ECN-C--05-005

RECOMMENDATIONS FOR INSTITUTIONAL POLICY AND NETWORK REGULATORY FRAMEWORKS TOWARDS DISTRIBUTED GENERATION IN EU MEMBER STATES

Benchmarking network regulation and policy for the integration of Distributed Generation

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ENIRDG-net

European Network for Integration of Renewables and Distributed Generation

January2005

Acknowledgement/Preface
The ENIRDG-net project is supported by the European Commission under the 5th RTD Framework Programme 'Energy, Environment and Sustainable Development' under the contract No. ENK5-CT-2001-20528. This document or any other documents produced within the ENIRDG-net project does not represent the opinion of the European Commission. Neither the European Commission, nor any person acting on the behalf of the Commission, is responsible for the use that might be made of the information arising from the ENIRDG-net. The project is registered under ECN project number 77398.

The benchmarking methodology used in this ENIRDG-net study was developed in the framework of the FP5 project SUSTELNET by prof. Nicolas Boccard (University of Girona) and Fondazione Eni Enrico Mattei (FEEM). The authors would like to thank them for allowing their benchmarking methodology to be used for this research and in using the work of SUSTELNET as an example in this report. The authors would also like to thank the following ENIRDG-net partners for their contribution to this research:
- Houda Allal - OME, France
- John Hickey - ESBI, Ireland
- Sirpa Repo - VTT, Finland
- Gerd Schauer - Verbund, Austria
- Elena Turienzo - Labein, Spain
- Alvaro Ryan & Javier Rodriguez Sola - Iberdrola, Spain.

Abstract
This report presents recommendations regarding the development of regulatory frameworks and institutional policies towards an optimal integration of distributed generation into electricity networks. These recommendations are based on findings from a benchmarking study conducted in the framework of the ENIRDG-net project.

The aim of the benchmarking exercise was to identify examples of well-defined pro-DG policies, with clear targets and adequate implementation mechanisms. In this study an adequate pro-DG policy is defined on the basis of a level playing field, a situation where distributed and centralised generation receive equal incentives and have equal access to the liberalised markets for electricity.

The benchmark study includes the results of a similar study conducted in the framework of the SUSTELNET project. When comparing the results a certain discrepancy can be noticed between the actual regulation and policy in a number of countries, the medium to long-term targets and the ideal situation described by the level playing field objective. To overcome this discrepancy, a number of recommendations have been drafted for future policy and regulation towards distributed generation.

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ABBREVIATIONS

AER	Alternative Energy Requirement
AET	Average Electricity Tariff
CAPEX	Capital Expenditures
CER	Irish Commission for Electricity Regulation
CHP	Combined Heat and Power production
DG	Distributed Generation
DSO	Distribution System Operator
DTe	Dienst uitvoering en toezicht Energie (Dutch regulator)
DUoS	Distribution Use of System
ENIRDG-net	European Network for Integration of Renewables and Distributed Generation
HV	High voltage
IPP	Independent Power Producer
ICT	Information and Communication Technology
kV	Kilovolts
LV	Low voltage
MS	(EU) Member States
MV	Medium voltage
MW	Megawatt
NETA	New Electricity Trading Arrangements
O&M	Operation & Maintenance
OFGEM	UK Office of Gas and Electricity Markets
OPEX	Operational Expenditures
OTC	Over the Counter
PBR	Performance Based Regulation
PPA	Power Purchasing Agreement
PV	Photovoltaics
QoS	Quality of Service
R&D	Research and Development
RAB	Regulatory Asset Base
RES	Renewable Energy Sources
RPI-X	Retail Price Index *minus* X factor
SUSTELNET	Sustainable electricity networks (5^{th} Framework Research Project)
nTPA	Negotiated Third Party Access
rTPA	Regulated Third Party Access
TSO	Transmission System Operator
TUoS	Transmission Use of System
UoS	Use of System
VA	Volt Ampere
VAT	Value Added Tax

EXECUTIVE SUMMARY

Introduction

This study has analysed the existing policy and regulation aimed at the integration of a growing share of Distributed Generation (DG) in electricity supply systems in the European Union. It illustrates the state of the art and progress in the development of support mechanisms and network regulation for large-scale integration of DG. An increasing share of DG will aim at meeting EU targets in the next decade regarding Combined Heat and Power (CHP) production, renewable energy sources (RES) and other efficient and environmentally friendly technologies. Through a benchmark study a systematic comparison has been made of different DG support schemes and distribution network regulation in EU Member States to a predefined standard, the level playing field. This level playing field has been defined as the situation where energy markets, policy and regulation provide neutral incentives to central vs. distributed generation, which results in an economically more efficient electricity supply to the consumer.

In current regulation and policy a certain discrepancy can be noticed between the actual regulation and policy support systems in a number of countries, the medium to long term targets and the ideal situation described according to the level playing field objective. Policies towards DG and RES are now mainly aimed at removing short-term barriers, increasing the production share of DG and RES. By having such a relatively limited scope, they often ignore the more complex barriers of integrating DG and RES that is influenced by economic network regulation in current electricity markets.

A growing share of DG and RES in the electricity supply system will require the modification of support schemes in place to a cost-effective approach in the medium- and long term, creating a level playing field. The following steps are therefore required:

- To value the costs and benefits that DG contributes to the network in economic terms and allocate them between different market actors in accordance with the prices of their services.
- Ensure network and electricity market access for all types of generation, including the access of DG to ancillary services and balancing markets.
- Include innovatory approaches in network management to facilitate a larger share of DG and RES into electricity networks.

DG policy

For achieving an increasing integration and high share of DG in the long-term, creating a level playing field with a correct framework of incentives is highly important. However, this situation is also strongly influenced by both support mechanisms for DG as well as the network regulatory framework. If applied properly, DG support mechanisms and the network regulatory framework can complement each other in creating a correct allocation of benefits and costs of DG and thereby stimulate the convergence towards an optimal and efficient integration of DG/RES in energy supply.

Support schemes such as feed-in tariffs can facilitate specific DG sources to penetrate into the energy market and in this way overcome a number of barriers, such as the upfront investment, access to the energy market and the connection to the network. When reaching a certain level or market share, however, these support schemes should be adapted to prevent distortion of the energy markets and the creation of inefficiencies and higher electricity supply prices. Therefore, market-based instruments should replace the feed-in tariff system and other instruments that are mainly designed to create and protect DG niche markets or DG markets still at infancy level.

The other important factor is the *network regulatory framework*, containing the following elements:

- *The system of network connection charges* paid by DG operators for connection to the network. To optimise the connection charging system, it should be designed in such a way that costs and benefits of the DG connection can be optimally allocated to the right market actor and its services. For that purpose, network connection charges could include a locational signal to more optimally allocate costs & benefits of new grid connections.
- *Use of System (UoS) charges*, present an important source of revenue for DSOs. The way they are composed and by whom they are set will influence the integration of DG. UoS charges are usually composed by an electricity (kWh) and capacity (kW) component and are paid by consumers and/or producers. Of similar importance is that the UoS charges are set by an independent party that has no bias against further development of DG.
- *Allocation of ancillary services and other system benefits*. In some countries, power generators (including DG) can receive compensation for certain system and network services. This leads to a more equal position of DG in the electricity market, a fairer allocation of network costs and benefits and in a number of cases an additional revenue stream for DG operators.

Benchmark results

The ENIRDGnet benchmark study provided for a EU-wide assessment of policy and regulatory frameworks and forms the basis for the recommendations in this report. The approach in this benchmarking exercise builds upon the methodology adopted in the SUSTELNET project (5th Framework Programme), providing for a first systematic comparison of distribution network regulation.

The benchmark study has led to the following findings regarding the use of support schemes:

- In general, countries with currently low-DG levels have mostly introduced fixed feed-in tariffs as a first step to promote the integration of DG. In some other countries these fixed feed-in tariffs are gradually being replaced by market-based mechanisms like price premiums or tradable green certificates. Main reasons for this replacement are that RES & DG have become nearly mature power sources and have increased their share in power production. There are a number of examples where support mechanisms have been transformed, such as Spain or Belgium.
- The effectiveness of feed-in tariffs can be illustrated by current DG penetration levels in Denmark, Germany and Spain. All these countries have reached a relatively high level of DG penetration, in particular regarding wind power. But these high levels of intermittent wind power sources, have also posed a challenge to appropriate network management.

The analysis of the network regulatory framework led to the following findings:

- Both shallow and deep connection charging is commonly used even as 'combined systems' where additional grid reinforcements are shared between DG operators and DSOs. In some countries, such as Austria and Finland, the DSO has the possibility to choose between shallow and deep charging, based on the available capacity of the grid. This makes it possible to allocate grid costs to the proper party (the DG operator wishing to connect). It requires, however, supervision from a regulator to ensure that deep connection charges are merely being applied for covering costs related to that particular connection.
- Consumers generally pay UoS charges, although in some countries producers also pay a share of it. DG operators are generally exempted from paying UoS charges for the transmission network or exempted from paying UoS charges at all.
- In countries with shallow connection charges there are little incentives for DSOs to connect DG into the network. The most straightforward incentive is an obligation, as applied in Denmark and Germany, but this may not lead to efficient network investments. A performance based regulation system as recently introduced in the Netherlands may be an incentive for more efficient network investments and the integration of DG.

- With a system of deep connection charges, such as in the UK, DSOs should not have a problem with connecting DG. However, when DSOs are only benchmarked on the basis of cost efficiency, meaning that UoS is charged on the basis of kWh transported, the integration of DG brings no additional benefits to the DSOs.

Policy recommendations:
Based on the benchmarking exercise a number of recommendations have been made for policy makers to consider when integrating DG into electricity networks:

- To reach a level playing field between DG/RES and centralised power generation, existing support schemes will have to be gradually modified when the DG share in electricity supply is growing. This will ensure a cost-effective approach in network management in the medium and long-term.
- With regards to the regulatory framework, a general pre-condition is non-discriminatory network access for DG. This includes access to the wholesale electricity market in the short-term and access to newly developed markets for ancillary services (balancing, securing power quality, etc.) in the longer-term.
- The benefits and cost of distributed generation to the electricity system are directly related to the geographical point of connection. It is therefore considered fair that these costs and benefits are somehow reflected in the UoS charges and electricity pricing to the distributed generator.
- When DG/RES levels increase it will become important that DSOs develop active network management aimed at integrating DG to the network. This active network management entails investment in innovations to improve network management, in particular in the field of ICT applications. This requires in particular a change in the regulatory framework related to DSOs, meaning that not only cost-efficient management of networks should be rewarded, but also their willingness to invest in innovations.
- In view of the required innovations in network management, both EU and national policies should also seek to stimulate the exchange of knowledge in the field of DSO incentivisation and innovation in distribution networks EU-wide.

1. INTRODUCTION

The general aim of Work Package 7 of ENIRDG-net is to define recommendations for improving regulatory frameworks and other institutional policies for the promotion of distributed generation and renewable energy technologies and their share in distribution networks in the EU Member States. This report will provide a clear overview and analysis of the current situation and expected near-term developments of institutional policy and regulatory framework in the light of enhancing the distributed generation (DG) share in liberalised EU electricity markets. This report analyses the current network regulatory framework in a number of Member States through a benchmark study and forms the basis for further recommendations in the field of DG regulation and policy.

Benchmarking is an exercise that systematically compares certain processes or institutions against a predefined standard. Such a standard usually presents a certain policy goal or another predefined level of excellence. The benchmark study of ENIRDG-net is using the methodology and some of the results of the SUSTELNET project, another project within the DG cluster of 5th Framework Projects, finished in June 2004. Within the SUSTELNET project, national energy policy and regulation towards DG is benchmarked with the objective to provide recommendations to better adapt countries' policies to foster the use of DG across Europe in the mid-term horizon of 2020.

The starting point of SUSTELNET was the belief that a level playing field in the regulation of the electricity system is a *sine qua non* condition to achieve an effective and economic efficient participation of DG in a liberalised market. The regulatory framework should entail markets and regulation that provide neutral incentives for central versus distributed generation and support mechanisms that are viewed as temporary forces to tilt the balance in favour of DG.

The aim of the benchmarking exercise was to identify examples of well-defined pro-DG policies, with clear targets and adequate implementation mechanisms. The benchmarking does not seek to assess the impact of these policies on the economic efficiency of the electricity market; rather it was intended to disseminate knowledge about how and why particular policies are appropriate for particular needs. This should help national and EU policy makers to improve the design of their respective policies and to follow positive, tested examples wherever possible and relevant.

The *level playing field* is defined as a situation where distributed and centralised generation of electricity receive equal incentives and have equal access (market conditions) to the liberalised markets for electricity. The position of DG in many countries is not equal to that of centralised generation. This can mean on one hand that DG&RES is heavily subsidised/protected or on the other hand that DG has no or limited opportunities to enter the electricity market due to more preferable conditions for centralised generation. Both situations are far from the needed conditions for a level playing field and are not favourable for the development of a sustainable electricity system in the future. The DG Benchmark study within the SUSTELNET project aimed to examine the network regulatory framework for DG in nine European countries[1] with the purpose to analyse whether the currently existing regulation enables the creation of a level playing field for DG (Boccard, 2004). Within Work Package 7 of the ENIRDG-net project this benchmarking is extended to a number of *other European countries* that participate in DG-net WP7[2], but not in SUSTELNET.

[1] The Netherlands, United Kingdom, Germany, Italy, Denmark, Czech Republic, Poland, Slovakia and Hungary.
[2] Austria, Belgium, Finland, France, Ireland, Spain and Sweden.

This report is structured as follows. Chapter 2 will start with a description of the theoretical framework and the principles that form the background of the benchmarking research. This review should make the reader more familiar with the principles of the level playing field and network regulation studied and developed in SUSTELNET. Benchmarking is executed against a certain reference level or level of excellence, defined in this study as the level playing field between centralised and distributed power generation. After this theoretical background Chapter 3 will continue with explaining the methodology of the benchmarking used in this study and give a detailed description of the questionnaire that has been used. Chapter 4 will give the detailed outcomes of the results per country. In this research the countries studied are Austria, Belgium, Finland, France, Ireland, Spain and Sweden. Chapter 5 will present a country comparison and will also compare these results with the outcomes from the SUSTELNET benchmarking exercise. Chapter 6 will present a number of policy and R&D recommendations based on the benchmarking exercise.

2. THEORETICAL BACKGROUND

Benchmarking is generally understood as a systematic comparison of certain processes or institutions against one of a generally recognised excellence. When benchmarking DG policy, one faces the problem that a ‘perfect pro-DG policy’ does not exist. In discussions with DG experts it was not easy to agree on what a ‘perfect pro-DG policy’ actually is and if this should be the ultimate goal at all. Also we are faced with the lack of a generally accepted benchmarking methodology. These were the two major challenges of this study.

2.1 Defining the reference level - the level playing field

Within this study it was agreed to restrict the ‘level playing field for DG’ to regulatory issues. So it should entail markets and regulation that provide neutral incentives for central vs. distributed generation. However, this requires the recognition and inclusion of all the values (costs and benefits) of DG contribution, and the set-up of an appropriate mechanism to put a monetary value to these contributions. Furthermore, incentives should be provided to the network operators and DG generators to exploit these values in the best possible way.

Therefore, this level of excellence of DG contribution had to be defined with a set of criteria. For the purpose of the SUSTELNET project the basic ideas for an ‘adequate’ regulatory framework for Distribution System Operators (DSOs)[3] have been developed. Next focus point was then how to define what, from the project team’s point of view, ‘adequate’ means with respect to a level playing field. Between large scale power generation on the one hand and distributed generation (DG) on the other, and how this could be operationalised.

Three major issues for developing an optimal pro-DG policy have been identified by Leprich & Bauknecht (2004):
1. Values (costs and benefits) of DG for the distribution network.
2. The position of the DSO: i.e. current incentives and future tasks for network development and integration of DG.
3. The definition of a charging and tariff system for the distribution network.

Within this study, more attention is also given to the role of support schemes in the promotion of DG. As the regulatory framework in many countries shows a bias in favour of centralised generation, *tilting* the balance in the short-term in favour of DG may be justified. A role in tilting this level playing field will have to be played by specific support schemes.

Support schemes for the promotion of electricity generation by renewable energy sources and combined heat and power production are mainly introduced for the following reasons:
- Fostering the dissemination of new DG technologies,
- Internalisation of environmental externalities,
- Overcoming specific market failures.

[3] For the operator of the distribution network (150 kV and lower) both the terms Distribution Network Operator (DSO) and Distribution System Operator (DSO) are used. Directive 2003/54/EC concerning common rules for the internal market in electricity defines the DSO as operator of the distribution network. The term DSO will also be used in this report.

A '*perfect' DG integration policy* should in the long-term reach a level playing field, meaning the creation of neutral incentives for both centralised and decentralised generation. This should lead to the elimination of most market failures. The role of support mechanisms should therefore be limited to temporary support for new technologies not yet able to compete with other generation sources and to the internalisation of environmental benefits (e.g. CO_2 free electricity generation) (Leprich & Bauknecht, 2004).

2.1.1 Actors involved

The main actors involved in this interaction are the DG operators and their interface, the DSOs. From the point of view of a generator, stepping into the DG market is a long-term *investment* decision while producing, selling and amplifying its scale is a short-term *management* activity. Therefore, the factors that affect the fixed cost and those that affect the variable cost of production, the latter being the main drivers of the operator's behaviour, should be treated differently.

Each country, given its particular objectives and above all the current market presence of DG, may be more interested in one aspect than the other, i.e. long-term versus short-term. According to the present situation, aspects of the DG-regulation should be valued differently. The tasks and responsibilities for DSOs are different from that of DG operators for the obvious reason that they are already in place and have a different function. The DSOs task today is to transport electricity, a passive 'wire business' that can be transformed into a 'pro-active' management activity.

2.1.2 Benefits and costs for DG

Distributed generation technologies bring a number of costs and benefits or values to the electricity distribution system. When creating a level playing field, these costs and benefits must be valued in economic terms. This is a quite complicated task because these system effects are often difficult to pin down and they consist of short-term and long-term effects.

The *benefits of DG* can generally be separated in two broad categories, network related benefits (infrastructure) and energy related benefits (commodity). Within each category (and subcategory) there can be a range of different benefits to the DSOs, the Transmission System Operators (TSOs), the customers and the society as a whole. Each benefit tends to be highly technology-, site- and time-specific; they do not necessarily apply equally to every individual DG case and some DG plants may create no benefits at all.

For both benefit categories it is crucial to differentiate between short-term and long-term benefits. In the short-term some of the mentioned benefits may actually be *additional costs to the system*. There may be a need for additional grid capacity because of DG entering the market. Or there may also be a need for additional balancing power because of the intermittent character of wind plants or PV. And if the reliability of the system is already very high the scope for DG to improve this situation is very limited. But in the long run a more decentralised system has the potential to provide an electricity supply system that is more economically efficient than the centralised system. Therefore the long-run benefits must already be considered today in some way because the lifetime of investment decisions has a horizon of 20 years and more.

The *costs of DG* can also be separated into the same categories, network and energy related costs. Most of the costs are short-term costs that cannot be offset directly against the long-term benefits of DG because of the time lag. In addition to this the bearer of the costs is not necessarily the receiver of the benefits. So one has to think about an adequate allocation of these costs with respect to a long-run optimisation of the system.

This leads to the view that the leading regulatory principle with respect to DG integration is the creation of an economic level playing field, meaning that costs and benefits for both centralised and distributed generation are treated equally. Another key finding from discussions with key stakeholders in different countries was that the level playing field idea cannot be implemented without a clear idea about the future role of the DSO in liberalised electricity markets.

2.1.3 The position of the DSO

Currently, DSOs are predominantly passive organisations in a sense that they try to avoid measures that go beyond their original wire business. If DSOs stick to this role in the future, they will consider DG to be troublesome, causing additional costs that they might not be able to recover completely through the network charges. All costs connected with DG are then considered to be additional costs to the DSOs compared to the situation where they still get centralised generated electricity.

For DG to be successfully accommodated in the electricity system on level playing field terms, electricity distribution networks must be transformed into ‘active networks’. This concept is based on the theory that active networks have a more flexible business model than traditional DSOs, and they run their operations in a more innovative and business-like way than traditional DSOs (van Overbeeke & Roberts, 2002). The flexibility in the business model of active networks can be used to:

- Create new innovative ways of providing service - considering all available alternatives when the existing network is not adequate, including demand side management, integrating DG and securing its optimal location and a flexible network structure (economic optimisation regardless of the resulting network structure).
- Take on new responsibilities for system services, meaning that the DSO takes over some system services that are currently the responsibility of the TSO. The idea is to create local control areas in the distribution system that have expanded responsibilities and control of its concession area and thus contracting DG.

Before reaching such a state of play where DSO’s will accept a more active role, general rules should be developed with respect to the allocation of costs and benefits of DG. With respect to DG one could emphasise the following objectives leading to the allocation of costs and benefits:

- Identification of DG costs and benefits,
- Proper allocation of DG costs and benefits if it is not too complex to quantify them,
- Neutralisation of any bias in favour of centralised power generation,
- Optimisation of the network with regard to local/regional potential of DG.

Every regulatory regime has to ensure that the DSOs can cover their incurred costs, earn a fair rate of return on equity and attract sufficient capital for future investments. Another way of allocation of costs and benefits can take place through markets, meaning that DG can participate in wholesale markets (e.g. through a power exchange) and/or a multi-settlement market with day-ahead, balance and ancillary services markets.

2.1.4 Connection charges and Use-of-System charges

The DSOs are considered as key actors in the process of fair market access of DG. This requires a close look at the incentives for DSOs which are usually closely connected with their revenue streams. To create an economic level playing field, the incentives against DG integration in the existing regulatory framework will have to be identified and neutralised. The key issues with respect to the incentive structure of the DSOs are (Leprich & Bauknecht, 2004):

- The method of charging the connection costs,
- The method of calculating the Use of System (UoS) charges.

It is generally agreed that *shallow connection charges* (only connection is charged, no additional grid enforcements) do not create a level playing field from a strict economic point of view. When full costs of connecting DG is not charged to the DG investor, economically inefficient investments in DG may be made. In addition, shallow connection charges do not give DG operators the right signal as where to locate a new plant, and it might discourage DSOs from connecting DG. With *deep connection charges* every new entrant is treated individually and will face actual marginal cost of connection. In theory this will give correct signals for investment. However, there are some severe problems with this theory:

- Economies of scale and first mover disadvantage[4].
- Grid reinforcement in meshed grids may benefit customer other than DG.
- Difficult or even impossible to determine deep connection charges correctly.

Therefore, within the SUSTELNET project, a guideline has been formulated that combines the elements of shallow and deep connection charging. In the first place shallow connection charges should be chosen including individual entry charges that give correct locational signals to DG operators. Then the revenue balance of the entry charges has to be considered when calculating the UoS charges. The difference between shallow and deep connection charges should be a part of the UoS charges.

UoS charges represent the main revenue stream to DSOs, and their incentives are strongly related to the way they are calculated. The proper setting of use-of-system charges can help in creating the level playing field (Leprich & Bauknecht, 2004):

1. Ensure the recovery of all (planned and unplanned) costs associated with the connection of (economic efficient) DG plants that are not paid for by the DG plant operators.
2. Neutralise the sales maximisation incentive through the application of a UoS charge adjustment formula that has different revenue drivers (multiple driver regulation).
3. Include the grid reinforcement costs induced by DG plants and possibly the connection costs in the regulatory asset base (RAB) of the DSO.

Or in other words, introduce a dependency between the allowed rate of return and both the performance standards with regard to customer satisfaction, system reliability and DG connections, and the long-run network optimisation including local/regional DG plants and line losses.

As already pointed out, 'incentive regulation' systems aim at encouraging cost minimisation of DSOs, which intrinsically goes against promotion of innovation. Two different issues should be discussed:

- The stability of the system; if regulation provides enough incentives to invest in the grid in order to satisfy peak demand and ensure the reliability of the system.
- Innovation; if regulation provides enough incentives for DSOs to innovate.

When innovating, DSOs are exposed to higher risks than when focusing on its core business. As a result, a different treatment would be appropriate where a DSO is pursuing new technologies and connection solutions.

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[4] This is also called the 'first comer problem', meaning that the first DG operator connecting to the network is paying for necessary enforcements that benefit 2nd, 3rd … etc. entrants).

2.2 Network regulatory issues

In the SUSTELNET project the network regulatory issues for optimal DG integration have been divided in those specifically related to *regulation of the network* and those related to *market access* for DG. This is presented in Table 2.1.

Table 2.1 *Regulatory roadmaps scheme*

Market Access of DG		Presence	Low	Medium	High
		Participation	Protected niche	Wholesale market	Level playing field
Network regulation	I	No regulation/self-regulation	I-L	I-M	I-H
	II	Cost driven incentive regulation	II-L	II-M	II-H
	III	Output driven incentive regulation	III-L	III-M	III-H
	IV	Innovative in test		IV-M	IV-H
	V	Innovative active network	No innovative networks required		V-H

The market access of DG distinguishes three different stages, i.e. low, medium and high market presence (Sambeek, et al, 2003):

- *Protected niche market (low)* - With low to moderate penetration levels of DG, support mechanisms such as priority dispatch or obligatory purchase regimes are justified. If this is the case, DG does not have to deal with the access to energy and ancillary services markets. In other words, DG works outside the market. All external energy costs and benefits are born by other actors in the electricity market. With low penetration levels, priority access and obligatory purchase schemes, such as feed-in tariffs may be the most efficient way to incorporate DG in the electricity infrastructure. However, as the penetration of DG rises, the efficiency of such schemes is likely to diminish and participation of DG in energy and ancillary services markets may be warranted. In some countries wholesale energy and ancillary services markets have not yet developed to the extent that facilitates DG integration. In these cases creating a protected niche market for DG may be justified.
- *Participation in wholesale market (medium)* - In this stage DG is supported through market conform pricing mechanisms such as green certificates or premium tariffs based on the environmental attributes of the power. DG has to sell its energy on the wholesale market, just like any other generator. It also has to purchase ancillary services from the TSO, DSO or from the ancillary services market. This means that DG can only enter on the demand side of the ancillary services market and cannot yet participate in the supply side. For example, in the Netherlands DG operators can sell their electricity on the wholesale electricity market. They have to purchase most ancillary services from the TSO. However, DG is not allowed to offer balancing capacity in the balancing market and it cannot be compensated for providing ancillary services to the grid operator.
- *Level playing field (high)* - In systems with a high level of DG/RES supply, dispatch problems can occur, for example if large amounts of wind power are supplied to the market. DG/RES supply should respond to changes in the power demand, i.e. DG/RES supply start playing a role in balancing the electricity system. In this stage of development of energy and ancillary services markets DG can also participate in the supply side of markets. For example, DG is allowed to bid its supply into the balancing market, or a DG can have contract with a DSO to provide voltage support and reactive power. A supply contract for ancillary services with a DSO requires that the DSO has a free choice in deciding where to source its ancillary services. This also has to be taken into account in network regulation.

An increasing level of DG in the electricity system requires more equal participation of DG in electricity markets. Therefore network regulation has to be adapted accordingly. Table 2.1 distinguishes five stages of network regulation (Sambeek, et al, 2003):

- *Self-regulation* - This system relies on negotiation (nTPA) to determine contracts and tariffs and it is generally developed with the absence of a central regulator. It is argued that the system is significantly inefficient, as grid companies tend to charge higher than cost reflective charges, because no strict regulation is enforced.
- *Cost-based incentive regulation* - Aims at reducing the problem of asymmetric information between the regulator and the DSOs, while providing incentives for efficiency improvements. The system can be implemented through either a price or revenue cap. The latter system favours the development of DG by discouraging DSOs to maximise flows in the grid - as a price-cap does. It is important to note that this type of regulation while encouraging DSOs to reduce costs does not provide, by itself, enough incentives to improve or even maintain the technical performance of the network.
- *Multiple drivers incentive regulation* - Under this regulation framework, short-term benefits and costs of DG are allocated through the regulatory framework. The main difference between a simple cost based incentive regulation and a multiple driver incentive regulation is the benchmarking of separate DSOs. In other words, incentive regulation does not only focus on costs, but also on other issues such as quality, number of connections or network losses, which are also benchmarked between DSOs. This regulatory framework provides incentives to maintain or improve technical performance of distribution networks.
- *Innovative regulation* - The innovative regulatory framework emphasises on the provision of innovation incentives to DSOs. Although some short and long term benefits and costs of DG are allocated, some of them are not as, for example, network losses still cannot be individually measured. Connection charging in this regulation stage remains shallow, but the compensation to treat unequal division of connection costs between DG and centralised generation is replaced by the introduction of entry and exit charges[5].
    - *Entry charges* are a single or annual payment for generation connected to the distribution grid which can be positive, zero or negative. This depends on the pursued incentives.
    - *Exit charges* should encompass all other costs related to the distribution of generated electricity. These include: the payment for the difference between deep and shallow connection, the payment for electricity transport (in kWh) across the network, the payment for operation and maintenance of the network and the payment to ensure capacity to meet peak demand. Moreover, different demand customer sets could pay for different elements of the costs. For example, all demand customers might pay an average charge for the difference between shallow and deep connection while demand customers in a DSO region might pay for O&M (operation and maintenance) of their region.
- *Active networks* - Active network regulation is the final stage of the series of subsequent regulatory frameworks that evolve overtime towards the final goals of incorporating DG as an integral part of the regulatory framework. Consequently, all costs and benefits of DG are, when possible, effectively allocated. As an example, network losses can be measured individually under active networks. In active networks, DSOs become entrepreneurs; business oriented firms that should gain from connections and be incentivised to keep costs down, meet performance outputs and do things differently or in an innovative way.

[5] The information on entry and exit charges is based from the response to Ofgem's Update on Structure of Electricity Charges, written by Dr. Catherine Mitchell, Warwick Business School, October 2002. This report can be downloaded from: http://users.wbs.warwick.ac.uk/cmur/publications/other_publications.htm.

2.3 Additional aspects of the level playing field

The establishment of a level playing field includes a number of additional aspects to the regulatory framework that also need to be taken into account. The following aspects are of importance:

- Establishment of transparency with respect to grid data, load data, plant data etc. for all parties in the distribution network environment, including DG operators. Lack of transparency in data means an extra barrier for a DG operator that normally is not as well informed on a number of network related issues as large power producers, DSOs etc.
- The stability of the regulatory environment. DG operators, but also other parties such as DSOs, need to have certainty regarding the regulatory environment in which they operate. This includes network regulation, but also regulation and procedures for authorisation of new power plants etc. Regulatory stability for a fixed number of years (through regulatory periods) is required.
- A clear understanding of the active network issue and the role and responsibilities the DSO should have in such an active network. A clear understanding ensures that this new role of the DSO can be ensured through incentives and possible licensing.

The current playing field in the electricity market is mainly biased in favour of centralised generation. Due to the predominantly centralised infrastructure and the stronger market position of centralised power producers, one cannot speak of the existence of a level playing field. The centralised players are ahead of the DG producers and to ‘counter’ this situation a (short-term) bias towards DG may contribute to the creation of a level playing field in the long-term.

3. BENCHMARKING METHODOLOGY

The approach in this benchmarking exercise builds upon the methodology adopted in SUSTELNET but now applied for the 'non-Sustelnet' countries *Austria, Belgium, France, Finland, Ireland, Spain and Sweden*. Together with the results of the SUSTELNET countries, we get an almost complete EU-picture. The benchmark methodology applied in SUSTELNET provided for a first systematic comparison of distribution network regulation and it is viewed to be the most effective way to build upon these experiences and to further optimise the benchmark methodology. This chapter will describe the benchmarking methodology and the questionnaire in detail.

The DG-net project will take the benchmarking exercise a bit further by comparing support mechanisms for DG in the different countries and assessing their impact on network functionality. A critical step for the benchmarking exercise will be to translate the findings into concrete regulatory and policy recommendations, which is the major task of WP7 in the ENIRDG-net project. Making use of a benchmarking exercise provides the opportunity to lay down a broader vision on needed regulatory framework changes for integrating DG more effectively in the electricity network in the medium and long term.

The proposed evaluation method is based on three 'normative valuation grids', one for each different stage of market presence of DG, namely: low, intermediate and high share of DG (in %). These three levels of DG share are distinguished from each other by the impact of network regulation on the creation of a level playing field, which may differ with the current or increased shares of DG. For example the DG generation capacity in Germany increases rapidly, but the regulatory framework for DG lags behind this development. The thresholds then determine in which category each country falls and therefore which countries are comparable with each other. For each class (low, medium and high) and qualitative or quantitative question the possible answers are evaluated as being *repulsive* (-1), *neutral* (0) or *supportive* (+1) to DG in the light of the defined level playing field objective (Boccard, 2004).

Country policies are not benchmarked against each other but against best practices (as identified and defined earlier in the SUSTELNET project). Whenever two countries belong to the same group it nevertheless makes sense to compare their overall results for groups of questions. Note that the overall scores (summing the valuation for all items) are frequently negative since the benchmark corresponds to the ideal situation where a level playing field is in place.[6] Assessing whether 'bad' regulation is really hurting DG penetration should be supported by a cost-benefit analysis. Lastly, some characteristics as such are not good or bad for DG, they are *country* specific and are used in conjunction with other criteria.

3.1 Benchmark topics

Within the benchmark study the following issues have been studied with the use of a questionnaire (Boccard, 2004):

1. Network regulation:
    - A - Legal framework for DG operation and generation, regulation is in place for DG in relation to authorisation procedures and access to markets.
    - B - Financial relationship between DG operators and DSOs, what is the position of DG operators in relation to the DSO regarding connection charges and charges for using the distribution network etc.

[6] Because the weighting of topics is very subjective, weighted summing has not (yet) been performed.

- C - Legal framework for DSOs, what is the status of unbundling and what incentive mechanisms are in place.

2. Market access:
   - D - Market penetration, what is the share of DG in electricity production/consumption.
   - E - Market participation, how does DG participate in the electricity market.

Although the *benchmarking study* identifies the main potentials for regulatory improvement in each of the EU Member States (MS), an additional analysis of the RES&DG support schemes is carried out to see whether present schemes conflict with short and medium term goals of a level playing field for DG. Such a review will also help to explain the relatively high DG share in some countries although the regulatory framework (according to the benchmark study) is in fact still 'hostile' to this development.

3.2 The benchmarking questionnaire

The DG-net questionnaire, presented below, was send to VTT, OME, Verbund, ESBI and Labein, the partners in WP7 of the ENIRDG-net project. Information was gathered on the network regulatory framework for DG in the electricity market and related issues, their impact on distributed generation and the steps necessary to take to create a level playing field for DG in the medium term. The answers in the questionnaire will be analysed in order to obtain recommendations for policies and improving the regulatory framework.

The first part of the benchmarking questionnaire deals with *market access* within two topics, namely: a) the current market presence of DG and b) the conditions for future market participation in a fully liberalised electricity market. The second part tackles *network regulation* and is subdivided in three topics: (1) the legal framework for DG, the (2) DG-DSO financial relationship and (3) the legal framework of DSOs. The benchmarking judges whether the actual and projected conditions (in the timeframe of 2010/2012) are likely to implement the jump from the initial regulatory situation (likely to be of type I or II, see Table 2.1) to the aimed final one (V). For each category a table groups the questions that were answered by the partners. In these tables the best practice is indicated and assigned 1 point, any practice deemed to have the opposite effect is assigned - 1 point and whenever the practice is considered neutral it scores 0. Because most countries involved in the project were not able to achieve the aimed desired situation of 'active networks' in the medium term implicitly considered, best practice is rarely observed which in turn triggers negative scores.

Regarding market access it is important to distinguish between the presence of DG that results from politically backed support mechanisms or from the full and transparent participation of DG. Therefore a distinction is made between the current market *presence* of DG and the conditions for future market *participation* in a fully liberalised electricity market. The former is used to classify countries while the latter is used to judge their actual or intended efforts to facilitate participation of DG in electricity markets.

3.2.1 Market presence

The distinction between the degree of penetration of DG among countries (low, medium, high) is necessary to avoid comparing completely different situations given that EU MS differ in their level of DG development. The definition of DG as agreed in the SUSTELNET project is reported in Table 3.1.

Table 3.1 *Definition of DG and relation to CHP and RES*

Typology	Combined Heat and Power (CHP)	Renewable Energy Sources (RES)
Distributed Generation	Medium district heating Medium industrial CHP Commercial CHP Micro CHP	Medium and small hydro On-shore wind, tidal energy Biomass and waste, incineration, gasification Solar energy (Photo Voltaic)
Centralised generation	Large district heating Large industrial CHP (both >50 MW)	Large hydro (>10 MW) Off-shore wind Co-firing biomass in coal power plants Geothermal energy

The questions selected to assess market presence are gathered in Table 3.2.

Table 3.2 *Information relative to market presence of DG*

#	Question
34	Latest share of CHP+RES in national electricity consumption (%).
35	If available, share of large scale facilities in previous figure.
36	Expected DG share 5 years later based on actual trend.
37	RES objective for 2010-12 (EU commitment) for electricity.
38	Share of intermittent electricity in production.
39	Within 5 years, previous figure is expected to increase or decrease? Intermittent electricity incidence (out of #38) (lesser better).

3.2.2 Market participation

This research distinguishes three levels of market participation in the full range of production of the electricity commodity: as a protected commodity (*low*), as a participant in the wholesale market (*medium*) and as a participant in the balancing and reserve markets (*high*) (Table 2.1).

When introduced, DG is very often supported by specific support schemes; the participation of DG operators in the wholesale market for energy is either subsidised or protected (mandatory rule). Among the possible support schemes there are priority rules in the form of quota systems, feed-in tariffs, green tax exemptions, income tax reductions for investments, and VAT reductions on sales. Apart from such support schemes access to markets for wholesale electricity and ancillary services is of importance for the position of DG. Respondents were asked to describe the features with regard to the DG position. The questions selected to assess market participation are presented in Table 3.3.

Table 3.3 *Information relative to market participation of DG*

#	Question	Low	Med	High
40	Describe support mechanism for DG (merged with #42 on RES-CHP differences, #21 and #24)[1].			
41	Duration foreseen by law (value for short duration).	-1	0	+1
43	Support in % of average market price (don't tilt too much).	+1	0	-1
44	Wholesale market for energy/electricity?	+1	+1	+1
45	DG has access to wholesale market? Practically?	0	+1	+1
46	DG has access to ancillary market? (merged with #6)[2]	0	0	+1
47	Market form is (related to DG support mechanism).			
48	Concentration in the energy market is? (lesser better).	0	+1	+1

1 #21: Describe support mechanism (regulated price, market price + margin, …), #24: Are there other support mechanisms for DG? (duration in years if applicable).

2 #6: Is there a balancing market? Is it (really) open to DG?

3.2.3 Legal framework for DG operation

Two topics are identified where the legal framework applied to DG matters for the level playing field. First there are the transaction costs with regard to entering the DG market, fastening of the authorization procedures for DG installations and the transparency of these procedures. Secondly there is the provision of ancillary services: non-discrimination of RES for ancillary services fees, participation of DG in the balancing market, and market-based methods to procure reserves and energy losses. In a first stage of market integration the issue is to provide ancillary services to DG operators on a economically justifiable level while later on, when active networks will be implemented, DG operators might also become providers of ancillary services. To reach the level playing field for DG, ICT based metering can be a catalyst. The questions selected to assess the legal framework of DG are presented in Table 3.4.

Table 3.4 *Information relative to the legal framework for DG*

#	Question	Low	Med	High
1	Has the relevant law been revised to fasten the authorization procedures for small generating units and connecting them to the distribution network?	Yes = 1	+1	0
2	Same Question for CHP (in case there's a difference).			
3	Does the law foresee publication of DSO technical and (connection) cost-sharing rules?	Yes = 1	+1	0
4	Does the law mention the non-discriminating of RES and/or CHP with respect to the provision of ancillary services?	Yes = 0	+1	+1
5	Who provides ancillary services? (DSO, TSO) related to market participation.	TSO = 1	Idem	
7	Is there any project for two-way metering installation?	Yes = 1	+1	+1

3.2.4 DG - DSO financial relationship

The financial relationships between DG operators and their DSO are important from two perspectives, one long term and one short term: the initial connection charge and the charges for using the distribution network. The connection topic deals with regulated TPA, the first-comer problem, and the debate about shallow versus deep connection charges. The Use of System charges topic deals with non-discrimination of DG and RES, network benefits, and location signals (entry and exit charges). The questions selected to assess the financial relationships between DSOs and DG operators are presented in Table 3.5.

Table 3.5 *Information relative to the DG-DSO financial relationship*

#	Question	Low	Med	High
8	How long has Regulated TPA been in force?	Sooner better	Idem	Idem
9	Does the law address the first-comer problem for RES?	Yes = +1	+1	0
10	Same for CHP (in case there's a difference).			
11	Connection charge is? (deep or shallow?).	Shallow = 1	0	Deep = 1
12	If #11 = shallow, is the DSO compensated for the difference (deep - shallow)?	+1	+1	+1
13	Structure of UoS charges: capacity and/or energy component?	Many drivers = 1	+1	+1
14	UoS is initially set by a national authority (e.g., Regulator) or negotiated by association of DSOs and DG operators?	Regulator = 1	1	-1
15	Is there some leeway for DSO in the application of the UoS?	Yes = -1	-1	-1
16	Who pays UoS charges? (ability to discriminate sources and sinks).	0	Idem	User = -1
17	Is there a compensations scheme for DG network benefits like loss reduction?	Yes = +1	+2	+1
18	Existence of geographical location signal in connection cost or UoS?	Yes = +1	+1	+1

3.2.5 Legal framework for DSO operation

The legal framework of DSOs contains unbundling and incentive mechanisms. Unbundling deals with the required (weak) legal unbundling for all actors, the degree of DG ownership by DSOs, and information transparency. The incentive mechanisms issue deals with the recommendation to relate parts of the Regulatory Asset Base (RAB) to performance standards such as Quality of Service (QoS) indices.

A legal framework that does not include any specific quality parameters may give rise to a maximisation of sales which goes against DG auto production. Other DSO regulatory mechanisms may include multiple drivers regulation of DSOs' revenue streams, the design of a reference model of the distribution system in order to compute the fair share of revenues allowed to each DSO given its geographical features. The questions selected to assess the legal framework of DSOs are presented in Table 3.6.

Table 3.6 *Information relative to the legal framework of DSOs*

#	Question	Low	Med	High
25	Level of DSO-Supply unbundling (accounting, management, legal, ownership).	0	Idem	Higher better
26	Level of DSO-Generation unbundling (acc, mgt, legal, own).	Higher better	Idem	0
27	Are there any performance standards in the DSO revenue (e.g., link to the regulatory asset base)?	Yes = 1	+1	+1
28	Benchmarking of DSOs (whether actual or projected) builds on CAPEX and/or OPEX?	Input = -1	Idem	Idem
30	How much DG is owned by DSOs?	-1	0	+1
31	Is there a national scheme providing optimisation incentive to DSOs ?	Yes = 0	Idem	Yes = 1

4. BENCHMARKING RESULTS ENIRDG-NET

This chapter describes some of the key outcomes of the ENIRDG-net benchmarking exercise carried out in *seven* countries[7]. The complete, detailed answers from the questionnaires are presented in Annex A. This chapter will discuss the results of the questionnaire regarding two topics. The first part will view DG market access, looking at the share of DG in a given country and the way DG is supported into gaining increased market access. The second part will look at the regulation, including network regulation for DG, the DG/DSO financial relationship and the legal framework of DSOs.

4.1 DG market access

4.1.1 Austria

Market share

Electricity consumption in Austria is for a large part covered by renewable energy sources, mainly from large hydropower stations. Basic data about DG and RES market shares are the following:

- The total share of renewable energy sources in electricity consumption is approximately 70%. Only a relatively small part of this RES potential consists of small hydropower stations (9%) and other RES sources (wind, biomass, PV) (1%), meaning that RES-DG includes about 10% of national electricity consumption.
- The remaining 30% of thermal electricity production includes a significant share of CHP, about 10% of electricity consumption. The total share of electricity consumption by DG is therefore around 20%, at the *medium* level.
- The indicative target for 2010 agreed in the framework of the RES-E Directive is 78,1%. As the share of large scale DG is not expected to grow substantially anymore, the increase will have to come from RES-DG.
- The share of RES-DG, other than small hydro, is expected to grow in the coming years. In the case of wind energy scenarios predict an increase from 0.5% to 3.5%.

Support mechanisms

Austria has a high share of RES in electricity consumption, but this is due to the high share of hydropower electricity. Further growth in the coming years, to meet the indicative RES target has to come from smaller sources, such as wind power, small hydro and biomass. For this purpose Austria has introduced support schemes in the form of feed-in tariffs to support these sources. The feed-in tariffs have a limited duration (13 years) and the level (above 100% of the current electricity market price) has to ensure certainty for investors so that the share of these sources will grow significantly. The level of the feed-in tariffs varies from 3 to 7.8 ct/kWh for the more common sources of RES (Wind, biomass, small hydro) to nearly 60 ct/kWh for PV. For comparison, the current electricity market price in Austria (2nd quarter 2004) is 3.027 ct/kWh. This shows that the support for the different RES per kWh fed into the grid is 100% or more of the market price.

[7] Austria, Belgium, Finland, France, Ireland, Spain and Sweden.

The current support scheme considers DG to be part of a 'niche market'. This is the case for wind energy and PV, as both sources only have a very small share of the market. For other sources, like small hydro this may not be the case. So far all RES sources are treated the same way. One has to raise the question if the level of the feed-in tariffs does not distort the market (and the level playing field) too much. Nevertheless, the tariffs stated above are only valid for installations put into operation before 30.6.2006, and may be quite different afterwards. The system may therefore be seen as a temporary tilting of the level playing field.

Market access

Since the full deregulation of the electricity market on 1 October 2001, the Austrian electricity market has been operating on the basis of a balance group model. Each participant in the market (electricity producers, traders and consumers) is obliged to join a balance group. By combining several market participants in balance groups, which are organised on market principles, it is possible to optimise the equalisation of fluctuations in generation and demand. The basis for this market model is the Austrian Electricity Industry Organisation Act (EIWOG 2000). The E-control GmbH as the regulatory authority has the task of strengthening competition in a functioning electricity market with reliable supply.

Every provider of electrical energy should feed as exactly as possible the amount of energy into the grid which corresponds to the consumption by its customers. In the case of large-scale customers, this is solved by requiring them to provide detailed information about their purchase needs in advance. Small customers are condensed into groups, to which standardised load profiles are allocated.

APG (the Austrian TSO) leads a separate eco-balance group (eco-BG), through which it purchases eco-electricity from eco-plant operators at legally-set tariff rates. The amounts of energy bought have to be predicted in advance and then sold by means of schedules to all electricity traders who supply end-users in the Austrian market. This has to be done according to a quota based on final consumption, and the price is set at 4.5 eurocent/kWh. The promotion of eco-electricity is financed firstly by a resale price above the market price and secondly by grid tariff supplements, which the grid operators collect from end-users and pass on to the eco-balance group leader.

4.1.2 Belgium

Market share

Electricity in Belgium is mainly produced from nuclear, gas and coal plants. Hydro plants produce most of the renewable electricity although the installed capacity of wind energy and biomass is increasing. The share of RES-E in electricity consumption in 2000 was 1.9%. Electricity production from cogeneration is around 6%. This leads to the conclusion that Belgium is a country with a *low* DG share. Market concentration in Belgium is high due to the existence of one large power producer (Electrabel).

Support mechanisms

The main policy instruments for stimulation of renewable energy at Federal level have been a feed-in system, a 13.5% tax abatement for investments in renewable energy technologies, and a 20% investment subsidy for schools and hospitals. From 1995 feed-in tariffs have been in place. PV, wind and small-hydro projects (<10 MW) implemented before 2003 received support during a period of 10 years.

Major developments at regional level have taken place for renewable energy stimulation schemes in 2002. Both the Flanders and the Walloon region have introduced an obligation system with tradable green certificates. The same green certificate system was introduced for 'high-quality' cogeneration in the three Belgian regions in 2003/2004. The quality standard ensures that the sources with the highest environmental benefits are supported. The Flemish obligation was set at 1.4% in 2002, and will increase to 5% in 2010. The penalty level also increases in time. Furthermore, minimum prices for the green certificates are set per renewable energy. The Walloon Green Certificate System sets obligations on the supply from renewable energy and CHP, increasing from 4.1% in 2004 to 12% in 2010. Only certificates originating from the Walloon area count in meeting the obligation. The Brussels region also designed a Green Certificate System, implemented in 2003 (de Vries, et al, 2003).

The position of DG in Belgium can be characterised by a niche market situation, given its low share and the feed-in tariff system in place. The system of tradable certificates for renewables and cogeneration aims at giving DG a more stable position in the wholesale market and is a first step in a new phase of market access.

4.1.3 Finland

Market share

RES and CHP covers a significant part of electricity consumption in Finland. The share of CHP in electricity consumption amounts up to 34% and the share of RES is 28%. These numbers also include large-scale facilities, such as large hydropower plants. Subtracting these large-scale sources leads to a total share of DG of approximately 25%, presenting a *medium* level of DG in Finland. The share of intermittent production, such as wind energy is very low, presenting less than 1%. The indicative target for Finland within the framework of the EU RES-E directive is an increase up to 31.5% RES-E in 2010. An important role in the increase of the RES share will be played by bio energy. The role of wind power will be limited, the national wind power programme aims at the construction of 100 MW of wind power capacity by 2005.

Support mechanisms

Finland has introduced a number of support mechanisms for CHP and RES. Main instruments are:

- Investment support, support up to max. 30-40% of acceptable investment costs
- Energy tax reimbursements (0.25-0.69 ct/kWh depending on type of production) → Electricity tax paid by consumers is refunded as a subsidy to the producer (per kWh), which means a form of feed-in tariff.

These instruments have a limited duration, however, and are planned to be in place up to 2006 (tax reimbursements) and 2007 (investment support). This limited time-scale has been chosen as governmental support requires approval from European Commission and this can only be done for a prescribed period. I.e. these support mechanisms may exist also after 2006 when approved by the European Commission again.

4.1.3.1 Market access

The support mechanisms identified here are typical for a situation with an increased share of DG in the electricity system. Although a wholesale market is in place in Finland, trading fees are high for small producers, presenting a barrier to full market access.

4.1.4 France

Market share

The current share of renewables in electricity consumption in France is 15.7%. The majority of this share, however, exists of large hydro power plants. The total share of DG is estimated at 4% of which 2% is small hydro and small-scale CHP forms another 2%. The share of intermittent sources like wind energy is currently less significant, but is increasing and reached 240 MW at the end of 2003. The indicative RES objective for France for 2010 is 21% of electricity consumption from RES. This will also mean an increase of small-scale RES sources up to 8%. The share of CHP is also expected to increase to 4 - 6%.

Support mechanisms

There are a number of support mechanisms in place in France. The most important are:

- Fixed feed-in tariffs for various kinds of RES and CHP (for installed power <12 MW)
- Purchase obligations
- Investment subsidy schemes for investments in renewables and demand-side management in rural areas (mainly used for PV systems).

The duration of the feed-in tariffs is relatively long and depends on the kind of technology and differs between 12 years for CHP, 15 years for wind energy and 20 years for PV-systems and small hydro power plants. The percentage of support (of market price) differs between 20% for small hydro power, 22 - 34% for CHP installations, 31,5% for wind energy and up to 57% for PV-systems.

Market access

The situation on the electricity market in France is the following, due to the existence of one major player (EdF) market concentration is high. According to the law, DG has access to the wholesale and ancillary services market, although this is considered as being only theoretical according to some experts (Menanteau, 2004). Taking this into account we can say that the phase of DG access in France is in a typical niche market state.

4.1.5 Ireland

Market share

The DG share in national electricity consumption is currently relatively low. RES forms 2% of total consumption and CHP another 2%, making the total DG share 4%. Large-scale hydropower forms another 3% share in electricity consumption. The small-scale RES share is mainly formed by wind power and the available capacity of this source is rapidly increasing. Of the RES objective of 13.2% for 2010, the majority will be met by wind power. About 9% of electricity consumption around 2010 will be met by intermittent resources. The growth of wind power is expected to increase from 214 MW in 2004 to over 850 MW in 2009.

Support mechanisms

The two main instruments that used to realise the Irish RES targets were corporate tax relief and a bidding system, the Alternative Energy Requirement (AER). Up to 2003 there have been a series of AER competitions that offer fixed price PPAs to projects for periods of up to 15 years. Six such competitions have been held to date, offering financial support for a pre-determined capacity of DG/RES across different technologies - predominantly wind. This has resulted in a stop/start development nature in the sector, rather than organic growth.

The government has issued a consultation document reviewing the current system and examining future support options, and the consultation period extended until the end of February 2004. The options for new support schemes under consideration to cover the period up to 2010 are:

- Competitive tender (existing mechanism in Ireland)
- Fixed feed-in tariff
- Production credit (e.g. tax credit)
- Renewable obligations and tradable renewable credits.

The consultation responses are currently being evaluated. The Irish government will make a final decision by the end of 2004. So far no information was available about this final decision.

Under the AER scheme, support levels are set by technology. The last round of the AER programme worked on the basis of price caps for each category, related to Best New Entrant (BNE) prices. So if the price cap was x cent/kWh, bidders had to offer to generate at a price at or below the price cap for the category. In terms of the average market price for 2003 the price caps in each category compare as follows (de Vries, et al, 2003) [8]:

- Large wind 5.216 (BNE + 8,7%)
- Small wind 5.742 (BNE + 19.6%)
- Offshore wind 8.4 (BNE + 75%)
- Small hydro 7.018 (BNE + 46.2%)
- Biomass 6.412 (BNE + 33.6%)
- Biomass AD 7.000 (BNE + 45.8%)
- Biomass CHP 7.000 (BNE + 45.8%).

Electricity market

The electricity market in Ireland currently operates as a bilateral market; with a planned migration to a mandatory centralised pool in 2006. The DG support mechanism that has been used to date is not related to the market form. The wholesale market currently operates as a bilateral trading system with a balancing market operating under a 'top-up' and 'spill' arrangement. RES + CHP have access to the whole market despite the fact that the market is not fully open yet. Since the first phase of market opening in 2000, CHP and RES generators have had access to the whole market. A licence from the regulator is required. Only centrally dispatched generating units have access to ancillary services market, this excludes DG.

The production of electricity is concentrated in the hands of the Electricity Supply Board (ESB), having almost 97% of the total electricity market. During the last years, however, there has been an emerging production of Independent Power Producers (IPPs). These IPPs use the electricity they produce on site or sell it to ESB. Mainly the electricity produced by the IPPs comes from renewable energy sources (RES) or from CHP plants. It is expected that the number of IPPs will grow with the liberalisation of the electricity market.

The DG market in Ireland contains elements of both a protected niche market and wholesale market access. The support mechanism in place until 2003, the alternative energy requirement, is a typical example of creating a protected niche market of a limited size. Support was given to projects of a pre-determined size, not really leading to steady growth of installed capacity. Uncertainty remains about the new support schemes and whether they will aim at supporting wholesale market access of DG. The access to the wholesale market for electricity is guaranteed to RES and CHP generators, and this is a major step in the direction of a level playing field.

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[8] Average market price: every year the regulator reviews the mechanism by which imbalance prices are set. A BNE *('best new entrant')* price is determined every year and used in the setting of top-up and spill payment levels for the following year. Thus it may be considered as a guide to the average annual price that new generators could expect to receive. For the year 2004 this level is €47.90/MWh.

4.1.6 Spain

Market share

The total share of DG (RES + CHP) in Spain is 16.5% of which 9% is RES and 7.5% CHP. The DG share is expected to grow to 23% in 2010. A significant share of this growth will come from wind energy. The share of wind energy is expected to grow from the current 3.5% to 7% in 2010. In terms of installed capacity this will mean a growth from 6000 MW today to 13,000 MW. The Spanish renewable electricity target for 2010 is 30.6% of the electricity demand.

Support mechanisms

The Electric Power Act distinguishes between two electricity production systems: the Ordinary System and the Special System. In the ordinary system the regulatory basis is the free power market or electricity pool where demand and supply bids for electricity are matched prices are set in consequence. In the Special System generation plants below 50 MW belonging to three clearly separated areas (co-generation, renewable energy sources and waste) are given a special status. According to the Act RES-E producers are entitled to:

- Feed all their power into the grid system.
- Receive the conventional market price plus a premium so that the total amount paid must be in the range between 80 - 90% of the average electricity price (Feed-in tariffs).

According to the Royal Decree 436/2004 owners of electric power installations within the Special Regime (registered before 28.03.2004) have the possibility between two options (Bustos, 2004):

1. Sell the electricity to a distribution company, receiving:
   - A fixed price per kWh (adjusted annually by the Government) of 80 to 90% of the average eletricity tariff (AET).
   - A reactive power service supplement.
   - Supplement for continuity of the supply against voltage dips (wind turbines only).
2. Sell the electricity freely on the market (daily sale bids, bilateral contracts). The operators will receive the following remuneration:
   - The price per kWh set in the pool or agreed price in the (bilateral) contract.
   - *Plus* a premium per kWh of the average electricity tariff (reflecting the environmental value of renewable production).
   - An incentive per kWh for participating in the market.
   - A reactive power service supplement.
   - A capacity payment (under same conditions as applied to plants operating within the *Ordinary Regime*).
   - Supplement for continuity of the supply against voltage dips (wind turbines only).

Every year, renewable generators are allowed to choose to follow one or another variant. In cases where the fixed prices are related to the market price of electricity there will in reality be little difference between the fixed price and fixed premium schemes.

From 2006, and every four years from then onwards, the Government will carry out a revision of tariffs, premiums and incentives. This revision takes into account the fulfilment of the RES goals, the costs of the different RES technologies, the participation in the coverage of demand and the impact on the technical and economic management of the electrical system. The tariff changes will only be applicable to those installations commissioned later than January 1st of the second year after the year the revision was approved. Apart from this revision, no time limit is placed upon the feed-in system. Support in percentage of average market price varies between 55% for CHP, 78% for wind and 97% for biomass.

As shown above within the support mechanisms RES and CHP sources have full access to the wholesale market in Spain. According to CNE, in 2003, more than 6000 GWh were sold to the market. The same holds for the access to the ancillary services market.

The example above shows that Spain has developed a support mechanism for RES-E that is stable for investors in the long-term. There is a possibility for tariff change when costs for RES-E technologies decrease, but for existing units, such changes will not occur. The choice between a full feed-in tariff and a premium up to the market price gives independent power producers the possibility to choose the most profitable option. It also ensures access to the wholesale market for all DG producers.

The revision of the feed-in system in 2004 was an important step from a protected niche market phase to wholesale market access. The system with a fixed premium above the market price is preferable from a level playing field perspective. Through this system RES producers are to a certain extent dependent on the market price of electricity, as other (large-scale) power producers are too. A specific feature of the Spanish mechanism is the reactive power supplement (ancillary services remuneration). This can be considered as a first step in access to an ancillary service market, leading to a level playing field situation for DG.

4.1.7 Sweden

Market share

The RES+CHP share in Sweden is relatively high and consists of 61% of the total electricity production (RES 49%). The majority of this is large scale hydro, the DG share can be considered as being of a medium level (~15%). The share of intermittent production (e.g. wind) is low (<1%). In the EU Renewables Directive, the indicative target for Sweden has been set at 60% of the electricity consumption in 2010 (including large hydro). This is an increase of more than 10% compared to the share of 49.1% in 1997.

Support mechanisms

Since the nineties, Sweden has made use of subsidies and tax incentives to stimulate renewable electricity production. Subsidies can give an incentive to investors while tax incentives can stimulate the consumption of renewable electricity by exempting the use of renewable electricity from certain taxes. In May 2003, a new system based on tradable green certificates was introduced.

The following support schemes are currently in place in Sweden (de Vries, et al, 2003):

- Investment subsidies for small RES, in particular the following technologies (biomass - CHP, wind power onshore (>200 kW), small hydropower (<1500kW).
- Quota based certificate system for renewable energy (started in May 2003).
- Feed-in tariffs for wind power, this is seen as a transitional subsidy in order to support wind power production under the tradable green certificate system. This subsidy will only be given for a five-year transitional period in which the bonus will be gradually phased out (the subsidy starting from 1.63 ct/kWh in 2003 will decrease to 0.33 ct/kWh in 2007 and then phased out).

As in Finland a wholesale market exists in the form of the Nordpool[9]. Next to this wholesale market there is a bilateral market. In Sweden there are seven large electricity producers that have 94% of the total electricity generation capacity. The number of distribution companies is reduced from 300 to 184.

Three major companies cover 70% of the end-user market. Sweden has introduced market-based systems to support DG, with a specific (temporary) feed-in system for wind power that is not yet able to fully compete on the market. The creation of a level playing field, however, depends on the access of DG to the wholesale market, which remains limited until now.

4.1.8 Summary of support mechanisms

The countries studied have adopted different types of support mechanisms for renewable energy and CHP, from feed-in tariffs to investment subsidies and green certificate schemes. Most EU MS have the same objective, reaching an agreed RES target. The way how to reach this objective, however, is often different per country:

- Ensuring maximum stability for investors through fixed feed-in tariffs for RES technologies set for a fixed number of years covering the complete production costs.
- Introducing market based mechanisms, such as price premiums above market price or green certificates, believing that RES technologies only need a little push forward to be competitive.
- Promoting new (efficient) technologies through investment subsidies.

The type of support mechanism chosen is often related to the situation of DG producers in the given country. A low share of DG and a weak position on the market requires a mechanism leading to the creation of a ‘protected’ niche market. Fixed feed-in tariffs set at certain level for a number of years give income stability to investors in DG. In this respect they are effective in increasing the market share of DG. In countries where DG has already gained a stable share on the market, more market-based mechanisms are more appropriate, such as price premiums on top of the market price or certificate systems. The overview of the countries above showed that this is already the case in some countries. For example, France, with a low level of DG has chosen the path of feed-in tariffs. In Ireland a tendering scheme with fixed PPA was in place until 2004. Finland and Sweden, having a higher DG level have introduced more market based incentives. Austria and Spain, already having a higher share of DG, still base their support on feed-in tariffs. However, in Austria these tariffs are valid for a limited number of years and in Spain DG producers can chose between a fixed feed-in tariff or a premium on top of the market price, introducing a more market based approach. The Spanish system, therefore, is moving from a niche-market based to a wholesale market based support system where the revenues for RES & DG are adopted to market price.

Other substantial differences between the level of support is the following:

- Support in % of average market price, varying from 20-35% in France to more than 100% in Austria.
- Changes in level of feed-in tariffs, no change in tariffs or change after a number of years. E.g. in Spain, for DG already connected there is no change, but tariffs may be modified for new entrants. In Sweden a temporary feed-in system exists for wind power, gradually being phased out in five years.

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9 Nordpool, the Nordic power exchange is a multinational exchange for trading electric power comprising of the electricity markets of Norway, Sweden, Finland and Denmark.

One can argue that feed-in tariffs existing for a large number of years or even for the whole lifetime of a technology may distort the market too much and not lead to a level playing field between centralised and decentralised production. Temporary support until a technology is 'mature' i.e. is able to compete on the electricity market on an equal footing may be a more optimal solution. But as has already been argued, distribution network regulation also plays a major role in ensuring that DG receives an 'equal' treatment reaching a level playing field. This is investigated in the next section.

4.2 DG network regulation

4.2.1 Austria

Network regulation

In Austria three types of network fees can be distinguished that compose the revenues of the DSOs:

- The grid allocation fee (UoS charge), paid by customers.
- The grid utilization fee (UoS charge), paid by producers.
- The grid access fee, paid by parties wishing to be connected to the electricity network.

The UoS charges, being composed of the grid allocation and grid utilization fees are set by the National Regulator and are fixed. The grid access (connection) fee is set by the respective DSO. So far there is no common practise for grid connection in Austria and the level of the connection charge depends on the DSO (and the capacity of the grid). The DSO mentions a suitable feed-in point, given the capacity of the grid.

In Austrian network regulation there is an important role for the regulator (UoS charges) and the DSO (connection charges). Connection charges are completely determined by the DSO, which gives the DSO a powerful position compared to the DG operator (although the DG operator may complain at the regulator in case of 'unfair' treatment).

DSO regulation

The main features of DSO regulation are the following:

- Unbundling of DSO only on the basis of accounting. The EU directive requires legal unbundling and this is expected to come into force by 1.7.2005.
- The National Regulator has carried out benchmark studies of DSOs. These studies have been mainly carried out for comparison purposes only and were not meant to penalise or incentivise DSOs.
- In general large DSOs do not own power plants in Austria. The exception are small DSOs, having the possibility to own power plants in supplying small villages.

Other special features

- No compensation scheme for loss reduction exists for DG producers at the moment, although the topic is coming into discussion.
- Demand and supply must accounted separately.
- Ancillary services, at least primary and secondary control, are provided by the heads of the different balancing groups. Voltage control is the duty of the DSO.

4.2.2 Belgium

In Belgium no fixed authorisation procedures nor specific regulations exist, this can lead to time constraints for DG projects.
Belgium has a system of predominantly shallow connection charges. A CHP (DG) owner has the following connection costs:

- Construction of the electric wire from the CHP to the connection point of the grid
- Transformation to mains voltage
- The connector.

The (connection) tariffs that are applicable are published by the grid owner and can be obtained at the CREG (www.creg.be). All other costs are at the account of the DSO[10].

4.2.3 Finland

Network regulation

Network regulation in Finland does not include any standardisation of *connection charges*. Connection charges can be both shallow and deep, depending on the DSO. The DSO has the right to collect all reasonable costs resulting from connection, but not every DSO does so. The DSO has to have fair and non-discriminatory causes for connection charging and these causes have to apply to all. Therefore, the DSO has to give a detailed and comprehensive estimate of connection cost upon request. In some cases connection charging is based on price per power unit or at least realized costs. This means that there is no explicit choice for deep or shallow charges.

The *Use of System charges* are also set by the DSO, the Finnish energy market authority is not responsible for tariff setting but only gives some basic guidelines. There is no standardised scheme for loss reduction and no locational signals are given. However, loss reduction can be part of Use of System charges.

DSO regulation

The position of DSOs in Finland is as follows:

- The electricity market law is being revised at the moment, and further unbundling of DSOs is going to take place. It is *proposed* that legal unbundling would concern DSOs with over 150 GWh distributed energy at LV (would concern 45% of DSOs, this limit is tighter than required in the EU-directive). Further administrative unbundling would concern DSOs with over 50000 customers (13 companies) and full operational unbundling DSOs with over 100000 customers (only 6 companies).
- Benchmarking of the DSO's is based on costs, not on performance → this is being further developed by the regulator.
- The market operator only checks (supervises) the reasonableness of electricity network transmission pricing. This leaves a lot of room for interpretation.

The description above shows that in Finland DSOs have large freedom to set their own connection and UoS charges. The Energy Market Authority (EMA) gives guidelines in this matter, but has an ex-post supervisory role. The EMA will make a judgement whether or not pricing has been ‘reasonable’ in case of a complaint. If this is not the case, the DSO will have to make improvements in the tariffs and pricing afterwards (Kinnunen, 2002).

[10] Further information about the network regulation in Belgium could not be collected in the framework of this project.

The DSO regulatory framework in Finland can therefore be summarised as follows:

- No ongoing price regulation, principle holds that prices reflect real costs of the DSO.
- Tariffs are set independently by the DSOs.
- There is a case by case ex-post price supervision by the energy market authority.
- Investigation of prices may start through a complaint or as the initiative of the EMA.

The Finish situation can lead to the conclusion that the DSO has a relatively independent and important position in the distribution system and can to a large extent influence the penetration of DG in the power system.

4.2.4 France

Network regulation

At the moment standardised authorisation and connection procedures exist for DG producers. The standardised connection rules are published. When addressing the question of shallow and deep connection costs one sees that in France there is neither a pure shallow nor deep connection charge system, but can be considered as a *shallow cost plus* system.

In the present legislative context, the producers pay all the costs implied by the grid connection of their generating plant and by the networks reinforcements needed between their connection point up to (and including) the substation to the higher voltage level, i.e. the HV/MV (High Voltage/Medium Voltage) substation for a connection to the MV network. If reinforcements are needed on the higher voltage level, these additional costs are paid by the network operator.

Use of System charges include an energy component for producers. UoS charges in France are not set by the energy regulator but specified in the law and more specifically in government decrees. In France the regulator is independent from the government. The regulator may comment on the government decrees but it cannot cancel nor modify them. As UoS charges are specified in the law, there is no possibility for DSOs to modify them, or negotiate about them with (DG) producers. Connection costs, however, may be shared between several producers or between producers and DSOs if the connection and possible reinforcements may be used for other network customers. In France, UoS costs and connection costs are completely separated. Within the UoS charges there is a possibility to take into account the proximity of the source to the load when considering network benefits like loss reduction (*Menanteau, 2004: Art. 4 of Decree of 26 April 2001*).

DSO regulation

So far there is no DSO incentivisation scheme in place in France. The unbundling of DSOs is moving from the current account unbundling to legal unbundling.

4.2.5 Ireland

The ESB is, besides its producing activities, the only distributor for Ireland. It also manages the electricity network, the ESB national grid. EU legislation requires the existence of an independent TSO that operates the national electricity grid. The Commission for Electricity Regulation (CER) has licensed Eirgrid to be that TSO but the ESB national grid maintains the functions so far until this transfer is effected. Until this time ESB National Grid is the legal entity with full responsibility for the TSO functions. EirGrid will eventually facilitate the entry of IPPs and suppliers to the market.

- The current *licence and authorisation procedures* operating under the control of the CER (Regulator) do not cause any serious delays to DG projects. Network connection delays may occur as a result of technical rather than procedural difficulties.
- Technical and cost-sharing rules are published in the form of a Distribution Code. Increases in DSO connection charges are controlled by the CER, the Irish regulator.
- SEI (Sustainable Energy Ireland) is currently sponsoring a project to investigate the benefits to DG of providing low cost *two way metering*.

Network regulation

Connection charges reflect actual costs necessitated to facilitate connection. For generators connecting to the distribution system, deep connection charging applies. The statement of charges for connection to the distribution system states that generators connecting to the distribution system must pay for '100% of the cost of the connection (including reinforcements)'. The first comer problem that may occur under a deep connection charging system is not covered yet in legislation.

Use of System charges are set by the DSO in agreement with the regulator. There is no loss reduction compensation scheme or locational signal on the distribution system, but existing on the transmission system.

DSO regulation

There is only one DSO in Ireland, appointed by the regulator. CER approval is required under the Electricity Regulation Act and the Distribution System Operator licence for any increases in tariffs charged by the DSO (DSO's CAPEX and OPEX controlled by CER).
The DSO licence is currently awarded to ESB Networks and it is not foreseen that this will change. The DSO is unbundled from accounting, management and legal perspectives, but ownership remains with the parent company (ESB).

4.2.6 Spain

Network regulation

DSO connection and cost-sharing rules for DG are published in Royal Decree 436/2004. DG has a number of benefits or special arrangements in relation to network connection and use (Rivier, 2004):

- Shallow connection charging (only paying for direct connection costs), in case the capacity of the existing network is enough to assume the connection of the new customer.
- Exceptions - if there is a need to reinforce the grid, the generator will participate depending on the exclusivity of the reinforcement use. Practically this means that only if its size does not comply with surrounding loads it pays the additional costs which means a deep connection charge.

This choice between shallow and deep connection charges, depending on the exclusivity of the connection, gives the DSO some leeway in charging connection fees.

The *UoS charges* will be approved by the Government (Law 54/97). Government approves some maximum tariffs and the transport and distribution companies set the final ones. Use of system charges are paid by the final consumers. Concerning the producers in the Special System, the RD 436/2004 (Art. 19.c) establishes that they are under an obligation to satisfy the UoS charges when they act as qualified consumers and sign contracts of electric power supply.

The Law 54/97 establishes that the UoS charges will be the same nationwide and they will be settled down for voltage levels and according to the use of the grid or to the characteristics of the consumptions, as they correspond to the transport or the distribution. So UoS charges depend on the voltage level but not on the geographical location. RES producers have to pay this tariffs only if they act as consumers as well.

RD 436/2004 establishes a compensation for Reactive Energy (quality of energy). There are also compensations for Power Guarantee and secondary and third Regulation.

The Law 54/97 establishes the separation of generation, distribution and supply businesses on DSO level. These activities needed to be carried out by different companies although they might belong to the same group. This means legal unbundling of distribution and supply.

Power production forecast and deviation

As of January 1, 2005, all the RES generating facilities with a capacity higher than 10 MW that sell their output to a distribution company at a regulated tariff must communicate the amount of electricity they forecast to transfer to this DSO (Bustos, 2004). This forecast shall have top be done in each one of the twenty four scheduling hourly intervals of the electricity production market each day, giving at least thirty hours advance notice of that day. Likewise, they may make corrections to that schedule with one-hour advance notice of the start of each intra-day market. The deviation costs shall be passed on to the installations referred to above provided that the difference or deviation in each one of the scheduling intervals between forecast and real output delivered is more than:

- 20% higher or lower for solar and wind power plants,
- 5% higher or lower for any other RES-E plant.

Those renewable installations that opt to sell their electricity into the market will have obviously to fulfil the forecast obligation and pay the deviation costs required within the market rules (10% of the daily market price multiplied by the deviations). In this case the deviation costs are applied immediately to all installations regardless of their capacity.

DSO regulation

- Performance standards in the DSO revenue are related to the regulatory asset base. There is no performance benchmarking of DSOs taking place.
- An optimisation incentive exists in the form of a penalty for low quality of services (but no incentive in case of higher quality of services).
- Distribution companies are not allowed to own generating plants or, in general terms, to carry out deregulated activities.

4.2.7 Sweden

Network regulation

Both deep and shallow connection charging can be applied in Sweden. If reinforcement of the grid is undertaken for one customer only, then deep connection charging is applied. If more than one grid connected customer can exploit grid improvement then the costs should be covered by the DSO and shallow connection charges apply. This way the 'first comer' to the network will only have to cover all reinforcement costs when no other customer is using the grid[11].

[11] The 'first comer problem' arises when the first customer, this can be both a consumer and a (DG) producer, applies for grid connection and has to pay for all connections and grid reinforcements (in case of deep connection charging) that might benefit second and third customers applying for grid connection. Overcoming this 'first comer problem' is one of the crucial steps towards a level playing field.

There is a compensation scheme for network loss reduction existing for small units. There is a calculation model, which defines loss and cost from higher voltage level reduction benefits for DG units below 1500 kW. These small units also pay only for the metering and billing. Possibility exists for a DSO to provide locational signals.

In Sweden a special generator distribution UoS charge exists for small generators of less than 1.5 MW.

DSO regulation

DSOs in Sweden are legally unbundled. Like Finland, also Sweden uses an ex post regulation method. This means that the prices are monitored individually for each utility after each period. It was considered that the electric utilities should be able to guide the development of the sector themselves.

Performance of DSOs is measured through the use of a ‘network benefit model’. In this model allowed revenue is based on performance of fictive network. This fictive network is modelled based on information about DSO’s customers, network connections, distributed energy, interruption density, local production etc. This model should ensure an objective measure for technical efficiency.

4.2.8 Summary of network regulation

The countries studied above have some distinct differences regarding the network regulation in place. In the field of DSO regulation the following has been noticed:

- There is a great difference in authorisation procedures for new DG facilities. The standardisation or speeding up of authorisation procedures for new power plants (including DG facilities) not yet adopted within the legal framework of every country.
- Standardisation/harmonisation of technical standards and publication of these standards is realised in a number of countries.

The DG-DSO financial relationship, mainly connected to connection and UoS charging leads to the following conclusions:

- The network charging system differs, some countries have introduced shallow connection charging, others deep connection charging. Other combined systems are also common. In some countries, e.g. Austria, Finland, it is up to the DSO to judge what connection costs to collect. In France, connection costs are ‘deep’ up to the next voltage level.
- UoS charges are set by the regulator in Austria and Spain. In France, charges are directly set by the government through decrees. In Finland, Ireland and Sweden, DSOs set the tariffs, supervised by the regulator.
- There are a few examples of compensation schemes for DG benefits, such as the Spanish compensation scheme for reactive power and the Swedish system for network loss reduction compensation for small units (<1.5 MW).

The assessment of the DSO legal framework leads only to very preliminary results:

- Both benchmarking and supervision of tariff setting are applied in only a few countries. Benchmarking is generally carried out in countries with a market that is already functioning for a number of years (e.g. Sweden, Finland). In Finland and in Ireland benchmarking is taking place based on CAPEX and OPEX.
- Incentivisation of DSOs or benchmarking of the DSO performance is not fully developed in most of the studied countries.

A distinctive feature in a number of countries is the relatively high independence of the DSO in setting connection charges, such as the choice between deep or shallow connection charging, and the setting of UoS charges. On one hand this can be viewed as positive, as the DSO should be able to optimise its revenues in order to recover all its costs. On the other hand, a DSO may not be completely independent in setting its tariffs. The connection of additional DG to the electricity network may not be viewed as beneficial to the DSO and this may influence the way the DSO sets its tariffs. Supervision by a regulator will therefore always be needed to ensure independent evaluation of tariffs.

5. BENCHMARKING RESULTS SUSTELNET

This chapter analyses the results of the SUSTELNET benchmarking exercise that has been carried out for the nine countries involved in SUSTELNET, five from the old EU15 and four from the new Member States. One of the projects' aims was to anticipate on the accession of these new States and see how far the integration of DG has developed from a regulatory and policy point of view. From the EU 15 the countries studied were Denmark, Germany, Italy, the Netherlands and the United Kingdom. From the new Member States these were the Czech Republic, Hungary, Poland and Slovakia. Section 5.1 describes the DG policy framework and market access in these nine countries and Section 5.2 will look at the regulatory framework.

The information presented below is partly based on the information collected through the SUSTELNET benchmarking study (Boccard, 2004), but includes also information from other reports in the framework of SUSTELNET analysing DG support mechanisms and the DG regulatory framework in the nine SUSTELNET countries (Connor & Mitchell, 2002; ten Donkelaar, *et al*, 2003; Wals, *et al*, 2003). The complete benchmarking results of SUSTELNET can be obtained from Boccard (2004).

5.1 DG policy and market access

5.1.1 DG policy and market access in selected EU15 states

Denmark

The country with the largest share of DG on its electricity supply system is Denmark, with a share of about 36% of its electricity production. Denmark reached such a high percentage due to decades of promotion of wind turbines and medium and small-scale CHP. In the western part of Denmark this has lead to a wind power capacity of 2155 MW connected to voltage levels of 60 kV and below. Together with the approximately 1600 MW of small-scale CHP, the DG in Western Denmark can produce as much as the peak load of the area, which in 2002 was 3685 MW, while the minimum load of 1189 MW often can be supplied by wind turbines alone (Ten Donkelaar & Scheepers, 2004).

The production of electricity in Denmark is split between traditional production and 'prioritised production', the latter covering mainly renewable electricity based on wind power, biomass and small-scale CHP. Presently, as a result of earlier agreements, the system operators are obliged to purchase the prioritised production at fixed, high billing prices. For renewables, the priority rule is combined with a fixed feed-in tariff, for CHP there is a priority rule and a price premium up above the market price in place. This prioritised production does, however, not have direct access to the wholesale market for electricity.

The main instruments that lead to this increase of renewables and CHP are a feed-in system, political obligations, investment subsidies and tax refunds. Since 1993 a feed-in tariff system exists in Denmark, where utilities were obliged to pay wind turbine owners 85% of the electricity price for household consumers. New tariffs were adopted in 2001 in anticipation of the start of the green certificate market. The support is now generally lower than in previous policies. For example, for onshore wind energy, the tariff set for electricity from new plants for the first running period is nearly 30% lower than that for existing plants. For plants commissioned in the years 2000, 2001 and 2002, the feed-in tariff is invariable at 5.8 ct/kWh for the first 22,000 hrs of operation and then reduced to 1.3 ct/kWh. Any support is given for a maximum of 20 years (de Vries, et al, 2003).

A Green Certificate Market was planned to replace the existing feed-in system from January 2003. However, the introduction of such a green certificate system has been postponed indefinitely due to concerns from the renewable energy sector about the market for green certificates, especially in the European context. An intermediate scheme has been designed for the period until the introduction of green certificates.

The description above shows that Denmark has created a protected niche market for DG, which is not completely in line with the share and impact that DG (especially wind power) has on the Danish power system. A more market-based system of support would therefore be more than desirable, creating in the long-term a level playing field between centralised and decentralised (wind/CHP) generation. The introduction of the already planned Green Certificate Market would be a logical next step.

Germany

The share of DG in Germany is approx. 15%, with 9.5% CHP and about 5.5% coming from renewable energy, mainly wind power. Germany therefore belongs to the group with a medium DG level.

The German federal government, as well as the state and district government, has put in place a number of measures for promoting renewable sources of energy. The Electricity Feed-in Law (EFL) of 1990 was the first to introduce feed-in tariffs and these tariffs were paid by the utilities. Since April 1st, 2000, Germany introduced a renewable energy sources act (EEG). The grid operators pay the feed-in tariffs under this new law and cover their costs by an additional fee to be paid by all consumers. The law targets wind, PV, geothermal, small hydro (<5 MW) and certain forms of waste biomass plants. The DSO whose grid is closest to the location of the RES installation has the obligation to pay the tariffs. The EEG states that the electricity from renewable energy must be transported and charged to the final consumer.

The prices paid under the EEG are based on a fixed price scheme combined with a decreasing price element. From 2002 on, new installations receive tariffs lowered by a certain percentage each year (1-5%). For every installation the expiry date is 20 years time from the date of operation. The EEG addressed some shortcomings of the EFL as the feed-in tariffs are not longer linked to average consumer prices but based on generation costs of various renewable energy sources. Apart from a decrease of the tariffs for plants put into operation after January 1, 2002, bi-annual revisions of the feed-in tariffs are possible depending on the cost evolution and the degree of market penetration of the RES-E technology concerned. These revisions are based in evaluation reports the responsible ministries have to submit to parliament every two years (Sijm, 2002).

The EFL and the EEG have been very effective in increasing the penetration of wind energy in Germany. Installed capacity increased from 1,100 MW in 1995 to 6,100 MW in the year 2000 and continued to grow to more than 14,600 MW by the end of 2003.

To promote small-scale CHP and support existing CHP plants, Germany introduced its CHP Law in 2002 (‘Law on the Conservation, Modernisation and Development of Combined Heat and Power’). The Law regulates the purchase of, and remuneration for electricity exported to the public grid from CHP plants in operation before April 1, 2002, and for new small-scale CHP units up to 2 MW_e The Law enacts a duty to connect certain types of CHP units to the grid and purchase their electricity exports to the public grid. On top of the agreed price for these exports, the operators of the units are entitled to obtain supplementary payments on each kWh exported (Cogen Europe, 2002).

The situation in Germany is to some extent comparable to the situation in Denmark. There is a large share of wind power, having very beneficial circumstances, but without really contributing to the electricity market. So far no plans are made for transforming the current support mechanism.

Italy

Italy has so far a limited share of DG in its electricity system. It mainly includes CHP (4%) and small-scale RES (close to 2%). Italy has, however, a large share of large-scale hydropower (19%) but this cannot be considered as DG. A feed-in tariff system exists since 1992 and under this system RES technologies receive a certain premium for the higher costs of RES generation. This premium is only paid during the first 8 years of plant operation. In addition, a quota system was introduced in 1999 that obliges all electricity producers or importers to feed-in at least 2% RES of the total amount of electricity they produced or imported in the previous year into the national grid. This obligation refers to those who produce or import an amount of electricity exceeding 100 GWh/year. To fulfil this obligation, the power producer can either buy this amount of green certificates from the TSO, or build new RES plants. RES operators are entitled to receive GC's, related to the amount of kWh produced from RES, for the first eight years of production since their commissioning. CHP plants do not receive green certificates, but producers owning CHP plants are exempted from the 2% level for the part that is covered by CHP (de Vries, et al, 2003).

Italy will introduce a power exchange in 2004. So far it seems that power plants under 10 MVA will not be admitted to the power exchange but RES and CHP units below this size have priority access to the grid. To conclude, the Italian DG market has all characteristics of a niche market. The position of DG is, however, far less beneficial than in Denmark or Germany, given the limited time that the price premium for RES is paid.

The Netherlands

The Dutch power system includes about 16% of distributed generation, of which the majority is CHP (13%). RES-E, and mainly wind power makes up for the remaining 3%. Since 2000, the most important policy scheme for the support of RES has been the regulating energy tax (REB): a combination of financial stimulation of green electricity consumption o the one hand, and support for renewable energy production on the other hand. The system makes use of Green Certificates. In 2003 the REB was partly replaced by a feed-in system, the MEP (de Vries, et al, 2003). The MEP ('environmental quality of electricity production') aims to increase the stability to investors and improve the cost-effectiveness of renewable electricity support. The MEP provides for operating support through a combination of feed-in tariffs and a reduced ecotax exemption. The feed-in tariffs are financed through an annual levy on electricity connections to the network grid. As the future of the exemption is subject of political discussion, the Dutch support scheme is more likely to evolve into a pure feed-in system. Under the MEP the total level of operating support is determined by the sum of the MEP feed-in tariff and the value ecotax exemption. The government guarantees this total level of support for a period of 10 years after entering into operation. For CHP a separate REB tariff exists that is differentiated by the reduction of CO_2 for a given technology.

The Netherlands has originally chosen to introduce a market-based system for RES support. In 2003, however, the system was transferred into a hybrid system of green certificates and feed-in tariffs. The main reason for this change was that the tax exemption in combination with green certificates did not lead to a significant increase of RES electricity in the Netherlands and many suppliers were purchasing their RES electricity abroad. One might argue that the Dutch market for RES-E was not yet that developed that it could increase its share with market based instruments only.

United Kingdom

Distributed generation in the UK includes about 8.5% of electricity production. CHP makes up 6.2% and the remaining share is RES-E. Support for CHP and renewables in the UK are based on the following key elements:

- The renewables obligation, replacing the Non Fossil Fuel Obligation (NFFO), a bidding system which has stimulated renewables deployment since 1989.
- Renewable electricity exemption from the Climate Change Levy.

In the UK, the regulator (OFGEM) is responsible for the Renewables Obligation and a Climate Change Levy to encourage the use of renewables and to reduce carbon outputs respectively.

The Renewables Obligation is the key component to boost the generation of RES-E. This obligation was implemented on 1st of April 2002 and requires electricity companies to supply an increasing proportion of their production from renewable sources. The proportion of electricity required under the Renewables Obligation will increase between the implementation date and 2010. The obligation accounts for around 3% in the first compliance period that ended 31 March 2003, rising to about 10.4% in the year ending March 2011.

The renewable electricity produced within the UK will be rewarded with Renewable Obligations Certificates (ROCs). A penalty is set for non-obligation of 30 GBP/MWh. The Climate Change Levy came into effect in April 2001 and applies to sales of electricity to private and public sectors. RES generators can apply to Ofgem to have their output exempted via the issue of a Levy Exemption Certificate (de Vries, et al, 2003). The support mechanism in the UK can be characterised as being purely market-based as it does not include any feed-in tariffs or price premiums.

5.1.2 DG policy and market access in selected new Member States

Czech Republic

The Czech Republic has a relatively high share of distributed generation in its power system, consisting mainly of CHP units (20% of electricity production). An obligatory purchase (priority access) regime for DSOs for electricity from RES and CHP generation exists in the Czech Republic. This facilitates the market access of electricity produced from RES and some cogeneration sources. Furthermore, the Czech Republic has introduced a system of regulated feed-in tariffs in 2001 for RES (fixed feed-in tariffs) and for CHP (price premiums). RES purchase obligations apply to the DSO to which the DG operator is connected. The Energy Regulatory Office sets minimum purchase prices varying from approx. 5 to 20 ct/kWh based on the type of technology. A major concern, however, is that the feed-in tariffs are not guaranteed in the long-term, presenting some uncertainty to investors. There are plans for the introduction of a tradable green certificate system to be introduced in 2006.

Since 2003 the Czech Republic has an energy market in place (power exchange and OTC bilateral contracts), a balancing market and ancillary services market, which is arranged by the TSO and the market operator. System services are managed by the TSO and are charged to DSOs through tariffs set by the regulator. Although DG can participate in the ancillary services market, in many cases their facilities are unable to fulfil technical requirements.

Hungary

In Hungary, where DG amounts up to 5% of generation, electricity generated by CHP and RES-E plants has to be taken by a regulated retail supplier (which is separated only in accounting terms from the corresponding regional DSO) at a fixed feed in tariff. The system operator compensates the supplier for additional costs over and above the regulated wholesale price arising from the feed in tariff. Consequently, DG/RES generators do not have to deal with market access issues.

Up to 2003 a non-differentiating feed-in system was in place for CHP and RES. The Ministry of Economic Affairs ensured a fixed purchase price irrespective of the renewable energy type (with take over obligation for electricity distributors) for peak and off peak periods. As these prices were the same for CHP, it resulted in an overwhelming interest in CHP (due to the combination of fixed prices and an artificially low gas price) but less in RES-E. As of January 2003 RES-E is still not differentiated by technology type, but receives a higher tariff than CHP. Also, CHP feed-in tariffs are differentiated according to capacity (regressive with higher capacity) and whether it serves district heating or not. Apart from small-scale generation (capacity <6 MW), CHP with district heating utilisation receives a higher feed in tariff than with other heat uses. For the longer term the government is considering the introduction of a tradable green certificate system as a paragraph in the Electricity Act (2001) authorises it. The introduction of a Hungarian TGC system is expected to take place only after the EU assessment of experiences with RES-E support schemes in 2005.

The trading structure in Hungary can be divided into a regulated and an open market. The first is governed by long-term contracts (PPAs covering 80 to 90% of total power generation) between large generators and the public wholesaler (MVM). MVM then sells this electricity at the regulated wholesale price to regulated retail suppliers; which in turn also sell it at another - higher - regulated price to captive consumers. The second is the open market, based on bilateral contracts between producers, traders and eligible consumers (those with consumption above 6.5 GWh/yr for the first stage of market opening). The electricity exchange is only now being established. The system operator (MAVIR) manages the balancing market, securing reserves from power plants and settling deviations from schedule with so-called balancing groups. Every generator (including DG), trader and consumer has to participate in a balancing group.

Poland

In Poland, PPAs, must run generation and RES and CHP priority access electricity accounts for around 80% of electricity supplied to final consumers. As a result, little trading on the Power Exchange occurs compared with the degree of legal market openness (51% of the market). The Polish power market is divided into three markets: contract market, exchange market and balancing market. The balancing market enables companies to purchase additional amounts of energy not covered by the previously concluded contracts (i.e. those traded on the contract and exchange markets) necessary to balance national energy system. The detailed rules of the balancing market imposed by the TSO are considered to be unfavourable to DG, especially to wind generators. They require power graphics 48 hours in advance eliminating or at least hampering the operation of wind in the energy market. However, this is likely to be changed by giving the RES producers a special position in the balancing market regulations. Since 2001 an obligation exists for energy suppliers to purchase a certain percentage of electricity and heat from non-conventional and renewable energy sources connected to the electricity grid. This percentage is gradually increasing from 2.1% in 2001 to 7.5% in 2010.

Slovakia

In Slovakia, as the market is only beginning to open, neither a power exchange nor balancing or ancillary markets exists. The dominant producer SE (Slovak Power Company) provides currently all balancing and ancillary services. Considering RES, an obligation to purchase electricity from generating stations is in place, provided that such purchase is environmentally justified and technical and economic conditions allow. There is an intention to legally enforce the mandatory purchase of electricity generated by cogeneration and renewable-based power plants through an amendment of the Energy Act currently under development.

In all four new Member states, renewable energy generation (with the exception of large hydro) has the characteristics of a niche market. Support mechanisms are only now being introduced and it has to be seen whether they will be effective in increasing the penetration of RES-E in the future. For CHP, the situation is different, having market shares of 5% (Hungary) to 20% (Czech Republic). In Hungary, the uniform feed-in tariff leads to a major increase of CHP, while in the other countries the CHP share does not have strong support mechanisms. This means that CHP might gain access to wholesale electricity markets once established in the near future.

5.1.3 Summary of market access

Successful integration of DG requires policy and regulation that ensures on one hand support that creates stability for investors in terms of financial return and on the other hand, the guaranteed access to networks and markets. Access to networks can be divided between connection - discussed in the next section - and the ability when generating to be able to sell electricity and, if possible, ancillary services. Market access of DG can occur either by normal channels, i.e. competing with large-scale generators, or through priority access.

The overview of support mechanisms in the nine SUSTELNET countries leads to the following findings:

- Feed-in tariffs are the predominant mechanism for RES support, and to a limited extent also CHP support (Germany, Netherlands, Czech Republic and Hungary). The UK forms an exemption as it completely relies on market-based mechanisms.
- Two types of feed-in systems can be distinguished, one is the fixed price for produced electricity. This type of tariff is usually applied for RES electricity. The other is the fixed premium, more often introduced for CHP electricity.
- Green certificate systems, combined with quota obligations have recently been introduced in a number of countries (Netherlands, United Kingdom, Italy) and are planned to be introduced in others (Denmark, Czech Republic, Hungary).
- An ecotax/climate change levy exemption is in place in the Netherlands and the UK.
- Like in the countries covered in the ENIRDG-net project, changes occur in support mechanisms. Denmark and the Czech Republic have plans for the introduction of a green certificate system. The UK moved from a tendering system to a renewable portfolio standard.
- The situation in the Netherlands is different as here a feed-in system was introduced after the existence of a green certificate system. The main reason was that the tax exemption in combination with green certificates did not lead to a significant increase of RES electricity in the Netherlands and many suppliers were purchasing their RES electricity abroad. One might argue that the market for RES-E was not yet developed to such as extent that it could increase with market based instruments only.
- Denmark and Germany have the longest experience with feed-in tariff systems. In both countries these systems were effective in increasing the share of RES & CHP. Both countries had, however, to make changes in the system to make it more cost efficient and effective in the long run.

Regarding the access to (energy) markets, the following can be concluded:

- Access to energy market largely depends on the development of energy liberalisation. Countries such as Italy and Slovakia do not have an electricity wholesale market in place, while others, such as the Netherlands and the UK have both a wholesale and balancing market in place.

General concluding remarks:

- The example from the Netherlands shows that a market based system is not always effective. Problems may occur when support systems are not harmonised between countries. Under such circumstances it may also be to early to rely only on market based system unless a stable share of domestic DG production has been established.
- In Germany and Denmark, large shares of DG are more or less protected from the market. This might not be sustainable in the long run, especially if a level playing field is likely to be achieved.
- Potential conflict between free market principles and sustainability goals will have to be overcome. The level playing field objective might be the right way to do so.
- When applying a uniform feed-in tariff, investors will always search for the cheapest option under this feed-in system, as has been the case for Hungary with CHP, having the same tariff as RES but being the cheaper option. A differentiated tariff based on production costs provides opportunities for more types of RES and CHP, but may be more costly to realise.
- As the new Member States have only recently introduced support systems for RES (and CHP), there is little knowledge of the effectiveness of these support systems.

5.2 DG network regulation

5.2.1 Connection charging

In general terms, *Denmark*, *Germany, Italy* and *the Netherlands* each employ a system of shallow connection charging, though there can be variance in the charges to different DG technologies.

Such variance occurs in *Denmark*, for example. Those CHP systems which have been defined as priority suppliers pay only to connect to the nearest part of the 10kV grid. Above this capacity the DG operator must also fund upgrades to the system grid. If the DSO wishes the DG operator to connect at another point then the DSO picks up all costs of grid connection. Wind turbine operators are compelled to pay costs only to the edge of the specific planning zones allocated for turbine construction, with DSOs paying all other connection costs which are then passed on to consumers. Connections from the perspective of the generator are therefore transparent and reasonable. When wind turbines are established outside these areas, the wind power operator must pay.

The *German* approach is also based on shallow connection charging. The Renewable Energy Law (EEG) indicates that DG developers cover only the costs of connecting their plant to the grid and DSOs must provide any necessary grid extension, where this does not entail excessive costs. However, considerable problems have arisen from the interpretation of how costs should be broken down between DSOs and DG developers, with some DSOs ruling that the developer must pay for any new line connecting to the grid, significantly raising the cost burden for the DG operator. Whilst court cases have so far favoured DG, DSOs continue to take new cases through the courts, both slowing development and raising costs. The problem is enhanced through a lack of transparency caused by poor information regarding connection costs in the public domain.

Connection tariffs in *the Netherlands* depend on the type of connection. Connections until 10 MVA are shallow, regulated and averaged. Connections above 10 MVA are negotiated and deep, meaning that DG operators will have to cover all costs raised by connecting to the grid. They included the direct costs of connecting to the grid and all indirect costs raised inside the grid. Charges are determined through negotiation processes between users and the DSOs.

In *Italy*, connection charges are shallow but negotiated between DG operators and DSOs.

The *United Kingdom* currently employs a system of deep connection charging wherein any new generator connecting to the distribution network must pay the full costs of connection to the grid, including any remote reinforcement costs, and costs of upgrades required at higher voltage levels.

In the four *new Member States* considered here, connection charges cannot be strictly defined by deep or shallow as in the EU 15. However, the Czech Republic, Slovakia and Poland can be considered to have deep connection charges while Hungary, on the other hand, has connection charges that approach the shallow costs principle.

In the *Czech Republic* rules for grid connection are approved by the market operator, standardised and published. Applicants for connection are asked not only to pay the costs related to the connection line to its premises, but are also asked to pay up to 60% of the connection costs arising in the distribution and transmission systems to the nearest highest voltage level.

Slovakia can also be considered to have deep connection charges, which are determined subject to agreement between the parties. Slovakia has a standard distribution code for grid connection, but DSOs may include specific requirements for connecting DG plants based on a case-to-case basis.

In *Poland*, connection charges depend on whether the connection was included in a local plan of development. If so, then the cost of the connection is split into two components, one quarter paid by the new customer, and the remainder paid by the DSOs, which is authorised to pass down these costs completely to its customers through the UoS charges. If it is not included in a local plan of development, the customer has to pay the full connection costs.

In *Hungary* the situation is quite ambiguous. Connection charges can be either regulated or negotiated. In the first case, connection charges approach shallow costs - and in some circumstances may be smaller than shallow - and the DSOs may recover the difference via the UoS charges. However, DG investors and DSOs interpret the ordinance differently, and a further amendment is expected. Generators can also negotiate connection charges, though in practice this tends to result in costs similar to those for deep connection. Finally they can opt to carry out the necessary investments themselves, thus incurring the costs generated by the connection to the grid. This resembles shallow charging, however, as generators own the new assets, they will encounter extra operating and maintenance costs.

5.2.2 Use of System charging

In *Denmark* those DG technologies which are classified as priority producers are exempted from the payment of Distribution or Transmission Use of System Tariffs (DUoS and TUoS) which all other producers and consumers must pay. With the exception of those technologies which hold an exemption as detailed above, most customers and generators would pay connection charges on a costs basis. All producers pay a fixed subscription fee which covers the DSO's depreciation and return on the investment in meters including installation costs; billing and reading of meters.

The DSO is also able to include a sum that covers other relevant costs. The fee varies depending on which voltage level the wind turbine/CHP is connected to and the number of meter readings each year. DSOs may also make an additional charge to demand customers as well as the subscription payment (though sometimes the two are combined). This load payment defrays any connection costs not fully covered in the connection fees. Thus, UoS is the vehicle by which the operation of the system and transport of the priority producers is paid for in a socialised manner.

The *German* system involves costs relating to both balancing and reserves, and use of system costs. This second section can be further broken down in:

- System costs (grid, transformers)
- Operating costs
- Costs of system services
- System losses
- Metering and billing costs.

All system users who receive electricity (i.e., all but generators) contribute towards the system costs through an annual use-of-system charge, which includes both an energy component and capacity component. These charges cover the use of system at the voltage level at which the user is connected to the system for a given system operator, and use of all higher voltage levels. Thus, all system users have access to the system as a whole. Annual charges are calculated by the system operator based on the above range of factors and allowing for depreciation and a reasonable rate of return. System losses including line losses are considered as average losses for each system operator at different voltage levels, and thus DSOs have the incentive not to exceed the average. If DG can contribute to decrease the system losses in this case, then DSOs have an incentive to support them. Furthermore, the charges for metering and billing used to have a high margin; as a result DSOs wishing to maximise the number of their customers might welcome distributed generators in their service territory as this directly relates the numbers of customers in their area.

In *Italy*, UoS charges include a capacity and energy component. All UoS charges are set by the regulator who bases its decision on hearings with stakeholders. UoS charges are paid by generators and end-users, whereby DG generators do not have to pay for transmission charges.

In *the Netherlands* all tariffs are calculated by application of the Tariff Code. Specific tariffs are calculated by the DSOs, and then approved by the Dutch Regulator (DTe) before they can be applied. Consumers pay tariffs following the cascade principle, that is, paying for the voltage level at which they connect to the grid and then proportionally for their use of higher voltage levels. The Transport tariff covers the transmission dependent and independent costs incurred by the network operators. The former includes the maintenance and depreciation of infrastructure, compensation energy for network losses and the upgrading of network constraints. The latter includes meter reading and data management.

Since July 1, 2004 consumers fully bear the costs of use of both higher and lower voltage grids. Up to June 30, 2004, producers having connections to the high voltage grid (110 kV and higher) or having a generation capacity of more than 150 MW had to pay the National Uniform Producer Tariff (LUP). This accounted for 25% of the sum of the total transmission dependent costs of these grids. As neighbouring countries (Belgium, Germany, France) did not have a similar price system in place, Dutch producers had a competitive disadvantage, which was the main reason for putting an end to the LUP.

In the *United Kingdom* all transmission and distribution use of system charges were passed to the consumer prior to the establishment of the New Electricity Trading Arrangements (NETA) in March 2001. Since the institution of NETA there are two transmission charges: the Transmission Network Use of System Charges (TNUoS) and Balancing Services Use of System Charges (BSUoS). TNUoS is only payable by generators and suppliers that are connected to the transmission network and generate more than 100 MW a year. Smaller generators do not pay TNUoS and may thus act to reduce supplier charges and should therefore add an incentive for suppliers with respect to DG. BSUoS is paid by generators and electricity suppliers who participate in the national electricity market. It covers the costs of system operation including ancillary services.

In addition, all demand (or load) customers currently pay a distribution use of system charge and this is differentiated by customer class. The DUoS is paid to the DSO and is the sole revenue raiser for the DSO, creating incentives to maximise distribution of kWhs. There is therefore a disincentive on them to promote any generation which undermines that, in particular on-site or micro-generation which minimises customer demand taken from the network. DUoS charges cover the costs of transportation of kWh, maintenance of the network, depreciation, energy losses and a fixed return to the DSO.

UoS charges in the *Czech Republic* are composed of an energy and a capacity element. These two components are a capacity reservation fee (MW) and a use of system fee (MWh). UoS charges are paid by the end consumers, which also pay for system services.

UoS charges in *Hungary*, *Poland* and *Slovakia* include costs that can be entirely passed down to consumers and costs that are limited based on the inflation of consumers' prices and anticipated efficiency improvements. In *Hungary* UoS are currently paid by consumers and exporters only (generators and importers do not pay for the UoS charges). Furthermore the fees are paid directly to those network operators (DSOs, TSO) to whom users connect. UoS charges can be broken down into five components: a fixed charge, which covers the metering costs; a capacity and energy charge that covers other network costs so that these are shared 50-50% between the two charging types; a loss charge, which compensates for the costs of recognised losses and lastly a reactive energy charge.

In *Poland*, the UoS charges are composed of grid rates, system rates and settlement rates. The grid rate is composed of a fixed component and a variable component. The system rate, on the other hand, has a quality component calculated according to the costs of maintaining the system-related standards of quality and reliability, a compensatory and a balancing component. Customers pay all UoS charges.

In the case of *Slovakia*, UoS charges include the fee for grid access, the transmission system dispatch and the losses in electricity transmission. Other fees charged to the consumer are a system costs fee, a balancing services fee and a distribution loss fee. Each final consumer (both eligible and captive consumers) pays all the listed fees, with the exception of the consumers being connected directly to the transmission system. Such consumers pay all the fees listed above, i.e. they do not pay for distribution losses.

5.2.3 DSO regulation

Denmark has adopted a system of benchmarking which includes DG costs. While it currently does not appear to provide a direct penalty to 'poor' DSOs, it could potentially do so. The income framework/efficiency requirements are defined for a 4-year period. Within this period, variations below and above the efficiency requirements are allowed. If, by the end of the 4-year period, the DSOs have not met the efficiency requirements they are added to the efficiency requirements in the next period. Thus there is no punishment for not meeting the requirement except that you have to comply in a later period. However, if the Energy Regulatory Authority (ERA) suspects that the DSO tariffs are too high they may instruct the DSO to lower the tariffs and thereby meet the income framework. If the DSO fails to comply with this request, the ERA has the power to revoke the DSO's licence.

In *Germany*, connection costs may be added to the UoS charge. A DSO's UoS charge is derived from the regulatory asset base (RAB) and is therefore an incentive to connect since this can be added to the RAB.

The Federal Cartel Office (FCO) carries out benchmarking between DSOs. The FCO currently compares best practice amongst networks with similar market structure although the focus seems to be aimed at preventing price increases rather than achieving ongoing efficiency reductions.

It may be that the FCO does not allow a higher UoS charge and therefore the costs of connection cannot be passed down to consumers. In this situation, there would be no incentive for DSOs to connect DG.

In German legislation there is, however, a relatively straightforward incentivisation basis for DSOs. DSOs have an obligation to connect DG operators to the grid, take off their output and pay a fixed rate for renewables and a rate above the market price for CHP plants. Despite this formal obligation, a DSO may try to make it more difficult or more costly for a DG plant to get grid access, thereby making projects less profitable or even unprofitable. The weak regulation and the heavy reliance on court rulings gives DSOs significant scope for doing this.

The DSO can pass on the remuneration paid to EEG plants to the TSO to which it is connected. The TSO in turn can pass it on to the supply companies, which will distribute it to all end users. This burden sharing mechanism introduced by the new EEG Law has removed one of the main incentives for DSOs to oppose an increase in renewable generation.

The system in *the Netherlands* includes a price cap, benchmarking and performance based regulation. DSO incomes rely on minimising both operational expenditures and expenditure on capital assets. The benchmarking process considers the capital and operational costs together; hence DSOs are forced to reduce these expenditures in comparison with other companies in order to increase profits.

In 2004 DTe introduced a new performance based regulation system for DSOs. In this yardstick system, the tariffs are determined based on the average productivity changes of the sector. In other words, the performance of DSOs is benchmarked against the performance of the whole sector and not against an efficiency benchmark like in the current price cap system. Companies that do better than the sector average receive extra benefits. Conversely, DSOs that do worse than the sector average see their benefits reduced. In order to ensure that the efficiency improvements are not made at the expense of the reliability of the network, DTe will extend the system of yardstick competition to include quality regulation. Under this new system, tariffs are also determined based on reliability and quality standards set by DTe. An individual network company may achieve a profit if it outperforms the standard, but a loss if it performs poorly relative to the standard. Initially the standard will be determined for each network company separately and will be adjusted annually by the same factor that applies to all companies thereafter.

In the *UK*, the specific incentivisation mechanism for a DSO is based on its Regulatory Asset Base (RAB), and income is linked to sales, the RPI-X system[12] and to number of customers. The UK's system of deep connection charging means that adding DG to a network does not bring any income incentive for a DSO as no increase in RAB attends it.

A system of benchmarking DSO operational expenditure against other DSOs to increase overall efficiency also acts to discourage any investment which does not add to the RAB. The incentive system also fails to take into account both reduced costs stemming from DG and the potential networks benefits of DG to distribution networks.

[12] The RPI-X (also referred to as CPI-X) is a price-cap system for network tariffs. The system establishes maximum network tariffs that have to be decreased annually according to the retail price index (RPI) and the x-factor, a discount to promote efficient operation by DSOs.

In the *Czech Republic* a cost-based pricing system, i.e. the system based on the individual cost analysis of eight electricity distribution companies, has been implemented. Under this system, justified capital and operational expenditures are allowed, while a certain rate of return is guaranteed.

DSOs are therefore regulated by a system that, on the one hand, does not promote efficiency by benchmarking the DSOs but, on the other hand, can be argued to give degrees of liberty for DG to be deployed into the system.

Hungary implemented a hybrid price regulation system conformed by a 'cost plus' system, which determines the tariffs at the beginning of the regulatory period, and an RPI-X (price cap) system that sets discounts within the given period. As UoS charges are uniform across DSOs representing averaged costs, DSOs that provide distribution cheaper than the average are rewarded. Also, a DSO can improve its profitability within a four-year cycle by reducing cost over time or by increasing sales (and thereby reducing unit costs). Two aspects of the regulatory system can provide DSOs incentives to use DG. The existence of three quality benchmarks - annual number of average outages (averaged over customers supplied), average duration of outages and non-delivered electric energy due to network failures - can encourage DSOs to use DG if they can improve these service parameters. Furthermore, DSOs receive a fixed compensation for network losses, and the use of DG can be an efficient way to reduce them.

In *Poland*, tariffs should cover both 'justified costs' incurred by energy enterprises, including costs associated with modernisation, development and environmental protection, and should also protect consumers against unjustified price levels. That is, tariffs for electricity should protect customers but also ensure the coverage of costs including operating and maintenance costs, depreciation costs, taxes, and costs of capital (debt & equity) based on the rate of return acceptable in infrastructural sectors. Nonetheless, in order to promote efficiency, tariffs since 2002 are determined by an incentive regulation (yardstick) system. Transmission tariffs are adjusted from period to period by a RPI-X adjustment, with X (the efficiency factor) set by the Polish regulator (ERA) every 2 to 5 years.

In *Slovakia*, regulation applied to electricity prices for all consumers is based on a formula that allows distribution companies to transfer any uncontrollable costs (i.e. electricity purchase, including transmission and balancing charges) to consumers, while limiting controllable costs (operational expenditures, depreciation and adequate profit) through inflation of consumers prices and anticipated efficiency improvements (RPI-X system). At the end of the regulatory period, the authority performs tariff revisions, determines new costs for electricity delivery and makes tariff adjustments accordingly to be used as a basis for subsequent regulatory periods.

5.2.4 Summary of network regulation

The previous section showed that there are considerable differences in the types of network regulation in the Member States under which DG has to operate:

- The type of network connection charge influences the upfront connection costs for the DG operator. In Denmark, Germany, Hungary, Italy and the Netherlands, most DG operators face shallow connection charges.
- In the UK, all grid extensions costs are allocated to DG operators and in the Czech Republic, Poland and Slovakia DG operators practically face deep connection costs (they have to cover at least part of the grid extensions).
- Some circumstances can form an additional barrier to the connection of DG, such as negotiated connection costs in Italy and the possibility for the DSO in Slovakia to include specific technical connection requirements for DG operators.

- Use of System charges are generally paid by consumers only. In Italy DG operators pay for the use of the distribution network, in Denmark and the UK only large generators pay UoS charges.
- Except for covering transport and system services, UoS may also cover a component that includes connection costs that are not completely covered through connection charging. This is the case in Denmark and, indirectly, also in Germany. Thus, UoS charges may form the vehicle by which the operation of the electricity system is paid for in a socialised manner.
- In countries with shallow connection charges the incentives for DSO connecting DG into the network remains a problem. The most straightforward incentive is an obligation (as applied in Denmark and Germany). A performance based regulation system as now applied in the Netherlands may be beneficial for DG in some cases. With deep connection charges, such as in the UK, DSOs should not have a problem with connecting DG. However, when their activities are only benchmarked on the basis of cost efficiency or when they charge UoS on the basis of kWh's exported, then the integration of DG brings no additional benefits to the DSOs.
- Some charging systems enable the connections to consumers and operators to be included in the regulatory asset base. When the DSO's UoS charges are derived from this RAB, then this may provide an additional incentive to connect DG to the network.
- Price control and benchmarking of DSOs is yet mainly taking place on the basis of cost-effectiveness and provides therefore little incentives to connect DG. A system with a performance benchmark, such as the yardstick system in the Netherlands, can present a first step in DSO incentivisation.

6. INTEGRATION WITH SUSTELNET BENCHMARKING RESULTS

In this chapter we compare the results of the benchmarking exercise of ENIRDG-net with those results of the SUSTELNET project. Next, the results will be integrated to be able to draw conclusions and to formulate policy recommendations.

6.1 Results of ENIRDG-net benchmarking

The seven countries studied can be grouped according to the RES, CHP and DG share.

Table 6.1 *DG shares in the countries studied in ENIRDG-net*

Country	RES Share [%]	Small-scale RES [%]	CHP share [%]	DG share [%]	DG market presence
Austria	70	10	10	~20	Medium
Belgium	2	0.5	6	~5	Low
Finland	28	~5-10	34	~25	Medium
France	15.7	2	2	4	Low
Ireland	5	2.1	2	4	Low
Spain	16	9.1	12.5	16.5	Medium
Sweden	61	~5-10	7	~15	Medium

None of the countries has yet a DG share that exceeds the 30% level defined for a high DG penetration. The high RES level in countries like Austria and Sweden mainly includes a high share of large hydropower plants.

6.1.1 Cross country comparison for network regulation

A score list has been drawn of the outcomes of the benchmarking exercise. This has lead to the following results presented in Table 6.2 below. So far, this score-list has not lead to results that could be used for drawing conclusions and making policy and regulatory recommendations. For this reason, the scores have been illustrated as being positive (+), neutral (0) or negative only (-) instead of differentiating by numbers (e.g. +1, +2, etc.). A similar problem has been found when analysing the results from the SUSTELNET benchmarking exercise (see discussion section 6.3). Findings from SUSTELNET show that high ranking in the field of network regulation does not necessarily mean a high level of DG and vice versa. Nevertheless, a positive or negative score can be an indication of the progress in network regulation so far.

Table 6.2 *Results from the evaluation of the ENIRDG-net benchmarking*

ENIRDG-net	AT	FI	ES	SE	BE	FR	IE
A- Legal framework for DG	+	+	+	-	-	+	+
B- DG-DSO relationship	+	0	+	+	-	0	--
C- Legal framework for DSO	--	-	0	+	-	-	-
D - Market presence	Med	Med	Med	Med	Low	Low	Low
E - Market access	+	0	0	-	+	++	+

6.1.2 Explanation of scores per country

Austria - medium DG level

Network regulation in Austria includes some favourable elements for DG operators, scoring positively in (A). Regarding the DG-DSO financial relationship (B), Austria includes some positive elements regarding standardised network tariffs and authorisation procedures. In the field of DSO regulation, Austria is lagging behind, causing negative scores. The support mechanisms under (E) yield a positive score, although the support provided for certain RES is relatively high with regard to the level playing field objective. The overall positive score is due to the establishment and access of DG to the electricity market.

Finland - medium DG level

Finland has some favourable elements in the field of DG regulation (A), leading to a positive score similar to Austria. The final score for the DG/DSO financial relationship (B) is neutral due to the power of DSOs to determine network tariffs, which presents a powerful position for DSOs compared to DG operators. The negative score in (C) is caused by the uncomplete unbundling of DSOs in Finland. The existence of performance standards for DSOs makes the score in (C) only slightly negative. Market access (E) scores neutral, temporary support is available, but the access of DG to the market is not yet sufficient.

Spain - medium DG level

In the field of DG regulation Spain has a neutral score, as some favourable elements are present but others are not. A slightly positive score was found in (B) due to favourable connection charging and the way some benefits of DG are taken into account. The DSO regulation can be considered as neutral, legal unbundling is in place, but no incentivisation. Spain has an extensive system of support mechanisms, but due to their long duration and relatively high tariffs (in % of market prices), it promotes DG in such a way that the balance is titled too much in favour of DG to create a real level playing field. This causes the overall neutral score in market access (E).

Sweden - medium level DG

Legislation in Sweden is not (yet) favourable for DG, causing the slightly negative score (A). A slightly positive score under B due to favourable connection charging and the possibility to reward DG benefits. Sweden is the only country that scores positive under (C), due to legal unbundling of DSOs and the existence of performance standards for DSO revenue. Market access for DG (E) does not lead to a positive score, however, due to the limited support mechanisms in place and limited access of DG to the wholesale market.

Belgium - low level of DG

Too little information was available for Belgium to make a good judgement. Only market access (E) could be analysed yielding a positive score. This is caused by the fact that the support system in place tilts the level playing field in favour of DG which is valued positively with the relatively low level of DG in Belgium.

France - low level DG

The regulatory framework for DG is slightly positive (A), the DG-DSO relationship (B) is neutral, DSO regulation is still in development. The support mechanisms in place seem to be appropriate to enable market access (E) of DG in France, the score here is high. Due to the low level of DG tilting the level playing field in favour of DG is valued positive (in contrary to countries with a high level of DG).

Ireland - low level of DG
Ireland scores slightly positive under (A) legal procedures for DG. The DG-DSO relationship yields a negative score, as deep connection charges are viewed negative in countries with low DG, and no mechanisms are in place to allocate specific DG benefits. Lack of any favourable DSO regulation also results in a negative score under (C).

Market access conditions are so far favourable in Ireland, resulting in a positive score (E). The remark has to be made that the Irish support mechanisms are under review and it is not certain how favourable the new mechanisms for DG will be.

6.1.3 Comments to the results

The results presented so far will have to be taken with some caution. First off all, for some countries the information that has been presented is slightly incomplete (e.g. Belgium, Sweden) and that makes the score list less suitable for drawing conclusions. A few other issues:

- Paradoxically, France scores rather well in market access, although the level of DG is still low. This might be caused by the fact that the type of support mechanisms in place in France is, according to the methodology, suitable for a niche-market situation.
- The way of assessing issues like authorisation procedures is difficult, especially giving a certain quantitative judgement to a given situation.
- Some scores are slightly arbitrary as it is difficult to present a scale against which to make the assessment.
- The predominantly negative scores in (C) are caused by lack of incentives for DSOs and the absence of any (performance) based benchmarking.

6.2 Results of SUSTELNET benchmarking

Table 6.3 summarises all the results of the SUSTELNET benchmarking exercise to 3 separated categories (Boccard, 2004). Within this research positive and negative scores, based on the tables in Chapter 3, have been summed leading to these results. The project team has chosen not to give a certain score to the market presence level, as this may be influenced by completely other factors than network regulation.

Of the nine countries studied in SUSTELNET, only Denmark is included in the category of countries with a high DG share (more than 30%). Five countries, the Czech Republic, Germany, Netherlands, Poland and Slovakia have a medium share of DG (between 10 and 30%). Three countries, Hungary, Italy and the United Kingdom have a low DG share (below 10%).

Table 6.3 *Results from the evaluation of the SUSTELNET benchmarking*

SUSTELNET	DK	CZ	DE	NL	PL	SK	HU	IT	UK
A- Legal framework for DG	-2	4	3	3	-1	-1	4	-1	0
B- DG-DSO relationship	-1	2	-3	-1	-1	-3	2	0	-3
C- Legal framework for DSO	-2	-5	-5	-1	-3	-1	-1	-5	-1
D - Market Presence	High	Med	Med	Med	Med	Med	Low	Low	Low
E - Market Access	-2	-1	-1	3	1	1	0	1	1

6.2.1 Explanation of scores per country

Denmark - High DG Group

The Danish regulatory system tilts the playing field in favour of DG both in terms of market access and in terms of regulation of the DSO. While the system may be well suited for getting more DG into a power system with low current penetration of DG, it is badly suited for the Danish power system where already 36% of production comes from DG. This is reflected in the negative scores for all four categories.

The Danish regulatory system would have received high marks with a low level DG penetration, but in the SUSTELNET project it has been concluded that for countries with a high level DG penetration both market access (E) and DG-DSO regulation (B) should create a level playing field for DG based on economic efficiency. For example market access for DG should be on the same terms that central generation faces.

Czech Republic - Medium DG group

The Czech Republic cares for its DG operators since the law addresses the main concerns of the level playing field; however it has not provided DSOs with a similar legal framework (C). The market participation suffers from durable and large support mechanisms that ought to be only temporary given the already high level of DG penetration in the country. DG-DSO regulation includes more good points that bad ones and scores acceptably (B).

Germany - Medium DG group

Germany took a great care of DG since it score positively on (A) but neglected the DSO's regulation as the score on DG-DSO relationship (B) and DSO regulation (C) are quite low. Market access (E) incorporates a number of well-known impediments yielding another low score. Another run of the benchmarking in one year could yield much higher scores once a proper regulator will have been set-up.

The Netherlands - Medium DG group

The Netherlands appears to favour DG operators since it scores positively on (A) like Germany or the Czech Republic. The governmental involvement through updated laws and a strong regulatory body yield better scores than Germany for DG-DSO regulation (B) and DSO regulation (C). Market access fares quite well due to some degree of openness and lighter support mechanisms than in the neighbouring Germany.

Poland - Medium DG group

The market access seems the most promising element in the Polish approach since it involves limited market power and no heavy support mechanism. Yet the weak legal framework of DG might be an impediment to DG expansion in the absence of other support. Finally the DG-DSO relationship and more crucially, the legal framework of DSOs remain lagging behind the developments seen in other countries.

Slovakia - Medium DG group

The current market design seems appropriate for the future development if market concentration can be reduced. However, all regulatory settings score negatively indicating that efforts remain to be applied especially for the DG-DSO regulation.

Hungary - Low DG group

As compared to UK and Italy, the other countries in the low DG group, an impressive best score is achieved for the regulation of DG. The network cost setting (B) is also better handled than elsewhere, probably due to its novelty that has enabled to incorporate best practices. The remaining fields perform honourably.

Italy - Low DG group
The best score is achieved for market participation not so surprisingly given the delay taken by Italy to liberalize its electricity market; it has build on successful foreign experiences to make a good start. Italy scores neutral on DG-DSO regulation (B) but very badly on DSO regulation (C) given the role played by the dominant market player ENEL. This does not mean that Italy will not develop DG but if it does, ENEL is expected to play a key, a context that has not been explicitly considered by the SUSTELNET level playing field vision.

United Kingdom - Low DG group
The best score is achieved for market participation which is no surprise given the traditional UK emphasis on building efficient markets. Regulation of DG achieves a neutral score while DG-DSO relations (B) and DSO regulation (C) score negatively.

6.2.2 Conclusion

- Paradoxically, the country with the highest level of DG penetration, Denmark, receives relatively low marks for its regulatory regime. The Danish regulatory regime was (successfully) used to achieve the policy objective of achieving a higher level of DG in the power system. However, this benchmarking study shows that Denmark has failed to adjust its regulatory regime to a situation where DG is a major market player, and where DG should be included in the market on terms that induce efficiency. It must be stressed that the criteria used for high levels of DG penetration are more stringent than for low levels.
- Conversely, countries with low levels of DG presence fare rather well (except Italy-C) for the reason explained above.
- As a general result NAS (Newly Associated States)[13] outperform older EU member states since their relatively recent implementation of electricity law has closely followed the EU directives. It is obvious that differences in scores are strongly affected by the number of questions addressing separate issues. E.g. different levels of unbundling creating large differences in Item C.
- The last item of the questionnaire, the legal framework for the DSO under C, showed that the legal framework for DSOs in all the MS/NAS seems not to incentivised the DSO in such a way that it would favour DG.
- To conclude, this report is only a first step towards a systematic benchmarking board where item weights and finer valuation will have to be subject for further research.

6.2.3 Comments to the results

Is has not been possible to draw any general conclusions from the benchmarking exercise of SUSTELNET. The numbers presented in Table 6.3 do not speak for themselves and can therefore not be interpreted exactly. This is mainly caused by the fact that the successful deployment of DG in some of the SUSTELNET countries was caused by completely other factors than the regulatory environment that was assessed in the benchmark. A good example is the ‘Danish paradox’, a high level of DG in the Danish power system but no regulatory framework that is adapted to this situation and is still treating DG as being part of a protected niche-market.

Another issue that influences the integration of DG is the role of intermittent resources. Controllable and non-controllable DG sources create different values to the distribution network. This has not been taken into account, as it was difficult to give a certain weight to intermittent/non-intermittent resources.

[13] In SUSTELNET originally the Candidate Countries Czech Republic, Poland, Slovakia and Hungary and since May 1, 2004 new Member States.

The SUSTELNET benchmarking exercise provided a first methodological approach for benchmarking DG network regulation. Is this is still a methodology in development, there should not be to much emphasis on the results. It has also been difficult, or even impossible to compare network regulation with support schemes. This requires a separate study.

7. CONCLUSIONS AND RECOMMENDATIONS

7.1 Conclusions

This study has analysed the existing policy and regulation aimed at the integration of DG in electricity supply systems in the European Union. It illustrates the state of the art and progress in the development of support mechanisms and network regulation for DG. Through a benchmark study a comparison has been made of DG support schemes and distribution network regulation. This benchmark study, systematically compared the DG policy and regulation to the achievable standard, a level playing field. This level playing field has been defined as the situation where energy markets, policy and regulation provide neutral incentives to central vs. distributed generation.

In current regulation and policy a certain discrepancy can be noticed between the actual regulation and policy in a number of countries, the medium to long term targets and the ideal situation described according to the level playing field objective.

The integration of DG and reaching the level playing field is influenced by both support mechanisms for DG as the network regulatory framework. Support schemes such as feed-in tariffs can help certain DG sources to penetrate into the energy market at all. This way they can overcome a number of barriers, such as the upfront investment, access to the energy market and the connection to the network. When reaching a certain level or market share, however, these support schemes should be adapted to prevent distortion of the market. Market based instruments should replace feed-in tariff systems and other instruments that are mainly designed to protect DG niche markets.

The following network regulatory issues influence the level playing field:

- The system of network connection charging should be developed in such a way that costs and benefits of DG connection can be optimally allocated to the right party. In practise this means neither the use of shallow connection charging nor deep connection charging. The charging system identified in SUSTELNET, shallow connection charging including a locational signal may be more optimal to allocate costs & benefits of new grid connections.
- Use of System charges, paid for by consumers and/or generators, are important revenue streams for DSOs. When UoS charges are (partly) covered by producers, their way of calculation can influence the integration of DG. When DSOs set the UoS charges, they may be only interested in their own revenue streams thereby possibly hindering the integration of DG. Whether UoS charges are based on kW connected or kWh transported may also influence the benefits of connecting DG.
- Allocation of ancillary services and other system benefits. In some countries, power generators (including DG) can receive compensation for certain system services. This leads to a more equal position of DG in the electricity market, a fairer allocation of network costs and benefits and in a number of cases an additional revenue stream for DG operators.
- Setting of connection charges and UoS charges by a more independent party such as the regulator increases the possibility of a fair treatment for DG in the electricity network system.

The ENIRDG-net benchmark study analysed the policy and regulatory framework for DG in seven European countries, namely Austria, Belgium, Finland, France, Ireland, Spain and Sweden. These results were compared to the results for nine other countries carried out in the framework of the SUSTELNET project, being Denmark, Germany, Italy, the Netherlands, United Kingdom, the Czech Republic, Hungary, Poland and Slovakia.

From both benchmark studies, the following could be concluded about support mechanisms:

- Difference between countries in type of instruments used. In some cases, support mechanisms are adapted to the position of DG in the market, but in some cases feed-in tariffs exist in countries that already have a relatively high DG share (Denmark, Germany, Spain). Other countries have recently introduced market-based mechanisms, such as green/CHP - certificates, although DG share remains low (e.g. Belgium, United Kingdom).
- Protecting DG in a niche-market when its share is already relatively high may not be cost-effective for the power system in the long-term. A number of countries recognised the need to make their support schemes more cost-effective at higher DG levels:
  - Spain has made a first step in transforming the support system by giving DG operators the choice to choose between fixed feed-in tariffs or a fixed premium on top of the market price.
  - Belgium is gradually moving from feed-in tariffs to a green/CHP- certificate system, recognising the need of a market based approach. In Sweden, only a temporary feed-in system exists for wind power, recognising the need for a temporary 'tilting' of the level playing field in favour of certain types of DG.
  - Denmark and Germany have made necessary adaptations in their support systems, but DG remains part of a protected niche market.
  - The Netherlands has introduced a 'hybrid' support system for RES with a combination of feed-in tariffs and green certificates. Although the long-term objective is to create a market-based system, these measures have not yet been sufficient in properly promoting new RES capacity.

The following could be concluded after assessment of the network regulatory framework:

- Different systems of connection charging exist. In most cases no pure shallow or deep connection charges exist but a certain mixture of both. In for example Austria and Finland, the DSO has the possibility to choose between shallow and deep charging, based on the available capacity of the grid. This makes it possible to allocate grid costs to the proper party (the DG operator wishing to be connected).
- UoS charges are generally paid by consumers, but some countries have also introduced them for centralised generation. DG is generally exempted from paying UoS charges. Therefore, within the current regulatory framework, there is little possibility to allocate specific network costs and benefits through the UoS charges.
- Another function of UoS charges that are paid by consumers is recovery of additional network costs when shallow connection charges are in place. This is a form of socialising additional network costs.
- Connection and UoS charges are set by different parties; by government (through decrees), the energy market regulator or the DSO. All have their advantages and disadvantages. Connection and UoS charges are more likely to be set independently by government or regulator, although when set in decrees, any changes may be time-consuming. DSOs, when having the authority to set these charges, may be more suitable to determine the optimal tariff level, but supervision of a regulator will be required to prevent any bias against DG from the side of the DSO and to assess whether only the costs required for connection or network use are charged.
- So far incentivisation mechanisms for DSOs are practically non-existent. The Netherlands are so far the only country that have introduced performance criteria for DSOs through a yardstick system.
- Benchmarking of DSOs is mainly based on cost-efficiency rather than on performance or innovation criteria. This does not yet motivate DSOs to innovate their networks, a precondition for effective large-scale integration of DG.

7.2 Recommendations for DG policy and regulation

Based on the results of the SUSTELNET and ENIRDG-net projects a number of policy recommendations can be formulated for the development of a more DG-friendly energy policy and network regulation.

When drafting new policy for DG on national and/or EU level, the following elements of policy and regulation are important when striving towards a level playing field:

- Ensuring non-discriminatory network access for DG, which is a key precondition to a level playing field between centralised and distributed generation.
- Market access of DG includes in the first place access to the wholesale electricity market. When this is achieved the scope of market access should be broadened to include ancillary services.
- The newly developed markets for ancillary services should be opened to distributed generators. In particular services related to balancing and power quality such as, reliability, reactive power and voltage support should be considered in this respect.
- DSOs should be given more flexibility in sourcing these ancillary services to meet their service obligations to their connected customers.
- The benefits and cost of distributed generation to the electricity system are directly related to the geographical point of connection. It is therefore considered fair that these costs and benefits are somehow reflected in the UoS charges and electricity pricing to the distributed generator.
- To facilitate the integration of DG in electricity networks DSOs have to endorse 'active network management'. This active network management entails investment in innovations to improve network management, in particular in the field of ICT. The current regulatory frameworks often do not stimulate or allow for DSOs to recover the cost of investments in innovation.
- This requires a change in the regulatory framework related to DSOs, meaning that not only cost-efficient management of networks should be rewarded, but also the willingness to invest in innovations.
- In view of the required innovations in network management EU and national policies should also seek to stimulate the exchange of knowledge in the field of DSO incentivisation and innovation in distribution networks.

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GLOSSARY

Active networks	Concept of future networks, enabling two-way transport of electricity and local control of network parameters.
Ancillary services market	Market for electricity network services related to power quality, sometimes including balancing services.
Balancing market	Market for short-term electricity services for maintaining the balance in the electricity grid between supply and demand.
Benchmarking	Systematic comparison of certain processes or institutions against one of recognised excellence.
CAPEX	Capital expenditures, such as investments in installations and grid connection.
Day-ahead market	Market where a commodity (here electricity) is traded up to a day in advance.
Deep connection charges	Charges that require to pay not only for the cost of the local connection but also for the incremental investment made on the wider system to accommodate the additional generating capacity or load.
Distributed Generation	Power generation, usually by use of CHP our RES sources connected to the distribution network (below 150 kV) or on the customer side of the network.
Distribution System Operator	Operator of the distribution network (150 kV and lower voltage lines).
Electricity Regulator	Independent state institution responsible for the operation of the electricity market.
Intermittent production	Power production with little or no controllable power output, such as wind power, depending on weather conditions.
Level playing field	Situation where all actors (in this case actors on the energy market) have equal incentives to carry out their activities.
OPEX	Operational expenditures.
PPA	Power purchase agreement, usually between producer and consumer, or between producer and energy supplier.
Price/revenue cap	Prices, tariffs or revenues capped to a certain maximum by a regulator or other government institution.
Priority dispatch	Priority access to the network.
Regulatory asset base	Assets (of a network) covered under a certain type of regulation.

Shallow connection charges	Connection charge covering only the actual connection of an electricity consumer or generator to the existing network.
Tradable green certificates	Certificates representing a certain amount of produced RES electricity that are tradable between energy suppliers/producers. A green certificate system may include quota, meaning that each supplier producer must produce a certain percentage of RES electricity or purchase certificates from other actors having a RES-E surplus.
Transmission System Operator	Operator of the (national) transmission network (above 150 kV lines).
Use of System charges	Charges for transport and system services, paid per kWh and/or per kW. Usually separated into two components, a transport and a system service charge.
Wholesale market	Main marketplace for the commodity electricity.

ANNEX A COMPLETE ENIRDG-NET BENCHMARKING RESULTS

A.1 Market presence (D)

This part provides some background information about the presence of DG in EU MS electricity systems. Three market levels for DG presence are distinguished, low (<10% share), medium (10 - 30% share) and high (>30% share). It may be difficult to calculate/estimate the share of DG in your country as most statistics only distinguish between type of source (fossil fuel, nuclear, RES) and not the voltage level of connection or the size.

Table A.1 *Market presence*

#	Cat	Question	Austria [%]	Belgium [%]	Finland [%]	France [%]	Ireland [%]	Spain [%]	Sweden [%]
34	D	Current share of CHP+RES in national electricity consumption [%][14]	RES total – 70 Small scale RES 10 CHP 10	RES 1.9 CHP 6	CHP 34 RES 28 (not all DG) → DG share 25	RES 15.7 (incl. large hydro) small hydro 2 CHP 2	DG share about 4 (total CHP +RES 8)	RES + waste 16 CHP 12.5 DG makes 16.5	RES 61 CHP 7 (some RES in CHP) DG makes 15-20%
35	D	If available, share of large scale facilities in previous figure (#34)	~ 60		45		Large -scale hydro: 2.9		Hydro 46
36	D	Expected DG share in 2010 based on actual developments	Goal 2008: Small hydro 9 Wind 4 Biomass 2 Other 2-3		Increase expected, no numbers available	Small RES 8 CHP 4-6	National target of 13.2 will be met	23	RES potential 63
37	D	RES objective for 2010-12 (EU commitment) for electricity	78.1	6	31.5	21	13.2	29.4	60
38	D	Share of intermittent electricity in production[15]	0.58		0.1 (wind)	240 MW wind (in 2010 up to 10)	2	3.45	0.4 (wind)

14 Please use the most recent statistical data (2002 or 2003).
15 For intermittent electricity provide the share of wind energy production in total power production. Wind energy is variable over short time, and can therefore influence short-term balancing of supply and demand.

#	Cat	Question	Austria [%]	Belgium [%]	Finland [%]	France [%]	Ireland [%]	Spain [%]	Sweden [%]
39	D	Within 5 years, previous figure (#38) is expected to increase or decrease?	Increase in GWh, share 3.5 (2007)		Increase (2010 target 1.1)	To significantly increase	Increasing rapidly (to 9)	Increase to at least 7	Increase

A.2 Market Access (E)

The questions selected to assess market participation are gathered in the table below. Our benchmarking study distinguishes three levels of market participation for distributed generation: as a protected commodity (low), often backed by support mechanisms, as a participant in the wholesale market (medium) and finally as a participant in the balancing and reserve market (high). This is not a quantitative distinction, but a qualitative one. Once the DG operators have left the stage of a protected commodity, they become full participants in the wholesale market but still rely on the DSOs and TSO in a regulated way for ancillary services; they are not yet allowed to participate in secondary markets for adjustments and reserves. The last stage of market evolution is the possibility for DG operators to buy and sell ancillary services in a dedicated market (probably of a local nature). The questions below aim to gain a picture of the access of DG on different markets and the role support schemes still have in promoting DG.

Table A.2 *Market Access*

#	Cat.	Question	Austria [%]	Belgium [%]	Finland [%]	France [%]	Ireland [%]	Spain [%]	Sweden [%]
40	E	Describe current support mechanism for DG in place	Feed-in tariffs for RES.	Feed-in tariffs, tax abatement and investment subsidies. From 2002 tradable green certificates for RES and CHP	Investment support/ energy tax reimbursements	Purchase obligations & conditions, call for tenders from public bodies, fixed rates for various kinds of RES/CHP	Current DG/RES policies under review. Up to now tendering system in place	Feed-in tariffs (fixed price *or* market price plus fixed premium). Investment support schemes	Investment grants, Feed-in tariffs, quota based certificate system for RES
41	E	Duration of the support mechanisms foreseen by law	13 years for RES (approved till 31/12/04, erected till 30/06/06	?	Inv. support up to 2007, Tax reimbursements up to 2006	12 to 20 years, depending on source	New support system will cover period up to 2010	No time limit placed on the system	?
43	E	Support in % of average market price	100 and more	50 – 100	10-30 (tax reimbursement) Incl. all 40-50	20 - 35, depending on source	Price cap for new entrants (20-75).	55 – 97, depending on source	20-40, depending on source
44	E	Wholesale market for energy/electricity established?	Yes	Yes	Yes, Nordpool	Yes	Yes	Yes	Yes, Nordpool
45	E	Does DG have access to wholesale market? And practically?	Theoretically yes	?	Yes, but fees are high for small producers	Yes, but only theoretical	Yes	Yes, theoretically and practically	Practically no

#	Cat.	Question	Austria [%]	Belgium [%]	Finland [%]	France [%]	Ireland [%]	Spain [%]	Sweden [%]
46	E	Does DG have access to ancillary service market?	Only for tertiary control	?	>10 MW	Foreseen by law	No, only centrally dispatched units	Yes	No (?)
47	E	Market form is (related to DG support mechanism)?[16]	Balance group model (SE)	?	Pool, bilateral	Other	Bilateral, pool from 2006	Pool and bilateral contracts	Pool, bilateral
48	E	Concentration in the energy market is[17]?	Low	High	High (prod.). medium (distr.)	High	Low	High	High

[16] Energy market form can be for example: Pool, Bilateral, Other.
[17] Low, Medium, High.

A.3 Legal/regulatory framework for DG (A)

There are two topics where the legal framework is related to the creation of a level playing field. First are the transaction costs that bear upon the decision to enter the DG market (including authorization for connection and transparency), second is the provision of ancillary services. Closely linked to this last topic is the issue of metering.

Table A.3 *Legal/regulatory for DG*

#	Cat.	Question	Austria	Belgium	Finland	France	Ireland	Spain	Sweden
1	A - I	Has legislation (e.g. energy law) been revised to speed up authorization procedures for building DG units and connecting them to the distribution network?	Special law for RES, not for DG Common rules for connection.	No	Non-discriminatory access. Incentives to lighten procedures, but no legislation.	Yes	No significant delays under current procedures	No	No
2	A - I	Same question for CHP (in case there is any difference)				Yes	Same as above		?
3	A - I	Does the law foresee publication of DSO technical and (connection) cost-sharing rules?	Yes	Yes	No, only recommendation	Yes	Distribution code published, connection charges controlled by regulator	Yes	
4	A - I	Does the law mention non-discrimination of RES and/or CHP with respect to provision of ancillary services?[18]			No	Yes	Not specifically	No, but advantages in some services	
5	A- II	Who provides ancillary services? E.g. TSO, DSO or also large/DG producers … ?	Prim./Sec. control by balance zone, voltage control grid operator		TSO, DSOs, large producers, large consumers	All of them	Large generators	Ordinary system producers and special system producers	
7	A - II	Is there any project for two-way metering installation?	Demand and supply accounted separate		Yes	No	No (but is studied)	No	Majority of feeding points have two way metering

[18] Only crucial when DG is well integrated into markets.

A.4 DG/DSO Financial Relationship (B)

This section looks at the financial relationships between DG operators and their DSO (Distribution System Operator) from two perspectives, one long term and one short term: the initial connection charge and the charges for using the distribution network (Use of System charges).

Table A.4 *Legal/regulatory framework for DG*

#	Cat.	Question	Austria	Belgium	Finland	France	Ireland	Spain	Sweden
8	B - I	How long has regulated Third Party Access (rTPA) been in force?	19/02/1999		Since 1997	Since 1995	Since February 2000	Since 29/11/1997	Since 01/01/1996
9	B - I	Does the law address the first-comer problem for RES?[19]	Usually no connection problems	No	No, but pricing takes into account c&b of connection	Producer may be reimbursed for part of the investment if the network reinforcement is used for connection of other producers	No	Yes, new producers connected should compensate those producers having financed earlier reinforcements	No
10	B - I	Same for CHP (in case there is any difference)						Same for CHP	
11	B - I	Connection charge is … ? (Shallow/deep connection charge)[20]	DSO states charge depending on capacity grid	Predominantly shallow	Can be both shallow and deep, depends on DSO.	Shallow + reinforcements of the grid of the same voltage level	Reflecting actual costs for the grid, practically deep charges	Shallow if capacity of grid is sufficient, else deep charges	Deep if reinforcement is done for only one customer, else shallow
12	B - I	If #11 = shallow, is the DSO compensated for the difference (deep - shallow)?	Usually grid upgrade costs refunded by grid utilization fee		No	No	-	No	
13	B - II	Structure of Use of System (UoS) charges: capacity and/or energy component?	No discrimination		Depending on DSO, fixed or energy/capacity based	Energy component - producers, energy & capacity -consumers	Energy charges vary with export voltage level	Capacity and energy components	For power plants below 1500 kW only fixed

[19] The Renewables Directive requires MS to set a connection cost compensation scheme for sharing the benefits of connections among all units connected.

[20] **Shallow connection charges** include only the cost of connecting the customer to the nearest point in the distribution network. **Deep connection charges** include any cost of reinforcements of the existing network that have been made necessary by the new customer. In case of shallow connection charges, the financial burden for DSOs could increase excessively and some compensation mechanism should exist (#12).

#	Cat.	Question	Austria	Belgium	Finland	France	Ireland	Spain	Sweden
14	B - II	UoS is initially set by a national authority (e.g., Regulator) or negotiated by association of DSOs and DG operators?	Tariffs are set by the regulator		Set by DSOs, regulator gives recommendation	Set by the government - specified in government decrees	DSO charges set by agreement with regulator	Approved by government (set by DSOs)	DSO sets them, regulator and law give basic guidelines
15	B - II	Is there some leeway for DSO in the application of the UoS[21]?	No, fixed tariffs.		Yes	Yes, sharing of reinforcement costs possible	No	Yes, in connection charges	
16	B - II	Who pays UoS charges (end-users/producers)? (Is there an ability to discriminate sources and sinks)	Producer pays		End-users and producers	End-users/Yes	Both, based on metered energy flows	Paid by the end-users	Both
17	B - II	Is there a compensation scheme for DG network benefits like loss reduction[22]?	No		Can be taken into account in defining UoS charges	Yes, UoS tariff modification possible	No	Compensation for reactive power	Yes, for units below 1500 kW
18	B - II	Existence of a location signal in connection cost or UoS[23]?	Costs independent of location		No	Only based on voltage level	Not on distribution grid	Only based on voltage level	Connection costs can depend on location

21 Flexibility or room for negotiation between DSO and DG for the sharing of connection costs.
22 E.g. this could be a compensation for auto-producers not making use of the network or for DG producers not using the transmission network.
23 This may be a vertical signal (based on voltage level) and/or a geographical signal.

A.5 Legal framework of DSOs (C)

There are two issues deemed fundamental with respect to the legal framework of DSOs for a successful implementation of the level playing field. The first one, long been recognized by the EC, is the unbundling of the various activities that used to perform integrated electricity utilities. The second issue deals with incentives; the DSO is a necessary organizer of electricity distribution and the level playing field, which cannot be achieved without its full participation. For that reason new regulatory mechanisms must be designed and implemented to change the way a DSO perceives its day to-day activity.

Table A.5 *Legal framework of DSOs*

#	Cat.	Question	Austria	Belgium	Finland	France	Ireland	Spain	Sweden
25	C - I	Level of DSO-Supply unbundling (accounting, management, legal, ownership)	Accounting, legal unbundling until 01.07.2005		Accounting	Accounting, management, legal in progress	Legal unbundling complete by Feb 2005	Accounting and legal	Legal
26	C - I	Level of DSO-Generation unbundling (acc, mgt, legal, own)			Accounting	Accounting, management, legal in progress	Legal unbundling complete by Feb 2005	Legal	Legal
27	C - II	Is there any performance standards in the DSO revenue (e.g., link to the regulatory asset base)?			Yes, supervision of reasonableness of pricing	-	None, but service levels are monitored	Linked to the regulatory asset base.	'Network benefit model' where allowed revenue is based on performance of fictive network
28	C - II	Is there any benchmarking of DSOs taking place (actual or planned), building on CAPEX and/or OPEX[24]?	Benchmark studies by regulator		Yes, cost-efficiency model	Controlled by the CRE (regulator)	The DSO's CAPEX and OPEX controlled by CER	No	
30	C - II	How much DG is owned by DSOs?	Small DSOs in remote areas own DG for local supply		None, if not financially separated	Very little	None	None, not allowed	
31	C - II	Is there or will be a national scheme providing optimisation incentive to DSOs ?	No incentives		In development by regulator	-	None	From 2005 low quality of service involves a penalty.	

[24] CAPEX - capital expenditures, OPEX - operational expenditures.