level of wind penetration rises, the capacity credit begins to tail off as shown in the Figures 4.16 (UK case) and 4.17 (German case) below.

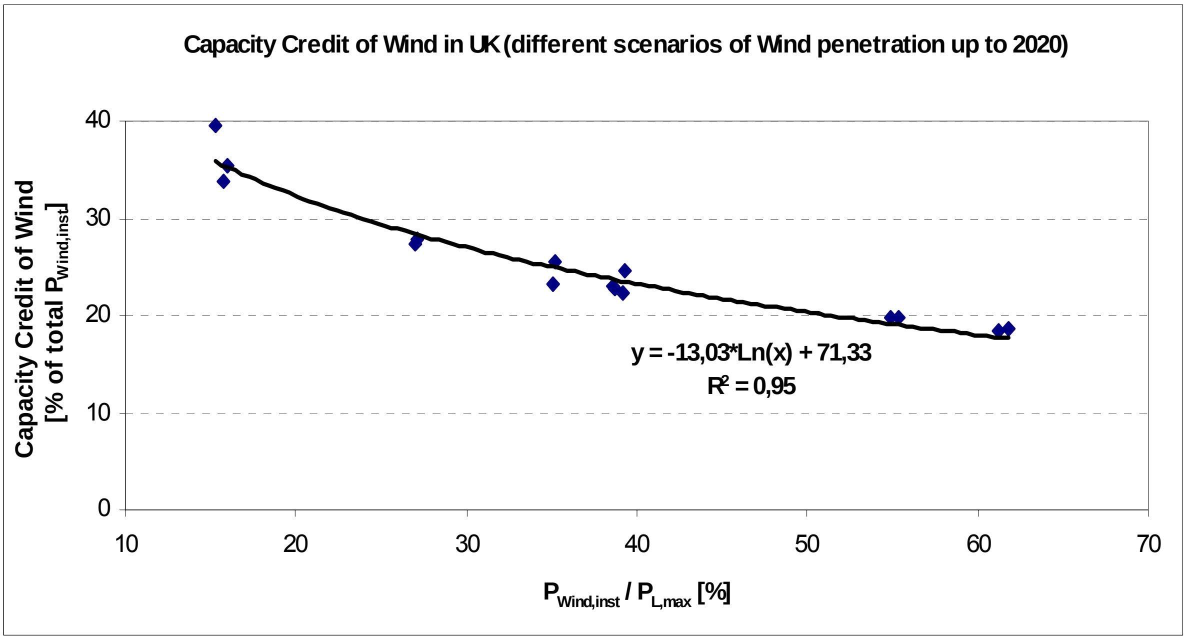

Figure 4.16. Capacity credit for different scenarios of wind penetration in the UK up to 2020. Source: ILEX Energy Consulting (2002).

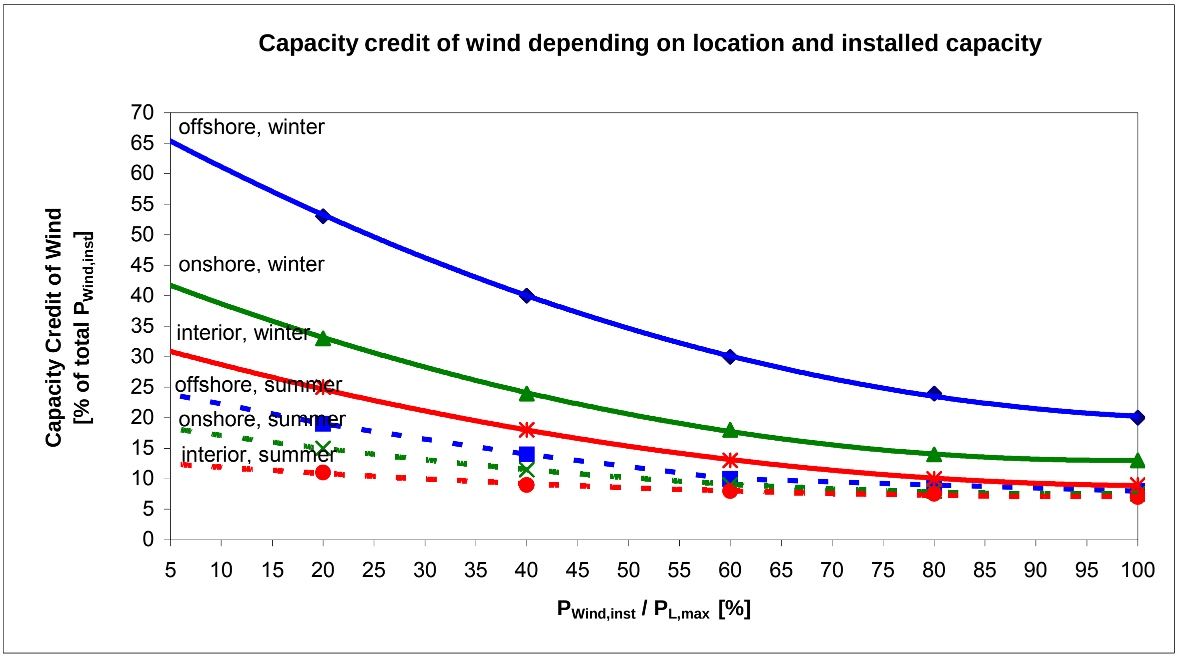

Figure 4.17. Capacity credit of wind depending on location and installed capacity in Germany. Source: Dany/Haubrich (2000).[48]

The key factor when determine the capacity credit is the average power that the source delivers at times when the system is at risk (i.e. winter peak in Figure 4.16 and Figure 4.17 for UK and Germany, respectively). However, as the capacity of intermittent source rises, it becomes increasingly less valuable for displacing the capacity of conventional plant, since there are times with little or no wind.

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[48] Sontow (1999) is another publication addressing the capacity credit of wind in Germany. The results are similar to Dany/Haubrich (2000).

4.3 (Rough) cost of RES-E technology grid integration

Please note, that a comprehensive empirical investigation of different cost for RES-E integration (grid connection cost, grid operation cost and grid extension cost) for several RES-E technologies takes place in the WP2 report. In WP2 these empirical data will be available in a comprehensive data base.

Here in the WP1 report this topic is just introduced showing a few selected case studies in different countries on cost for grid connection, grid operation and grid extension.

4.3.1 Cost of RES-E grid connection

4.3.1.1 Case Studies: Wind-Onshore

A comprehensive overview of specific cost of grid connection of onshore wind farms can be found in Consentec et al (2003).[49] Moreover, a variety of different connection cases of wind-onshore on different voltage levels under different conditions is discussed. E.g., in Figure 4.18 the specific cable cost (in TEuro/km) between wind farm and connection point on the existing grid (incl. excavations) is indicated for connection on the 20kV and 30 kV voltage level, respectively.

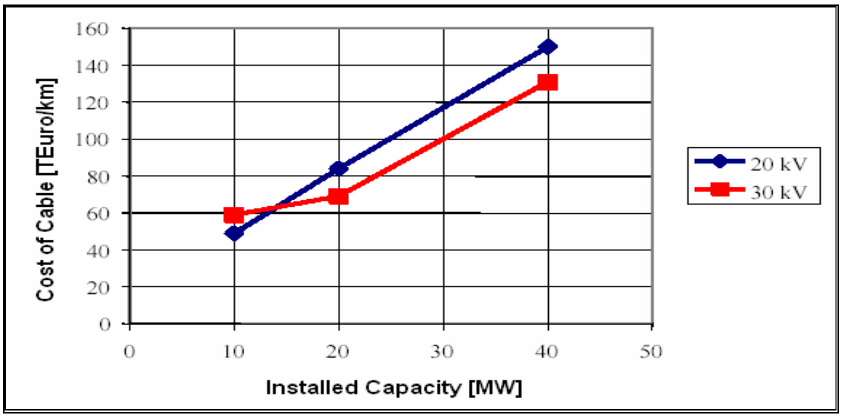

Figure 4.18. Specific cost of cable between wind farm and connection point to the existing grid (incl. excavations). Source: Consentec et al (2003).

As already shown in Figure 4.18 above there exist different options to connect wind farms on different voltage levels, e.g. either on a medium voltage (MV) turn off or an a free MV feeder (i.e. separate MV wind grid) being connected to the 110/220 kV grid. In Table 4.3 the economic difference between these two connection options is indicated (based on Consentec et al (2003)).

Table 4.3. Cost of onshore-wind farms depending on size (installed capacity) and voltage level of grid connection (20KV versus 110kV). Source: Consentec et al (2003).

Installed Capacity 20 kV	Cost		
	Min	Average	Max
10 MW	9,3 Mio. €	10,6 Mio. €	11,9 Mio. €
20 MW	18,4 Mio. €	21,0 Mio. €	23,3 Mio. €
30 MW	27,6 Mio. €	31,6 Mio. €	35,2 Mio. €
40 MW	36,8 Mio. €	42,0 Mio. €	46,8 Mio. €

Installed Capacity 110kV	Cost		
	Min	Average	Max
10 MW	9,7 Mio. €	11,2 Mio. €	12,3 Mio. €
20 MW	19,0 Mio. €	21,7 Mio. €	23,9 Mio. €
30 MW	28,3 Mio. €	32,3 Mio. €	35,8 Mio. €
40 MW	37,5 Mio. €	42,8 Mio. €	47,6 Mio. €

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[49] Consentec, RTWH Aachen, FGH-Mannhein: „Auswirkungen des Windkraftausbaus in Österreich", Studie von Consentec Consultung für Energiewirtschaft und –technik GmbH, Institut für Elektrische Anlagen und Energiewirtschaft der RWTH Aachen, Forschungsgemeinschaft für Elektrische Anlagen und Stromwirtschaft e.V. im Auftrag der E-Control GmbH, Schlussbericht, Wien, Juni 2003.

A comprehensive discussion an empirical documentation on individual differences in cost depending on the grid connection option is conducted in the WP2 report.

4.3.1.2 Case Studies: Wind-Offshore

With respect to cost of offshore-wind farms in general, and corresponding learning curves in particular, there exists an interesting publication: Junginger/Faaij (2003).[50] Figure 4.19 indicates the initial investment cost distribution in the reference offshore wind farm compared to the two scenarios in 2020 (sustained diffusion versus stagnating growth). The cost of the "external grid" (i.e. connection from the wind farm to the existing grid) is around 15% of total cost of 1565€/kW, see Figure 4.19. In the two scenarios up to 2020 the cost of the "external grid" are reduced proportional with the total cost.

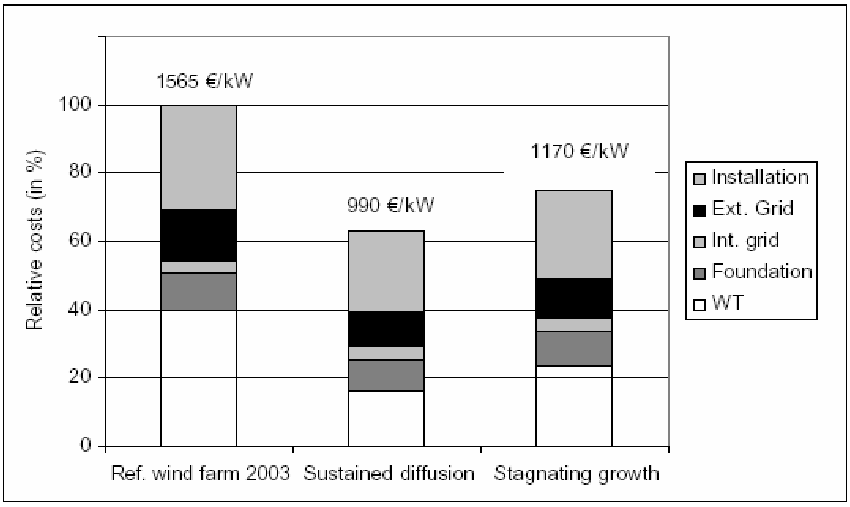

Figure 4.19. Initial investment cost distribution in the reference offshore wind farm compared to the two scenarios in 2020.

In Figure 4.20 the two scenarios of offshore wind farm investment cost reductions based on Junginger/Faaij (2003) are shown in detail. In the data base of WP2 these dynamic aspects are also taken into account.

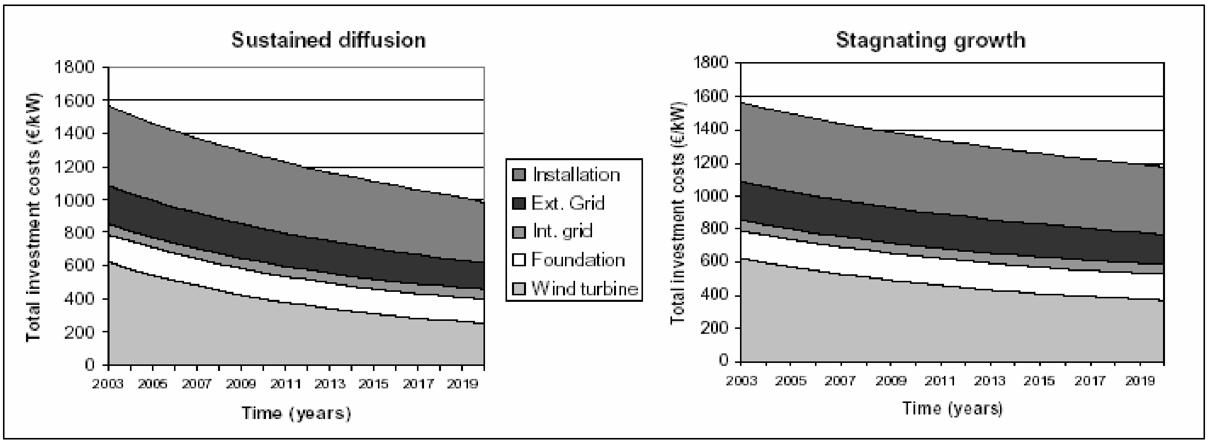

Figure 4.20. Two scenarios for offshore wind farm investment cost reductions. Source: Junginger/Faaij (2003).

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[50] Junginger/Faaij (2003): "Cost reduction prospects for the offshore wind energy sector", Paper presented at the EWEA 2003 in Madrid (June 2003), Department of Science, Technology and Society; Copernicus Institute, Utrecht University, The Netherlands, 2003.

Again, a comprehensive discussion an empirical documentation on individual differences in cost developments for offshore-wind grid connection is conducted in the WP2 report.

4.3.2 Cost of RES-E grid operation

For the UK a comprehensive study on the system cost of additional renewables in 2020 exists.[51] Mainly referring to the results in this publication in this section the major cost components are described briefly.

According to this study, Figure 4.21 presents the breakdown of additional annual system costs in the UK between the three elements examined: (i) balancing and capacity cost, (ii) transmission cost and (iii) distribution cost. It can be seen that balancing and capacity cost, principally the cost of maintaining the system security, dominate all other cost (except for high penetration of wind additional shares of transmission costs are also considerable), mainly because of the intermittency of wind.

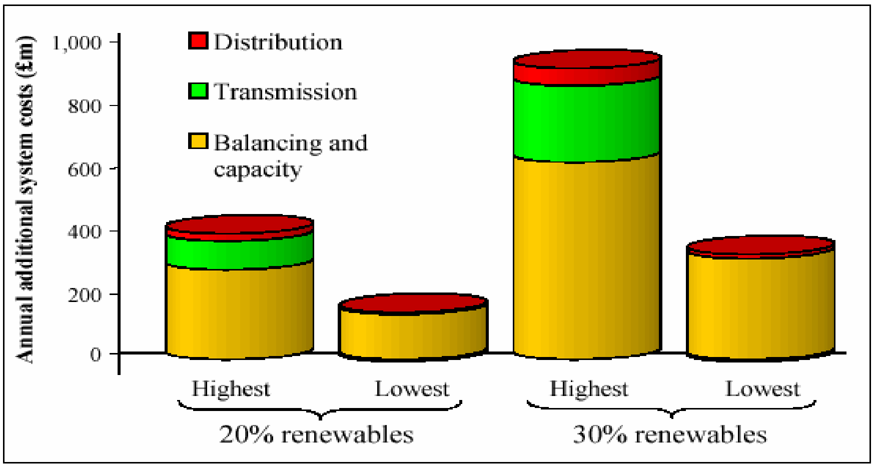
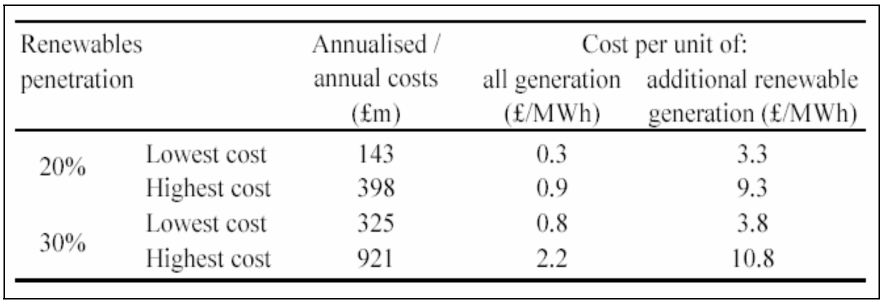


Figure 4.21. Breakdown of annual system costs in highest and lowest cost cases in the UK for 2020. Source: ILEX Energy Consulting (2002).

Derived from Figure 4.21 in Table 4.4 the additional annual system cost in the highest and lowest cost cases in UK for the year 2020 are presented on a Pound/MWh basis.

Table 4.4. Additional annual system cost in the highest and lowest cost cases in UK for the year 2020 on a Pound/MWh basis. Source: ILEX Energy Consulting (2002).



Renewables penetration		Annualised / annual costs (£m)	Cost per unit of:	
			all generation (£/MWh)	additional renewable generation (£/MWh)
20%	Lowest cost	143	0.3	3.3
	Highest cost	398	0.9	9.3
30%	Lowest cost	325	0.8	3.8
	Highest cost	921	2.2	10.8

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[51] ILEX Energy Consulting: „Quantifying the system costs of additional renewables in 2020“, A report of ILEX Energy Consulting in association with Manchester Centre for Electrical Energy (UMIST) for the Department of Trade and Industry (DTI), October 2002.

4.3.2.1 System balancing cost caused by intermittent RES-E generation

There are a number of ways in which the cost for balancing and additional capacity can be calculated. The most comprehensive manner would be to calculate the total capacity and energy costs of the electrical system as a whole. However, this route would not enable to segregate the capacity costs from the costs of establishing renewables. In this project we follow a simplified approach producing robust results also used in the UK study of ILEX Energy Consulting (2002).

In Figure 4.22 a breakdown of additional annual balancing and capacity costs in the UK is conducted. In several scenarios the most dominant part are the capacity cost. Based on the results in Figure 4.22, the overall shares of balancing and capacity cost can be estimated with the ratio: 1/3 versus 2/3. Details on methods to calculate balancing cost are discussed in the WP2-report.

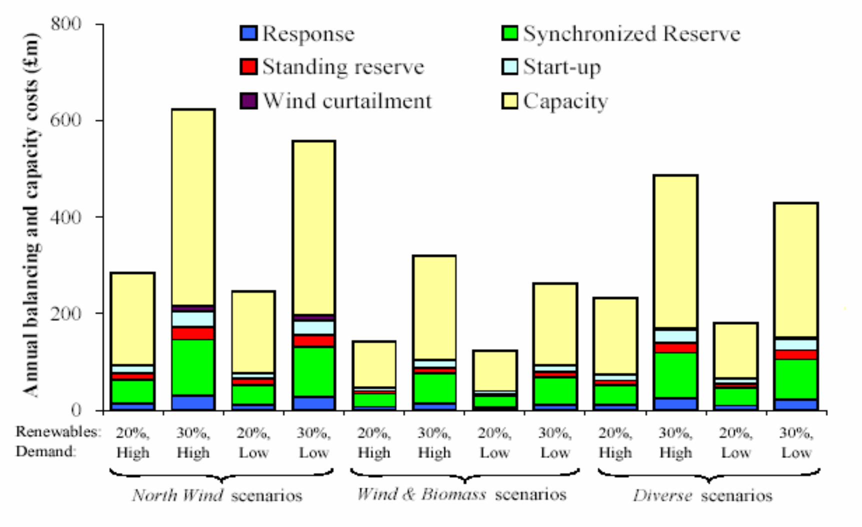

Figure 4.22. Breakdown of additional annual generation cost in UK. Source: ILEX Energy Consulting (2002).

4.3.2.2 System capacity cost caused by intermittent RES-E generation

As already mentioned above, the calculation of the total capacity and energy costs of the electrical system as a whole would not enable to segregate the capacity costs from the costs of establishing renewables. Therefore, we follow a simplified approach producing robust results also used in the UK study ILEX Energy Consulting (2002). Again, details on methods to calculate capacity cost are discussed in the WP2-report.

<u>Example:</u>
Firstly, the annual wind generation is calculated using installed capacity in MW and annual full load hours. Then the equivalent amount of conventional capacity is determined required to produce the same generation, assuming a CCGT (Combined Cycle Gas Turbine) at 85% load factor.

Assume further 10GW of wind capacity generating 30 TWh per annum (i.e. 3000 full load hours). 4 GW of CCGT (Combined Cycle Gas Turbine) at 85% load factor produces the same annual generation. However, conventional capacity can be viewed as delivering two services, energy production and capacity.

If it is considered that <u>wind can provide no contribution to capacity margin</u>, then to be equivalent to the conventional generation, wind would require back-up from generation equal to the equivalent conventional capacity. This capacity could come from a number of sources, including old conventional generation, new combined cycle gas turbine (CCGTs) or new open cycle gas turbines (OCGTs). We have allocated the capacity requirement at the price of a new, but not leading-edge OCGT (65 €/kW/yr), suitable for peaking operation, as we consider that at the margin, only OCGTs will be used, as any economically feasible existing generation would already be utilised on the system. Thus cost of 4 GW of OCGT peaking capacity at 65 €/kW/yr is around €260m per annum (i.e. 8.67 €/MWh).

If it is considered that wind does contribute to system security, albeit at a lower rate than conventional capacity, then the above capacity requirement is reduced by the level of that contribution. If it is assumed that 3.5 GW of wind capacity (out of 9.9 GW) contribute to the system the additional capacity requirement is reduced by this amount and now becomes 4 GW – 3.5 GW = 0.5 GW. At 65 €/kW/yr the capacity cost is now €32.5m per annum (i.e. 1.08 €/MWh).[52]

4.3.3 Cost of grid extension

Currently, at least the following country-specific studies quantifying grid extension measures and corresponding cost exist. They are based on detailed load flow calculations on the national transmission grids:

- *UK incl. Scotland* (ILEX Energy Consulting & UMIST): "Quantifying the System Costs of Additional Renewables in 2020", A report of Department of Trade & Industry and Manchester Centre for Electrical Energy, UMIST, October 2002.
- *Republic of Ireland* (GarradHassan Consultants): „The effects of increasing wind penetration on the electricity systems of Republic of Irland and Northern Ireland", ESB International, GarradHassan, 2003.
- *Belgium* (Univ. Leuven): "Impact of the wind generation on the Belgian high voltage grid", Department of Electrical Engineering ESAT/ELECTA, 2003.
- *Netherlands* (Jaap `t Hooft, Novem): "Survey of integration of 6000 MW offshore wind power in the Netherlands electricity grid in 2020", NOVEM, 2003.
- *Poland* (Polish Power Grid Company, Gdansk Institute of Power Engineering): "Study of Integration Possibilities of Wind Energy with the Polish Power Grid", 2003.
- *Germany* (Martin Luther, E.ON Netz)"Grid operation and management with large scale wind generation", Brussels, September Conference 2001.

The empirical results of these studies will be available in the WP2 data base. Furthermore, in WP2 own load flow calculations for selected grid structures in selected European countries as well as geographic regions will be conducted, requirements for grid extension will be identified and, finally, corresponding cost estimated.

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[52] However, the above calculations assume that wind generation is directly equivalent to that from a CCGT. This will not be the case. Wind generation tends to have an energy value approximately equivalent to the time-weighted average (TWA) price whereas, generation from a more controllable CCGT (operating at 85% load factor, as assumed above) would have a value some 4% above TWA.

4.4 Future requirements of the European grids for (large-scale) RES-E grid integartion

In the past, grids have been designed for large scale central generation whose power is transported outwards through the transmission and distribution systems. They have not been designed for and have not been operated with substantial distributed (embedded) generation. That requirement is coming not just as part of the integration of renewable energy, but also as a result of a much increased interest in small scale commercial generation as the electricity industry is liberalised. A change in attitude and operation will be required to accommodate this change.

Grid operators must be educated to recognise that although renewables (mainly wind) are variable they are also predictable and hence they can, when considered in significant aggregated capacity, be scheduled at a time scale which is commensurate with conventional plants. The level of penetration which can be achieved by renewables is essentially limited by cost rather than by some fundamental technical considerations.

The key future requirements of the European grid can be split into two categories:
1. Is it technically feasible to overcome the technical issues of grid integration of intermittent renewables in the near future, and at the same time maintain the quality of supply that we presently experience?
2. What are the costs, including the costs of development and operation of the electricity system based on large-scale renewable generation?

For the first question, it is clear that it is technically feasible to have very high penetration of intermittent renewable generation. In principle there are no technical limits. Very high renewable energy penetrations appear achievable, but only if cost is no object. It is more important to establish what the costs are, and compare them against the costs of competing options.

The variability of intermittent renewable generation (mainly wind) is not as severe as is often perceived, because of the major benefits (for system operators) of geographical diversity. This can be aided by relatively simple measures such as e.g. capping or ramp rate control of wind farms during critical periods. However it remains a major disadvantage that becomes more important at high penetrations, principally because it increases the amount of reserve that an operator must carry on the system, and/or requires some other solution such as curtailment of wind generation or increased inter-connector capacity.

As for the issue of variability, the unpredictability of wind generation requires system operators to carry additional reserve or possibly force curtailment of wind generation. Significant improvements in wind output forecasting are anticipated through work currently in progress. Also grid code requirements especially for wind generation are being developed. It is expected that technical solutions will be developed to meet corresponding technical requirements, at costs which will not be significant in the context of overall project costs.

The second question on costs cannot be answered fully at present, as the costs of operating an electricity system with very high wind penetration (e.g. above 30% energy penetration or so) are not yet understood clearly. The sources of these increased costs are becoming more clearly understood, as are means to mitigate them.

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